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, 2011

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, TX 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 211,133,404 Class A common units outstanding as of April 28, 2011.

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, 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, 2010.

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,	
	2011	2010
	(unaudited; in millions, except per unit amounts)	
Operating revenue (Note 10)	$2,288.9	$1,931.2
Operating expenses		
Cost of natural gas (Notes 4 and 10)	1,829.5	1,524.2
Environmental costs, net of recoveries (Note 9)	(34.6)	4.6
Operating and administrative	162.5	131.4
Power	35.6	32.3
Depreciation and amortization (Notes 5)	88.4	67.9
	2,081.4	1,760.4
Operating income	207.5	170.8
Interest expense (Notes 6 and 10)	79.4	59.3
Other income	6.0	16.8
Income before income tax expense	134.1	128.3
Income tax expense	2.3	2.2
Net income	131.8	126.1
Less: Net income attributable to noncontrolling interest (Note 8)	14.7	10.7
Net income attributable to general and limited partner ownership interest in Enbridge Energy Partners, L.P.	$ 117.1	$ 115.4
Net income allocable to limited partner interests	$ 96.7	$ 99.2
Net income per limited partner unit (basic and diluted) (Note 2)	$ 0.38	$ 0.42
Weighted average limited partner units outstanding	252.8	235.8

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,	
	2011	2010
	(unaudited; in millions)	
Net income	$131.8	$126.1
Other comprehensive income (loss), net of tax benefit (expense) of $0.5 and $(0.2), respectively (Note 10)	(57.4)	6.5
Comprehensive income	74.4	132.6
Less: Comprehensive income attributable to noncontrolling interest (Note 8)	14.7	10.7
Comprehensive income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 59.7	$121.9

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,	
	2011	2010
	(unaudited; in millions)	
Cash provided by operating activities		
Net income	$ 131.8	$ 126.1
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation and amortization (Note 5)	88.4	67.9
Derivative fair value losses (gains) (Note 10)	16.7	(8.1)
Inventory market price adjustments (Note 4)	—	1.1
Environmental costs, net of recoveries (Note 9)	(34.4)	4.6
Other (Note 14)	(6.8)	(11.8)
Changes in operating assets and liabilities, net of acquisitions:		
Receivables, trade and other	23.4	27.3
Due from General Partner and affiliates (Note 8)	(0.6)	3.1
Accrued receivables	119.6	(42.4)
Inventory (Note 4)	48.4	(1.3)
Current and long-term other assets (Note 10)	1.9	1.7
Due to General Partner and affiliates	0.5	23.4
Accounts payable and other (Notes 3 and 10)	23.4	(2.4)
Environmental liabilities (Note 9)	(90.2)	(2.3)
Accrued purchases	(85.8)	3.1
Interest payable	17.7	32.7
Property and other taxes payable	6.1	(0.9)
Settlement of interest rate derivatives (Note 10)	—	(13.2)
Net cash provided by operating activities	260.1	208.6
Cash used in investing activities		
Additions to property, plant and equipment (Notes 5, 8 and 9)	(181.6)	(189.1)
Changes in construction payables	(6.3)	(26.3)
Other	(1.5)	0.1
Net cash used in investing activities	(189.4)	(215.3)
Cash (used in) provided by financing activities		
Net proceeds from unit issuances (Note 7)	57.1	—
Distributions to partners (Note 7)	(132.0)	(115.2)
Repayment of loan from General Partner (Note 8)	—	(324.6)
Net proceeds from issuances of long-term debt (Note 6)	—	496.1
Net repayments under Credit Facility (Note 6)	—	(765.0)
Net commercial paper borrowings (Note 6)	25.0	274.9
Borrowings from General Partner (Note 8)	2.6	387.8
Contribution from noncontrolling interest (Note 8)	3.2	77.3
Distributions to noncontrolling interest (Note 8)	(21.8)	—
Net cash (used in) provided by financing activities	(65.9)	31.3
Net increase in cash and cash equivalents	4.8	24.6
Cash and cash equivalents at beginning of year	144.9	143.6
Cash and cash equivalents at end of period	$ 149.7	$ 168.2

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	March 31, 2011	December 31, 2010
	(unaudited; dollars in millions)	
ASSETS		
Current assets		
Cash and cash equivalents (Note 3)	$ 149.7	$ 144.9
Receivables, trade and other, net of allowance for doubtful accounts of $2.1 in 2011 and $1.8 in 2010	206.2	171.2
Due from General Partner and affiliates	27.7	27.1
Accrued receivables	562.9	683.7
Inventory (Note 4)	86.3	134.7
Other current assets (Note 10)	54.3	58.3
	1,087.1	1,219.9
Property, plant and equipment, net (Notes 5, 8 and 9)	8,737.6	8,641.6
Goodwill	246.7	246.7
Intangibles, net	273.6	276.4
Other assets, net (Note 10)	59.2	56.4
	$10,404.2	$10,441.0
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Due to General Partner and affiliates	$ 50.9	$ 53.3
Accounts payable and other (Notes 3 and 10)	355.4	289.2
Environmental liabilities (Note 9)	147.8	227.0
Accrued purchases	519.0	596.4
Interest payable	78.0	60.3
Property and other taxes payable	55.2	49.1
Note payable to General Partner (Note 8)	17.4	11.6
Current maturities of long-term debt (Note 6)	31.0	31.0
	1,254.7	1,317.9
Long-term debt (Note 6)	4,804.1	4,778.9
Note payable to General Partner (Note 8)	332.6	335.8
Other long-term liabilities (Notes 9 and 10)	144.8	122.9
	6,536.2	6,555.5
Commitments and contingencies (Note 9)		
Partners' capital (Notes 7 and 8)		
Class A common units (105,454,102 and 104,542,053 at March 31, 2011 and December 31, 2010, respectively)	2,665.3	2,641.0
Class B common units (3,912,750 at March 31, 2011 and December 31, 2010)	65.3	64.9
i-units (17,928,170 and 17,642,711 at March 31, 2011 and December 31, 2010, respectively)	596.7	579.1
General Partner	258.3	256.8
Accumulated other comprehensive income (loss) (Note 10)	(179.1)	(121.7)
Total Enbridge Energy Partners, L.P. partners' capital	3,406.5	3,420.1
Noncontrolling interest (Note 8)	461.5	465.4
Total partners' capital	3,868.0	3,885.5
	$10,404.2	$10,441.0

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

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 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 accounting principles generally accepted in the United States of America 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, 2011 and our results of operations and our cash flows for the three month periods ended March 31, 2011 and 2010. We derived our consolidated statement of financial position as of December 31, 2010 from the audited financial statements included in our Annual Report on Form 10-K for the fiscal year ended December 31, 2010. Our results of operations for the three month periods ended March 31, 2011 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 and the impact of forward natural gas 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, 2010.

Comparative Amounts

We have made reclassifications to the amounts reported in our consolidated statement of cash flows as of March 31, 2010 to conform to our current year presentation. We reclassified $4.6 million from “Other” to “Environmental costs” in our consolidated statement of cash flows for the three month period ended March 31, 2010. We also reclassified $2.3 million from “Accounts payable and other” to “Environmental liabilities” in our consolidated statement of cash flows for the three month period ended March 31, 2010. Additionally, we made a reclassification of $4.6 million from “Operating and administrative” to “Environmental costs” in our consolidated statement of income for the three month period ended March 31, 2010.

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 to be 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 current and 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 take effect of 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,	
	2011	**2010**
	(in millions, except per unit amounts)	
Net income	$ 131.8	$ 126.1
Less: Net income attributable to noncontrolling interest	14.7	10.7
Net income attributable to general and limited partner interests in Enbridge Energy Partners, L.P.	117.1	115.4
Less distributions paid:		
Incentive distributions to our general partner	(18.4)	(14.2)
Distributed earnings allocated to our general partner	(2.7)	(2.4)
Total distributed earnings to our general partner	(21.1)	(16.6)
Total distributed earnings to our limited partners	(130.9)	(118.3)
Total distributed earnings	(152.0)	(134.9)
Overdistributed earnings	$ (34.9)	$ (19.5)
Weighted average limited partner units outstanding	252.8	235.8
Basic and diluted earnings per unit:		
Distributed earnings per limited partner unit[1]	$ 0.52	$ 0.50
Overdistributed earnings per limited partner unit[2]	(0.14)	(0.08)
Net income per limited partner unit (basic and diluted)	$ 0.38	$ 0.42

(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 $17.3 million at March 31, 2011 and $28.9 million at December 31, 2010 are included in "Accounts payable and other" on our consolidated statements of financial position.

4. INVENTORY

Our inventory is comprised of the following:

	March 31, 2011	December 31, 2010
	(in millions)	
Materials and supplies	$ 2.2	$ 6.3
Crude oil inventory	16.6	8.1
Natural gas and NGL inventory	67.5	120.3
	$86.3	$134.7

The "Cost of natural gas" on our consolidated statement of income for the three month period ended March 31, 2010 includes charges totaling $1.1 million 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, 2011	December 31, 2010
	(in millions)	
Land	$ 35.7	$ 35.7
Rights-of-way	518.6	510.9
Pipelines	6,026.8	5,981.6
Pumping equipment, buildings and tanks	1,360.6	1,306.9
Compressors, meters and other operating equipment	1,495.8	1,477.8
Vehicles, office furniture and equipment	200.8	201.6
Processing and treating plants	438.4	438.3
Construction in progress	460.4	401.9
Total property, plant and equipment	10,537.1	10,354.7
Accumulated depreciation	(1,799.5)	(1,713.1)
Property, plant and equipment, net	$ 8,737.6	$ 8,641.6

6. DEBT

Credit Facilities

Our credit facilities consist of our $1,167.5 million Second Amended and Restated Credit Agreement, or Credit Facility, and our $350 million unsecured senior revolving credit agreement. The two credit agreements, which we collectively refer to as the Credit Facilities, provide an aggregate amount of $1,517.5 million of bank credit to support our commercial paper program.

Effective March 31, 2011, our Credit Facilities were 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 Credit Facilities, to increase from $450 million to $550 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, 2011 we were in compliance with the terms of our financial covenants.

The amounts we may borrow under the terms of our Credit Facilities are reduced by the principal amount of our commercial paper issuances, if any, and the balance of our letters of credit outstanding. At March 31, 2011, we could borrow $577.4 million under the terms of our Credit Facilities, determined as follows:

	(in millions)
Total credit available under Credit Facilities	$1,517.5
Less: Amounts outstanding under Credit Facilities	—
Principal amount of commercial paper issuances	910.0
Balance of letters of credit outstanding	30.1
Total amount we could borrow at March 31, 2011	$ 577.4

Individual borrowings under the terms of our Credit Facilities generally become due and payable at the end of each contract period, which is typically a period of three months or less. We have the option to repay these amounts on a non-cash basis by net settling with the parties to our Credit Facilities, which we accomplish by contemporaneously borrowing at the then current rate of interest and repaying the principal amount due. We net settled borrowings of $915.0 million for the three month period ended March 31, 2010, 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 $1 billion of commercial paper that is supported by our Credit Facilities. We access the commercial paper market primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions when the available interest rates we can obtain are lower than the rates available under our Credit Facilities. At March 31, 2011, we had $910.0 million of commercial paper outstanding at a weighted average interest rate of 0.38%, excluding the effect of our interest rate hedging activities. At December 31, 2010, we had $885.0 million of commercial paper outstanding at a weighted average interest rate of 0.44%, excluding the effect of our interest rate hedging activities. At March 31, 2011, we could issue an additional $90.0 million in principal amount of commercial paper under our commercial paper program. The commercial paper we can issue is limited by the credit available under our Credit Facilities.

We have the ability and intent to refinance all of our commercial paper obligations on a long-term basis through borrowings under our unsecured, long-term Credit Facilities or permanent financing through the issuance of term debt or additional limited partner interests. 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 on our Credit Facilities approximate their fair values at March 31, 2011 and December 31, 2010 due to the short-term nature and frequent repricing of these obligations. The fair value of our outstanding commercial paper and borrowings on our Credit Facilities are included with our long-term debt obligations below since we have the ability to refinance the amounts on a long-term basis. The approximate fair values of our long-term debt obligations are determined using a standard methodology that incorporates pricing points that are obtained from independent, third-party investment dealers who actively make markets in our debt securities. We use these pricing points to calculate the present value of the principal obligation to be repaid at maturity and all future interest payment obligations for any debt outstanding.

	March 31, 2011		December 31, 2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Commercial Paper	$ 910.0	$ 910.0	$ 884.9	$ 884.9
9.150% First Mortgage Notes	31.0	32.9	31.0	33.5
7.900% Senior Notes due 2012	100.0	110.6	100.0	112.1
4.750% Senior Notes due 2013	199.9	211.8	199.9	214.4
5.350% Senior Notes due 2014	200.0	219.0	200.0	221.8
5.875% Senior Notes due 2016	299.8	334.0	299.8	338.1
7.000% Senior Notes due 2018	99.9	117.7	99.9	119.2
6.500% Senior Notes due 2018	398.5	457.0	398.5	463.0
9.875% Senior Notes due 2019	499.9	688.2	499.9	699.1
5.200% Senior Notes due 2020	499.8	522.3	499.8	526.6
7.125% Senior Notes due 2028	99.8	120.3	99.8	121.7
5.950% Senior Notes due 2033	199.7	206.7	199.7	209.0
6.300% Senior Notes due 2034	99.8	107.0	99.8	108.2
7.500% Senior Notes due 2038	399.0	487.4	398.9	493.0
5.500% Senior Notes due 2040	398.5	367.8	398.5	371.6
8.050% Junior subordinated notes due 2067	399.5	426.6	399.5	408.5
Total	$4,835.1	$5,319.3	$4,809.9	$5,324.7

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 unit split of our common and i-units outstanding to unit holders of record on April 7, 2011. The following table sets forth the number of units outstanding immediately prior to and following the split of our common and i-units:

Shares	Pre-split Units Outstanding	Post-split Units Outstanding
Class A common units	105,566,702	211,133,404
Class B common units	3,912,750	7,825,500
i-units	17,928,170	35,856,340

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, 2011.

Distribution Declaration Date	Record Date	Distribution Payment Date	Distribution per Unit[(1)]	Cash available for distribution	Amount of Distribution of i-units to i-unit Holders[(2)]	Retained from General Partner[(3)]	Distribution of Cash
		(in millions, except per unit amounts)					
January 28, 2011	February 4, 2011	February 14, 2011	$1.0275	$150.5	$18.1	$0.4	$132.0

(1) Distributions per unit are presented prior to the two-for-one split of our units.

(2) We issued 285,459 i-units, on a pre-split basis, to Enbridge Management, the sole owner of our i-units, during 2011 in lieu of cash distributions.

(3) 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 period ended March 31, 2011. The noncontrolling interest in the OLP arises from the joint funding arrangement with our General Partner and its affiliates to finance construction of the U.S. portion of the Alberta Clipper crude oil pipeline and related facilities, which we refer to as the Alberta Clipper Pipeline.

	For the three month periods ended March 31,	
	2011	2010
	(in millions)	
General and limited partner interests		
Beginning balance	$3,541.8	$3,803.4
Proceeds from issuance of partnership interests, net of costs	58.7	—
Capital contribution	—	1.9
Net income	117.1	115.4
Distributions	(132.0)	(115.2)
Ending balance	$3,585.6	$3,805.5
Accumulated other comprehensive income (loss)		
Beginning balance	$ (121.7)	$ (74.6)
Net realized losses on changes in fair value of derivative financial instruments reclassified to earnings	18.8	9.9
Unrealized net loss on derivative financial instruments	(76.2)	(3.4)
Ending balance	$ (179.1)	$ (68.1)
Noncontrolling interest		
Beginning balance	$ 465.4	$ 341.1
Capital contributions	3.2	77.3
Comprehensive income:		
Net income	14.7	10.7
Distributions to noncontrolling interest	(21.8)	—
Ending balance	$ 461.5	$ 429.1
Total partners' capital at end of period	$3,868.0	$4,166.5

Equity Distribution Agreement

In June 2010, we entered into an Equity Distribution Agreement, or EDA, for the issue and sale from time to time of our Class A common units up to an aggregate amount of $150.0 million. The EDA allows us to issue and sell our Class A common units at any time from the execution date of the agreement through January 28, 2012 at prices we deem appropriate for our Class A common units. The issue and sale of our Class A common units can be conducted on any day that is a trading day for the New York Stock Exchange, unless we have suspended sales under the EDA.

The following table presents the net proceeds from our Class A common unit issuances, pursuant to the EDA, during the three month period ended March 31, 2011:

Three Month Period Ended	Number of Class A common units Issued[(1)]	Average Offering Price per Class A common unit	Net Proceeds to the Partnership[(2)]	General Partner Contribution[(3)]	Net Proceeds Including General Partner Contribution
	(unaudited; in millions, except units and per unit amounts)				
March 31, 2011	886,724	$64.52	$55.9	$1.2	$57.1

(1) Common units issued are presented prior to the two-for-one split of our units.

(2) Net of commissions and issuance costs of $1.3 million for the three month period ended March 31, 2011.

(3) Contributions made by the General Partner to maintain its two percent general partner interest.

8. RELATED PARTY TRANSACTIONS

Line 13 Exchange

Enbridge Pipelines (Southern Lights), L.L.C., which we refer to as Southern Lights, a wholly-owned subsidiary of our General Partner, incurred an additional $1.9 million of construction costs during the three month period ended March 31, 2010, associated with the light sour crude oil pipeline it transferred to us in exchange for Line 13, a 156-mile section of crude oil pipeline that we previously owned. Similar construction costs were not incurred for the three month period ended March 31, 2011. The additional costs increased the balance of our "Property, plant and equipment, net" and the capital account of our General Partner. As of March 31, 2011, we have recorded total costs for the light sour crude oil pipeline of $170.3 million, representing the $175.3 million of construction costs incurred by Southern Lights less the $5.0 million net book value of the Line 13 assets we exchanged.

Joint Funding Arrangement for Alberta Clipper Pipeline

In July 2009, we entered into a joint funding arrangement to finance construction of the U.S. segment of the Alberta Clipper Pipeline with several of our affiliates and affiliates of Enbridge 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 Project, 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 senior notes due 2020, except that the A1 Term Note has recourse only to the assets of the U.S. portion of the Alberta Clipper Project 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 Project 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 Project. In April 2011, we made a $6.3 million payment of principal and interest on our A1 Term Note. The approved terms for the Alberta Clipper Project are described in the "Alberta Clipper U.S. 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, 2011 and 2010 are as follows:

	A1 Term Note	
	2011	2010
Beginning Balance	$347.4	$ —
Borrowings	2.6	332.9
Ending Balance	$350.0	$332.9

Our General Partner also made equity contributions totaling $3.2 million and $77.3 million to the OLP during the three month periods ended March 31, 2011 and 2010, respectively, to fund its equity portion of the construction costs associated with the Alberta Clipper Project.

We allocated earnings derived from operating the Alberta Clipper Project in the amounts of $14.7 million and $10.7 million to our General Partner for its 66.67 percent share of the earnings of the Alberta Clipper Project for the three month periods ended March 31, 2011 and 2010, respectively. We have presented the amounts we allocated to our General Partner for its share of the earnings of the Alberta Clipper Project in "Net income attributable to noncontrolling interest" on our consolidated statements of income.

Distribution to Series AC Interests

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, representing limited partner ownership interest at the OLP that are specifically related to the assets, liabilities and operations of the Alberta Clipper Pipeline, declared a distribution payable to the holders of the Series AC general and limited partner interests on January 28, 2011. The distribution was paid on February 14, 2011 by the OLP to our General Partner and its affiliate representing the noncontrolling interest in the Series AC, and to us in the amounts of $21.8 million and $10.9 million, respectively.

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, 2011 and December 31, 2010, we have $36.8 million and $44.2 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 Leaks

Line 6B Crude Oil Release

We continue to make visible progress on the clean up, remediation and restoration of the areas affected by the Line 6B release. A significant portion of the effort to clean up, remediate and restore the areas affected by the Line 6B release was performed by the end of 2010. However, we continue to remediate identified sites, and we expect to make payments for additional costs associated with remediation and restoration of the area, air and groundwater monitoring, along with other 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 incident area to the satisfaction of the appropriate regulatory authorities.

We have not revised our $550 million cost estimate for this incident at March 31, 2011 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, 2011. Our estimates do not include amounts we have capitalized or any unasserted fines, penalties and claims associated with the release that may later become evident. 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 invoices are received for the actual personnel, equipment and services, our estimates will 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 reasonably possible as more reliable information becomes available. We have the potential of incurring additional costs in connection with this incident 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 estimated loss for the cleanup, remediation and restoration associated with the Line 6B incident include the following:

	(in millions)
Equipment and other resources	$153
Field response personnel	194
Professional, regulatory and other	203
Total	$550

We continue to expect that we will pay approximately 90 percent of the estimated costs associated with this incident by the end of 2011. For the three month period ended March 31, 2011, we paid $82.8 million for costs associated with the Line 6B crude oil release and have a remaining liability of $173.6 million, a majority of which is presented as current, on our consolidated statement of financial position at March 31, 2011.

Line 6A Crude Oil Release

We have substantially completed the cleanup, remediation and restoration of the areas affected by the crude oil release from Line 6A of our Lakehead system.

In connection with this incident, we have not changed our original estimate that we will incur aggregate costs of approximately $45 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. For the three month period ended March 31, 2011, we paid $6.8 million related to the costs on the Line 6A release and have a remaining total liability of $3.8 million, a majority of which is presented as current, on our consolidated statement of financial position as of March 31, 2011.

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

Lines 6A & 6B Fines and Penalties

Our estimated environmental costs for both the Line 6A and Line 6B leaks do not include an estimate for fines and penalties at March 31, 2011, which may be imposed by the Environmental Protection Agency, or EPA, and Pipeline and Hazardous Materials Safety Administration, or PHMSA, in addition to other 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 leaks. As a result, we have not recorded any liability for expected fines and penalties.

Insurance Recoveries

We maintain commercial liability insurance coverage that is consistent with coverage considered customary for our industry. The commercial liability insurance covers costs associated with environmental incidents such as those we have incurred for the releases from Lines 6A and 6B, excluding costs for fines and penalties. We are included in the comprehensive insurance program that is maintained by Enbridge for its subsidiaries and affiliates, which has an aggregate limit of $650.0 million for pollution liability through the policy renewal date of May 1, 2011. Enbridge and its subsidiaries and affiliates, including us, have remaining coverage under these insurance policies of approximately $70 million. Enbridge is currently negotiating the renewal of its existing policies with its insurance carriers.

Apart from the amounts for which we are not insured, we anticipate that substantially all of the costs we have incurred from the releases will ultimately be recoverable under our existing insurance policies. We recognized $35.0 million of insurance recoveries as a reduction to "Environmental costs, net of recoveries" in our consolidated statement of income for the three month period ended March 31, 2011 and in "Receivables, trade and other" in our consolidated statement of financial position as of March 31, 2011. In April 2011, we received an insurance payment of $10 million for claims we filed in connection with the Line 6B release, and we have been advised by one of our insurance carriers that an additional $25 million payment is imminent. 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.

Pipeline Integrity Commitment

In connection with the restart of Line 6B of our Lakehead system, we committed to accelerate a process we had initiated prior to the release to perform additional inspections, testing and refurbishment of Line 6B within and beyond the immediate area of the July 26, 2010 incident. 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 is scheduled for tie-in during June 2011. 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.

In February 2011, we filed a supplement to our Facilities Surcharge Mechanism, or FSM, to be effective on April 1, 2011, for recovery of $175 million of capital costs and $5 million of operating costs which are related to the 2010/2011 Line 6B Integrity Program. The costs associated with the Line 6B Integrity Program, which include an equity return component, interest expense on 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.

Gain Contingencies

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 $11.6 million to "Receivables, trade and other" on our consolidated statements of financial position at March 31, 2011 for the amounts we received in April 2011, of which we recorded $5.6 million as a reduction to "Operating and administrative" expenses and $6.0 million as "Other income" in our consolidated statements of income.

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 incidents. 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 incident, including direct actions, actions seeking class status and actions seeking derivative status. With respect to the Line 6B incident, no penalties or fines have been assessed against us to-date. Governmental agencies and regulators have also initiated investigations into the Line 6A incident. One claim has been filed against us and our affiliates, by the State of Illinois, in state court in connection with this incident. The parties are operating under an agreed interim order which we expect to mature into a final order in the near future, thereby resolving that proceeding. The costs associated with this order are included in the estimated environmental costs are accrued for Line 6A. We have accrued a provision for future legal costs associated with the Line 6A and Line 6B incidents 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 2016 in accordance with our risk management policies.

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.

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" 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.
- **Natural Gas Collars**—In our Natural Gas segment, we previously entered into natural gas collars to hedge the sales price of natural gas. The natural gas collars were based on a New York Mercantile Exchange, or NYMEX, pricing index, while the physical gas sales were based on a different index. To better align the index of the natural gas collars with the index of the underlying sales, we de-designated the original cash flow hedging relationship with the intent of contemporaneously re-designating the natural gas collars as hedges of forecasted physical natural gas sales with a NYMEX pricing index. However, because the fair value of these derivative instruments was a liability to us at re-designation, they are considered net written options and, pursuant to the authoritative accounting guidance, do not qualify for hedge accounting. These derivatives are being marked-to-market, with the changes in fair value from the date of de-designation recorded to earnings each period. As a result, our operating income is subject to greater volatility due to movements in the prices of natural gas until the underlying long-term transactions are settled.

- **Optional Natural Gas Processing Volumes**—In our Natural Gas segment, we use derivative financial instruments to hedge the volumes of NGLs produced from our natural gas processing facilities. Some of our natural gas contracts allow us the choice of processing natural gas when it is economical and to cease doing so when processing becomes uneconomic. We have entered into derivative financial instruments to fix the sales price of a portion of the NGLs that we produce at our discretion and to fix the associated purchase price of natural gas required for processing. We typically designate derivative financial instruments associated with NGLs we produce per contractual processing requirements as cash flow hedges when the processing of natural gas is probable of occurrence. However, we are precluded from designating the derivative financial instruments as qualifying hedges of the respective commodity price risk when the discretionary processing volumes are subject to change. As a result, our operating income is subject to increased volatility due to fluctuations in NGL prices until the underlying transactions are settled or offset.

- **NGL Forward Contracts**—In our Natural Gas segment, we use forward contracts to fix the price of NGLs we purchase and store in inventory and to fix the price of NGLs that we sell from inventory to meet the demands of our customers that sell and purchase NGLs. Prior to April 1, 2009, these forward contracts were not treated as derivative financial instruments pursuant to the normal purchase normal sale, or NPNS, exception allowed under authoritative accounting guidance, since the forward contracts resulted in physical receipt or delivery of NGLs. However, evolving markets for NGLs have increased opportunities for a portion of our forward contracts to be settled net rather than physically receiving or delivering the NGLs. Accordingly, we have revoked the NPNS election on certain forward contracts associated with the liquids marketing operations of Dufour Petroleum, L.P., our wholly-owned subsidiary, executed after April 1, 2009. 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. In 2010, we began executing derivative financial instruments for the current year and for 2011, which fixes the sales prices we receive in the future for this crude oil. We elected not to designate these derivative financial instruments as cash flow hedges due to the relatively small volumes involved. As a result, our operating income is subject to 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 within the requirements of applicable risk policies. 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 market 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 historical cost) 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 period ended March 31,	
	2011	**2010**
Liquids segment		
Non-qualified hedges	$ (4.6)	$(1.2)
Natural Gas segment		
Hedge ineffectiveness	1.2	0.5
Non-qualified hedges	(10.3)	9.7
Marketing		
Non-qualified hedges	(2.9)	(0.4)
Commodity derivative fair value gains (losses)	(16.6)	8.6
Corporate		
Non-qualified interest rate hedges	(0.1)	(0.5)
Derivative fair value gains (losses)	$(16.7)	$ 8.1

Derivative Positions

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

	March 31, 2011	December 31, 2010
	(in millions)	
Other current assets	$ 36.2	$ 37.1
Other assets, net	5.3	5.0
Accounts payable and other	(123.9)	(79.2)
Other long-term liabilities	(97.1)	(67.1)
	$(179.5)	$(104.2)

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 "Accumulated other comprehensive income," or 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 $28.3 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. We estimate that approximately $64.3 million, representing unrealized net losses from our cash flow hedging activities based on pricing and positions at March 31, 2011, will be reclassified from AOCI to earnings during the next 12 months.

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

	March 31, 2011	December 31, 2010
	(in millions)	
Counterparty Credit Quality*		
AAA	$ (0.1)	$ —
AA	(91.8)	(48.7)
A	(89.8)	(61.3)
Lower than A	2.2	5.8
	$(179.5)	$(104.2)

* 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 or 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 the tiered contractual collateral thresholds. Counterparty collateral may consist of cash or letters of credit, both of which must be fulfilled with immediately available funds.

At March 31, 2011, we were in an overall net liability position of $179.5 million, which included assets of $41.5 million. 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, 2011 we would have been required to provide additional letters of credit in the amount of $116.0 million.

At March 31, 2011 and December 31, 2010, we had credit concentrations in the following industry sectors, as presented below:

	March 31, 2011	December 31, 2010
	(in millions)	
U.S. financial institutions and investment banking entities	$(114.5)	$ (53.2)
Non-U.S. financial institutions	(44.5)	(46.8)
Small non-integrated energy companies	(14.6)	(1.6)
Integrated oil companies	(5.9)	(2.6)
	$(179.5)	$(104.2)

We are holding no cash collateral on our asset exposures, and we have provided letters of credit totaling $29.2 million and $7.3 million relating to our liability exposures pursuant to the margin thresholds in effect at March 31, 2011 and December 31, 2010, respectively, under our ISDA® agreements.

Gross derivative balances are presented below without the effects of collateral received or posted and without the effects of master netting arrangements. Our assets are adjusted for the non-performance risk of our counterparties using their credit default swap spread rates and are reflected in the fair value. Likewise, in the case of our liabilities, our nonperformance risk is considered in the valuation and is also adjusted based on current credit default swap spread rates on our outstanding indebtedness. 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, 2011	December 31, 2010	Financial Position Location	March 31, 2011	December 31, 2010
			(in millions)			
Derivatives designated as hedging instruments						
Interest rate contracts	Other current assets	$24.5	$22.9	Accounts payable and other	$ (21.4)	$ (21.4)
Interest rate contracts	Other assets, net	4.8	2.5	Other long-term liabilities	(31.6)	(44.0)
Commodity contracts	Other current assets	8.6	10.7	Accounts payable and other	(72.1)	(43.4)
Commodity contracts	Other assets, net	9.3	14.1	Other long-term liabilities	(76.4)	(38.1)
		47.2	50.2		(201.5)	(146.9)
Derivatives not designated as hedging instruments						
Interest rate contracts	Other current assets	3.8	5.1	Accounts payable and other	(3.4)	(4.6)
Interest rate contracts	Other assets, net	6.6	6.6	Other long-term liabilities	(5.9)	(5.9)
Commodity contracts	Other current assets	21.8	23.7	Accounts payable and other	(49.4)	(35.1)
Commodity contracts	Other assets, net	5.1	8.7	Other long-term liabilities	(3.8)	(6.0)
		37.3	44.1		(62.5)	(51.6)
Total derivative instruments		$84.5	$94.3		$(264.0)	$(198.5)

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, 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
For the three month period ended March 31, 2010					
Interest rate contracts	$(13.9)	Interest expense	$ (1.4)	Interest expense	$ —
Commodity contracts	33.6	Cost of natural gas	(8.5)	Cost of natural gas	0.5
Total	$ 19.7		$ (9.9)		$0.5

(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

Derivatives Not Designated as Hedging Instruments	Location of Gain or (Loss) Recognized in Earnings	For the three month period ended March 31, 2011	2010
		Amount of Gain or (Loss) Recognized in Earnings[1]	
		(in millions)	
Interest rate contracts	Interest expense	$ (0.1)	$(0.5)
Commodity contracts	Operating revenue	(4.5)	(1.2)
Commodity contracts	Power	(0.1)	—
Commodity contracts	Cost of natural gas	(13.2)	9.3
Total		$(17.9)	$ 7.6

(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, 2011			December 31, 2010		
	Assets	Liabilities	Total	Assets	Liabilities	Total
			(in millions)			
Fair value of derivatives—gross presentation	$ 84.5	$(264.0)	$(179.5)	$ 94.3	$(198.5)	$(104.2)
Effects of netting agreements	(43.0)	43.0	—	(52.2)	52.2	—
Fair value of derivatives—net presentation	$ 41.5	$(221.0)	$(179.5)	$ 42.1	$(146.3)	$(104.2)

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, 2011 and December 31, 2010. 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, 2011				December 31, 2010			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
		(in millions)				(in millions)		
Interest rate contracts	$—	$ (22.6)	$ —	$ (22.6)	$—	$(38.8)	$ —	$ (38.8)
Commodity contracts—financial	—	(85.4)	(75.7)	(161.1)	—	(52.4)	(24.8)	(77.2)
Commodity contracts—physical	—	—	0.1	0.1	—	—	3.4	3.4
Commodity options	—	(0.1)	4.2	4.1	—	(0.2)	8.6	8.4
Total	$—	$(108.1)	$(71.4)	$(179.5)	$—	$(91.4)	$(12.8)	$(104.2)

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, 2011 to March 31, 2011. No transfers of assets between any of the Levels occurred during the period.

	2011			
	Commodity Financial Contracts	Commodity Physical Contracts	Commodity Options	Total
Beginning balance as of January 1	$(24.8)	$ 3.4	$ 8.6	$(12.8)
Transfer out of Level 3[1]	—	—	—	—
Gains or losses				
Included in earnings (or changes in net assets)	(16.4)	(3.3)	(0.9)	(20.6)
Included in other comprehensive income	(43.9)	—	(3.2)	(47.1)
Purchases, issuances, sales and settlements				
Purchases	—	—	—	—
Settlements[2]	9.4	—	(0.3)	9.1
Ending balance as of March 31	$(75.7)	$ 0.1	$ 4.2	$(71.4)
Amount of changes in net assets attributable to the change in unrealized gains or losses related to assets still held at the reporting date	$(57.6)	$(2.2)	$(3.8)	$(63.6)
Amounts reported in operating revenue	$ (3.2)	$ —	$ —	$ (3.2)

(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, 2011 and December 31, 2010.

	At March 31, 2011						At December 31, 2010	
			Wtd. Average Price[2]		Fair Value[3]		Fair Value[3]	
	Commodity	**Notional[1]**	**Receive**	**Pay**	**Asset**	**Liability**	**Asset**	**Liability**
Portion of contracts maturing in 2011								
Swaps								
Receive variable/pay fixed	Natural Gas	8,707,743	$ 4.53	$ 4.63	$2.6	$ (3.4)	$0.4	$ (4.9)
	NGL	290,000	$ 85.42	$ 66.21	$5.6	$ —	$6.8	$ —
	Crude Oil	315,000	$107.22	$102.06	$1.6	$ —	$0.4	$ —
Receive fixed/pay variable	Natural Gas	13,476,276	$ 4.07	$ 4.55	$1.2	$ (7.6)	$2.6	$ (6.7)
	NGL	3,686,350	$ 46.86	$ 59.82	$1.9	$(49.6)	$5.0	$(38.8)
	Crude Oil	1,583,600	$ 83.41	$106.76	$ —	$(36.9)	$ —	$(22.9)
Receive variable/pay variable	Natural Gas	73,050,858	$ 4.40	$ 4.38	$2.7	$ (1.2)	$5.0	$ (1.2)
Physical Contracts								
Receive fixed/pay variable	NGL	986,083	$ 79.11	$ 84.63	$0.1	$ (5.6)	$0.5	$ (4.4)
	Crude Oil	435,840	$ 96.98	$107.05	$0.3	$ (4.7)	$ —	$ (1.9)
Receive variable/pay fixed	NGL	438,463	$ 88.09	$ 82.88	$2.3	$ —	$1.6	$ —
	Crude Oil	263,840	$106.92	$ 97.42	$2.5	$ —	$1.1	$ —
Pay fixed	Power[4]	56,910	$ 32.66	$ 44.20	$ —	$ (0.7)	$ —	$ (0.8)
Receive variable/pay variable	Crude Oil	401,381	$106.91	$106.18	$1.0	$ (0.8)	$0.5	$ (0.2)
	NGL	3,100,892	$ 83.62	$ 82.78	$4.7	$ (2.1)	$6.2	$ (1.4)
	Natural Gas	26,586,222	$ 4.40	$ 4.36	$1.0	$ —	$1.1	$ —
Portion of contracts maturing in 2012								
Swaps								
Receive variable/pay fixed	Natural Gas	2,182,813	$ 5.03	$ 6.55	$0.5	$ (3.8)	$ —	$ (3.8)
Receive fixed/pay variable	Natural Gas	4,000,002	$ 4.82	$ 5.03	$1.7	$ (2.5)	$1.7	$ (2.1)
	NGL	1,887,680	$ 58.12	$ 65.41	$4.4	$(18.1)	$8.0	$ (7.6)
	Crude Oil	938,790	$ 83.62	$106.28	$ —	$(21.1)	$ —	$(10.7)
Receive variable/pay variable	Natural Gas	50,809,000	$ 4.97	$ 4.97	$1.2	$ (0.8)	$1.0	$ (0.8)
Physical Contracts								
Receive variable/pay variable	Natural Gas	17,889,001	$ 4.97	$ 4.94	$0.6	$ —	$0.6	$ —
	NGL	651,143	$ 68.97	$ 66.61	$2.1	$ (0.6)	$0.7	$ —
Pay fixed	Power[4]	24,120	$ 31.44	$ 40.83	$ —	$ (0.2)	$ —	$ —
Portion of contracts maturing in 2013								
Swaps								
Receive variable/pay fixed	Natural Gas	93,066	$ 5.29	$ 5.19	$ —	$ —	$ —	$ —
Receive fixed/pay variable	Natural Gas	730,000	$ 9.83	$ 5.25	$3.3	$ —	$3.3	$ —
	NGL	930,385	$ 65.39	$ 80.41	$ —	$(13.6)	$0.3	$ (3.2)
	Crude Oil	904,105	$ 87.14	$103.34	$1.5	$(15.7)	$2.2	$ (7.4)
Receive variable/pay variable	Natural Gas	29,550,000	$ 5.34	$ 5.35	$0.1	$ (0.2)	$0.1	$ (0.2)
Physical Contracts								
Receive variable/pay variable	Natural Gas	6,612,450	$ 5.38	$ 5.34	$0.2	$ —	$0.2	$ —
Portion of contracts maturing in 2014								
Swaps								
Receive variable/pay fixed	Natural Gas	21,870	$ 5.70	$ 5.22	$ —	$ —	$ —	$ —
Receive fixed/pay variable	NGL	262,800	$ 79.78	$ 96.19	$ —	$ (4.1)	$ —	$ (1.1)
	Crude Oil	722,700	$ 88.89	$101.86	$ —	$ (8.9)	$ —	$ (2.8)
Receive variable/pay variable	Natural Gas	6,300,000	$ 5.77	$ 5.79	$ —	$ (0.1)	$ —	$ (0.1)
Portion of contracts maturing in 2015								
Swaps								
Receive fixed/pay variable	Crude Oil	350,400	$ 93.00	$101.35	$ —	$ (2.7)	$ —	$ (0.7)
	NGL	109,500	$ 88.36	$ 95.86	$ —	$ (0.7)	$ —	$ (0.1)
Portion of contracts maturing in 2016								
Swaps								
Receive fixed/pay variable	Crude Oil	45,750	$ 99.31	$101.60	$ —	$ (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, 2011 and December 31, 2010, 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 $1.6 million of gains and $0.6 million of gains at March 31, 2011 and December 31, 2010, 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, 2011 and December 31, 2010.

	At March 31, 2011						At December 31, 2010	
					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 2011								
Calls (written)	Natural Gas[4]	275,000	$ 4.31	$ 4.58	$ —	$(0.1)	$ —	$(0.2)
Puts (purchased)	Natural Gas[4]	275,000	$ 3.40	$ 4.58	$ —	$ —	$ —	$ —
	NGL	477,950	$54.79	$ 66.95	$1.3	$ —	$3.6	$ —
	Crude Oil	163,625	$88.65	$107.94	$0.4	$ —	$1.3	$ —
Portion of option contracts maturing in 2012								
Puts (purchased)	NGL	284,382	$65.90	$ 74.30	$2.6	$ —	$3.9	$ —

(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, 2011 and December 31, 2010, 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 December 31, 2010. No credit valuation adjustments related to our outstanding commodity options existed at March 31, 2011.

(4) Indicates transactions which, in combination, create a collar, representing a floor and ceiling on the price and provide long-term price protection.

Fair Value Measurements of Interest Rate Derivatives

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

				Fair Value[2] at	
Date of Maturity & Contract Type	Accounting Treatment	Notional	Average Fixed Rate[1]	March 31, 2011	December 31, 2010
		(dollars in millions)			
Contracts maturing in 2013					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$600	4.15%	$(45.2)	$(51.8)
Interest Rate Swaps—Pay Fixed	Non-qualifying	$125	4.35%	$ (9.4)	$(10.7)
Interest Rate Swaps—Pay Float	Non-qualifying	$125	4.75%	$ 10.5	$ 11.9
Contracts maturing in 2015					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$300	2.43%	$ 2.8	$ 1.9
Contracts settling prior to maturity					
2011—Pre-issuance Hedges	Cash Flow Hedge	$300	2.92%	$ 24.8	$ 23.4
2012—Pre-issuance Hedges	Cash Flow Hedge	$600	4.57%	$ (8.4)	$(13.7)
2013—Pre-issuance Hedges	Cash Flow Hedge	$300	4.62%	$ 2.1	$ (0.3)

(1) Interest rate derivative contracts are based on the one-month or three-month LIBOR.

(2) The fair value is determined from quoted market prices at March 31, 2011 and December 31, 2010, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values are presented in millions of dollars and exclude credit valuation adjustments of approximately $0.2 million of gains at March 31, 2011 and $0.5 million of gains at December 31, 2010.

11. 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, 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)
Operating and administrative	66.2	93.6	1.6	1.1	162.5
Power	35.6	—	—	—	35.6
Depreciation and amortization	48.5	39.9	—	—	88.4
Operating income	185.7	22.8	0.1	(1.1)	207.5
Interest expense	—	—	—	79.4	79.4
Other income	—	—	—	6.0	6.0
Income 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	185.7	22.8	0.1	(76.8)	131.8
Less: Net income attributable to the noncontrolling interest	—	—	—	14.7	14.7
Net income 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.

	As of and for the three month period ended March 31, 2010				
	Liquids	Natural Gas	Marketing	Corporate[1]	Total
			(in millions)		
Total revenue	$ 262.1	$1,390.6	$693.8	$ —	$2,346.5
Less: Intersegment revenue	0.3	405.9	9.1	—	415.3
Operating revenue	261.8	984.7	684.7	—	1,931.2
Cost of natural gas	—	847.8	676.4	—	1,524.2
Environmental costs	4.6	—	—	—	4.6
Operating and administrative	59.1	69.6	2.7	—	131.4
Power	32.3	—	—	—	32.3
Depreciation and amortization	37.1	30.7	0.1	—	67.9
Operating income	128.7	36.6	5.5	—	170.8
Interest expense	—	—	—	59.3	59.3
Other income	—	—	—	16.8	16.8
Income from continuing operations before income tax expense	128.7	36.6	5.5	(42.5)	128.3
Income tax expense	—	—	—	2.2	2.2
Income from continuing operations	128.7	36.6	5.5	(44.7)	126.1
Loss from discontinued operations	—	—	—	—	—
Net income	128.7	36.6	5.5	(44.7)	126.1
Less: Net income attributable to the noncontrolling interest	—	—	—	10.7	10.7
Net income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 128.7	$ 36.6	$ 5.5	$ (55.4)	$ 115.4
Total assets	$5,323.1	$3,324.4	$243.9	$268.6	$9,160.0
Capital expenditures (excluding acquisitions)	$ 162.9	$ 24.3	$ —	$ 1.9	$ 189.1

(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.

12. 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 or settled as cash 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 our customers and the FERC. 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 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. As a result, for the three month period ended March 31, 2011, we reduced our revenues by $12.4 million on our consolidated statement of income with a corresponding regulatory liability on our consolidated statement of financial position at March 31, 2011 for the differences in transportation volumes. The amounts will be refunded through our tolls beginning April 2012 when we update our transportation rates to account for the higher than estimated delivered volumes.

For 2010, 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 2010 were lower than the forecasted costs used to calculate the toll charge. As a result, in 2010 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 2011 to recognize the amounts we previously collected as revenue due to the lower toll rate in 2011 and to account for the over collected amounts. For the three month period ended March 31, 2011, we increased our revenues by $1.4 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, 2011. At March 31, 2011 and December 31, 2010 we had a $2.2 million and $3.6 million regulatory liability, respectively, on our consolidated statements of financial position. The amounts will be refunded to our customers through our tolls beginning April 2011 when our transportation rates that account for the higher delivered volumes and lower costs than estimated become effective.

For 2009, we under collected revenue for our Southern Access Pipeline in-part because actual volumes were lower than the forecast volumes used to calculate the toll surcharge, which resulted in a regulatory receivable, the balance of which was $2.1 million on our consolidated statement of financial position as of December 31, 2010. Beginning April 1, 2010, we began to collect the previously recognized revenue when the annual update to our transportation rates became effective. During the three month period ended March 31, 2011, we collected the remaining under collected revenue and the related regulatory receivable was satisfied.

Alberta Clipper Pipeline

Under the authoritative accounting provisions applicable to regulated operations we are permitted to capitalize and recover costs for rate-making purposes that include an allowance for equity costs during construction, referred to as AEDC. In connection with the construction of the Alberta Clipper Pipeline we have recorded AEDC in "Property, plant and equipment" on our consolidated statements of financial position in amounts totaling $27.9 million at both March 31, 2011 and December 31, 2010. Related to the recognition of AEDC, we also recorded $14.3 million of "Other income" in our consolidated statement of income for the three month period ended March 31, 2010.

For 2011, 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, 2011, we reduced our revenues by $11.2 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, 2011 for the differences in transportation volumes and costs. The amounts will be reimbursed beginning April 2012 when we update our transportation rates to account for the higher delivered volumes and higher costs than estimated.

During 2010 we over collected revenue on our Alberta Clipper Pipeline because the actual operating costs recognized in 2010 were lower than the forecasted costs used to calculate the toll charge. As of March 31, 2011 and December 31, 2010, we had regulatory liabilities of $7.5 million and $10.1 million, respectively, in our consolidated statements of financial position for the difference in costs. The amounts will be refunded to our customers through our tolls beginning April 2011 when our transportation rates that account for the lower costs than estimated become effective.

Regulatory Liability for Southern Lights Pipeline In-Service Delay

In December 2006, as part of the regulatory approval process for its pipeline, 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 Lights 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, 2011, we had over collected costs related to the Southern Lights in-service delay of $23.3 million which we have recorded as a regulatory liability on our consolidated statement of financial position. We will reduce the transportation rates we charge the shippers in the future for the additional amounts we collected beginning in April 2012 when we update the transportation rates on our Lakehead system.

FERC Transportation Tariffs

Effective April 1, 2011, 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 2011 related to our expansion projects. Also included was a supplement to our FSM for recovery of the costs related to the 2010/2011 Line 6B Integrity Program, including costs associated with the PHMSA Corrective Action Order and as discussed in Footnote 9—*Commitments and Contingencies—Pipeline Integrity Commitment*. 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 $0.21 per barrel, to an average of approximately $1.76 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 March 18, 2011, we filed FERC Tariff 72.6.0 and 73.4.0 to incorporate an updated calculation of the surcharges on our North Dakota system of two previously approved expansion projects, North Dakota Phase V and Phase VI. Both phases are cost-of-service based surcharges that are trued up each year to actual costs. Both tariff filings are effective April 1, 2011.

13. SUBSEQUENT EVENTS

Class A common unit issuances

We issued 112,600 Class A common units in April 2011 under the terms of the EDA at sales prices averaging $64.27 per unit, for proceeds of approximately $7.1 million, net of $0.1 million of commissions and issuance costs within the period of April 1 and April 5, 2011. The 112,600 Class A common units we issued represent 225,200 Class A common units on a split-adjusted basis. In addition, our General Partner contributed approximately $0.1 million to us to maintain its two percent general partner interest.

Distribution to Partners

On April 28, 2011, the board of directors of Enbridge Management declared a distribution payable to our partners on May 13, 2011. The distribution will be paid to unitholders of record as of May 6, 2011, of our available cash of $152.0 million at March 31, 2011, or $0.51375 per limited partner unit on a split adjusted basis. Of this distribution, $133.2 million will be paid in cash, $18.4 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 28, 2011, 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 $21.6 million to the noncontrolling interest in the Series AC, while $10.8 million will be paid to us.

14. SUPPLEMENTAL CASH FLOWS INFORMATION

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

	For the three month period ended March 31,	
	2011	2010
	(in millions)	
Discount accretion	$ 0.2	$ 0.1
Amortization of debt issuance and hedging costs	4.2	5.5
Deferred income taxes	0.1	0.3
Allowance for equity used during construction	—	(14.3)
Allowance for doubtful accounts	0.3	(4.0)
Gain on sale of CO_2 plant	(1.5)	—
Settlement of claims, net	(10.0)	—
Other	(0.1)	0.6
	$ (6.8)	$(11.8)

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 the three month periods ended March 31, 2011 and 2010.

	For the three month period ended March 31,	
	2011	2010
	(unaudited; in millions)	
Operating Income		
Liquids	$185.7	$128.7
Natural Gas	22.8	36.6
Marketing	0.1	5.5
Corporate, operating and administrative	(1.1)	—
Total Operating Income	207.5	170.8
Interest expense	79.4	59.3
Other income	6.0	16.8
Income tax expense	2.3	2.2
Net income	131.8	126.1
Less: Net income attributable to noncontrolling interest	14.7	10.7
Net income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$117.1	$115.4

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 operating income of our Liquids business for the three month period ended March 31, 2011 increased from the same period in 2010 primarily due to the transportation rate increase that became effective in April 2010 associated with the completion and start up of the U.S. portion of the Alberta Clipper crude oil pipeline and related facilities, or Alberta Clipper Pipeline. Also impacting our operating income for the Liquids segment for the three month period ended March 31, 2011 when compared to the same period in 2010 were the following:

- Higher average daily volumes delivered on all of our major liquids systems;
- Insurance recoveries of $35 million we recognized for claims we filed for the environmental and remediation costs we incurred in connection with the leak on Line 6B of our Lakehead system; and
- Increased operating and administrative, power and depreciation costs associated with the additional assets we placed into service in 2010.

Natural Gas

The following factors affected the operating income of our Natural Gas business for the three month period ended March 31, 2011 as compared with the same period of 2010:

- Unrealized, non-cash, mark-to-market net losses of $9.1 million associated with derivative financial instruments that do not qualify for hedge accounting treatment under authoritative accounting guidance compared with $10.2 million of net gains for the comparable period of 2010;
- Increased natural gas and NGL volumes on our Anadarko and Elk City systems as a result of growth in the Granite Wash play and on our East Texas system due to new assets being placed in service to capture the growing Haynesville production. Partially offsetting these increases were severe winter weather conditions and plant downtime, which reduced average daily volumes on our systems by approximately 56,000 MMBtu/d;
- Increased fees associated with higher volumes on our systems; and
- Increase in depreciation expense associated with the Elk City system we acquired in September 2010 and additional assets that we placed in service during 2010.

Marketing

Included in the operating results of our Marketing business for the three month period ended March 31, 2011 were unrealized, non-cash, mark-to-market net losses of $2.9 million in 2011 associated with derivative financial instruments that do not qualify for hedge accounting treatment under authoritative accounting guidance compared with $0.4 million of net losses generated in the same period of 2010. Further contributing to lower operating income for the three month period ended March 31, 2011 were relatively stable natural gas prices during these periods, which limited our opportunities to benefit from price differentials between market centers.

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,	
	2011	2010
	(unaudited; in millions)	
Liquids segment		
Non-qualified hedges	$ (4.6)	$(1.2)
Natural Gas segment		
Hedge ineffectiveness	1.2	0.5
Non-qualified hedges	(10.3)	9.7
Marketing		
Non-qualified hedges	(2.9)	(0.4)
Commodity derivative fair value gains (losses)	(16.6)	8.6
Corporate		
Non-qualified interest rate hedges	(0.1)	(0.5)
Derivative fair value gains (losses)	$(16.7)	$ 8.1

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,	
	2011	2010
	(unaudited; in millions)	
Operating Results		
Operating revenues	$301.8	$261.8
Environmental costs, net of recoveries	(34.2)	4.6
Operating and administrative	66.2	59.1
Power	35.6	32.3
Depreciation and amortization	48.5	37.1
Operating expenses	116.1	133.1
Operating Income	$185.7	$128.7
Operating Statistics		
Lakehead system:		
United States[(1)]	1,357	1,266
Province of Ontario[(1)]	386	358
Total Lakehead system deliveries[(1)]	1,743	1,624
Barrel miles (billions)	114	108
Average haul (miles)	727	738
Mid-Continent system deliveries[(1)]	218	206
North Dakota system:		
Trunkline	171	161
Gathering	4	6
Total North Dakota system deliveries[(1)]	175	167
Total Liquids Segment Delivery Volumes[(1)]	2,136	1,997

(1) Average barrels per day in thousands.

Three month period ended March 31, 2011 compared with three month period ended March 31, 2010

Operating revenue of our Liquids business increased for the three month period ended March 31, 2011 when compared with the same period in 2010 primarily due to the increase in average transportation rates for our Lakehead system, associated with the completion and start up of the Alberta Clipper Pipeline in April 2010. The changes affecting our transportation rates included the following:

- Effective April 1, 2010, we increased the rates for transportation on our Lakehead system in connection with the completion of our Alberta Clipper Pipeline. We also increased the transportation rates on our Lakehead system for additional facilities we added for which we receive a cost-of-service return and a true-up for costs associated with the Southern Access Pipeline;
- Effective April 1, 2010, we extended by four years the term of the looping surcharge on our North Dakota system, which is a component of the North Dakota Phase V expansion. The impact of the term extension reduced the looping surcharge from $0.70 per barrel to $0.38 per barrel for certain transported volumes; and

- Effective July 1, 2010, we decreased the average transportation rates on all three of our Liquids systems in connection with the annual index rate ceiling adjustment.

Further contributing to the increase in operating revenue on our Liquids segment was an increase in average daily delivery volumes on each of our major systems. The overall increase in average delivery volumes on our systems contributed approximately $14 million of additional operating revenues to our Liquids segment. The increase in average daily delivery volumes was primarily attributable to our Lakehead system, which increased approximately seven percent, to 1.743 million barrels per day, or Bpd, for the three month period ended March 31, 2011 from 1.624 million Bpd for the same period in 2010. The increase in average deliveries on our Lakehead system was primarily derived from increases of crude oil supplies from upstream production facilities associated with the ongoing development of the Alberta Oil Sands coupled with the additional transportation capacity provided by our Alberta Clipper Pipeline being in service during the three month period ended March 31, 2011 while it was not in service during the same period in 2010.

Average daily delivery volumes on our North Dakota system also increased during the three month period ended March 31, 2011 to 175,000 Bpd from 167,000 Bpd during the same period in 2010. The additional volumes were the result of an increase in capacity on our North Dakota system resulting from the elimination of segregated sour service on the system. We expect to further expand the capacity of our North Dakota system by 25,000 Bpd to 210,000 Bpd when the Portal Reversal Expansion Project, or PREP, is completed in the second quarter of 2011.

During the three month period ended March 31, 2011 we recognized insurance recoveries of $35.0 million for claims we filed for environmental costs associated with the crude oil release on Line 6B of our Lakehead system. The insurance recoveries we recorded coupled with fewer environmental costs resulted in a $38.8 million decline in environmental expenses for the three month period ended March 31, 2011 from the $4.6 million of environmental expenses recognized for the same period in 2010.

Operating and administrative expenses for our Liquids business increased $7.1 million from the three month period ended March 31, 2011 when compared with the same period in 2010 primarily due to the following:

- Additional workforce related costs associated with the operational, administrative, regulatory and compliance support necessary for our systems;
- Higher costs for repair and maintenance activities and our pipeline integrity program;
- Property tax increases associated with assets we constructed and placed in service; and
- Increases in other variable costs incurred in relation to our expanded pipeline systems.

The increase in operating and administrative expenses was partially offset by $5.6 million of proceeds received in April 2011 that we recognized for the settlement of a claim in the three month period ended March 31, 2011.

Power costs increased $3.3 million for the three month period ended March 31, 2011, compared with the same period in 2010. The increase in power costs is primarily associated with rate increases on power used on our Lakehead system offset by a decline associated with the additional capacity provided by our Southern Access Pipeline and Alberta Clipper that enabled us to more efficiently utilize our pipelines to transport crude oil.

The increase in depreciation expense of $11.4 million is directly attributable to the additional assets we have placed in service during 2010, the most significant of which was the Alberta Clipper Project that was ready for service on April 1, 2010.

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. We recognized approximately $595 million of actual and estimated costs in our Liquids business during the year ended

December 31, 2010, for the emergency response, environmental remediation and cleanup activities associated with the crude oil releases from Lines 6A and 6B, and potential claims by third parties. We have not revised the estimated cost for these incidents at March 31, 2011 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.

For the three month period ended March 31, 2011 we recorded $35.0 million for insurance recoveries related to the costs of our Line 6B leak, which we recognized as a reduction of our environmental costs. We continue to process and file claims for payment of our insured losses under the comprehensive insurance program that is maintained by Enbridge Inc., which we refer to as Enbridge, for its subsidiaries and affiliates, including us, which has an aggregate limit of $650.0 million for pollution liability through the policy renewal date of May 1, 2011. The remaining coverage under these insurance policies is approximately $70 million through May 1, 2011. Enbridge is currently negotiating renewal of its existing policies with its insurance carriers. We expect insurance payments for our insured losses to be received over an extended period, which will cause fluctuations in our earnings as these payments are received and recognized in our consolidated statements of income.

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 of our Annual Report on Form 10-K for the year ended December 31, 2010.

Partnership Projects

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 Line 26 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 increase the takeaway capacity from this region by 145,000 Bpd, with further expansion available to increase the takeaway capacity to 325,000 Bpd. The United States portion of the Bakken Project will have an estimated cost of approximately $339 million. We completed a successful binding open season in February 2011 with commitments received for an aggregate of 100,000 Bpd of capacity. Construction is scheduled to commence in the second quarter of 2011 with an expected in-service date in the first quarter of 2013.

Portal Reversal Expansion Project

The initial phase of the Bakken Project, PREP, will reactivate and reverse the flow of the existing Line 26 pipeline between Berthold, North Dakota and Steelman, Saskatchewan. PREP will have an estimated cost of approximately $9 million and will be complete in the second quarter of 2011, making 25,000 Bpd of the 145,000 Bpd of capacity available at that time.

Cushing Terminal Storage Expansion Project

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. The additional storage tanks will have an estimated cost of $78 million and are expected to be in service in early 2012.

Other Matters

Pipeline Integrity Plan—Line 6B

We completed on schedule all the work required by the Pipeline and Hazardous Materials Safety Administration, or PHMSA, that we agreed to as part of our restart of Line 6B. Additionally, a new line was installed beneath the St. Clair River in March 2011 and is scheduled for tie-in during June 2011. 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.

In February 2011, we filed a supplement to our Facilities Surcharge Mechanism, or FSM, to be effective on April 1, 2011, for recovery of $175 million of capital costs and $5 million of operating costs which are related to the 2010/2011 Line 6B Integrity Program. The costs associated with the Line 6B Integrity Program, 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.

International Joint Toll Agreement

We anticipate that Enbridge Pipelines Inc., or EPI, will file a new settlement agreement, the Competitive Toll Settlement, or CTS, in the second quarter to be effective July 1, 2011. The CTS includes a provision for a joint tariff for volumes originating in Western Canada that are transported on our Lakehead system. We will enter into an International Joint Tariff Agreement, or IJTA, with EPI that ensures that the joint tariff revenues are allocated based on the existing Lakehead rate structures. United States tolls for service on our portion of the Lakehead system will not be affected by the CTS and will continue to be established by our existing toll agreements. We do not expect the terms of the CTS or the IJTA to affect our operating results, cash flows or financial position.

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 per day, or MMBtu/d, for the periods presented.

	For the three month period ended March 31,	
	2011	**2010**
	(unaudited; in millions)	
Operating revenues	$ 1,449.7	$ 984.7
Cost of natural gas	1,293.8	847.8
Environmental costs, net of recoveries	(0.4)	—
Operating and administrative	93.6	69.6
Depreciation and amortization	39.9	30.7
Operating expenses	1,426.9	948.1
Operating Income	$ 22.8	$ 36.6
Operating Statistics (MMBtu/d)		
East Texas	1,315,000	1,195,000
Anadarko	929,000	547,000
North Texas	339,000	347,000
Total[1]	2,583,000	2,089,000

(1) Average daily volumes for the three month period ended March 31, 2011 include 216,000 MMBtu/d of volumes associated with our acquisition of the Elk City Natural Gas Gathering and Processing System, referred to as the Elk City system.

Three month period ended March 31, 2011 compared with three month period ended March 31, 2010

The primary factors affecting the operating income of our Natural Gas business for the three month period ended March 31, 2011 as compared with the same period of 2010 are as follows:

- $19.3 million of additional unrealized, non-cash, mark-to-market net losses from derivative instruments that do not qualify for hedge accounting treatment under authoritative accounting guidance, as compared with the same period of 2010;
- Increases in operating and administrative costs associated with the expansion of our systems, maintenance activities, and additional costs related to our September 2010 Elk City system acquisition; and
- $9.2 million increase in depreciation expense associated with the Elk City system we acquired in September 2010 and additional assets that were put in service during 2010.

Offsetting the above decreases in operating income are the following:

- Increased natural gas and NGL volumes on our Anadarko system as a result of growth in the Granite Wash play and the additional 216,000 MMBtu/d of volumes associated with our acquisition of the Elk City system in September 2010;
- Increased volumes on our East Texas system due to new assets being placed in service to capture the growing Haynesville production; and
- Increased fees associated with the higher volumes on our systems.

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 in our Natural Gas business. Conversely, hedges of our natural gas length significantly increased in value during the first quarter of 2010 due to sharp declines in forward natural gas prices, which generated net gains of $10.2 million from our non-qualifying commodity derivatives used to economically hedge a portion of the natural gas, NGLs and condensate in our Natural Gas segment. These movements in the forward prices of natural gas that occurred during the first quarter of 2011 as compared with the first quarter of 2010 resulted in $19.3 million of additional unrealized non-cash, mark-to-market net losses 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 periods ended March 31, 2011 and 2010:

	For the three month period ended March 31,	
	2011	2010
	(unaudited; in millions)	
Hedge ineffectiveness	$ 1.2	$ 0.5
Non-qualified hedges	(10.3)	9.7
Derivative fair value gains (losses)	$ (9.1)	$10.2

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 15 to 30 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 decrease when the prices are declining. NGL prices were higher for the three month period ended March 31, 2011 compared to prices in the same period in 2010, which had a positive impact on our gross margin.

Our volumes and revenues are the result of wellhead supply contracts and drilling activity in the areas served by our Natural Gas business, primarily the Bossier Trend, Barnett Shale, Granite Wash and the Haynesville Shale. During the three month period ended March 31, 2011, natural gas volumes on our systems increased approximately 24 percent, in relation to the same period of 2010 primarily due to production increases in the Granite Wash and new assets being placed in service to capture the growing production from the Haynesville shale play. Volumes on our Anadarko system increased 70 percent for the three month period ended March 31, 2011 compared with the same period in 2010, of which approximately 57 percent were associated with the Elk City system we acquired in September 2010. Although volumes were higher on the majority of our systems for the three month period ended March 31, 2011 compared with the same period of 2010, in February uncharacteristically cold weather and freezing precipitation moved through Oklahoma and north Texas with temperatures dropping below freezing for extended periods, thus creating mechanical issues with our producers equipment and their ability to flow natural gas. Producers shut in significant volumes during this period which reduced average daily volumes by approximately 56,000 MMBtu/d for the quarter. 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 three month period ended March 31, 2011.

A variable element of the operating results of our Natural Gas segment is derived from processing natural gas under keep-whole arrangements on our East Texas, North Texas and Anadarko systems. Operating revenue less the cost of natural gas derived from keep-whole processing arrangements for the three month period ended March 31, 2011 was $25.0 million, representing an increase of $5.7 million from the $19.3 million we produced for the same period in 2010. We also continue to experience a trend of replacing or renegotiating some of our existing keep-whole contracts with Percentage of Liquids, or POL, type contracts and other similar arrangements. This trend may reduce our exposure to commodity price risk along with a portion of the operating income we derive from processing natural gas under keep-whole arrangements.

Operating and administrative costs of our Natural Gas segment were $24.0 million higher for the three month period ended March 31, 2011 compared to the same period in 2010, primarily due to an increase in workforce-related costs and maintenance activities associated with the expansion of our systems, including the Elk City system we acquired in September 2010 and a common carrier trucking company we acquired in October 2010.

Future Prospects for Natural Gas

We intend to expand our natural gas gathering and processing services through internal growth projects designed to provide exposure to incremental supplies of natural gas at the wellhead, increase opportunities to serve additional customers, including new wholesale customers, and allow expansion of our treating and processing businesses. Additionally, we will pursue acquisitions to expand our natural gas services in situations where we have natural advantages to create additional value for our existing assets.

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 is expected to increase the capacity of our East Texas system by 900 million cubic feet per day, or MMcf/d. Commitments from natural gas producers in the form of demand payments, acreage dedications and other contractual structures were more than sufficient to proceed with the project. 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 continue through the second quarter of 2011. Future compression will be layered in, 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.

Allison Cryogenic Processing Plant

In April 2010, we announced plans to construct a cryogenic processing plant and other facilities on our Anadarko system, which we refer to as the Allison Plant. The Allison Plant will have a planned capacity of 150 MMcf/d and is intended to accommodate the resurgence of horizontal drilling activity that exists in the Granite Wash formation in the Texas Panhandle, where our Anadarko system is located. The Allison Plant, when operational, will increase the total processing capacity of our Anadarko system to approximately 950 MMcf/d. The Allison Plant is anticipated to be in service prior to the end of 2011.

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,	
	2011	2010
	(unaudited; in millions)	
Operating revenues	$537.4	$684.7
Cost of natural gas	535.7	676.4
Operating and administrative	1.6	2.7
Depreciation and amortization	—	0.1
Operating expenses	537.3	679.2
Operating Income	$ 0.1	$ 5.5

A majority of the operating income of our Marketing segment is derived from buying natural gas from producers on our Natural Gas segment assets and selling to wholesale customers downstream of our Natural Gas segment assets. Our Natural Gas segment assets provide our Marketing business with access to multiple downstream natural gas pipelines. The Marketing business has purchased long-term transportation and storage rights on multiple interstate and intrastate pipelines, which it can use to transport natural gas to primary markets where it can be sold at more favorable prices.

Three month period ended March 31, 2011 compared with three month period ended March 31, 2010

Included in the operating results of our Marketing segment for the three month period ended March 31, 2011 were unrealized, non-cash, mark-to-market net losses of $2.9 million associated with derivative financial instruments that do not qualify for hedge accounting treatment under authoritative accounting guidance, as compared with the $0.4 million of unrealized non-cash, mark-to-market net losses for the same period in 2010. For the three month period ended March 31, 2011, the non-cash, mark-to-market, net losses primarily related to our financial instruments that we use to hedge our transportation and storage positions. The net losses associated with our transportation derivative instruments resulted from the widening of the difference between forward natural gas purchase and sales prices between market centers, which negatively impacted the values of derivative financial instruments we use to hedge our transportation positions. The net losses associated with our storage derivative instruments resulted from the widening difference between the natural gas injection price paid to purchase and store natural gas and the withdrawal price at which the natural gas is sold from storage. Comparatively, during the three month period ended March 31, 2010, the negative impact of the derivative financial instruments we use to hedge our transportation positions due to widening differences between forward prices for natural gas purchases and sales at primary market centers were significantly offset by unrealized, mark-to-market net gains on our physical commodity derivative instruments. Contributing to the lower operating income of our Marketing business were relatively stable natural gas prices during the three month period ended March 31, 2011, which limited opportunities to benefit from significant price differentials between market centers.

Operating and administrative expenses for the three month period ended March 31, 2011 were $1.1 million lower when compared to the same period in 2010 primarily due to us establishing a bad debt reserve for a customer in 2010 whereas there was no similar reserve recorded during 2011.

Corporate

Our interest cost for the three month periods ended March 31, 2011 and 2010 is comprised of the following:

	For the three month period ended March 31,	
	2011	**2010**
	(unaudited; in millions)	
Interest expense	$79.4	$59.3
Interest capitalized	1.5	4.8
Interest cost incurred	$80.9	$64.1
Weighted average interest rate	*6.4%*	*6.1%*

The increase in interest expense between the three month periods ended March 31, 2011 and 2010 is primarily the result of a higher weighted average outstanding debt balance during the three month period ended March 31, 2011 as compared with the same periods in 2010. The increased weighted average outstanding debt balance was primarily a result of the following:

- An increase in our weighted average balance of commercial paper outstanding for the three month period ended March 31, 2011 compared to the same period in 2010, partially offset by a decrease in the weighted average outstanding balance of our Credit Facilities, which consists of our Second Amended and Restated Credit Agreement along with the $350 million unsecured senior revolving credit agreement;

- The issuance and sale in March 2010 of $500 million of our 5.20% senior unsecured notes due 2020; and
- The issuance and sale in September 2010 of $400 million of our 5.50% senior unsecured notes due 2040.

Other Matters

Alberta Clipper Project Joint Funding Arrangement and Regulatory Accounting

In July 2009, we entered into a joint funding arrangement to finance construction of the U.S. segment of the Alberta Clipper Pipeline with several of our affiliates and affiliates of Enbridge including our General Partner. 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 amounts of $14.7 million and $10.7 million to our General Partner and its affiliate for its combined 66.67 percent interest in the earnings of the Alberta Clipper Pipeline for the three month periods ended March 31, 2011 and 2010, 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

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 $11.6 million to "Receivables, trade and other" on our consolidated statements of financial position at March 31, 2011 for the amounts we received in April 2011, of which 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.

LIQUIDITY AND CAPITAL RESOURCES

Available Liquidity

As set forth in the following table, we had in excess of $725 million of liquidity available to us at March 31, 2011 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	$ 149.7
Total credit available under Credit Facilities	1,517.5
Less: Amounts outstanding under Credit Facilities	—
Principal amount of commercial paper issuances	910.0
Balance of letters of credit outstanding	30.1
Total	$ 727.1

General

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

Our current business strategy emphasizes developing and expanding our existing Liquids and Natural Gas businesses through targeted acquisitions and organic growth. We expect to initially fund our long-term cash requirements for expansion projects and acquisitions as well as retiring our maturing and callable debt first from operating cash flows, and then from issuances of commercial paper and borrowings on our Credit Facilities. Likewise, we anticipate initially retiring our maturing debt with similar borrowings on these existing facilities. We expect to obtain permanent financing as needed through the issuance of additional equity and debt securities, which we will use to repay amounts initially drawn to fund these activities, although there can be no assurance that such financings will be available on favorable terms, if at all.

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.

Equity Distribution Agreement

In June 2010, we entered into an Equity Distribution Agreement, or EDA, for the issue and sale from time to time of our Class A common units up to an aggregate amount of $150.0 million. The EDA allows us to issue and sell our Class A common units at any time from the execution date of the agreement through January 28, 2012, at prices we deem appropriate for our Class A common units. The issue and sale of our Class A common units can be conducted on any day that is a trading day for the New York Stock Exchange unless we have suspended sales under the EDA. The following table presents the net proceeds from our Class A common unit issuances, resulting from the EDA, during the three month period ended March 31, 2011:

Three Month Period Ended	Number of Class A common units Issued[1]	Average Offering Price per Class A common unit	Net Proceeds to the Partnership[2]	General Partner Contribution[3]	Net Proceeds Including General Partner Contribution
	(unaudited; in millions, except units and per unit amounts)				
March 31, 2011	886,724	$64.52	$55.9	$1.2	$57.1

(1) Common units issued are presented prior to the two-for-one split of our units.

(2) Net of commissions and issuance costs of $1.3 million for the three month period ended March 31, 2011.

(3) Contributions made by the General Partner to maintain its two percent general partner interest.

Available Credit

Our two primary sources of liquidity are provided by our commercial paper program and our Credit Facilities. We have a $1 billion commercial paper program that is supported by our long-term Credit Facilities, which we access primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions when the interest rates available to us for commercial paper are more favorable than the rates available under our Credit Facilities.

Credit Facilities

At March 31, 2011, we had no amounts outstanding under our Credit Facilities, and letters of credit totaling $30.1 million. The amounts we may borrow under the terms of our Credit Facilities are reduced by the principal amount of our commercial paper issuances and the balance of our letters of credit outstanding. At March 31, 2011, we could borrow $577.4 million under the terms of our Credit Facilities, determined as follows:

	(unaudited; in millions)
Total credit available under Credit Facilities	$1,517.5
Less: Amounts outstanding under Credit Facilities	—
Principal amount of commercial paper issuances	910.0
Balance of letters of credit outstanding	30.1
Total amount we could borrow at March 31, 2011	$ 577.4

Individual borrowings under the terms of our Credit Facilities generally become due and payable at the end of each contract period, which is typically a period of three months or less. We have the option to repay these amounts on a non-cash basis by net settling with the parties to our Credit Facilities, which we accomplish by contemporaneously borrowing at the then current rate of interest and repaying the principal amount due. We net settled borrowings of $915.0 million for the three month period ended March 31, 2010, on a non-cash basis.

Effective March 31, 2011, we amended our Credit Facilities to increase from $450 million to $550 million, the aggregate amount of the costs associated with the crude oil releases on Lines 6A and 6B that are excluded from Consolidated Earnings Before Income Taxes Depreciation and Amortization, or Consolidated EBITDA, as defined by our Credit Facilities. We requested the increase to alleviate any constraints on our leverage ratio financial covenant attributable to the crude oil releases that resulted from the $120 million increase in the accrual we recorded in the fourth quarter of 2010 for these costs. Our Credit Facilities require us to maintain a maximum leverage ratio of 5.00 to 1.00. At March 31, 2011 we were in compliance with the terms of our financial covenants.

Commercial Paper

At March 31, 2011 we had $910.0 million in principal amount of our commercial paper outstanding, at a weighted average interest rate of 0.38%, before the effect of our interest rate hedging activities. Under our commercial paper program, we had net borrowings of approximately $25.0 million during the three month period ended March 31, 2011, which include gross issuances of $3,714.2 million and gross repayments of $3,689.2 million. At March 31, 2011, we could issue an additional $90.0 million in principal of commercial paper under our commercial paper program. The commercial paper we can issue is limited by the credit available under our Credit Facilities.

Joint Funding Arrangement for Alberta Clipper Project

In July 2009, we entered into a joint funding arrangement to finance construction of the U.S. segment of the Alberta Clipper Project, with several of our affiliates and affiliates of Enbridge. The Alberta Clipper Project 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 senior notes, except that the A1 Term Note has recourse only to the assets of the U.S. portion of the Alberta Clipper Project. 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 Project 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, 2011, we had approximately $350.0 million outstanding under the A1 Term Note.

Our General Partner also made equity contributions totaling $3.2 million and $77.3 million to the Enbridge Energy Limited Partnership, or OLP, during the three month periods ended March 31, 2011 and 2010, to fund its equity portion of the construction costs associated with the Alberta Clipper Project. The OLP paid a distribution of $21.8 million to our General Partner and its affiliate during the three month period ended March 31, 2011 for their noncontrolling interest in the Series AC, representing limited partner ownership interest 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 Project in the amounts of $14.7 million and $10.7 million to our General Partner for its 66.67 percent share of the earnings of the Alberta Clipper Project for the three month periods ended March 31, 2011 and 2010, respectively. We have presented the amounts we allocated to our General Partner for its share of the earnings of the Alberta Clipper Project 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 and crude oil transportation infrastructure. In 2011, we expect to spend approximately $1,270 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. At March 31, 2011, we had approximately $331.7 million in outstanding purchase commitments attributable to capital projects for the construction of assets that will be recorded as property, plant and equipment during 2011.

Lines 6A and 6B Crude Oil Releases

During the three month period ended March 31, 2011, our cash flows were adversely affected by the approximate $89.6 million we paid for the environmental remediation, restoration and cleanup activities resulting from the crude oil releases that occurred in 2010 on Lines 6A and 6B of our Lakehead system. We anticipate paying approximately 90 percent of the total costs associated with these leaks by the end of 2011.

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 Credit Facilities and the issuance of additional debt and equity securities. All acquisitions are considered in the context of the practical financing constraints presented by the capital markets.

Forecasted Expenditures

We categorize our capital expenditures as either core maintenance or enhancement expenditures. Core maintenance expenditures are those expenditures that are necessary to maintain the service capability of our existing assets and 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, 2011. Although we anticipate making these expenditures in 2011, 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 $181.6 million, including $15.8 million on core maintenance activities, for the three month period ended March 31, 2011. For the full year ending December 31, 2011, we anticipate our capital expenditures to approximate the following:

	Total Forecasted Expenditures
	(unaudited; in millions)
System enhancements	$ 350
Liquids integrity program	290
Core maintenance activities	115
Haynesville projects	170
North Dakota Expansion Program	115
Allison Related Expansion Capital	150
Cushing storage	80
	$1,270

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.

In connection with the restart of Line 6B of our Lakehead system, we committed to accelerate a process we had initiated prior to the release to perform additional inspections, testing and refurbishment of Line 6B within and beyond the immediate area of the July 26, 2010 incident. Pursuant to this agreement, 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. 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 is scheduled for tie-in during June 2011. 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.

In February 2011, we included in the FSM, to be effective April 1, 2011, recovery of $175 million of capital costs and $5 million of operating costs which are related to the 2010/2011 Line 6B Integrity Program. The costs associated with the Line 6B Integrity Program, 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 Credit Facilities, with permanent debt and equity funding being obtained when appropriate.

Derivative Activities

We use derivative instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to mitigate the volatility of our cash flows and manage the risks associated with market fluctuations in commodity prices and interest rates. Based on our risk management policies, all of our derivative instruments are employed in connection with an underlying asset, liability or anticipated transaction and are not entered into with the objective of speculating on commodity prices or interest rates.

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, 2011 for each of the indicated calendar years:

	Notional	2011	2012	2013	2014	2015	2016	Total[4]
		(unaudited; dollars, in millions)						
Swaps								
Natural gas[1]	188,921,628	$ (5.7)	$ (3.7)	$ 3.2	$ (0.1)	$ —	$ —	$ (6.3)
NGL[2]	7,166,715	(42.1)	(13.7)	(13.6)	(4.1)	(0.7)	—	(74.2)
Crude[2]	4,860,345	(35.3)	(21.1)	(14.2)	(8.9)	(2.7)	(0.1)	(82.3)
Options								
Natural gas—puts purchased[1]	275,000	—	—	—	—	—	—	—
Natural gas—calls written[1]	275,000	(0.1)	—	—	—	—	—	(0.1)
NGL—puts purchased[2]	762,332	1.3	2.6	—	—	—	—	3.9
Crude—puts purchased[2]	163,625	0.4	—	—	—	—	—	0.4
Forward contracts								
Crude[2]	1,101,061	(1.7)	—	—	—	—	—	(1.7)
Natural gas[1]	51,087,673	1.0	0.6	0.2	—	—	—	1.8
NGL[2]	5,176,581	(0.6)	1.5	—	—	—	—	0.9
Power[3]	81,030	(0.7)	(0.2)	—	—	—	—	(0.9)
Totals		$(83.5)	$(34.0)	$(24.4)	$(13.1)	$(3.4)	$(0.1)	$(158.5)

(1) Notional amounts for natural gas are recorded in millions of British thermal units, or MMBtu.

(2) Notional amounts for NGL and Crude are recorded in Barrels, or Bbl.

(3) Notional amounts for power are recorded in Megawatt hours, or MWh.

(4) Fair values exclude credit adjustments of approximately $1.6 million of gains at March 31, 2011.

The following table provides summarized information about the timing and expected settlement amounts of our outstanding interest rate derivative instruments at March 31, 2011 for each of the indicated calendar years:

	Notional Amount	2011	2012	2013	2014	2015	Thereafter	Total[(1)]
			(unaudited; dollars in millions)					
Interest Rate Derivatives								
Interest Rate Swaps:								
Floating to Fixed	$1,025.0	$(19.7)	$(22.3)	$(12.5)	$2.5	$0.3	$—	$(51.7)
Fixed to Floating	125.0	3.8	4.9	1.8	—	—	—	10.5
Pre-issuance hedges	1,200.0	24.8	(8.4)	2.1	—	—	—	18.5
		$ 8.9	$(25.8)	$ (8.6)	$2.5	$0.3	$—	$(22.7)

(1) Fair values are presented in millions of dollars and exclude credit adjustments of approximately $0.2 million of gains at March 31, 2011.

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 2011 vs. 2010
	2011	2010	Increase (Decrease)
	(unaudited; in millions)		
Total cash provided by (used in):			
Operating activities	$ 260.1	$ 208.6	$ 51.5
Investing activities	(189.4)	(215.3)	25.9
Financing activities	(65.9)	31.3	(97.2)
Net increase (decrease) in cash and cash equivalents	4.8	24.6	(19.8)
Cash and cash equivalents at beginning of year	144.9	143.6	1.3
Cash and cash equivalents at end of period	$ 149.7	$ 168.2	$(18.5)

Operating Activities

Net cash provided by our operating activities increased $51.5 million for the three month period ended March 31, 2011 compared with the same period in 2010 primarily due to higher changes in our working capital accounts for the three month period ended March 31, 2011 compared to the same period of 2010 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 3, 2011 were also affected by $90.2 million of environmental costs we paid, which included $89.6 million associated with the Lines 6A and 6B crude oil releases compared with $2.3 million of environmental costs in the same period of 2010.

Investing Activities

Net cash used in our investing activities during the three month period ended March 31, 2011 decreased by $25.9 million compared to the same period of 2010 primarily due to a $27.5 million reduction of amounts spent in 2010 on our construction projects compared to 2011. The decrease in the amounts spent on our construction projects is primarily attributed to the completion of the second stage of our Alberta Clipper pipeline expansion project in early 2010. This reduction in cash used for construction projects was offset by $3.0 million in cash proceeds received from the sale of a CO_2 plant in Louisiana.

Financing Activities

The net cash used in our financing activities increased $97.2 million during the three month period ended March 31, 2011 compared to the same period in 2010 primarily due to the following:

	(unaudited; in millions)
Net repayment on our Credit Facilities in 2010 and none in 2011[1]	$ 765.0
Increase in net commercial paper repayments in 2011 compared to 2010[1]	(249.9)
Net proceeds from senior notes due in 2020 issues in 2010 and none in 2011	(496.1)
Decrease in net affiliate borrowings in 2011 compared to 2010[2]	(60.6)
Net proceeds related to Class A common units issued under EDA in 2011 and none in 2010[3]	57.1
Increase in distributions to our partners in 2011 compared to 2010	(16.8)
Decrease in capital contributions from our General Partner and its affiliate for its ownership interest in the Alberta Clipper Project	(74.1)
Distributions to our General Partner and its affiliate for its ownership interest in the Alberta Clipper Project paid in 2011 compared to no distributions in 2010	(21.8)
	$ (97.2)

(1) In 2011, we have utilized our commercial paper program rather than our Credit Facilities due to the interest rates on our commercial paper being more favorable than rates available under our Credit Facilities.

(2) For the three month period ended March 31, 2010, we borrowed $387.8 million from our general partner which we used to repay $324.6 million we borrowed on the A1 Credit Facility and to fund $63.2 million of additional costs incurred for the construction of the Alberta Clipper Project. During the same period in 2011, we borrowed only $2.6 million from our general partner and affiliates.

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

OFF-BALANCE SHEET ARRANGEMENTS

We have no significant off-balance sheet arrangements.

SUBSEQUENT EVENTS

Class A common unit issuances

We issued 112,600 Class A common units in April 2011 under the terms of the EDA at sales prices averaging $64.27 per unit, for proceeds of approximately $7.1 million, net of $0.1 million of commissions and issuance costs within the period of April 1 and April 5, 2011. The 112,600 Class A common units we issued represent 225,200 Class A common units on a split-adjusted basis. In addition, our General Partner contributed approximately $0.1 million to us to maintain its two percent general partner interest.

Distribution to Partners

On April 28, 2011, the board of directors of Enbridge Energy Management, L.L.C., or Enbridge Management, declared a distribution payable to our partners on May 13, 2011. The distribution will be paid to unitholders of record as of May 6, 2011, of our available cash of $152.0 million at March 31, 2011, or $0.51375 per limited partner unit on a split adjusted basis. Of this distribution, $133.2 million will be paid in cash, $18.4 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 28, 2011, 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 $21.6 million to the noncontrolling interest in the Series AC, while $10.8 million will be paid to us.

REGULATORY MATTERS

FERC Transportation Tariffs

Effective April 1, 2011, we filed our annual tariff rate adjustment with the Federal Energy Regulatory Commission, or 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 2011 related to our expansion projects. Also included was a supplement to our FSM for recovery of the costs related to the 2010/2011 Line 6B Integrity Program, including costs associated with the PHMSA Corrective Action Order and as discussed in Footnote 9—*Commitments and Contingencies—Pipeline Integrity Commitment*. 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 $0.21 per barrel, to an average of approximately $1.76 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 March 18, 2011, we filed FERC Tariff 72.6.0 and 73.4.0 to incorporate an updated calculation of the surcharges on our North Dakota system of two previously approved expansion projects, North Dakota Phase V and Phase VI. Both phases are cost-of-service based surcharges that are trued up each year to actual costs. Both tariff filings are effective April 1, 2011.

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, 2010, 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 (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 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, 2011.

				Fair Value[2] at	
Date of Maturity & Contract Type	**Accounting Treatment**	**Notional**	**Average Fixed Rate[1]**	**March 31, 2011**	**December 31, 2010**
	(dollars in millions)				
Contracts maturing in 2013					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$600	4.15%	$(45.2)	$(51.8)
Interest Rate Swaps—Pay Fixed	Non-qualifying	$125	4.35%	$ (9.4)	$(10.7)
Interest Rate Swaps—Pay Float	Non-qualifying	$125	4.75%	$ 10.5	$ 11.9
Contracts maturing in 2015					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$300	2.43%	$ 2.8	$ 1.9
Contracts settling prior to maturity					
2011—Pre-issuance Hedges	Cash Flow Hedge	$300	2.92%	$ 24.8	$ 23.4
2012—Pre-issuance Hedges	Cash Flow Hedge	$600	4.57%	$ (8.4)	$(13.7)
2013—Pre-issuance Hedges	Cash Flow Hedge	$300	4.62%	$ 2.1	$ (0.3)

(1) Interest rate derivative contracts are based on the one-month or three-month LIBOR.

(2) The fair value is determined from quoted market prices at March 31, 2011 and December 31, 2010, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values are presented in millions of dollars and exclude credit valuation adjustments of approximately $0.2 million of gains at March 31, 2011 and $0.5 million of gains at December 31, 2010.

Commodity Price 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, 2011 and December 31, 2010.

	At March 31, 2011						At December 31, 2010	
			Wtd. Average Price[2]		Fair Value[3]		Fair Value[3]	
	Commodity	Notional[1]	Receive	Pay	Asset	Liability	Asset	Liability
Portion of contracts maturing in 2011								
Swaps								
Receive variable/pay fixed	Natural Gas	8,707,743	$ 4.53	$ 4.63	$2.6	$ (3.4)	$0.4	$ (4.9)
	NGL	290,000	$ 85.42	$ 66.21	$5.6	$ —	$6.8	$ —
	Crude Oil	315,000	$107.22	$102.06	$1.6	$ —	$0.4	$ —
Receive fixed/pay variable	Natural Gas	13,476,276	$ 4.07	$ 4.55	$1.2	$ (7.6)	$2.6	$ (6.7)
	NGL	3,686,350	$ 46.86	$ 59.82	$1.9	$(49.6)	$5.0	$(38.8)
	Crude Oil	1,583,600	$ 83.41	$106.76	$ —	$(36.9)	$ —	$(22.9)
Receive variable/pay variable	Natural Gas	73,050,858	$ 4.40	$ 4.38	$2.7	$ (1.2)	$5.0	$ (1.2)
Physical Contracts								
Receive fixed/pay variable	NGL	986,083	$ 79.11	$ 84.63	$0.1	$ (5.6)	$0.5	$ (4.4)
	Crude Oil	435,840	$ 96.98	$107.05	$0.3	$ (4.7)	$ —	$ (1.9)
Receive variable/pay fixed	NGL	438,463	$ 88.09	$ 82.88	$2.3	$ —	$1.6	$ —
	Crude Oil	263,840	$106.92	$ 97.42	$2.5	$ —	$1.1	$ —
Pay fixed	Power[4]	56,910	$ 32.66	$ 44.20	$ —	$ (0.7)	$ —	$ (0.8)
Receive variable/pay variable	Crude Oil	401,381	$106.91	$106.18	$1.0	$ (0.8)	$0.5	$ (0.2)
	NGL	3,100,892	$ 83.62	$ 82.78	$4.7	$ (2.1)	$6.2	$ (1.4)
	Natural Gas	26,586,222	$ 4.40	$ 4.36	$1.0	$ —	$1.1	$ —
Portion of contracts maturing in 2012								
Swaps								
Receive variable/pay fixed	Natural Gas	2,182,813	$ 5.03	$ 6.55	$0.5	$ (3.8)	$ —	$ (3.8)
Receive fixed/pay variable	Natural Gas	4,000,002	$ 4.82	$ 5.03	$1.7	$ (2.5)	$1.7	$ (2.1)
	NGL	1,887,680	$ 58.12	$ 65.41	$4.4	$(18.1)	$8.0	$ (7.6)
	Crude Oil	938,790	$ 83.62	$106.28	$ —	$(21.1)	$ —	$(10.7)
Receive variable/pay variable	Natural Gas	50,809,000	$ 4.97	$ 4.97	$1.2	$ (0.8)	$1.0	$ (0.8)
Physical Contracts								
Receive variable/pay variable	Natural Gas	17,889,001	$ 4.97	$ 4.94	$0.6	$ —	$0.6	$ —
	NGL	651,143	$ 68.97	$ 66.61	$2.1	$ (0.6)	$0.7	$ —
Pay fixed	Power[4]	24,120	$ 31.44	$ 40.83	$ —	$ (0.2)	$ —	$ —
Portion of contracts maturing in 2013								
Swaps								
Receive variable/pay fixed	Natural Gas	93,066	$ 5.29	$ 5.19	$ —	$ —	$ —	$ —
Receive fixed/pay variable	Natural Gas	730,000	$ 9.83	$ 5.25	$3.3	$ —	$3.3	$ —
	NGL	930,385	$ 65.39	$ 80.41	$ —	$(13.6)	$0.3	$ (3.2)
	Crude Oil	904,105	$ 87.14	$103.34	$1.5	$(15.7)	$2.2	$ (7.4)
Receive variable/pay variable	Natural Gas	29,550,000	$ 5.34	$ 5.35	$0.1	$ (0.2)	$0.1	$ (0.2)
Physical Contracts								
Receive variable/pay variable	Natural Gas	6,612,450	$ 5.38	$ 5.34	$0.2	$ —	$0.2	$ —
Portion of contracts maturing in 2014								
Swaps								
Receive variable/pay fixed	Natural Gas	21,870	$ 5.70	$ 5.22	$ —	$ —	$ —	$ —
Receive fixed/pay variable	NGL	262,800	$ 79.78	$ 96.19	$ —	$ (4.1)	$ —	$ (1.1)
	Crude Oil	722,700	$ 88.89	$101.86	$ —	$ (8.9)	$ —	$ (2.8)
Receive variable/pay variable	Natural Gas	6,300,000	$ 5.77	$ 5.79	$ —	$ (0.1)	$ —	$ (0.1)
Portion of contracts maturing in 2015								
Swaps								
Receive fixed/pay variable	Crude Oil	350,400	$ 93.00	$101.35	$ —	$ (2.7)	$ —	$ (0.7)
	NGL	109,500	$ 88.36	$ 95.86	$ —	$ (0.7)	$ —	$ (0.1)
Portion of contracts maturing in 2016								
Swaps								
Receive fixed/pay variable	Crude Oil	45,750	$ 99.31	$101.60	$ —	$ (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, 2011 and December 31, 2010, 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 $1.6 million of gains and $0.6 million of gains at March 31, 2011 and December 31, 2010, 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, 2011 and December 31, 2010.

	At March 31, 2011						At December 31, 2010	
					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 2011								
Calls (written)	Natural Gas[4]	275,000	$ 4.31	$ 4.58	$ —	$(0.1)	$ —	$(0.2)
Puts (purchased)	Natural Gas[4]	275,000	$ 3.40	$ 4.58	$ —	$ —	$ —	$ —
	NGL	477,950	$54.79	$ 66.95	$1.3	$ —	$3.6	$ —
	Crude Oil	163,625	$88.65	$107.94	$0.4	$ —	$1.3	$ —
Portion of option contracts maturing in 2012								
Puts (purchased)	NGL	284,382	$65.90	$ 74.30	$2.6	$ —	$3.9	$ —

(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, 2011 and December 31, 2010, 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 December 31, 2010. No credit valuation adjustments related to our outstanding commodity options existed at March 31, 2011.

(4) Indicates transactions which, in combination, create a collar, representing a floor and ceiling on the price and provide long-term price protection.

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.

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

	March 31, 2011	December 31, 2010
	(in millions)	
Counterparty Credit Quality*		
AAA	$ (0.1)	$ —
AA	(91.8)	(48.7)
A	(89.8)	(61.3)
Lower than A	2.2	5.8
	$(179.5)	$(104.2)

* As determined by nationally-recognized statistical ratings organizations.

Item 4. Controls and Procedures

We and Enbridge maintain systems of disclosure controls and procedures designed to provide reasonable assurance that we are able to record, process, summarize and report the information required to be disclosed in our annual and quarterly reports under the Securities Exchange Act of 1934, as amended (the “Exchange Act”) within the time periods specified in the rules and forms of the Securities and Exchange Commission. These disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure. Our management, with the participation of our principal executive and principal financial officers, has evaluated the effectiveness of our disclosure controls and procedures as of March 31, 2011. Based upon that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures are 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. We have not made any changes that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting during the three month period ended March 31, 2011.

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, 2010.

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: April 29, 2011

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

Date: April 29, 2011

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

Index of Exhibits

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

Exhibit Number	Description
3.1	Certificate of Limited Partnership of the Partnership (incorporated by reference to Exhibit 3.1 to the Partnership's Registration Statement on Form S-1 (No. 33-43425)).
3.2	Certificate of Amendment to Certificate of Limited Partnership of the Partnership, dated August 28, 2001 (incorporated by reference to Exhibit 3.2 to the Partnership's Second Amendment to Annual Report on Form 10-K/A for the year ended December 31, 2000, filed on October 9, 2001).
3.3	Fourth Amended and Restated Agreement of Limited Partnership of the Partnership, dated August 15, 2006 (incorporated by reference to Exhibit 3.1 of the Partnership's Current Report on Form 8-K, filed on August 16, 2006).
3.4	Amendment No. 1 to Fourth Amended and Restated Limited Partnership Agreement of the Partnership, dated December 28, 2007 (incorporated by reference to Exhibit 3.1 of the Partnership's Current Report on Form 8-K, filed on January 3, 2008).
3.5	Amendment No. 2 to Fourth Amended and Restated Agreement of Limited Partnership of the Partnership, dated August 6, 2008 (incorporated by reference to Exhibit 3.1 of the Partnership's Current Report on Form 8-K, filed on August 7, 2008).
3.6	Amendment No. 3 to Fourth Amended and Restated Agreement of Limited Partnership of the Partnership, dated April 21, 2011 (incorporated by reference to Exhibit 3.1 of the Partnership's Current Report on Form 8-K, filed on April 25, 2011).
4.1	Form of Certificate representing Class A Common Units (incorporated by reference to Exhibit 4.1 to the Partnership's Second Amendment to Annual Report on Form 10-K/A for the year ended December 31, 2000, filed on October 9, 2001).
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.