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 June 30, 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 219,517,198 Class A common units outstanding as of July 29, 2011.

ENBRIDGE ENERGY PARTNERS, L.P.

TABLE OF CONTENTS

In this report, unless the context requires otherwise, references to "we," "us," "our" or the "Partnership" are intended to mean Enbridge Energy Partners, L.P. and its consolidated subsidiaries. We refer to our general partner, Enbridge Energy Company, Inc., as our "General Partner."

This Quarterly Report on Form 10-Q contains forward-looking statements, which are typically identified by words such as "anticipate," "believe," "continue," "estimate," "expect," "forecast," "intend," "may," "plan," "position," "project," "strategy," "target," "could," "should" or "will" and similar words or statements, express or implied, suggesting future outcomes or statements regarding an outlook or the negative of those terms. Although we believe that these forward-looking statements are reasonable based on the information available on the dates these statements are made and processes used to prepare the information, these statements are not guarantees of future performance, and we caution you not to place undue reliance on these statements. By their nature, these statements involve a variety of assumptions, unknown risks, uncertainties and other factors, which may cause actual results, levels of activity and performance to differ materially from those expressed or implied by these statements. Material assumptions may include, among others, the expected supply of and demand for crude oil, natural gas and natural gas liquids, or NGLs; prices of crude oil, natural gas and NGLs; inflation and interest rates; operational reliability; and weather.

Our forward-looking statements are subject to risks and uncertainties pertaining to operating performance, regulatory parameters, weather, economic conditions, interest rates and commodity prices, including but not limited to, those risks and uncertainties discussed in this Quarterly Report on Form 10-Q and our other reports that we have filed or will file with the Securities and Exchange Commission, or SEC. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these factors are interdependent, and our future course of action depends on the assessment of all information available at the relevant time by those responsible for the management of our operations. Except to the extent required by law, we assume no obligation to publicly update or revise any forward-looking statements made herein whether as a result of new information, future events or otherwise. All subsequent forward-looking statements, whether written or oral, attributable to us or persons acting on our behalf are expressly qualified in their entirety by these cautionary statements and, as such, may be updated in our future filings with the SEC. For additional discussion of risks, uncertainties and assumptions, see "Item 1A. Risk Factors" included in our Annual Report on Form 10-K for the fiscal year ended December 31, 2010.

PART I—FINANCIAL INFORMATION

Item 1. Financial Statements

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF INCOME

	For the three month period ended June 30,		For the six month period ended June 30,	
	2011	2010	2011	2010
	(unaudited; in millions, except per unit amounts)			
Operating revenue (Note 10)	$2,372.0	$1,747.4	$4,660.9	$3,678.6
Operating expenses				
Cost of natural gas (Notes 4 and 10)	1,861.3	1,270.4	3,690.8	2,794.6
Environmental costs, net of recoveries (Notes 1 and 9)	23.3	(0.1)	(11.3)	4.5
Oil measurement adjustments (Notes 1 and 12)	(54.1)	1.1	(58.7)	—
Operating and administrative (Note 1)	167.6	135.3	334.7	267.8
Power (Note 10)	33.9	36.5	69.5	68.8
Depreciation and amortization (Note 5)	89.6	77.6	178.0	145.5
	2,121.6	1,520.8	4,203.0	3,281.2
Operating income	250.4	226.6	457.9	397.4
Interest expense (Notes 6 and 10)	78.5	69.6	157.9	128.9
Other income (expense) (Notes 9 and 14)	—	(0.1)	6.0	16.7
Income before income tax expense	171.9	156.9	306.0	285.2
Income tax expense (Note 11)	0.9	2.4	3.2	4.6
Net income	171.0	154.5	302.8	280.6
Less: Net income attributable to noncontrolling interest (Note 8)	14.1	14.5	28.8	25.2
Net income attributable to general and limited partner ownership interest in Enbridge Energy Partners, L.P.	$ 156.9	$ 140.0	$ 274.0	$ 255.4
Net income allocable to limited partner interests	$ 130.3	$ 120.3	$ 227.0	$ 219.5
Net income per limited partner unit (basic and diluted) (Note 2)	$ 0.51	$ 0.51	$ 0.90	$ 0.93
Weighted average limited partner units outstanding	255.2	236.5	254.0	236.2

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	For the three month period ended June 30,		For the six month period ended June 30,	
	2011	2010	2011	2010
	(unaudited; in millions)			
Net income	$171.0	$154.5	$302.8	$280.6
Other comprehensive income (loss), net of tax expense of $0.6, $0.2, $0.1 and $0.4, respectively (Note 10)	(3.7)	(52.9)	(61.1)	(46.4)
Comprehensive income	167.3	101.6	241.7	234.2
Less: Comprehensive income attributable to noncontrolling interest (Note 8)	14.1	14.5	28.8	25.2
Comprehensive income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$153.2	$ 87.1	$212.9	$209.0

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the six month period ended June 30,	
	2011	2010
	(unaudited; in millions)	
Cash provided by operating activities		
Net income	$ 302.8	$ 280.6
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization (Note 5)	178.0	145.5
Derivative fair value net gains (Note 10)	(3.3)	(25.9)
Inventory market price adjustments (Note 4)	0.2	2.6
Environmental costs, net of recoveries (Notes 1 and 9)	24.0	4.3
Oil measurement adjustments (Notes 1 and 12)	(52.2)	—
Other (Notes 1 and 16)	7.2	(5.7)
Changes in operating assets and liabilities, net of acquisitions:		
Receivables, trade and other (Note 9)	(32.0)	37.7
Due from General Partner and affiliates	4.7	(17.4)
Accrued receivables	102.4	15.0
Inventory (Note 4)	(3.5)	(58.2)
Current and long-term other assets (Note 10)	1.5	(0.9)
Due to General Partner and affiliates (Note 8)	27.8	18.7
Accounts payable and other (Notes 1, 3 and 10)	23.0	1.1
Environmental liabilities (Notes 1 and 9)	(105.3)	(4.9)
Accrued purchases	(12.9)	(20.1)
Interest payable	(0.1)	8.7
Property and other taxes payable	(1.3)	(2.5)
Settlement of interest rate derivatives (Note 10)	—	(13.2)
Net cash provided by operating activities	461.0	365.4
Cash used in investing activities		
Additions to property, plant and equipment (Notes 5 and 9)	(363.1)	(356.2)
Changes in construction payables	(8.3)	(9.9)
Asset acquisitions	(27.2)	(17.0)
Other	(7.8)	—
Net cash used in investing activities	(406.4)	(383.1)
Cash (used in) provided by financing activities		
Net proceeds from unit issuances (Note 7)	74.4	15.1
Distributions to partners (Note 7)	(265.2)	(233.0)
Repayments to General Partner (Note 8)	(6.4)	(324.6)
Net proceeds from issuances of long-term debt (Note 6)	—	496.1
Net borrowings (repayments) under Credit Facility (Note 6)	75.0	(765.0)
Net commercial paper borrowings (Note 6)	115.1	409.9
Borrowings from General Partner (Note 8)	7.0	395.8
Contribution from noncontrolling interest (Note 8)	3.3	87.0
Distributions to noncontrolling interest (Note 8)	(43.4)	—
Net cash (used in) provided by financing activities	(40.2)	81.3
Net increase in cash and cash equivalents	14.4	63.6
Cash and cash equivalents at beginning of year	144.9	143.6
Cash and cash equivalents at end of period	$ 159.3	$ 207.2

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	June 30, 2011	December 31, 2010
	(unaudited; dollars in millions)	
ASSETS		
Current assets		
Cash and cash equivalents (Note 3)	$ 159.3	$ 144.9
Receivables, trade and other, net of allowance for doubtful accounts of $1.9 in 2011 and $1.8 in 2010 (Note 9)	247.0	171.2
Due from General Partner and affiliates	22.4	27.1
Accrued receivables	580.1	683.7
Inventory (Note 4)	138.0	134.7
Other current assets (Note 10)	42.8	58.3
	1,189.6	1,219.9
Property, plant and equipment, net (Notes 5, 9 and 14)	8,859.8	8,641.6
Goodwill	246.7	246.7
Intangibles, net	270.8	276.4
Other assets, net (Note 10)	63.6	56.4
	$10,630.5	$10,441.0
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Due to General Partner and affiliates	$ 78.7	$ 53.3
Accounts payable and other (Notes 3 and 10)	318.2	289.2
Environmental liabilities (Note 9)	122.5	227.0
Accrued purchases	592.8	596.4
Interest payable	60.2	60.3
Property and other taxes payable	47.8	49.1
Note payable to General Partner (Note 8)	12.0	11.6
Current maturities of long-term debt (Note 6)	31.0	31.0
	1,263.2	1,317.9
Long-term debt (Note 6)	4,969.3	4,778.9
Note payable to General Partner (Note 8)	336.0	335.8
Other long-term liabilities (Notes 9 and 10)	164.1	122.9
	6,732.6	6,555.5
Commitments and contingencies (Note 9)		
Partners' capital (Notes 7 and 8)		
Class A common units (211,467,198 and 209,084,106 at June 30, 2011 and December 31, 2010, respectively)	2,683.4	2,641.0
Class B common units (7,825,500 at June 30, 2011 and December 31, 2010)	65.9	64.9
i-units (36,410,356 and 35,285,422 at June 30, 2011 and December 31, 2010, respectively)	617.2	579.1
General Partner	260.1	256.8
Accumulated other comprehensive income (loss) (Note 10)	(182.8)	(121.7)
Total Enbridge Energy Partners, L.P. partners' capital	3,443.8	3,420.1
Noncontrolling interest (Note 8)	454.1	465.4
Total partners' capital	3,897.9	3,885.5
	$10,630.5	$10,441.0

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

ENBRIDGE ENERGY PARTNERS, L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

1. BASIS OF PRESENTATION

The accompanying unaudited interim consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America 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 June 30, 2011, our results of operations for the three and six month periods ended June 30, 2011 and 2010 and our cash flows for the six month periods ended June 30, 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 and six month periods ended June 30, 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 June 30, 2010 to conform to our current year presentation. We reclassified $4.3 million from "Other" to "Environmental costs, net of recoveries" in our consolidated statement of cash flows. We also reclassified $4.9 million from "Accounts payable and other" to "Environmental liabilities" in our consolidated statement of cash flows for the six month period ended June 30, 2010. These reclassifications did not impact our net cash provided by operating activities for the six month period ended June 30, 2010. We made a reclassification of $0.1 million of recoveries and $4.5 million of costs from "Operating and administrative" to "Environmental costs, net of recoveries" in our consolidated statements of income for the three and six month periods ended June 30, 2010, respectively. Additionally, in our consolidated statement of income, we made a reclassification of $1.1 million for oil measurement losses from "Operating and administrative" to "Oil measurement adjustments" for the three month period ended June 30, 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 and restated the number of units in our consolidated statement of financial position to present the prior year amounts on a split-adjusted basis. Additionally, the formula for distributing available cash among our General Partner and limited partners was revised to reflect this unit split, as set forth in our partnership agreement, as amended, and is presented below.

Distribution Targets	Portion of Quarterly Distribution Per Unit	Percentage Distributed to General Partner	Percentage Distributed to Limited partners
Minimum Quarterly Distribution	Up to $0.295	2%	98%
First Target Distribution	> $0.295 to $0.35	15%	85%
Second Target Distribution	> $0.35 to $0.495	25%	75%
Over Second Target Distribution	In excess of $0.495	50%	50%

We allocate our net income among our General Partner and limited partners using the two-class method in accordance with applicable authoritative accounting guidance. Under the two-class method, we allocate our net income, including any incentive distribution rights, or IDRs, embedded in the general partner interest, to our General Partner and our limited partners according to the distribution formula for available cash as set forth in our partnership agreement. We also allocate any earnings in excess of distributions to our General Partner and limited partners utilizing the distribution formula for available cash specified in our partnership agreement. We allocate any distributions in excess of earnings for the period to our General Partner and limited partners based on their sharing of losses of 2 percent and 98 percent, respectively, as set forth in our partnership agreement.

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

	For the three month period ended June 30,		For the six month period ended June 30,	
	2011	2010	2011	2010
	(in millions, except per unit amounts)			
Net income	$ 171.0	$ 154.5	$ 302.8	$ 280.6
Less: Net income attributable to noncontrolling interest	14.1	14.5	28.8	25.2
Net income attributable to general and limited partner interests in Enbridge Energy Partners, L.P.	156.9	140.0	274.0	255.4
Less distributions paid:				
Incentive distributions to our General Partner	(24.0)	(17.2)	(42.4)	(31.4)
Distributed earnings allocated to our General Partner	(2.8)	(2.5)	(5.5)	(4.9)
Total distributed earnings to our General Partner	(26.8)	(19.7)	(47.9)	(36.3)
Total distributed earnings to our limited partners	(140.4)	(122.0)	(271.3)	(240.3)
Total distributed earnings	(167.2)	(141.7)	(319.2)	(276.6)
Overdistributed earnings	$ (10.3)	$ (1.7)	$ (45.2)	$ (21.2)
Weighted average limited partner units outstanding	255.2	236.5	254.0	236.2
Basic and diluted earnings per unit:				
Distributed earnings per limited partner unit[1]	$ 0.55	$ 0.52	$ 1.07	$ 1.02
Overdistributed earnings per limited partner unit[2]	(0.04)	(0.01)	(0.17)	(0.09)
Net income per limited partner unit (basic and diluted)	$ 0.51	$ 0.51	$ 0.90	$ 0.93

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

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

3. CASH AND CASH EQUIVALENTS

We extinguish liabilities when a creditor has relieved us of our obligation, which occurs when our financial institution honors a check that the creditor has presented for payment. Accordingly, obligations for which we have made payments that have not yet been presented to the financial institution totaling approximately $24.4 million at June 30, 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:

	June 30, 2011	December 31, 2010
	(in millions)	
Materials and supplies	$ 2.2	$ 6.3
Crude oil inventory	9.7	8.1
Natural gas and NGL inventory	126.1	120.3
	$138.0	$134.7

The "Cost of natural gas" on our consolidated statements of income for the three and six month periods ended June 30, 2011 includes charges totaling $0.2 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 of $1.5 million and $2.6 million were recorded to reduce our natural gas and NGLs inventories for the three and six month periods ended June 30, 2010.

5. PROPERTY, PLANT AND EQUIPMENT

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

	June 30, 2011	December 31, 2010
	(in millions)	
Land	$ 35.8	$ 35.7
Rights-of-way	519.0	510.9
Pipelines	6,067.3	5,981.6
Pumping equipment, buildings and tanks	1,360.7	1,306.9
Compressors, meters and other operating equipment	1,489.2	1,477.8
Vehicles, office furniture and equipment	202.1	201.6
Processing and treating plants	438.7	438.3
Construction in progress	631.6	401.9
Total property, plant and equipment	10,744.4	10,354.7
Accumulated depreciation	(1,884.6)	(1,713.1)
Property, plant and equipment, net	$ 8,859.8	$ 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 which also supports our commercial paper program.

On July 20, 2011, we amended the $350 million unsecured senior revolving credit agreement to reflect an increase in the lending commitments to $600 million. The amended $600 million credit agreement has terms consistent with our existing Credit Facility and has the same maturity date of April 4, 2013. After this amendment, our Credit Facilities provide an aggregate amount of $1,767.5 million of bank credit.

Effective March 31, 2011, our Credit Facilities were amended to further modify the definition of 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 June 30, 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 June 30, 2011, we could borrow $391.8 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	75.0
Principal amount of commercial paper issuances	1,000.0
Balance of letters of credit outstanding	50.7
Total amount we could borrow at June 30, 2011	$ 391.8

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 six month period ended June 30, 2010, on a non-cash basis.

Commercial Paper

We have a commercial paper program that provides for the issuance of up to $1 billion in aggregate principal amount 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 June 30, 2011, we had $1 billion of commercial paper outstanding at a weighted average interest rate of 0.35%, 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. 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. Accordingly, such amounts have been classified as “Long-term debt” in our accompanying consolidated statements of financial position.

Senior Notes due 2019

The holders of our Senior Notes due 2019 have an option to require us to repurchase all or a portion of the notes on March 1, 2012 at a purchase price of 100 percent of the principal amount of the notes tendered plus accrued and unpaid interest. If the holders of the senior notes require us to repay the notes on March 1, 2012, we have the ability and intent to finance them on a long-term basis through borrowings under our unsecured, long-term Credit Facilities, including the $250 million of additional capacity resulting from the July 2011 amendment to our unsecured senior revolving credit agreement. 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 June 30, 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, borrowings on our Credit Facilities and our Senior Notes due 2019 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.

	June 30, 2011		December 31, 2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Commercial Paper	$1,000.0	$1,000.0	$ 884.9	$ 884.9
Credit Facility	75.0	75.0	—	—
9.150% First Mortgage Notes	31.0	32.2	31.0	33.5
7.900% Senior Notes due 2012	100.0	109.6	100.0	112.1
4.750% Senior Notes due 2013	199.9	212.2	199.9	214.4
5.350% Senior Notes due 2014	200.0	220.7	200.0	221.8
5.875% Senior Notes due 2016	299.8	339.0	299.8	338.1
7.000% Senior Notes due 2018	99.9	118.9	99.9	119.2
6.500% Senior Notes due 2018	398.6	463.4	398.5	463.0
9.875% Senior Notes due 2019	500.0	693.0	499.9	699.1
5.200% Senior Notes due 2020	499.8	529.3	499.8	526.6
7.125% Senior Notes due 2028	99.8	120.6	99.8	121.7
5.950% Senior Notes due 2033	199.7	206.3	199.7	209.0
6.300% Senior Notes due 2034	99.8	106.6	99.8	108.2
7.500% Senior Notes due 2038	399.0	484.1	398.9	493.0
5.500% Senior Notes due 2040	398.5	363.7	398.5	371.6
8.050% Junior subordinated notes due 2067	399.5	447.4	399.5	408.5
Total	$5,000.3	$5,522.0	$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 split of our common units and i-units outstanding to unit holders of record on April 7, 2011. The net income per share and weighted average shares outstanding for the three and six month periods ended June 30, 2010 presented in our consolidated statements of income and the number of units presented in our consolidated statements of financial position are presented reflecting the retroactive effects of the share split.

Distribution to Partners

The following table sets forth our distributions, as approved by the board of directors of Enbridge Management, during the six month period ended June 30, 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	$0.51375	$150.5	$18.1	$0.4	$132.0
April 28, 2011	May 6, 2011	May 13, 2011	$0.51375	$152.0	$18.4	$0.4	$133.2

(1) Distributions per unit for the distribution paid on February 14, 2011 are presented retrospectively applying the two-for-one split of our units.

(2) We issued 1,124,934 split adjusted i-units, 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 and six month periods ended June 30, 2011 and 2010. The noncontrolling interest in the OLP arises from the joint funding arrangement with our General Partner and its affiliate to finance construction of the United States portion of the Alberta Clipper crude oil pipeline and related facilities, which we refer to as the Alberta Clipper Pipeline.

	For the three month periods ended June 30,		For the six month periods ended June 30,	
	2011	2010	2011	2010
	(in millions)			
General and limited partner interests				
Beginning balance	$3,585.6	$3,805.5	$3,541.8	$3,803.4
Proceeds from issuance of partnership interests, net of costs	17.3	15.1	76.0	15.1
Capital contribution	—	—	—	1.9
Net income	156.9	140.0	274.0	255.4
Distributions	(133.2)	(117.8)	(265.2)	(233.0)
Ending balance	$3,626.6	$3,842.8	$3,626.6	$3,842.8
Accumulated other comprehensive income (loss)				
Beginning balance	$ (179.1)	$ (68.1)	$ (121.7)	$ (74.6)
Net realized losses on changes in fair value of derivative financial instruments reclassified to earnings	27.3	9.0	46.1	18.9
Unrealized net loss on derivative financial instruments	(31.0)	(61.9)	(107.2)	(65.3)
Ending balance	$ (182.8)	$ (121.0)	$ (182.8)	$ (121.0)
Noncontrolling interest				
Beginning balance	$ 461.5	$ 429.1	$ 465.4	$ 341.1
Capital contributions	0.1	9.7	3.3	87.0
Comprehensive income:				
Net income	14.1	14.5	28.8	25.2
Distributions to noncontrolling interest	(21.6)	—	(43.4)	—
Ending balance	$ 454.1	$ 453.3	$ 454.1	$ 453.3
Total partners' capital at end of period	$3,897.9	$4,175.1	$3,897.9	$4,175.1

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 allowed us to issue and sell our Class A common units at prices we deemed appropriate for our Class A common units. Under the EDA, we sold 2,118,025 Class A common units, representing 4,236,050 units after giving effect to a two-for-one split of our Class A common units that became effective on April 21, 2011, for aggregate gross proceeds of $124.8 million, of which $64.5 million are gross proceeds received in 2011. No further sales will be made under that agreement. On May 27, 2011, we de-registered the remaining aggregate $25.2 million of Class A common units that were registered for sale under the EDA and remained unsold as of that date.

On May 27, 2011, the Partnership entered into an Amended and Restated Equity Distribution Agreement, or Amended EDA, for the issue and sale from time to time of our Class A common units up to an aggregate amount of $500.0 million from the execution date of the agreement through May 20, 2014. The units issued under the Amended EDA are in addition to the units offered and sold under the EDA. The issue and sale of our Class A common units, pursuant to the Amended EDA, may be conducted on any day that is a trading day for the New York Stock Exchange, unless we have suspended sales under that agreement.

The following table presents the net proceeds from our Class A common unit issuances, pursuant to the Amended EDA, during the three month period ended June 30, 2011:

Issuance Date	Number of Class A common units Issued	Average Offering Price per Class A common unit	Net Proceeds to the Partnership(1)	General Partner Contribution(2)	Net Proceeds Including General Partner Contribution
	(unaudited; in millions, except units and per unit amounts)				
May 27 to June 30, 2011	333,794	$30.30	$9.9	$0.2	$10.1

(1) Net of commissions and issuance costs of $0.2 million for the three month period ended June 30, 2011.

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

8. RELATED PARTY TRANSACTIONS

Joint Funding Arrangement for Alberta Clipper Pipeline

In July 2009, we entered into a joint funding arrangement to finance construction of the United States segment of the Alberta Clipper Pipeline with several of our affiliates and affiliates of Enbridge Inc., or Enbridge. The Alberta Clipper Pipeline was mechanically complete in March 2010 and was ready for service on April 1, 2010. In March 2010, we refinanced $324.6 million of amounts we had outstanding and payable to our General Partner under the A1 Credit Agreement, a credit agreement between our General Partner and us to finance the Alberta Clipper Pipeline, by issuing a promissory note payable to our General Partner, at which time we also terminated the A1 Credit Agreement. The promissory note payable, which we refer to as the A1 Term Note, matures on March 15, 2020, bears interest at a fixed rate of 5.20% and has a maximum loan amount of $400 million. The terms of the A1 Term Note are similar to the terms of our senior notes due 2020, except that the A1 Term Note has recourse only to the assets of the United States portion of the Alberta Clipper Pipeline and is subordinate to all of our senior indebtedness. Under the terms of the A1 Term Note, we have the ability to increase the principal amount outstanding to finance the debt portion of the Alberta Clipper Pipeline that our General Partner is obligated to make pursuant to the Alberta Clipper Joint Funding Arrangement for any additional costs associated with our construction of the Alberta Clipper Pipeline that we incur after the date the original A1 Term Note was issued. The increases we make to the principal balance of the A1 Term Note will also mature on March 15, 2020. Pursuant to the terms of the A1 Term Note, we are required to make semi-annual payments of principal and accrued interest. The semi-annual principal payments are based upon a straight-line amortization of the principal balance over a 30 year period as set forth in the approved terms of the cost of service recovery model associated with the Alberta Clipper Pipeline. The approved terms for the Alberta Clipper Pipeline are described in the "Alberta Clipper United States Term Sheet," which is included as Exhibit I to the June 27, 2008 Offer of Settlement filed with the Federal Energy Regulatory Commission, or FERC, by the OLP and approved on August 28, 2008 (Docket No. OR08-12-000).

A summary of the cash activity for the A1 Term Note for the six month periods ended June 30, 2011 and 2010 are as follows:

	A1 Term Note	
	2011	2010
	(in millions)	
Beginning Balance	$347.4	$ —
Repayments	(6.4)	—
Borrowings	7.0	340.9
Ending Balance	$348.0	$340.9

Our General Partner also made equity contributions totaling $3.3 million and $87.0 million to the OLP during the six month periods ended June 30, 2011 and 2010, respectively, to fund its equity portion of the construction costs associated with the Alberta Clipper Pipeline.

We allocated earnings derived from operating the Alberta Clipper Pipeline in the amounts of $14.1 million and $28.8 million to our General Partner for its 66.67 percent share of the earnings of the Alberta Clipper Pipeline for the three and six month periods ended June 30, 2011, respectively. We allocated $14.5 million and $25.2 million for the same three and six month periods ended June 30, 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.

Distribution to Series AC Interests

The following table presents distributions paid by the OLP to our General Partner and its affiliate during the six month period ended June 30, 2011, representing the noncontrolling interest in the Series AC and to us, as the holders of the Series AC general and limited partner interests. The distributions were declared by the board of directors of Enbridge Management, acting on behalf of Enbridge Pipelines (Lakehead) L.L.C., the managing general partner of the OLP and the Series AC interests.

Distribution Declaration Date	Distribution Payment Date	Amount Paid to Partnership	Amount paid to the noncontrolling interst	Total Series AC Distribution
	(in millions)			
January 28, 2011	February 14, 2011	$10.9	$21.8	$32.7
April 28, 2011	May 13, 2011	10.8	21.6	32.4
		$21.7	$43.4	$65.1

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 June 30, 2011 and December 31, 2010, we have $49.9 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 Crude Oil Releases

Line 6B Crude Oil Release

We continue to make visible progress on the cleanup, remediation and restoration of the areas affected by the Line 6B crude oil release. A significant portion of the effort to cleanup, remediate and restore the areas affected by the Line 6B crude oil 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 crude oil release area to the satisfaction of the appropriate regulatory authorities.

We have revised our total estimate for this crude oil release to $585 million, as of June 30, 2011, an increase of $35.0 million from March 31, 2011, based on additional information concerning the reassessment of the overall monitoring area, related cleanup, including submerged oil recovery operations, and remediation activities. This estimate is before insurance recoveries and excluding fines and penalties. For purposes of estimating our expected losses associated with the Line 6B crude oil release, we have included those costs that we considered probable and that could be reasonably estimated at June 30, 2011. Our estimates do not include amounts we have capitalized or any 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 continue to be further refined. Our estimates also consider currently available facts, existing technology and presently enacted laws and regulations. These amounts also consider our and other companies' prior experience remediating contaminated sites and data released by government organizations. Despite the efforts we have made to ensure the reasonableness of our estimates, changes to the recorded amounts associated with this release are possible as more reliable information becomes available. We have the potential of incurring additional costs in connection with this crude oil release due to variations in any or all of the categories described above including modified or revised requirements from regulatory agencies in addition to fines and penalties as well as expenditures associated with litigation and settlement of claims.

The material components underlying our total estimated loss for the cleanup, remediation and restoration associated with the Line 6B crude oil release include the following:

	(in millions)
Response Personnel & Equipment	$197
Environmental Consultants	113
Professional, regulatory and other	275
Total	$585

We expect that we will have paid approximately 80 to 90 percent of the estimated costs associated with this crude oil release by the end of 2011. We have made payments totaling $422.3 million for costs associated with the Line 6B crude oil release, $128.7 million of which relates to the six month period ended June 30, 2011. We have a remaining liability of $162.7 million, a majority of which is presented as current, on our consolidated statement of financial position at June 30, 2011. Additionally, we recognized $15.0 million and $50.0 million of insurance recoveries in our consolidated statements of income for the three and six month periods ended June 30, 2011.

Line 6A Crude Oil Release

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

In connection with this crude oil release, we have revised our original estimate to $48 million, an increase of $3.0 million from March 31, 2011, based on a refinement of our future costs based on additional information. This estimate is before insurance recoveries and excluding fines and penalties. We continue to monitor this estimate based upon actual invoices received and paid for the personnel, equipment and services provided by our vendors and currently available facts specific to these circumstances, existing technology and presently enacted laws and regulations to determine if our estimate should be updated. We have made payments totaling $43.7 million for costs associated with the Line 6A crude oil release, $9.3 million of which relates to the six month period ended June 30, 2011. We have a remaining total liability of $4.3 million, a majority of which is presented as current, on our consolidated statement of financial position as of June 30, 2011.

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

Lines 6A & 6B Fines and Penalties

Our estimated environmental costs for both the Line 6A and Line 6B crude oil releases do not include an estimate for fines and penalties at June 30, 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 releases. As a result, we have not recorded any liability for expected fines and penalties.

Insurance Recoveries

We are included in the comprehensive insurance program that is maintained by Enbridge for its subsidiaries and affiliates, which renews May of each year. The program includes commercial liability insurance coverage that is consistent with coverage considered customary for our industry and includes coverage for environmental incidents such as those we have incurred for the crude oil releases from Lines 6A and 6B, excluding costs for fines and penalties. The claims for the crude oil releases from Lines 6A and 6B are covered by the insurance policy that expired on April 30, 2011, which had an aggregate limit of $650 million for pollution liability. Assuming that all of the claims for the releases are recoverable under this insurance policy, the occurrence-based coverage remaining under the commercial liability insurance policies related to costs associated with Lines 6A and 6B, and other claims of Enbridge and its subsidiaries and affiliates, including us, is approximately $20 million based on estimates as of June 30, 2011.

We anticipate that substantially all of the costs we have incurred from the crude oil releases will ultimately be recoverable under our existing insurance policies, except for fines and penalties and other amounts for which we are not insured. We recognized $15.0 million and $50.0 million of insurance recoveries as reductions to “Environmental costs, net of recoveries” in our consolidated statements of income for the three and six month periods ended June 30, 2011, respectively. At June 30, 2011, we have $15.0 million recorded in “Receivables, trade and other” in our consolidated statement of financial position for an insurance payment received in July 2011 for a claim we filed in connection with the Line 6B crude oil release. In second quarter 2011, we received insurance payments of $35 million for claims we filed. 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.

During the second quarter of 2011, Enbridge renewed its comprehensive insurance program and the current coverage year has an aggregate limit of $575.0 million for pollution liability for the period May 1, 2011 through April 30, 2012.

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

On May 12, 2011 we announced plans to replace 75-miles of non-contiguous sections of Line 6B of our Lakehead system at an estimated cost of $286 million. Our Line 6B pipeline runs from Griffith, Indiana through Michigan to the international border at the St. Clair River. Subject to regulatory approvals, the new segments of pipeline will be constructed mostly in 2012 and are targeted to be placed in-service by the first quarter of 2013 in consultation with, and to minimize impact to, refiners and shippers served by Line 6B crude oil deliveries.

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 for the 2010 and 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.

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.

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 $5.6 million as a reduction to “Operating and administrative” expenses of our Liquids segment and $6.0 million as “Other income” in our consolidated statements of income for the six month period ended June 30, 2011 for the amounts we received in April 2011.

Legal and Regulatory Proceedings

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

A number of governmental agencies and regulators have initiated investigations into the Line 6A and Line 6B crude oil releases. Approximately twenty-five actions or claims have been filed against us and our affiliates, in state and federal courts in connection with the Line 6B crude oil release, including direct actions, actions seeking class status. With respect to the Line 6B crude oil release, no penalties or fines have been assessed against us as of June 30, 2011. Governmental agencies and regulators have also initiated investigations into the Line 6A crude oil release. One claim has been filed against us and our affiliates, by the State of Illinois, in state court in connection with this crude oil release. 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 accrued for Line 6A. We have provided a retention fund for future legal costs associated with the Line 6A and Line 6B crude oil releases as described above in the section titled *Lakehead Lines 6A & 6B Crude Oil Releases* of this footnote.

10. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

Our net income and cash flows are subject to volatility stemming from changes in interest rates on our variable rate debt obligations and fluctuations in commodity prices of natural gas, NGLs, condensate, crude oil and fractionation margins. Fractionation margins represent the relative difference between the price we receive from NGL sales and the corresponding cost of natural gas we purchase for processing. Our interest rate risk exposure results from changes in interest rates on our variable rate debt and exists at the corporate level where our variable rate debt obligations are issued. Our exposure to commodity price risk exists within each of our segments. We use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the risks associated with market fluctuations in interest rates and commodity prices, as well as to reduce volatility to our cash flows. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on interest rates or commodity prices. We have hedged a portion of our exposure to variability in future cash flows associated with the risks discussed above through 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. These hedges create a fixed sales price for the crude oil that we will receive in the future. We elected not to designate these derivative financial instruments as cash flow hedges, and as a result, will experience some additional volatility associated with fluctuations in crude oil prices until the underlying transactions are settled or offset.

- **Power Purchase Agreements**—In our Liquids segment, we use forward physical power agreements to fix the price of a portion of the power consumed by our pumping stations in the transportation of crude oil in our owned pipelines. We designate these derivative agreements as non-qualifying hedges because they fail to meet the criteria for cash flow hedging or the NPNS exception. As various states in which our pipelines operate have legislated either partially or fully deregulated power markets, we have the opportunity to create economic hedges on power exposure 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 three month period ended June 30,		For the six month period ended June 30,	
	2011	2010	2011	2010
	(in millions)			
Liquids segment				
Non-qualified hedges	$ 9.4	$ 1.6	$ 4.8	$ 0.4
Natural Gas segment				
Hedge ineffectiveness	0.1	0.9	1.3	1.4
Non-qualified hedges	9.5	19.2	(0.8)	28.9
Marketing				
Non-qualified hedges	1.2	(3.9)	(1.7)	(4.3)
Commodity derivative fair value net gains	20.2	17.8	3.6	26.4
Corporate				
Non-qualified interest rate hedges	(0.2)	—	(0.3)	(0.5)
Derivative fair value net gains	$20.0	$17.8	$ 3.3	$25.9

Derivative Positions

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

	June 30, 2011	December 31, 2010
	(in millions)	
Other current assets	$ 26.9	$ 37.1
Other assets, net	3.8	5.0
Accounts payable and other	(89.6)	(79.2)
Other long-term liabilities	(104.4)	(67.1)
	$(163.3)	$(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 $32.4 million associated with derivative financial instruments that qualified for and were classified as cash flow hedges of forecasted transactions that were subsequently de-designated. These losses are reclassified to earnings over the periods during which the originally hedged forecasted transactions affect earnings. During the three month period ended June 30, 2011, $5.1 million of unrealized commodity hedge losses were de-designated as a result of the hedges no longer meeting hedge accounting criteria. We estimate that approximately $55.5 million, representing unrealized net losses from our cash flow hedging activities based on pricing and positions at June 30, 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).

	June 30, 2011	December 31, 2010
	(in millions)	
Counterparty Credit Quality*		
AAA	$ (0.1)	$ —
AA	(85.9)	(48.7)
A	(81.3)	(61.3)
Lower than A	4.0	5.8
	$(163.3)	$(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 June 30, 2011, we were in an overall net liability position of $163.3 million, which included assets of $30.7 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 June 30, 2011 we would have been required to provide additional letters of credit in the amount of $77.5 million.

At June 30, 2011 and December 31, 2010, we had credit concentrations in the following industry sectors, as presented below:

	June 30, 2011	December 31, 2010
	(in millions)	
United States financial institutions and investment banking entities	$ (96.4)	$ (53.2)
Non-United States financial institutions	(57.5)	(46.8)
Other	(9.4)	(4.2)
	$(163.3)	$(104.2)

We are holding no cash collateral on our asset exposures, and we have provided letters of credit totaling $50.1 million and $7.3 million relating to our liability exposures pursuant to the margin thresholds in effect at June 30, 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	June 30, 2011	December 31, 2010	Financial Position Location	June 30, 2011	December 31, 2010
				(in millions)		
Derivatives designated as hedging instruments						
Interest rate contracts	Other current assets	$14.4	$22.9	Accounts payable and other	$ (21.7)	$ (21.4)
Interest rate contracts	Other assets, net	0.2	2.5	Other long-term liabilities	(59.8)	(44.0)
Commodity contracts	Other current assets	3.5	10.7	Accounts payable and other	(43.1)	(43.4)
Commodity contracts	Other assets, net	10.0	14.1	Other long-term liabilities	(56.4)	(38.1)
		28.1	50.2		(181.0)	(146.9)
Derivatives not designated as hedging instruments						
Interest rate contracts	Other current assets	5.2	5.1	Accounts payable and other	(4.7)	(4.6)
Interest rate contracts	Other assets, net	4.9	6.6	Other long-term liabilities	(4.4)	(5.9)
Commodity contracts	Other current assets	26.0	23.7	Accounts payable and other	(42.3)	(35.1)
Commodity contracts	Other assets, net	8.1	8.7	Other long-term liabilities	(3.2)	(6.0)
		44.2	44.1		(54.6)	(51.6)
Total derivative instruments		$72.3	$94.3		$(235.6)	$(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 June 30, 2011					
Interest rate contracts	$ (43.2)	Interest expense	$ (6.5)	Interest expense	$ —
Commodity contracts	44.5	Cost of natural gas	(20.8)	Cost of natural gas	0.1
Total	$ 1.3		$(27.3)		$0.1
For the three month period ended June 30, 2010					
Interest rate contracts	$ (86.2)	Interest expense	$ (2.0)	Interest expense	$ —
Commodity contracts	33.6	Cost of natural gas	(7.0)	Cost of natural gas	0.9
Total	$ (52.6)		$ (9.0)		$0.9
For the six month period ended June 30, 2011					
Interest rate contracts	$ (26.9)	Interest expense	$(13.4)	Interest expense	$ —
Commodity contracts	(29.3)	Cost of natural gas	(32.7)	Cost of natural gas	1.3
Total	$ (56.2)		$(46.1)		$1.3
For the six month period ended June 30, 2010					
Interest rate contracts	$(100.1)	Interest expense	$ (3.4)	Interest expense	$ —
Commodity contracts	67.2	Cost of natural gas	(15.5)	Cost of natural gas	1.4
Total	$ (32.9)		$(18.9)		$1.4

(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 June 30, 2011	For the three month period ended June 30, 2010	For the six month period ended June 30, 2011	For the six month period ended June 30, 2010
		Amount of Gain or (Loss) Recognized in Earnings[(1)]		Amount of Gain or (Loss) Recognized in Earnings[(1)]	
		(in millions)			
Interest rate contracts	Interest expense	$ (0.2)	$ —	$(0.3)	$ (0.5)
Commodity contracts	Operating revenue	9.7	1.6	5.2	0.4
Commodity contracts	Power	(0.3)	—	(0.4)	—
Commodity contracts	Cost of natural gas	10.7	15.3	(2.5)	24.6
Total		$19.9	$16.9	$ 2.0	$24.5

(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

	June 30, 2011			December 31, 2010		
	Assets	Liabilities	Total	Assets	Liabilities	Total
			(in millions)			
Fair value of derivatives—gross presentation	$ 72.3	$(235.6)	$(163.3)	$ 94.3	$(198.5)	$(104.2)
Effects of netting agreements	(41.6)	41.6	—	(52.2)	52.2	—
Fair value of derivatives—net presentation	$ 30.7	$(194.0)	$(163.3)	$ 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 June 30, 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.

	June 30, 2011				December 31, 2010			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
	(in millions)							
Interest rate contracts	$—	$ (65.9)	$ —	$ (65.9)	$—	$(38.8)	$ —	$ (38.8)
Commodity contracts—financial	—	(50.8)	(56.0)	(106.8)	—	(52.4)	(24.8)	(77.2)
Commodity contracts—physical	—	—	5.9	5.9	—	—	3.4	3.4
Commodity options	—	(0.1)	3.6	3.5	—	(0.2)	8.6	8.4
Total	$—	$(116.8)	$(46.5)	$(163.3)	$—	$(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 June 30, 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)	(22.6)	(0.1)	(0.6)	(23.3)
Included in other comprehensive income	(38.0)	—	(4.0)	(42.0)
Purchases, issuances, sales and settlements				
Purchases	—	—	—	—
Settlements[(2)]	29.4	2.6	(0.4)	31.6
Ending balance as of June 30	$(56.0)	$ 5.9	$ 3.6	$(46.5)
Amount of changes in net assets attributable to the change in unrealized gains or losses related to assets still held at the reporting date	$(43.4)	$ 4.2	$(3.4)	$(42.6)
Amounts reported in operating revenue	$ (0.2)	$ —	$ —	$ (0.2)

(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 June 30, 2011 and December 31, 2010.

	At June 30, 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	5,425,773	$ 4.45	$ 4.65	$1.2	$ (2.3)	$0.4	$ (4.9)
	NGL	110,000	$ 88.38	$ 59.89	$3.1	$ —	$6.8	$ —
	Crude Oil	110,000	$ 96.31	$102.10	$ —	$ (0.6)	$0.4	$ —
Receive fixed/pay variable	Natural Gas	9,219,627	$ 4.09	$ 4.45	$0.9	$ (4.2)	$2.6	$ (6.7)
	NGL	2,571,176	$ 49.40	$ 63.38	$1.6	$(37.5)	$5.0	$(38.8)
	Crude Oil	940,136	$ 81.36	$ 95.67	$0.7	$(14.1)	$ —	$(22.9)
Receive variable/pay variable	Natural Gas	48,788,861	$ 4.34	$ 4.31	$2.7	$ (1.3)	$5.0	$ (1.2)
Physical Contracts								
Receive fixed/pay variable	NGL	1,014,439	$ 80.60	$ 80.01	$1.4	$ (0.8)	$0.5	$ (4.4)
	Crude Oil	130,000	$101.01	$ 95.95	$0.7	$ —	$ —	$ (1.9)
Receive variable/pay fixed	NGL	223,103	$ 92.14	$ 90.33	$0.6	$ (0.2)	$1.6	$ —
	Crude Oil	93,000	$ 95.70	$ 98.48	$ —	$ (0.3)	$1.1	$ —
Pay fixed	Power[4]	37,800	$ 34.02	$ 44.24	$ —	$ (0.4)	$ —	$ (0.8)
Receive variable/pay variable	Crude Oil	543,479	$ 96.12	$ 95.67	$1.2	$ (0.9)	$0.5	$ (0.2)
	NGL	3,004,452	$ 76.43	$ 75.69	$5.2	$ (3.0)	$6.2	$ (1.4)
	Natural Gas	18,742,920	$ 4.36	$ 4.32	$0.7	$ —	$1.1	$ —
Portion of contracts maturing in 2012								
Swaps								
Receive variable/pay fixed	Natural Gas	2,362,813	$ 4.79	$ 6.40	$0.2	$ (4.0)	$ —	$ (3.8)
Receive fixed/pay variable	Natural Gas	4,352,720	$ 4.82	$ 4.79	$1.9	$ (1.8)	$1.7	$ (2.1)
	NGL	2,067,380	$ 56.14	$ 62.48	$4.3	$(17.4)	$8.0	$ (7.6)
	Crude Oil	1,418,616	$ 88.73	$ 97.83	$3.0	$(15.8)	$ —	$(10.7)
Receive variable/pay variable	Natural Gas	51,264,000	$ 4.77	$ 4.75	$2.0	$ (0.9)	$1.0	$ (0.8)
Physical Contracts								
Receive fixed/pay variable	NGL	95,791	$ 79.19	$ 77.28	$0.3	$ (0.1)	$ —	$ —
Receive variable/pay variable	Natural Gas	18,394,101	$ 4.78	$ 4.73	$0.8	$ —	$0.6	$ —
	NGL	1,102,229	$ 70.82	$ 69.57	$2.4	$ (1.0)	$0.7	$ —
Pay fixed	Power[4]	62,330	$ 35.40	$ 40.29	$ —	$ (0.3)	$ —	$ —
Portion of contracts maturing in 2013								
Swaps								
Receive variable/pay fixed	Natural Gas	93,066	$ 5.07	$ 5.19	$ —	$ —	$ —	$ —
Receive fixed/pay variable	Natural Gas	730,000	$ 9.83	$ 5.01	$3.5	$ —	$3.3	$ —
	NGL	994,260	$ 64.86	$ 74.72	$0.6	$(10.3)	$0.3	$ (3.2)
	Crude Oil	1,430,435	$ 93.38	$100.94	$3.3	$(14.0)	$2.2	$ (7.4)
Receive variable/pay variable	Natural Gas	29,550,000	$ 5.11	$ 5.10	$0.4	$ (0.2)	$0.1	$ (0.2)
Physical Contracts								
Receive variable/pay variable	Natural Gas	6,685,350	$ 5.14	$ 5.10	$0.3	$ —	$0.2	$ —
	NGL	44,286	$ 65.68	$ 64.00	$0.1	$ —	$ —	$ —
Pay fixed	Power[4]	43,042	$ 38.41	$ 42.86	$ —	$ (0.2)	$ —	$ —
Portion of contracts maturing in 2014								
Swaps								
Receive variable/pay fixed	Natural Gas	21,870	$ 5.42	$ 5.22	$ —	$ —	$ —	$ —
Receive fixed/pay variable	NGL	381,425	$ 77.58	$ 85.58	$0.6	$ (3.5)	$ —	$ (1.1)
	Crude Oil	1,228,955	$ 94.27	$100.68	$0.6	$ (8.2)	$ —	$ (2.8)
Receive variable/pay variable	Natural Gas	6,300,000	$ 5.48	$ 5.49	$ —	$ (0.1)	$ —	$ (0.1)
Physical Contracts								
Pay fixed	Power[4]	58,853	$ 41.46	$ 46.58	$ —	$ (0.3)	$ —	$ —
Portion of contracts maturing in 2015								
Swaps								
Receive fixed/pay variable	Crude Oil	865,415	$ 97.72	$100.31	$0.3	$ (2.4)	$ —	$ (0.7)
	NGL	109,500	$ 88.36	$ 91.37	$0.2	$ (0.5)	$ —	$ (0.1)
Portion of contracts maturing in 2016								
Swaps								
Receive fixed/pay variable	Crude Oil	45,750	$ 99.31	$100.22	$ —	$ —	$ —	$ —

(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 June 30, 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 \$0.9 million of gains and \$0.6 million of gains at June 30, 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 June 30, 2011 and December 31, 2010.

	At June 30, 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)	184,000	\$ 4.31	\$ 4.46	\$ —	\$(0.1)	\$ —	\$(0.2)
Puts (purchased)	Natural Gas(4)	184,000	\$ 3.40	\$ 4.46	\$ —	\$ —	\$ —	\$ —
	NGL	319,792	\$54.79	\$67.50	\$0.7	\$ —	\$3.6	\$ —
	Crude Oil	109,480	\$88.65	\$96.90	\$0.3	\$ —	\$1.3	\$ —
Portion of option contracts maturing in 2012								
Puts (purchased)	NGL	284,382	\$65.90	\$72.35	\$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 June 30, 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 June 30, 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)	June 30, 2011	December 31, 2010
		(dollars in millions)			
Contracts maturing in 2013					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	\$600	4.15%	\$(47.8)	\$(51.8)
Interest Rate Swaps—Pay Fixed	Non-qualifying	\$125	4.35%	\$ (9.3)	\$(10.7)
Interest Rate Swaps—Pay Float	Non-qualifying	\$125	4.75%	\$ 10.3	\$ 11.9
Contracts maturing in 2015					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	\$300	2.43%	\$ 0.2	\$ 1.9
Contracts settling prior to maturity					
2011—Pre-issuance Hedges	Cash Flow Hedge	\$300	2.92%	\$ 14.5	\$ 23.4
2012—Pre-issuance Hedges	Cash Flow Hedge	\$600	4.57%	\$(29.0)	\$(13.7)
2013—Pre-issuance Hedges	Cash Flow Hedge	\$300	4.62%	\$ (5.7)	\$ (0.3)

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

(2) The fair value is determined from quoted market prices at June 30, 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 \$0.9 million of gains at June 30, 2011 and \$0.5 million of gains at December 31, 2010.

11. INCOME TAXES

We are not a taxable entity for United States federal income tax purposes, or for the majority of states that impose an income tax. Taxes on our net income generally are borne by our unitholders through the allocation of taxable income. Our income tax expense results from the enactment of state income tax laws that apply to entities organized as partnerships by the States of Texas and Michigan. We computed our income tax expense by applying a Texas state income tax rate to modified gross margin and a Michigan state income tax rate to modified gross receipts. The Texas state income tax rate was 0.5% for the six month periods ended June 30, 2011 and 2010. The Michigan state income tax rate was 0.2% for the six month periods ended June 30, 2011 and 2010.

On May 25, 2011, the Governor of Michigan signed legislation implementing a new corporate income tax system. The new tax system becomes effective January 1, 2012 and repeals the Michigan Business Tax, or MBT, which imposes tax on individuals, LLCs, trusts, partnerships, S corporations, and C corporations and replaces it with the Michigan Corporate Income Tax, or CIT. The CIT only taxes entities classified as C Corporations, therefore, the Partnership is excluded from the CIT and will no longer pay Michigan income taxes beginning in 2012. Due to this change as of June 30, 2011 we reversed deferred tax liabilities of $1.2 million that were previously recognized on our consolidated statements of financial position, which decreased “Income tax expense” in our consolidated statements of income for the three and six month periods ended June 30, 2011, to reflect the tax associated with the difference between the net basis in assets and liabilities for financial and state tax reporting related to Michigan income taxes.

Our income tax expense is $0.9 million and $2.4 million and $3.2 million and $4.6 million for the three and six month periods ended June 30, 2011 and 2010 respectively.

At June 30, 2011 and December 31, 2010 we have included a current income tax payable of $5.0 million and $7.9 million in “Property and other taxes payable,” respectively. In addition, at June 30, 2011 and December 31, 2010, we have included a deferred income tax liability of $2.5 million and $3.6 million, respectively, in “Other long-term liabilities,” on our consolidated statements of financial position to reflect the tax associated with the difference between the net basis in assets and liabilities for financial and state tax reporting.

12. OIL MEASUREMENT ADJUSTMENTS

Oil measurement adjustments occur as part of the normal operations associated with our liquid petroleum operations. The three types of oil measurement adjustments that routinely occur on our systems include:

- Physical, which result from evaporation, shrinkage, differences in measurement (including sediment and water measurement) between receipt and delivery locations and other operational conditions;
- Degradation resulting from mixing at the interface within our pipeline systems or terminal and storage facilities between higher quality light crude oil and lower quality heavy crude oil in pipelines; and
- Revaluation, which are a function of crude oil prices, the level of our carriers inventory and the inventory positions of customers.

Quantifying oil measurement adjustments are difficult because: (1) physical measurements of volumes are not practical, as products continuously move through our pipelines, which are primarily located underground; (2) the extensive length of our pipeline systems and (3) the numerous grades and types of crude oil products we carry. We utilize engineering-based models and operational assumptions to estimate product volumes in our systems and associated oil measurement adjustments. Material changes in our assumptions may result in revisions to our oil measurement estimates in the period determined.

We settled a dispute with a shipper on our Lakehead crude oil pipeline system, which we recognized in June 2011, for oil measurement adjustments we had previously recognized in prior years. We recorded $52.2 million to “Receivables, trade and other” on our consolidated statements of financial position at June 30, 2011 and to “Oil measurement adjustments,” which is a reduction to operating expenses, for the three and six month periods ended June 30, 2011 in our consolidated statements of income for the cash amount we received for this settlement in July 2011.

13. SEGMENT INFORMATION

Our business is divided into operating segments, defined as components of the enterprise, about which financial information is available and evaluated regularly by our Chief Operating Decision Maker 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:

	For the three month period ended June 30, 2011				
	Liquids	Natural Gas	Marketing	Corporate[1]	Total
			(in millions)		
Total revenue	$310.2	$1,893.9	$569.2	$ —	$2,773.3
Less: Intersegment revenue	0.3	395.8	5.2	—	401.3
Operating revenue	309.9	1,498.1	564.0	—	2,372.0
Cost of natural gas	—	1,299.7	561.6	—	1,861.3
Environmental costs, net of recoveries	23.3	—	—	—	23.3
Oil measurement adjustments	(54.1)	—	—	—	(54.1)
Operating and administrative	73.3	91.7	1.7	0.9	167.6
Power	33.9	—	—	—	33.9
Depreciation and amortization	48.8	40.8	—	—	89.6
Operating income	184.7	65.9	0.7	(0.9)	250.4
Interest expense	—	—	—	78.5	78.5
Income from continuing operations before income tax expense	184.7	65.9	0.7	(79.4)	171.9
Income tax expense	—	—	—	0.9	0.9
Net income	184.7	65.9	0.7	(80.3)	171.0
Less: Net income attributable to the noncontrolling interest	—	—	—	14.1	14.1
Net income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$184.7	$ 65.9	$ 0.7	$(94.4)	$ 156.9

(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.

	For the three month period ended June 30, 2010				
	Liquids	Natural Gas	Marketing	Corporate[(1)]	Total
			(in millions)		
Total revenue	$320.1	$1,246.6	$549.0	$ —	$2,115.7
Less: Intersegment revenue	0.3	358.0	10.0	—	368.3
Operating revenue	319.8	888.6	539.0	—	1,747.4
Cost of natural gas	—	730.8	539.6	—	1,270.4
Environmental costs, net of recoveries	(0.1)	—	—	—	(0.1)
Oil measurement adjustments	1.1	—	—	—	1.1
Operating and administrative	64.2	67.9	2.0	1.2	135.3
Power	36.5	—	—	—	36.5
Depreciation and amortization	46.6	31.0	—	—	77.6
Operating income	171.5	58.9	(2.6)	(1.2)	226.6
Interest expense	—	—	—	69.6	69.6
Other expense	—	—	—	0.1	0.1
Income from continuing operations before income tax expense	171.5	58.9	(2.6)	(70.9)	156.9
Income tax expense	—	—	—	2.4	2.4
Net income	171.5	58.9	(2.6)	(73.3)	154.5
Less: Net income attributable to the noncontrolling interest	—	—	—	14.5	14.5
Net income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$171.5	$ 58.9	$ (2.6)	$(87.8)	$ 140.0

(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 six month period ended June 30, 2011				
	Liquids	Natural Gas	Marketing	Corporate[(1)]	Total
			(in millions)		
Total revenue	$ 612.4	$3,695.9	$1,120.3	$ —	$ 5,428.6
Less: Intersegment revenue	0.7	748.1	18.9	—	767.7
Operating revenue	611.7	2,947.8	1,101.4	—	4,660.9
Cost of natural gas	—	2,593.5	1,097.3	—	3,690.8
Environmental costs, net of recoveries	(10.9)	(0.4)	—	—	(11.3)
Oil measurement adjustments	(58.7)	—	—	—	(58.7)
Operating and administrative	144.1	185.3	3.3	2.0	334.7
Power	69.5	—	—	—	69.5
Depreciation and amortization	97.3	80.7	—	—	178.0
Operating income	370.4	88.7	0.8	(2.0)	457.9
Interest expense	—	—	—	157.9	157.9
Other income	—	—	—	6.0	6.0
Income from continuing operations before income tax expense	370.4	88.7	0.8	(153.9)	306.0
Income tax expense	—	—	—	3.2	3.2
Net income	370.4	88.7	0.8	(157.1)	302.8
Less: Net income attributable to the noncontrolling interest	—	—	—	28.8	28.8
Net income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 370.4	$ 88.7	$ 0.8	$(185.9)	$ 274.0
Total assets	$5,722.0	$4,508.9	$ 231.1	$ 168.5	$10,630.5
Capital expenditures (excluding acquisitions)	$ 201.7	$ 156.4	$ —	$ 5.0	$ 363.1

(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.

	As of and for the six month period ended June 30, 2010				
	Liquids	Natural Gas	Marketing	Corporate[1]	Total
			(in millions)		
Total revenue	$ 582.2	$2,637.2	$1,242.8	$ —	$4,462.2
Less: Intersegment revenue	0.6	763.9	19.1	—	783.6
Operating revenue	581.6	1,873.3	1,223.7	—	3,678.6
Cost of natural gas	—	1,578.6	1,216.0	—	2,794.6
Environmental costs, net of recoveries	4.5	—	—	—	4.5
Operating and administrative	124.4	137.5	4.7	1.2	267.8
Power	68.8	—	—	—	68.8
Depreciation and amortization	83.7	61.7	0.1	—	145.5
Operating income	300.2	95.5	2.9	(1.2)	397.4
Interest expense	—	—	—	128.9	128.9
Other income	—	—	—	16.7	16.7
Income from continuing operations before income tax expense	300.2	95.5	2.9	(113.4)	285.2
Income tax expense	—	—	—	4.6	4.6
Net income	300.2	95.5	2.9	(118.0)	280.6
Less: Net income attributable to the noncontrolling interest	—	—	—	25.2	25.2
Net income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 300.2	$ 95.5	$ 2.9	$(143.2)	$ 255.4
Total assets	$5,388.5	$3,425.0	$ 232.9	$ 268.6	$9,315.0
Capital expenditures (excluding acquisitions)	$ 250.1	$ 102.0	$ —	$ 4.1	$ 356.2

(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.

14. 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 and six month periods ended June 30, 2011, we reduced our revenues by $1.4 million and $13.8 million, respectively, on our consolidated statements of income with a corresponding regulatory liability on our consolidated statements of financial position at June 30, 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 and six month periods ended June 30, 2011, we increased our revenues by $0.7 million and $2.1 million, respectively, on our consolidated statement of income with a corresponding amount reducing the regulatory liability on our consolidated statement of financial position at June 30, 2011. At June 30, 2011 and December 31, 2010 we had a $1.5 million and $3.6 million regulatory liability, respectively, on our consolidated statements of financial position. The amounts are being refunded to our customers through our tolls which began in April 2011 when our transportation rates, which account for the higher delivered volumes and lower costs than estimated, became 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, resulting in a regulatory receivable, the balance of which was $2.1 million, on our consolidated statement of financial position as of December 31, 2010. We collected the $2.1 million regulatory receivable in the first quarter of 2011.

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, net" on our consolidated statements of financial position in amounts totaling $27.9 million at both June 30, 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 six month period ended June 30, 2010. For the three month period ended June 30, 2010, we did not record any additional income related to AEDC.

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 and six month periods ended June 30, 2011, we reduced our revenues by $4.0 million and $15.2 million, respectively, on our consolidated statement of income with a corresponding increase in the regulatory liability on our consolidated statement of financial position at June 30, 2011 for the differences in transportation volumes and costs. The amounts began being reimbursed as of 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 June 30, 2011 and December 31, 2010, we had regulatory liabilities of $5.0 million and $10.1 million, respectively, in our consolidated statements of financial position for the difference in costs. The amounts are being refunded to our customers through transportation rates which became effective in April 2011 and account for the lower costs than estimated.

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 June 30, 2011, we had $30.3 million recorded as a regulatory liability on our consolidated statement of financial position for amounts we over collected in connection with the Southern Lights in-service delay. We will reduce the transportation rates we charge the shippers in the future for the additional amounts we collected beginning in 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 and 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 May 2, 2011, we filed FERC Tariff 45.0.0 to establish International Joint Tariff rates applicable to the transportation of petroleum from all receipt points in Western Canada on Enbridge Pipelines Inc., or EPI's, Canadian Mainline system to all delivery points on the Lakehead pipeline system owned by Enbridge Energy Limited Partnership, or OLP, and delivery points on the Canadian mainline located downstream of the Lakehead system. This tariff filing became effective July 1, 2011.

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

15. SUBSEQUENT EVENTS

Class A common unit issuances

In July 2011, we completed an underwritten public offering of 8.05 million Class A common units at a price to the public of $30.00 per unit, less underwriting commissions and expenses, for net proceeds of $233.7 million. In addition, our General Partner contributed approximately $4.9 million to us to maintain its two percent general partner interest. We used the net proceeds to repay a portion of our outstanding commercial paper.

Credit Agreement Amendment and Increase

On July 20, 2011, we amended the $350 million unsecured senior revolving credit agreement to reflect an increase in the lending commitments to $600 million. We use the unsecured senior revolving credit agreement to fund our general activities and working capital needs. The amended $600 million credit agreement has terms consistent with our existing Credit Facility and has the same maturity date of April 4, 2013. After this amendment, our Credit Facilities provide an aggregate amount of $1,767.5 million of bank credit.

Distribution to Partners

On July 28, 2011, the board of directors of Enbridge Management declared a distribution payable to our partners on August 12, 2011. The distribution will be paid to unitholders of record as of August 5, 2011, of our available cash of $167.2 million at June 30, 2011, or $0.5325 per limited partner unit. Of this distribution, $147.4 million will be paid in cash, $19.4 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 July 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 $17.7 million to the noncontrolling interest in the Series AC, while $8.8 million will be paid to us.

16. 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 six month period ended June 30,	
	2011	2010
	(in millions)	
Discount accretion	$ 0.3	$ 0.3
Amortization of debt issuance and hedging costs	8.4	11.1
Deferred income taxes	(1.2)	0.6
Allowance for equity used during construction	—	(14.3)
Allowance for doubtful accounts	0.5	(4.0)
Gain on sale of CO_2 plant	(1.5)	—
Other	0.7	0.6
	$ 7.2	$ (5.7)

17. RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

Accounting Standards Update—Fair Value Measurement

In May 2011, the Financial Accounting Standards Board, or FASB, issued an amendment to the guidance on fair value measurement as part of the FASB's joint project with the International Accounting Standards Board, or IASB, to achieve common fair value measurement and disclosure requirements in U.S. generally accepted accounting principles, or GAAP, and International Financial Reporting Standards, or IFRS. The key changes relevant to our business include enhanced disclosures requiring additional information about unobservable inputs and valuation methods utilized and requiring the fair value hierarchy level of assets and liabilities not recorded at fair value but where fair value disclosure is required.

The accounting update is effective for the first reporting period beginning after December 15, 2011, with early application prohibited. The guidance will require prospective application. The adoption of this pronouncement is not anticipated to have a material impact on our financial statements.

Accounting Standards Update—Presentation of Comprehensive Income

In June 2011, the FASB issued guidance on the presentation of comprehensive income as part of the FASB's joint project with the IASB, requiring presentation of net income and other comprehensive income either in one continuous statement, referred to as the statement of comprehensive income, or in two separate, but consecutive, statements of net income and other comprehensive income. The guidance eliminated the option to report other comprehensive income and its components in the statement of changes in equity and the disclosure of reclassification adjustments in the footnotes. The guidance does not change which components of comprehensive income are recognized in net income or other comprehensive income, when an item of other comprehensive income must be reclassified to net income or the earnings-per-share computation.

The accounting update is effective for the first reporting period beginning after December 15, 2011, with early application permitted. The guidance requires retrospective application. We do not intend to adopt the provisions of this pronouncement early. Our adoption of this pronouncement will require us to modify the items we present in the consolidated statements of comprehensive income.

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.

Management has targeted annual growth in our cash distribution of 2 to 5 percent per year. Consistent with that objective, on July 28, 2011, the board of directors of Enbridge Management, L.L.C., or Enbridge Management, announced a distribution increase of $0.01875 per unit to $0.5325 per quarter which would equate to an annual distribution rate of $2.13 per year. Additional cash flows generated by our assets and current growth initiatives support the increase in our distribution rate. We continue to pursue numerous organic growth opportunities, and we periodically evaluate acquisitions in or near areas in which we have a competitive advantage to, further grow distributions to our unitholders.

RESULTS OF OPERATIONS—OVERVIEW

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

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

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

The following table reflects our operating income by business segment and corporate charges for each of the three and six month periods ended June 30, 2011 and 2010.

	For the three month period ended June 30,		For the six month period ended June 30,	
	2011	2010	2011	2010
	(unaudited; in millions)			
Operating Income				
Liquids	$184.7	$171.5	$370.4	$300.2
Natural Gas	65.9	58.9	88.7	95.5
Marketing	0.7	(2.6)	0.8	2.9
Corporate, operating and administrative	(0.9)	(1.2)	(2.0)	(1.2)
Total Operating Income	250.4	226.6	457.9	397.4
Interest expense	78.5	69.6	157.9	128.9
Other income (expense)	—	(0.1)	6.0	16.7
Income tax expense	0.9	2.4	3.2	4.6
Net income	171.0	154.5	302.8	280.6
Less: Net income attributable to noncontrolling interest	14.1	14.5	28.8	25.2
Net income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$156.9	$140.0	$274.0	$255.4

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 and six month periods ended June 30, 2011 increased $13.2 million and $70.2 million from the same periods in 2010, respectively, primarily due to the following:

<u>Three Month Periods Ended June 30, 2011 and 2010</u>

- Transportation rates we implemented July 1, 2010 which reduced the index rates on all three of our Liquids systems in connection with the annual index rate ceiling adjustment due to the fall in the Producer Price Index for Finished Goods as well as decreased transportation revenues due to shorter hauls and fewer heavy crude types being transported as compared to the same period in 2010;
- Insurance recoveries of $15.0 million we recognized for claims we filed for costs we incurred in connection with the remediation and cleanup of areas affected by the crude oil releases on Line 6B of our Lakehead system, offset by $38 million of additional expense we recognized for costs on Lines 6A and 6B; and
- $52.2 million we received for settlement of a dispute related to oil measurement losses, which we recognized as a reduction to operating expenses.

<u>Six Month Periods Ended June 30, 2011 and 2010</u>

In addition to the impact of the items noted above in our three month summary, the six month period was also affected by the following:

- An additional three months of operation of the Alberta Clipper pipeline during the six month period of 2011; and
- Insurance recoveries of $50 million we recognized for claims we filed for costs we incurred in connection with the remediation and cleanup of areas affected by the crude oil releases on Line 6B of our Lakehead system, partially offset by $38 million of additional expense we recognized for costs on Lines 6A and 6B.

Natural Gas

The following factors affected the operating income of our Natural Gas business for the three and six month periods ended June 30, 2011 as compared with the same periods of 2010:

- Unrealized, non-cash, mark-to-market net gains of $9.6 million and $0.5 million for the three and six month periods ended June 30, 2011, respectively, associated with derivative financial instruments that do not qualify for hedge accounting treatment compared with $20.1 million and $30.3 million of net gains we experienced in the respective periods of 2010;
- Increased natural gas and NGL volumes on our Anadarko system resulting from continuing production development in the Granite Wash play coupled with additional volumes associated with the Elk City system we acquired in September 2010;
- Volume growth and the related revenue derived from the services provided by our East Texas system resulting from new assets we have placed in service to capture the growing natural gas production from the Haynesville shale formation; and

- Partially offsetting the above are the additional operating costs associated with the Elk City system and the impact of severe winter weather conditions and plant downtime in the first quarter of 2011, which reduced average daily volumes on our East Texas and North Texas systems by approximately 56,000 MMBtu/d in the first quarter 2011, or 28,000 MMBtu/d for the first six months of 2011.

Marketing

Included in the operating results of our Marketing business for the three and six month periods ended June 30, 2011 were unrealized, non-cash, mark-to-market net gains of $1.2 million and net losses of $1.7 million, respectively associated with derivative financial instruments that do not qualify for hedge accounting treatment under authoritative accounting guidance compared with $3.9 million and $4.3 million, respectively, of net losses generated in the same periods of 2010. Partially offsetting the favorable impact of changes in the fair values of our derivative financial instruments for the three and six month periods ended June 30, 2011 from the same periods of 2010 are declines in operating income resulting from relatively stable natural gas prices during 2011, which have limited opportunities for us 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 June 30,		For the six month period ended June 30,	
	2011	2010	2011	2010
	(unaudited; in millions)			
Liquids segment				
Non-qualified hedges	$ 9.4	$ 1.6	$ 4.8	$ 0.4
Natural Gas segment				
Hedge ineffectiveness	0.1	0.9	1.3	1.4
Non-qualified hedges	9.5	19.2	(0.8)	28.9
Marketing				
Non-qualified hedges	1.2	(3.9)	(1.7)	(4.3)
Commodity derivative fair value gains	20.2	17.8	3.6	26.4
Corporate				
Non-qualified interest rate hedges	(0.2)	—	(0.3)	(0.5)
Derivative fair value gains	$20.0	$17.8	$ 3.3	$25.9

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 June 30,		For the six month period ended June 30,	
	2011	2010	2011	2010
	(unaudited; in millions)			
Operating Results				
Operating revenues	$309.9	$319.8	$611.7	$581.6
Environmental costs, net of recoveries	23.3	(0.1)	(10.9)	4.5
Oil measurement adjustments	(54.1)	1.1	(58.7)	—
Operating and administrative	73.3	64.2	144.1	124.4
Power	33.9	36.5	69.5	68.8
Depreciation and amortization	48.8	46.6	97.3	83.7
Operating expenses	125.2	148.3	241.3	281.4
Operating Income	$184.7	$171.5	$370.4	$300.2
Operating Statistics				
Lakehead system:				
United States[(1)]	1,245	1,397	1,301	1,332
Province of Ontario[(1)]	356	345	371	351
Total Lakehead system deliveries[(1)]	1,601	1,742	1,672	1,683
Barrel miles (billions)	106	117	220	225
Average haul (miles)	728	736	728	737
Mid-Continent system deliveries[(1)]	224	204	221	205
North Dakota system:				
Trunkline	180	161	176	157
Gathering	4	6	4	6
Total North Dakota system deliveries[(1)]	184	167	180	163
Total Liquids Segment Delivery Volumes[(1)]	2,009	2,113	2,073	2,051

(1) Average barrels per day in thousands.

Three month period ended June 30, 2011 compared with three month period ended June 30, 2010

The operating revenue of our Liquids business decreased for the three month period ended June 30, 2011 when compared with the same period in 2010 partially due to our reduction of the average transportation rates for all of our major systems. Approximately $11.0 million of the decrease in operating revenue for the quarter ended June 30, 2011 when compared to the same period in 2010 is attributable to the lower transportation rates. The changes affecting our transportation rates included the following:

- 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 due to the fall in the Producer Price Index for Finished Goods; and

- Effective April 1, 2011, we decreased the North Dakota Phase VI surcharge due to a change in cost allocation methodology as compared to the same period in 2010.

Further contributing to the decrease in operating revenue on our Liquids segment was the lower average daily delivery volumes on our Lakehead system when compared to the same period in 2010. The overall decrease in average delivery volumes on our Lakehead system reduced operating revenues by approximately $12.1 million for our Liquids segment. The average daily deliveries from our Lakehead system decreased approximately eight percent, to 1.601 million barrels per day, or Bpd, for the three month period ended June 30, 2011 from 1.742 million Bpd for the same period in 2010. The decrease in average deliveries on our Lakehead system was attributable to alternative transportation options available to shippers from competitor pipelines that were not utilized to the same extent in the same period in 2010.

Offsetting the overall decrease in operating revenue on our Liquids segment was a $7.8 million increase in unrealized, non-cash, mark-to-market net gains related to derivative financial instruments as compared with the same period in 2010. In March 2010, we began to use forward contracts to hedge a portion of the crude oil we expect to receive from our customers as a pipeline loss allowance as part of the transportation of their crude oil. We subsequently sell this crude oil at market rates. We executed derivative financial instruments for the current year, which fix the sales price we will receive in the future for the sale of this crude oil. We elected not to designate these derivative financial instruments as cash flow hedges.

We settled a dispute with a shipper on our Lakehead crude oil pipeline system, which we recognized in June 2011, for oil measurement adjustments we had previously experienced in prior years. We recorded $52.2 million to "Oil measurement adjustments", which is a reduction to operating expenses, for the three month period ended June 30, 2011 and there was no such settlement in the same period in 2010.

The "Operating and administrative" expenses of our Liquids business increased $9.1 million from the three month period ended June 30, 2011 when compared with the same period in 2010 primarily due to the following:

- Higher costs related to our pipeline integrity program;
- Additional workforce related costs associated with the operational, administrative, regulatory and compliance support necessary for our systems;
- Higher costs for repair and maintenance activities;
- 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.

Power costs decreased $2.6 million for the three month period ended June 30, 2011, compared with the same period in 2010. The decrease in power costs is primarily associated the lower volumes of crude oil transported on our Lakehead system.

The increase in depreciation expense of $2.2 million is directly attributable to the additional assets we have placed in service since the same period in 2010.

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

We continue to make 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. Following the spring thaw in the areas affected by the Line 6B crude oil release, we observed sheen and submerged oil in nearby waters we are monitoring, which resulted in additional cleanup activities. Based upon additional information and our reassessment of the overall monitoring area, related cleanup, including submerged oil recovery operations, and remediation activities, during the three month period ended June 30, 2011 we increased the total estimates for our environmental liabilities associated with the cleanup and remediation of the areas affected by the crude oil release from Line 6B by $35.0 million. We also increased our total estimated costs for the Line 6A crude oil release by $3 million based upon our review of costs and commitments incurred through June 30, 2011. We continue to incur costs for monitoring ground and surface water, as well as professional fees, which are included in our estimates. We have the potential of incurring additional costs in connection with these crude oil releases including modified remediation requirements, fines and penalties, as well as expenditures for litigation and settlement of claims. Our estimated costs for these crude oil releases 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 June 30, 2011, we recognized $15.0 million for insurance recoveries we received in July 2011 related to the costs of our Line 6B crude oil release, 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 had an aggregate limit of $650.0 million for pollution liability through the policy period that expired on April 30, 2011. Assuming that all of the claims for the releases are recoverable under this insurance policy, the occurrence-based coverage remaining under the commercial liability insurance policies related to costs associated with Lines 6A and 6B, and other claims of Enbridge and its subsidiaries and affiliates, including us, is approximately $20 million based on estimates as of June 30, 2011. We expect insurance payments for our insured losses to be received over an extended period, which will cause fluctuations in our earnings and cash flows as these payments are received and recognized in our consolidated statements of income.

The increase in our estimates for costs associated with the crude oil releases on Lines 6A and 6B coupled with the offsetting insurance recoveries we recognized produced the majority of the $23.4 million increase in environmental expenses for the three month period ended June 30, 2011 when compared to the same period in 2010.

Six month period ended June 30, 2011 compared with six month period ended June 30, 2010

Our Liquids segment contributed $370.4 million of operating income during the six month period ended June 30, 2011, representing a $70.2 million increase over the $300.2 million for the same period in 2010. The components comprising the operating income of our Liquids business changed during the six month period ended June 30, 2011 as compared with the same period in 2010, primarily for the reasons noted above in our three-month analysis, in addition to the items discussed below.

Effective April 1, 2010, we increased the rates for transportation on our Lakehead system in connection with the completion of our Alberta Clipper Project. Alberta Clipper contributed approximately $45.5 million of additional operating revenue for the six month period ended June 30, 2011 when compared with the same period in 2010.

For the six month period ended June 30, 2011 we recorded $50.0 million for insurance recoveries related to the costs of our Line 6B crude oil release, which increased operating 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.

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. We commenced construction in July 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, which has been completed, reverses the flow of the existing Line 26 pipeline between Berthold, North Dakota and Steelman, Saskatchewan. PREP was completed in the second quarter of 2011 for a cost of approximately $9 million, making 25,000 Bpd of the 145,000 Bpd of capacity available at that time. Due to flooding in the area, only minimal PREP deliveries were realized during the quarter.

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 by early 2012.

In April 2011, our board of directors approved plans to begin construction on four new tanks at our Cushing terminal with an approximate shell capacity of 1.0 million barrels. The new tanks will have an estimated cost of $33 million and are scheduled for completion by the third quarter of 2012.

Line Replacement Program

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

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 perform as part of our restart of Line 6B. Additionally, a new line was installed beneath the St. Clair River in March 2011 and was tied into the existing pipeline during June 2011. Further, we announced plans in May 2011 for a $286 million pipeline replacement program as discussed above. Additional integrity expenditures, which could be significant, may be required after this initial remediation program. The total cost of these integrity measures is separate from the environmental liabilities discussed above. The pipeline integrity and replacement costs will be capitalized or expensed in accordance with our capitalization policies as these costs are incurred, the majority of which are expected to be capital in nature. We expect to incur ongoing operating costs for pipeline integrity measures to ensure both regulatory compliance and to maintain the overall integrity of our pipeline systems.

In February 2011, we filed a supplement to our FSM which became effective on April 1, 2011, for recovery of $175 million of capital costs and $5 million of operating costs for the 2010 and 2011 Line 6B 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

Enbridge Pipelines Inc., or EPI, filed a settlement agreement in May 2011 that is referred to as the Competitive Toll Settlement, or CTS, to be effective July 1, 2011. On June 24, 2011, the National Energy Board, or NEB, announced its approval the CTS. The CTS includes a provision for a joint tariff for volumes originating in Western Canada that are transported on our Lakehead system. We have entered into an International Joint Tariff Agreement, or IJTA, with EPI that ensures 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. The CTS provides a solid platform for the liquids pipeline business to develop new market access points on the mainline by providing shippers with a stable and competitive long-term toll, thereby preserving and enhancing throughput on both the EPI and Lakehead systems.

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 June 30,		For the six month period ended June 30,	
	2011	2010	2011	2010
	(unaudited; in millions)			
Operating revenues	$ 1,498.1	$ 888.6	$ 2,947.8	$ 1,873.3
Cost of natural gas	1,299.7	730.8	2,593.5	1,578.6
Environmental costs, net of recoveries	—	—	(0.4)	—
Operating and administrative	91.7	67.9	185.3	137.5
Depreciation and amortization	40.8	31.0	80.7	61.7
Operating expenses	1,432.2	829.7	2,859.1	1,777.8
Operating Income	$ 65.9	$ 58.9	$ 88.7	$ 95.5
Operating Statistics (MMBtu/d)				
East Texas	1,392,000	1,172,000	1,354,000	1,183,000
Anadarko	1,054,000	613,000	992,000	580,000
North Texas	348,000	359,000	343,000	353,000
Total[(1)]	2,794,000	2,144,000	2,689,000	2,116,000

(1) Average daily volumes for the three and six month periods ended June 30, 2011 include 267,000 MMBtu/d and 242,000 MMBtu/d, respectively, 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 June 30, 2011 compared with three month period ended June 30, 2010

The primary factors affecting the operating income of our Natural Gas business for the three month period ended June 30, 2011 as compared with the same period of 2010 are as follows:

- $10.5 million decrease in unrealized, non-cash, mark-to-market net gains from derivative instruments that do not qualify for hedge accounting treatment under authoritative accounting guidance, as compared with the same period of 2010;
- Increased natural gas gathering and processing volumes on our Anadarko system as a result of growth in the Granite Wash play and the additional 267,000 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 growth associated with Haynesville production;

- Increases in operating and administrative costs associated with our September 2010 Elk City system acquisition and the expansion of our systems; and

- $9.8 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.

Changes in the average forward prices of natural gas, NGLs and condensate from March 31, 2011 to June 30, 2011 produced unrealized, non-cash, mark-to-market net gains of $9.6 million from the non-qualifying commodity derivatives we use to economically hedge a portion of the natural gas, NGLs and condensate resulting from the operating activities of our Natural Gas business. Fractionation margins, representing the relative difference between the price we receive from the sale of NGLs and the corresponding cost of natural gas we purchase for processing, narrowed during the second quarter of 2011 as a result of lower NGL forward prices and higher natural gas forward prices, which produced unrealized, non-cash mark-to-market gains on derivatives we use to hedge the forward prices of natural gas and NGLs.

Comparatively, changes in the average forward prices of natural gas, NGLs and condensate from March 31, 2010 to June 30, 2010, produced unrealized, non-cash, mark-to-market net gains of $20.1 million from the non-qualifying commodity derivatives we use to economically hedge a portion of the natural gas, NGLs and condensate resulting from the operating activities of our Natural Gas business. Fractionation margins, narrowed during the second quarter of 2010 as a result of lower NGL forward prices and higher natural gas forward prices, which produced unrealized, non-cash mark-to-market gains on derivatives hedging fractionation margins.

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 and six month periods ended June 30, 2011 and 2010:

	For the three month period ended June 30,		For the six month period ended June 30,	
	2011	2010	2011	2010
	(unaudited; in millions)			
Hedge ineffectiveness	$0.1	$ 0.9	$ 1.3	$ 1.4
Non-qualified hedges	9.5	19.2	(0.8)	28.9
Derivative fair value gains	$9.6	$20.1	$ 0.5	$30.3

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 20 to 35 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 June 30, 2011 compared to prices in the same period in 2010.

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 June 30, 2011, natural gas volumes on our systems increased approximately 30 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 72 percent for the three month period ended June 30, 2011 compared with the same period in 2010, of which approximately 61 percent were associated with the Elk City system we acquired in September 2010.

A variable element of the operating results of our Natural Gas segment is derived from processing natural gas on our systems. Under percentage of liquids, or POL, contracts we are required to pay producers a contractually fixed recovery of NGLs regardless of the NGLs we physically produce, or our ability to process the NGLs from the natural gas stream. NGLs that are produced in excess of this contractual obligation in addition to the barrels that we produce under traditional keep-whole gas processing arrangements we refer to collectively as keep-whole earnings. Operating revenue less the cost of natural gas derived from keep-whole earnings for the three month period ended June 30, 2011 was $9.1 million, representing a decrease of $6.2 million from the $15.3 million we produced for the same period in 2010.

The reduction in keep-whole earnings is a result of the increasing production of liquids rich natural gas on our Anadarko system, where a significant number of our contracts are POL type arrangements. This decrease is largely attributable to paying natural gas producers for liquids we are unable to recover due to gas volume increasing faster than our available capacity. The rapid increase in supply is exceeding our existing processing capacity as evidenced by the 28% increase in average daily volumes from 613,000 MMBtu/d to 787,000 MMBtu/d on the system for the three months ended June 30, 2011 compared to the same period last year. We are constructing facilities to increase the available processing capacity on both our Anadarko and Elk City systems, which we expect to increase incrementally throughout the year, the most significant of which is the Allison plant which we expect will be in service prior to the end of 2011.

Operating and administrative costs of our Natural Gas segment were $23.8 million higher for the three month period ended June 30, 2011 compared to the same period in 2010, primarily due to 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.

Six month period ended June 30, 2011 compared with six month period ended June 30, 2010

The primary factors affecting the operating income of our Natural Gas business for the six month period ended June 30, 2011 as compared with the same period of 2010 are the same as noted in our three-month analysis in addition to the factors discussed below.

Changes in the average forward prices of natural gas, NGLs and condensate from December 31, 2010 to June 30, 2011 produced unrealized, non-cash, mark-to-market net gains of $0.5 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. Comparatively, hedges of our natural gas length significantly increased in value during the first six months of 2010 due to sharp declines in forward natural gas prices, which generated net gains of $18.2 million more than in the same period of 2011. Also in 2010, NGL hedges and fractionation hedges experienced gains of approximately $11.6 million more than in the same six month period of 2011.

Although volumes were higher on the majority of our systems for the six month period ended June 30, 2011 compared with the same period of 2010, for the reasons discussed in the three-month analysis, 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 the average daily volumes by approximately 56,000 MMBtu/d for the first quarter 2011. 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 six month period ended June 30, 2011.

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 third 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 June 30,		For the six month period ended June 30,	
	2011	2010	2011	2010
	(unaudited; in millions)			
Operating revenues	$564.0	$539.0	$1,101.4	$1,223.7
Cost of natural gas	561.6	539.6	1,097.3	1,216.0
Operating and administrative	1.7	2.0	3.3	4.7
Depreciation and amortization	—	—	—	0.1
Operating expenses	563.3	541.6	1,100.6	1,220.8
Operating Income	$ 0.7	$ (2.6)	$ 0.8	$ 2.9

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 June 30, 2011 compared with three month period ended June 30, 2010

Included in the operating results of our Marketing segment for the three month period ended June 30, 2011 were unrealized, non-cash, mark-to-market net gains of $1.2 million associated with derivative financial instruments that do not qualify for hedge accounting treatment under authoritative accounting guidance, as compared with the $3.9 million of unrealized non-cash, mark-to-market net losses for the same period in 2010. For the three month period ended June 30, 2011, the non-cash, mark-to-market, net gains primarily related to our financial instruments that we use to hedge our transportation positions. The net gains associated with our transportation derivative instruments resulted from the narrowing of the difference between forward natural gas purchase and sales prices between market centers, which positively impacted the values of derivative financial instruments we use to hedge our transportation positions. Comparatively, during the three month period ended June 30, 2010, the negative impact of the derivative financial instruments and net-settled physical transactions primarily resulted from the widening of the difference between forward natural gas purchase and sales prices between market centers, which negatively affected the values of derivative financial instruments we use to hedge our transportation positions. Contributing to the lower operating income of our Marketing business were relatively stable natural gas prices during the three month period ended June 30, 2011, which limited opportunities to benefit from significant price differentials between market centers.

Six month period ended June 30, 2011 compared with six month period ended June 30, 2010

The components comprising our operating income changed during the six month period ended June 30, 2011 compared to the same period in 2010, primarily for the same reasons as in the three-month analysis, in addition to the items noted below.

The non-cash, mark-to market, net losses of $1.7 million during the six month period ended June 30, 2011 resulted from the widening of the difference between forward natural gas purchase and sales prices between market centers, relative to the prices at December 31, 2010, which negatively impacted the values of derivative financial instruments we use to hedge our transportation positions. Comparatively, during the six month period ended June 30, 2010, we had unrealized, mark-to-market net losses of $4.3 million resulting from widening transportation differentials from the decreases in the forward and daily market prices of natural gas from December 31, 2009.

Operating and administrative expenses for the six month period ended June, 2011 were $1.4 million lower when compared to the same period in 2010 primarily due to our establishment of 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 and six month periods ended June 30, 2011 and 2010 is comprised of the following:

	For the three month period ended June 30,		For the six month period ended June 30,	
	2011	2010	2011	2010
	(unaudited; in millions)			
Interest expense	$ 78.5	$ 69.6	$157.9	$128.9
Interest capitalized	2.2	0.8	3.7	5.6
Interest cost incurred	$ 80.7	$ 70.4	$161.6	$134.5
Weighted average interest rate	*6.3%*	*6.8%*	*6.4%*	*6.5%*

Three month period ended June 30, 2011 compared with three month period ended June 30, 2010

The increase in interest expense between the three month periods ended June 30, 2011 and 2010 is primarily the result of a higher weighted average outstanding debt balance during the three month period ended June 30, 2011 as compared with the same period 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 June 30, 2011 compared to the same period in 2010, partially offset by a decrease in the weighted average outstanding balance of our first mortgage note;
- The issuance and sale in September 2010 of $400 million of our 5.50% senior unsecured notes due 2040; and
- An increase in the weighted average outstanding balance of our Credit Facilities outstanding for the three month period ended June 30, 2011 compared to the same period in 2010.

Six month period ended June 30, 2011 compared with six month period ended June 30, 2010

The results for corporate activities for the six month period ended June 30, 2011 compared to the same period in 2010, changed for the same reasons as noted in the three-month analysis above, in addition to the following:

- A decrease in our weighted average balance of our Credit Facilities outstanding for the six month period ended June 30, 2011 compared to the same period in 2010; and
- The issuance and sale in March 2010 of $500 million of our 5.20% senior unsecured notes due 2020.

Other Matters

Alberta Clipper Pipeline Joint Funding Arrangement and Regulatory Accounting

In July 2009, we entered into a joint funding arrangement to finance construction of the United States segment of the Alberta Clipper Pipeline with several of our affiliates and affiliates of Enbridge including our General Partner. The Alberta Clipper Pipeline was mechanically complete in March 2010 and was ready for service on April 1, 2010. In connection with the joint funding arrangement, we allocated earnings derived from operating the Alberta Clipper Pipeline in the amounts of $14.1 million and $28.8 million to our General Partner for its 66.67 percent share of the earnings of the Alberta Clipper Pipeline for the three and six month periods ended June 30, 2011. We allocated $14.5 million and $25.2 million for the same three and six month periods ended June 30, 2010. 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 $5.6 million as a reduction to "Operating and administrative" expenses of our Liquids segment and $6.0 million as "Other income" in our consolidated statements of income for the six month period ended June 30, 2011 for the amounts we received in April 2011.

LIQUIDITY AND CAPITAL RESOURCES

Available Liquidity

As set forth in the following table, we had in excess of $550 million of liquidity available to us at June 30, 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	$ 159.3
Total credit available under Credit Facilities	1,517.5
Less: Amounts outstanding under Credit Facilities	75.0
Principal amount of commercial paper issuances	1,000.0
Balance of letters of credit outstanding	50.7
Total	$ 551.1

If the holders of our Senior Notes due 2019 require us to repay the notes on March 1, 2012, we expect to finance any amounts we are required to repay through borrowings from our unsecured long-term Credit Facilities, including the $250 million of additional capacity resulting from the July 2011 amendment to our unsecured senior revolving credit agreement.

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 allowed us to issue and sell our Class A common units at prices we deemed appropriate for our Class A common units. Under the EDA, we sold 2,118,025 Class A common units, representing 4,236,050 units after giving effect to a two-for-one split of our Class A common units that became effective on April 21, 2011, for aggregate gross proceeds of

$124.8 million, of which $64.5 million are gross proceeds received in 2011. No further sales will be made under that agreement. On May 27, 2011, we de-registered the remaining aggregate $25.2 million of Class A common units that were registered for sale under the EDA and remained unsold as of that date.

On May 27, 2011, the Partnership entered into an Amended and Restated Equity Distribution Agreement, or Amended EDA, for the issue and sale from time to time of our Class A common units up to an aggregate amount of $500.0 million from the execution date of the agreement through May 20, 2014. The units issued under the Amended EDA are in addition to the units offered and sold under the EDA. The issue and sale of our Class A common units, pursuant to the Amended EDA, may be conducted on any day that is a trading day for the New York Stock Exchange, unless we have suspended sales under that agreement.

The following table presents the net proceeds from our Class A common unit issuances, pursuant to the Amended EDA, during the three month period ended June 30, 2011:

Issuance Date	Number of Class A common units Issued	Average Offering Price per Class A common unit	Net Proceeds to the Partnership(1)	General Partner Contribution(2)	Net Proceeds Including General Partner Contribution
	(unaudited; in millions, except units and per unit amounts)				
May 27 to June 30, 2011	333,794	$30.30	$9.9	$0.2	$10.1

(1) Net of commissions and issuance costs of $0.2 million for the three month period ended June 30, 2011.

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

Equity Issuance

In July 2011, we completed an underwritten public offering of 8.05 million Class A common units at a price to the public of $30.00 per unit, less underwriting commissions and expenses, for net proceeds of $233.7 million. In addition, our General Partner contributed approximately $4.9 million to us to maintain its two percent general partner interest. We used the net proceeds to repay a portion of our outstanding commercial paper.

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 June 30, 2011, we had $75.0 million outstanding under our Credit Facilities, and letters of credit totaling $50.7 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 June 30, 2011, we could borrow $391.8 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	75.0
Principal amount of commercial paper issuances	1,000.0
Balance of letters of credit outstanding	50.7
Total amount we could borrow at June 30, 2011	$ 391.8

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 six month period ended June 30, 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 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 June 30, 2011 we were in compliance with the terms of our financial covenants.

On July 20, 2011, we amended the $350 million unsecured senior revolving credit agreement to reflect an increase in the lending commitments to $600 million. The amended $600 million credit agreement has terms consistent with our existing Credit Facility and has the same maturity date of April 4, 2013. After this amendment, our Credit Facilities provide an aggregate amount of $1,767.5 million of bank credit.

Commercial Paper

At June 30, 2011 we had $1 billion in principal amount of our commercial paper outstanding, at a weighted average interest rate of 0.35%, before the effect of our interest rate hedging activities. Under our commercial paper program, we had net borrowings of approximately $115.1 million during the six month period ended June 30, 2011, which include gross issuances of $7,953.5 million and gross repayments of $7,838.4 million. The commercial paper we can issue is limited by the credit available under our Credit Facilities.

Joint Funding Arrangement for Alberta Clipper Pipeline

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

In March 2010, we refinanced $324.6 million of amounts we had outstanding and payable to our General Partner under the A1 Credit Agreement by issuing a promissory note payable to our General Partner, at which time we also terminated the A1 Credit Agreement. The promissory note payable, which we refer to as the A1 Term Note, matures on March 15, 2020, bears interest at a fixed rate of 5.20% and has a maximum loan amount of $400 million. The terms of the A1 Term Note are similar to the terms of our senior notes, except that the A1 Term Note has recourse only to the assets of the United States portion of the Alberta Clipper Pipeline. Under the terms of the A1 Term Note, we have the ability to increase the principal amount outstanding to finance the debt portion of the investment our General Partner is obligated to make pursuant to the Alberta Clipper Joint Funding Arrangement to finance any additional costs associated with the construction of our portion of the Alberta Clipper Pipeline we incur after the date the original A1 Term Note was issued. The increases we make to the principal balance of the A1 Term Note will also mature on March 15, 2020. At June 30, 2011, we had approximately $348.0 million outstanding under the A1 Term Note.

Our General Partner also made equity contributions totaling $3.3 million and $87.0 million to the Enbridge Energy Limited Partnership, or OLP, during the six month periods ended June 30, 2011 and 2010, to fund its equity portion of the construction costs associated with the Alberta Clipper Pipeline. The OLP paid a distribution of $21.6 million and $43.4 million to our General Partner and its affiliate during the three and six month periods ended June 30, 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 Pipeline in the amounts of $14.1 million and $28.8 million to our General Partner for its 66.67 percent share of the earnings of the Alberta Clipper Pipeline for the three and six month periods ended June 30, 2011, respectively. We allocated $14.5 million and

$25.2 million for the same three and six month periods ended June 30, 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.

Cash Requirements

Capital Spending

We expect to make additional expenditures during the remainder of the year for the acquisition and construction of natural gas processing and crude oil transportation infrastructure. In 2011, we expect to spend approximately $1,250 million on system enhancements and other projects associated with our liquids and natural gas systems with the expectation of realizing additional cash flows as projects are completed and placed into service. Of this amount, we made capital expenditures of $363.1 million in the six month period ended June 30, 2011. At June 30, 2011, we had approximately $251.2 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 six month period ended June 30, 2011, our cash flows were adversely affected by the approximate $138.0 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 that we will have paid approximately 80 to 90 percent of the total costs associated with these releases 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 $363.1 million, including $40.7 million on core maintenance activities, for the six month period ended June 30, 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	$ 330
Liquids integrity program	300
Core maintenance activities	90
Haynesville projects	170
North Dakota Expansion Program	115
Allison Related Expansion Capital	150
Cushing Storage	95
	$1,250

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

Under our capitalization policy, expenditures that replace major components of property or extend the useful lives of existing assets are capital in nature while expenditures to inspect and test our pipelines are usually considered operating expenses. 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 crude oil release to perform additional inspections, testing and refurbishment of Line 6B within and beyond the immediate area of the July 26, 2010 crude oil release. Pursuant to this agreement, with PHMSA, we completed remediation of those pipeline anomalies identified by us between the years 2007 and 2009 that were scheduled for refurbishment and anomalies identified for action in a July 2010 PHMSA notification on schedule within 180 days of the September 27, 2010 restart of Line 6B, as required. In addition to the required integrity measures, we also agreed to replace a 3,600 foot section of the Line 6B pipeline that lies underneath the St. Clair River in Michigan within one year of the restart of Line 6B, subject to obtaining required permits. A new line was installed beneath the St. Clair River in March 2011 and was tied-into Line 6B during June 2011.

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

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

In February 2011, we included in the supplement to our FSM, to be effective April 1, 2011, recovery of $175 million of capital costs and $5 million of operating costs for the 2010 and 2011 Line 6B 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 June 30, 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]	158,108,730	$ (3.0)	$ (2.6)	$ 3.7	$ (0.1)	$ —	$—	$ (2.0)
NGL[2]	6,233,741	(32.8)	(13.1)	(9.7)	(2.9)	(0.3)	—	(58.8)
Crude[2]	6,039,307	(14.0)	(12.8)	(10.7)	(7.6)	(2.1)	—	(47.2)
Options								
Natural gas—puts purchased[1]	184,000	—	—	—	—	—	—	—
Natural gas—calls written[1]	184,000	(0.1)	—	—	—	—	—	(0.1)
NGL—puts purchased[2]	604,174	0.7	2.6	—	—	—	—	3.3
Crude—puts purchased[2]	109,480	0.3	—	—	—	—	—	0.3
Forward contracts								
Crude[2]	766,479	0.7	—	—	—	—	—	0.7
Natural gas[1]	43,822,371	0.7	0.8	0.3	—	—	—	1.8
NGL[2]	5,484,300	3.2	1.6	0.1	—	—	—	4.9
Power[3]	202,025	(0.4)	(0.3)	(0.2)	(0.3)	—		(1.2)
Totals		$(44.7)	$(23.8)	$(16.5)	$(10.9)	$(2.4)	$—	$(98.3)

(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 $0.9 million of gains at June 30, 2011.

The following table provides summarized information about the timing and expected settlement amounts of our outstanding interest rate derivative instruments at June 30, 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	$(12.9)	$(26.0)	$(18.2)	$—	$0.2	$—	$(56.9)
Fixed to Floating	125.0	2.4	5.5	2.4	—	—	—	10.3
Pre-issuance hedges	1,200.0	14.5	(29.0)	(5.7)	—	—	—	(20.2)
		$ 4.0	$(49.5)	$(21.5)	$—	$0.2	$—	$(66.8)

(1) Fair values are presented in millions of dollars and exclude credit adjustments of approximately $0.9 million of gains at June 30, 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 six month period ended June 30,		Variance 2011 vs. 2010
	2011	2010	Increase (Decrease)
	(unaudited; in millions)		
Total cash provided by (used in):			
Operating activities	$ 461.0	$ 365.4	$ 95.6
Investing activities	(406.4)	(383.1)	(23.3)
Financing activities	(40.2)	81.3	(121.5)
Net increase (decrease) in cash and cash equivalents	14.4	63.6	(49.2)
Cash and cash equivalents at beginning of year	144.9	143.6	1.3
Cash and cash equivalents at end of period	$ 159.3	$ 207.2	$ (47.9)

Operating Activities

Net cash provided by our operating activities increased $95.6 million for the six month period ended June 30, 2011 compared with the same period in 2010 primarily due to higher changes in our working capital accounts for the six month period ended June 30, 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 six month period ended June 30, 2011 were also affected by $140.3 million of environmental costs paid, which included $138.0 million of costs associated with the Lines 6A & 6B crude oil releases, offset by $35.0 million of environmental insurance recoveries associated with the Line 6B crude oil release, as compared with, only $4.9 million of environmental costs paid and no similar recoveries in the same period of 2010.

Investing Activities

Net cash used in our investing activities during the six month period ended June 30, 2011 increased by $23.3 million compared to the same period of 2010 primarily due to additional acquisitions and cash outlays in 2011. We spent an additional $10.2 million on asset acquisitions in 2011 when compared to the same period in 2010. Further contributing to the increase were $10.8 million of cash outlays for the purchase of homes and land in Michigan that were affected by the Line 6B crude oil release. We did not make similar outlays during the same period of 2010.

Financing Activities

The net cash used in our financing activities increased $121.5 million during the six month period ended June 30, 2011 compared to the same period in 2010 primarily due to the following:

	(unaudited; in millions)
Net proceeds related to Class A common units issued under EDA in 2011 and none in 2010[1]	$ 59.3
Increase in distributions to our partners in 2011 compared to 2010	(32.2)
Decrease in net affiliate borrowings in 2011 compared to 2010[2]	(70.6)
Net proceeds from senior notes due in 2020 issues in 2010 and none in 2011	(496.1)
Net repayments on our Credit Facilities in 2010 compared to 2011	840.0
Increase in net commercial paper repayments in 2011 compared to 2010	(294.8)
Decrease in capital contributions from our General Partner and its affiliate for its ownership interest in the Alberta Clipper Pipeline	(83.7)
Distributions to our General Partner and its affiliate for its ownership interest in the Alberta Clipper Pipeline paid in 2011 compared to no distributions in 2010	(43.4)
	$(121.5)

(1) Includes $1.6 million of contributions from the General Partner to maintain its two percent interest.

(2) For the six month period ended June 30, 2010, we borrowed $395.8 million from our general partner which we used to repay $324.6 million we borrowed on the A1 Credit Facility and to fund $71.2 million of additional costs incurred for the construction of the Alberta Clipper Pipeline. During the same period in 2011, we borrowed only $7.0 million and repaid $6.4 million to our general partner and affiliates.

SUBSEQUENT EVENTS

Class A common unit issuances

In July 2011, we completed an underwritten public offering of 8.05 million Class A common units at a price to the public of $30.00 per unit, less underwriting commissions and expenses, for net proceeds of $233.7 million. In addition, our General Partner contributed approximately $4.9 million to us to maintain its two percent general partner interest. We used the net proceeds to repay a portion of our outstanding commercial paper.

Credit Agreement Amendment and Increase

On July 20, 2011, we amended the $350 million unsecured senior revolving credit agreement to reflect an increase in the lending commitments to $600 million. The amended $600 million credit agreement has terms consistent with our existing Credit Facility and has the same maturity date of April 4, 2013. After this amendment, our Credit Facilities provide an aggregate amount of $1,767.5 million of bank credit.

Distribution to Partners

On July 28, 2011, the board of directors of Enbridge Management declared a distribution payable to our partners on August 12, 2011. The distribution will be paid to unitholders of record as of August 5, 2011, of our available cash of $167.2 million at June 30, 2011, or $0.5325 per limited partner unit. Of this distribution, $147.4 million will be paid in cash, $19.4 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 July 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 $17.7 million to the noncontrolling interest in the Series AC, while $8.8 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 and 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 May 2, 2011, we filed FERC Tariff 45.0.0 to establish International Joint Tariff rates applicable to the transportation of petroleum from all receipt points in Western Canada on EPI's Canadian Mainline system to all delivery points on the Lakehead pipeline system owned by the OLP and delivery points on the Canadian mainline located downstream of the Lakehead system. This tariff filing became effective July 1, 2011.

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

RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

Accounting Standards Update—Fair Value Measurement

In May 2011, the Financial Accounting Standards Board, or FASB, issued an amendment to the guidance on fair value measurement as part of the FASB's joint project with the International Accounting Standards Board, or IASB, to achieve common fair value measurement and disclosure requirements in U.S. generally accepted accounting principles, or GAAP, and International Financial Reporting Standards, or IFRS. The key changes relevant to our business include enhanced disclosures requiring additional information about unobservable inputs and valuation methods utilized and requiring the fair value hierarchy level of assets and liabilities not recorded at fair value but where fair value disclosure is required.

The accounting update is effective for the first reporting period beginning after December 15, 2011, with early application prohibited. The guidance will require prospective application. The adoption of this pronouncement is not anticipated to have a material impact on our financial statements.

Accounting Standards Update—Presentation of Comprehensive Income

In June 2011, the FASB issued guidance on the presentation of comprehensive income as part of the FASB's joint project with the IASB, requiring presentation of net income and other comprehensive income either in one continuous statement, referred to as the statement of comprehensive income, or in two separate, but consecutive, statements of net income and other comprehensive income. The guidance eliminates the option to report other comprehensive income and its components in the statement of changes in equity and the disclosure of reclassification adjustments in the footnotes. The guidance does not change which components of comprehensive income are recognized in net income or other comprehensive income, when an item of other comprehensive income must be reclassified to net income or the earnings-per-share computation.

The accounting update is effective for the first reporting period beginning after December 15, 2011, with early application permitted. The guidance requires retrospective application. We do not intend to adopt the provisions of this pronouncement early. Our adoption of this pronouncement will require us to modify the items we present in the consolidated statements of comprehensive income.

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

Interest Rate Derivatives

The table below provides information about our derivative financial instruments that we use to hedge the interest payments on our variable rate debt obligations that are sensitive to changes in interest rates and to lock in the interest rate on anticipated issuances of debt in the future. For interest rate swaps, the table presents notional amounts, the rates charged on the underlying notional 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 June 30, 2011.

				Fair Value[2] at	
Date of Maturity & Contract Type	**Accounting Treatment**	**Notional**	**Average Fixed Rate[1]**	**June 30, 2011**	**December 31, 2010**
	(dollars in millions)				
Contracts maturing in 2013					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$600	4.15%	$(47.8)	$(51.8)
Interest Rate Swaps—Pay Fixed	Non-qualifying	$125	4.35%	$ (9.3)	$(10.7)
Interest Rate Swaps—Pay Float	Non-qualifying	$125	4.75%	$ 10.3	$ 11.9
Contracts maturing in 2015					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$300	2.43%	$ 0.2	$ 1.9
Contracts settling prior to maturity					
2011—Pre-issuance Hedges	Cash Flow Hedge	$300	2.92%	$ 14.5	$ 23.4
2012—Pre-issuance Hedges	Cash Flow Hedge	$600	4.57%	$(29.0)	$(13.7)
2013—Pre-issuance Hedges	Cash Flow Hedge	$300	4.62%	$ (5.7)	$ (0.3)

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

(2) The fair value is determined from quoted market prices at June 30, 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 $0.9 million of gains at June 30, 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 June 30, 2011 and December 31, 2010:

	At June 30, 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	5,425,773	$ 4.45	$ 4.65	$1.2	$ (2.3)	$0.4	$ (4.9)
	NGL	110,000	$ 88.38	$ 59.89	$3.1	$ —	$6.8	$ —
	Crude Oil	110,000	$ 96.31	$102.10	$ —	$ (0.6)	$0.4	$ —
Receive fixed/pay variable	Natural Gas	9,219,627	$ 4.09	$ 4.45	$0.9	$ (4.2)	$2.6	$ (6.7)
	NGL	2,571,176	$ 49.40	$ 63.38	$1.6	$(37.5)	$5.0	$(38.8)
	Crude Oil	940,136	$ 81.36	$ 95.67	$0.7	$(14.1)	$ —	$(22.9)
Receive variable/pay variable	Natural Gas	48,788,861	$ 4.34	$ 4.31	$2.7	$ (1.3)	$5.0	$ (1.2)
Physical Contracts								
Receive fixed/pay variable	NGL	1,014,439	$ 80.60	$ 80.01	$1.4	$ (0.8)	$0.5	$ (4.4)
	Crude Oil	130,000	$101.01	$ 95.95	$0.7	$ —	$ —	$ (1.9)
Receive variable/pay fixed	NGL	223,103	$ 92.14	$ 90.33	$0.6	$ (0.2)	$1.6	$ —
	Crude Oil	93,000	$ 95.70	$ 98.48	$ —	$ (0.3)	$1.1	$ —
Pay fixed	Power(4)	37,800	$ 34.02	$ 44.24	$ —	$ (0.4)	$ —	$ (0.8)
Receive variable/pay variable	Crude Oil	543,479	$ 96.12	$ 95.67	$1.2	$ (0.9)	$0.5	$ (0.2)
	NGL	3,004,452	$ 76.43	$ 75.69	$5.2	$ (3.0)	$6.2	$ (1.4)
	Natural Gas	18,742,920	$ 4.36	$ 4.32	$0.7	$ —	$1.1	$ —
Portion of contracts maturing in 2012								
Swaps								
Receive variable/pay fixed	Natural Gas	2,362,813	$ 4.79	$ 6.40	$0.2	$ (4.0)	$ —	$ (3.8)
Receive fixed/pay variable	Natural Gas	4,352,720	$ 4.82	$ 4.79	$1.9	$ (1.8)	$1.7	$ (2.1)
	NGL	2,067,380	$ 56.14	$ 62.48	$4.3	$(17.4)	$8.0	$ (7.6)
	Crude Oil	1,418,616	$ 88.73	$ 97.83	$3.0	$(15.8)	$ —	$(10.7)
Receive variable/pay variable	Natural Gas	51,264,000	$ 4.77	$ 4.75	$2.0	$ (0.9)	$1.0	$ (0.8)
Physical Contracts								
Receive fixed/pay variable	NGL	95,791	$ 79.19	$ 77.28	$0.3	$ (0.1)	$ —	$ —
Receive variable/pay variable	Natural Gas	18,394,101	$ 4.78	$ 4.73	$0.8	$ —	$0.6	$ —
	NGL	1,102,229	$ 70.82	$ 69.57	$2.4	$ (1.0)	$0.7	$ —
Pay fixed	Power(4)	62,330	$ 35.40	$ 40.29	$ —	$ (0.3)	$ —	$ —
Portion of contracts maturing in 2013								
Swaps								
Receive variable/pay fixed	Natural Gas	93,066	$ 5.07	$ 5.19	$ —	$ —	$ —	$ —
Receive fixed/pay variable	Natural Gas	730,000	$ 9.83	$ 5.01	$3.5	$ —	$3.3	$ —
	NGL	994,260	$ 64.86	$ 74.72	$0.6	$(10.3)	$0.3	$ (3.2)
	Crude Oil	1,430,435	$ 93.38	$100.94	$3.3	$(14.0)	$2.2	$ (7.4)
Receive variable/pay variable	Natural Gas	29,550,000	$ 5.11	$ 5.10	$0.4	$ (0.2)	$0.1	$ (0.2)
Physical Contracts								
Receive variable/pay variable	Natural Gas	6,685,350	$ 5.14	$ 5.10	$0.3	$ —	$0.2	$ —
	NGL	44,286	$ 65.68	$ 64.00	$0.1	$ —	$ —	$ —
Pay fixed	Power(4)	43,042	$ 38.41	$ 42.86	$ —	$ (0.2)	$ —	$ —
Portion of contracts maturing in 2014								
Swaps								
Receive variable/pay fixed	Natural Gas	21,870	$ 5.42	$ 5.22	$ —	$ —	$ —	$ —
Receive fixed/pay variable	NGL	381,425	$ 77.58	$ 85.58	$0.6	$ (3.5)	$ —	$ (1.1)
	Crude Oil	1,228,955	$ 94.27	$100.68	$0.6	$ (8.2)	$ —	$ (2.8)
Receive variable/pay variable	Natural Gas	6,300,000	$ 5.48	$ 5.49	$ —	$ (0.1)	$ —	$ (0.1)
Physical Contracts								
Pay fixed	Power(4)	58,853	$ 41.46	$ 46.58	$ —	$ (0.3)	$ —	$ —
Portion of contracts maturing in 2015								
Swaps								
Receive fixed/pay variable	Crude Oil	865,415	$ 97.72	$100.31	$0.3	$ (2.4)	$ —	$ (0.7)
	NGL	109,500	$ 88.36	$ 91.37	$0.2	$ (0.5)	$ —	$ (0.1)
Portion of contracts maturing in 2016								
Swaps								
Receive fixed/pay variable	Crude Oil	45,750	$ 99.31	$100.22	$ —	$ —	$ —	$ —

(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 June 30, 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 $0.9 million of gains and $0.6 million of gains at June 30, 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 June 30, 2011 and December 31, 2010.

	At June 30, 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]	184,000	$ 4.31	$ 4.46	$ —	$(0.1)	$ —	$(0.2)
Puts (purchased)	Natural Gas[4]	184,000	$ 3.40	$ 4.46	$ —	$ —	$ —	$ —
	NGL	319,792	$54.79	$67.50	$0.7	$ —	$3.6	$ —
	Crude Oil	109,480	$88.65	$96.90	$0.3	$ —	$1.3	$ —
Portion of option contracts maturing in 2012								
Puts (purchased)	NGL	284,382	$65.90	$72.35	$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 June 30, 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 June 30, 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).

	June 30, 2011	December 31, 2010
	(in millions)	
Counterparty Credit Quality*		
AAA	$ (0.1)	$ —
AA	(85.9)	(48.7)
A	(81.3)	(61.3)
Lower than A	4.0	5.8
	$(163.3)	$(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 June 30, 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 June 30, 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: July 29, 2011	By: /S/ MARK A. MAKI Mark A. Maki *President* *(Principal Executive Officer)*
Date: July 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
1.1	Equity Distribution Agreement dated as of June 9, 2011 between the Partnership and UBS Securities LLC (incorporated by reference to Exhibit 1.1 of the Partnership's Current Report on Form 8-K, filed on May 27, 2011).
10.1	International Joint Tariff Agreement dated May 6, 2011 between Enbridge Pipelines Inc. and Enbridge Energy, Limited Partnership (incorporated by reference to Exhibit 10.1 of the Partnership's Current Report on Form 8-K, filed on June 29, 2011).
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.