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, 2010

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 97,840,697 Class A common units outstanding as of July 27, 2010.

ENBRIDGE ENERGY PARTNERS, L.P.

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

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

Our forward-looking statements are subject to risks and uncertainties pertaining to operating performance, regulatory parameters, weather, economic conditions, interest rates and commodity prices including but not limited to those risks and uncertainties discussed in this Quarterly Report on Form 10-Q and our other reports that we have filed or will file with the Securities and Exchange Commission. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these factors are interdependent, and our future course of action depends on the assessment of all information available at the relevant time by those responsible for the management of our operations. Except to the extent required by law, we assume no obligation to publicly update or revise any forward-looking statements made herein whether as a result of new information, future events or otherwise. All subsequent forward-looking statements, whether written or oral, attributable to us or persons acting on our behalf are expressly qualified in their entirety by these cautionary statements, as such may be updated in our future filings with the Securities and Exchange Commission. For additional discussion of risks, uncertainties and assumptions, see "Risk Factors" included in Part 1, Item 1A of our Annual Report on Form 10-K for the fiscal year ended December 31, 2009 and in Part II, Item 1A of this Quarterly Report on Form 10-Q.

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,	
	2010	2009	2010	2009
	(unaudited; in millions, except per unit amounts)			
Operating revenue (Note 11)	$1,747.4	$1,299.3	$3,678.6	$2,740.5
Operating expenses				
Cost of natural gas (Notes 5 and 11)	1,270.4	893.2	2,794.6	1,986.1
Operating and administrative	136.3	132.9	272.3	265.4
Power	36.5	29.8	68.8	63.2
Depreciation and amortization (Note 6)	77.6	66.1	145.5	126.5
	1,520.8	1,122.0	3,281.2	2,441.2
Operating income	226.6	177.3	397.4	299.3
Interest expense (Note 11)	69.6	57.9	128.9	109.2
Other income (expense) (Note 13)	(0.1)	0.2	16.7	(0.3)
Income from continuing operations before income tax expense	156.9	119.6	285.2	189.8
Income tax expense	2.4	2.1	4.6	4.1
Income from continuing operations	154.5	117.5	280.6	185.7
Income from discontinued operations, net of tax (Note 3)	—	—	—	0.4
Net income	154.5	117.5	280.6	186.1
Less: Net income attributable to noncontrolling interest (Notes 8 and 9)	14.5	—	25.2	—
Net income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 140.0	$ 117.5	$ 255.4	$ 186.1
Net income allocable to limited partner interests				
Income from continuing operations	$ 120.3	$ 102.9	$ 219.5	$ 157.5
Income from discontinued operations	—	—	—	0.4
Net income allocable to limited partner interests	$ 120.3	$ 102.9	$ 219.5	$ 157.9
Basic and diluted earnings per limited partner unit (Note 2)				
Income from continuing operations	$ 1.02	$ 0.88	$ 1.86	$ 1.36
Income from discontinued operations	—	—	—	0.01
Net income per limited partner unit (basic and diluted)	$ 1.02	$ 0.88	$ 1.86	$ 1.37
Weighted average limited partner units outstanding	118.2	116.1	118.1	115.6

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,	
	2010	2009	2010	2009
	(unaudited; in millions, except per unit amounts)			
Net income	$154.5	$117.5	$280.6	$186.1
Other comprehensive income (loss), net of tax benefit (expense) of $(0.2), $0.5, $(0.4) and $0.4, respectively (Note 11)	(52.9)	(81.9)	(46.4)	(76.3)
Comprehensive income	101.6	35.6	234.2	109.8
Less: Comprehensive income attributable to noncontrolling interest (Notes 8 and 9)	14.5	—	25.2	—
Comprehensive income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 87.1	$ 35.6	$209.0	$109.8

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,	
	2010	2009
	(unaudited; in millions)	
Cash provided by operating activities		
Net income	$ 280.6	$ 186.1
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization (Note 6)	145.5	134.2
Derivative fair value gains (Note 11)	(25.9)	—
Inventory market price adjustments (Note 5)	2.6	3.4
Other (Note 15)	(1.4)	14.0
Changes in operating assets and liabilities, net of acquisitions:		
Receivables, trade and other	37.7	(22.1)
Due from General Partner and affiliates	(17.4)	21.5
Accrued receivables	15.0	122.5
Inventory (Note 5)	(58.2)	(7.6)
Current and long-term other assets (Note 11)	(0.9)	(29.6)
Due to General Partner and affiliates	18.7	0.1
Accounts payable and other (Notes 4, 10 and 11)	(3.8)	(25.5)
Accrued purchases	(20.1)	(54.1)
Interest payable	8.7	20.7
Property and other taxes payable	(2.5)	(3.5)
Settlement of interest rate derivatives (Note 11)	(13.2)	(0.7)
Net cash provided by operating activities	365.4	359.4
Cash used in investing activities		
Additions to property, plant and equipment (Note 6)	(356.2)	(543.9)
Changes in construction payables	(9.9)	(33.3)
Asset acquisitions	(17.0)	—
Other	—	(0.1)
Net cash used in investing activities	(383.1)	(577.3)
Cash provided by financing activities		
Net proceeds from unit issuances (Note 8)	15.1	—
Distributions to partners (Note 8)	(233.0)	(186.5)
Repayment of long-term debt	—	(175.0)
Repayment of loan from General Partner (Note 9)	(324.6)	—
Net proceeds from issuance of long-term debt (Note 7)	496.1	—
Net borrowings (repayments) under Credit Facility (Note 7)	(765.0)	376.2
Net commercial paper borrowings (Note 7)	409.9	—
Borrowings from General Partner (Note 9)	395.8	—
Contribution from noncontrolling interest (Notes 8 and 9)	87.0	—
Other	—	(4.0)
Net cash provided by financing activities	81.3	10.7
Net increase (decrease) in cash and cash equivalents	63.6	(207.2)
Cash and cash equivalents at beginning of year	143.6	339.9
Cash and cash equivalents at end of period	$ 207.2	$ 132.7

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	June 30, 2010	December 31, 2009
	(unaudited; dollars in millions)	
ASSETS		
Current assets		
Cash and cash equivalents (Note 4)	$ 207.2	$ 143.6
Receivables, trade and other, net of allowance for doubtful accounts of $2.0 in 2010 and $6.8 in 2009	115.9	148.5
Due from General Partner and affiliates	35.4	18.0
Accrued receivables	425.4	440.4
Inventory (Note 5)	127.5	71.9
Other current assets (Note 11)	52.4	47.5
	963.8	869.9
Property, plant and equipment, net (Notes 6, 9 and 13)	7,963.3	7,716.7
Goodwill	246.7	246.7
Intangibles, net	80.9	82.9
Other assets, net (Note 11)	60.3	72.1
	$9,315.0	$8,988.3
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Due to General Partner and affiliates	$ 64.9	$ 46.2
Accounts payable and other (Notes 4, 10 and 11)	168.0	205.4
Accrued purchases	408.5	428.6
Interest payable	54.0	45.3
Property and other taxes payable	36.3	38.8
Loan from General Partner (Note 9)	11.4	269.7
Current maturities of long-term debt (Note 7)	31.0	31.0
	774.1	1,065.0
Long-term debt (Note 7)	3,936.3	3,791.2
Note payable to General Partner (Note 9)	329.5	—
Other long-term liabilities (Notes 10 and 11)	100.0	62.2
	5,139.9	4,918.4
Commitments and contingencies (Note 10)		
Partners' capital (Note 8)		
Class A common units (97,730,697 at June 30, 2010 and 97,443,352 at December 31, 2009)	2,887.4	2,884.9
Class B common units (3,912,750 at June 30, 2010 and December 31, 2009)	78.6	78.6
i-units (17,024,591 at June 30, 2010 and 16,388,867 at December 31, 2009)	620.8	588.8
General Partner	256.0	251.1
Accumulated other comprehensive income (Notes 8 and 11)	(121.0)	(74.6)
Total Enbridge Energy Partners, L.P. partners' capital	3,721.8	3,728.8
Noncontrolling interest (Notes 8 and 9)	453.3	341.1
Total partners' capital	4,175.1	4,069.9
	$9,315.0	$8,988.3

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, 2010 and our results of operations and cash flows for the three and six month periods ended June 30, 2010 and 2009. We derived our consolidated statement of financial position as of December 31, 2009 from the audited financial statements included in our 2009 Annual Report on Form 10-K. Our results of operations for the three and six month periods ended June 30, 2010 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. 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, 2009.

2. NET INCOME PER LIMITED PARTNER AND GENERAL PARTNER INTEREST

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% and 98%, respectively, as set forth in our partnership agreement. The formula for distributing available cash as set forth in our partnership agreement is as follows:

Distribution Targets	Portion of Quarterly Distribution Per Unit	Percentage Distributed to General Partner	Percentage Distributed to Limited Partners
Minimum Quarterly Distribution	Up to $0.59	2%	98%
First Target Distribution	> $0.59 to $0.70	15%	85%
Second Target Distribution	> $0.70 to $0.99	25%	75%
Over Second Target Distribution	In excess of $0.99	50%	50%

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,	
	2010	2009	2010	2009
	(in millions, except per unit amounts)			
Net income	$ 154.5	$ 117.5	$ 280.6	$ 186.1
Less: Net income attributable to noncontrolling interest	14.5	—	25.2	—
Net income attributable to general and limited partner interests in Enbridge Energy Partners, L.P.	140.0	117.5	255.4	186.1
Less: Net income from discontinued operations	—	—	—	0.4
Net income from continuing operations attributable to general and limited partner interests in Enbridge Energy Partners, L.P.	140.0	117.5	255.4	185.7
Less distributions paid:				
Incentive distributions to our general partner	(17.2)	(12.6)	(31.4)	(25.1)
Distributed earnings allocated to our general partner (2%)	(2.5)	(2.3)	(4.9)	(4.6)
Total distributed earnings to our general partner	(19.7)	(14.9)	(36.3)	(29.7)
Total distributed earnings to our limited partners (98%)	(122.0)	(115.4)	(240.3)	(229.8)
Total distributed earnings	(141.7)	(130.3)	(276.6)	(259.5)
Overdistributed earnings	$ (1.7)	$ (12.8)	$ (21.2)	$ (73.8)
Weighted average limited partner units outstanding	118.2	116.1	118.1	115.6
Basic and diluted earnings per unit:				
Distributed earnings per limited partner unit[1]	$ 1.03	$ 0.99	$ 2.04	$ 1.99
Overdistributed earnings per limited partner unit[2]	(0.01)	(0.11)	(0.18)	(0.63)
Net income from continuing operations attributable to our limited partner interests per limited partner unit	1.02	0.88	1.86	1.36
Net income from discontinued operations attributable to our limited partner interests per limited partner unit	—	—	—	0.01
Net income per limited partner unit (basic and diluted)	$ 1.02	$ 0.88	$ 1.86	$ 1.37

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

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

3. DISCONTINUED OPERATIONS

In November 2009, we sold non-core natural gas pipeline assets located predominantly outside of Texas. We have presented the operating results of the natural gas pipeline assets we sold for the three and six month periods ended June 30, 2009 in “Income from discontinued operations” on our consolidated statement of income. The following table presents the operating results of the discontinued operations of our natural gas pipeline assets that we derived from historical financial information:

	For the three month period ended June 30, 2009	For the six month period ended June 30, 2009
	(in millions)	
Operating revenue	$52.4	$108.5
Operating expenses		
Cost of natural gas	43.4	90.1
Operating and administrative	5.2	10.4
Depreciation and amortization	3.9	7.7
	52.5	108.2
Operating income (loss)	(0.1)	0.3
Other income	0.1	0.1
Income from discontinued operations	$ —	$ 0.4

4. CASH AND CASH EQUIVALENTS

We extinguish liabilities when a creditor has relieved us of our obligation, which occurs when our financial institution honors a check that the creditor has presented for payment. Accordingly, obligations for which we have made payments that have not yet been presented to the financial institution totaling approximately $19.5 million at June 30, 2010 and $24.2 million at December 31, 2009 are included in “Accounts payable and other” on our consolidated statements of financial position.

5. INVENTORY

Our inventory is comprised of the following:

	June 30, 2010	December 31, 2009
	(in millions)	
Materials and supplies	$ 6.4	$ 3.6
Crude oil inventory	13.2	4.1
Natural gas and NGL inventory	107.9	64.2
	$127.5	$71.9

Our consolidated statements of income include charges totaling $1.5 million and $2.6 million for the three and six month periods ended June 30, 2010, respectively, that we recorded in “Cost of natural gas” 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 for the three and six month periods ended June 30, 2009 totaled $0.1 million and $3.4 million, respectively.

6. PROPERTY, PLANT AND EQUIPMENT

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

	June 30, 2010	December 31, 2009
	(in millions)	
Land	$ 33.6	$ 29.8
Rights-of-way	477.1	438.7
Pipelines	5,600.0	4,401.9
Pumping equipment, buildings and tanks	1,302.8	1,115.9
Compressors, meters and other operating equipment	1,362.7	1,337.8
Vehicles, office furniture and equipment	177.0	164.8
Processing and treating plants	326.8	325.7
Construction in progress	244.5	1,326.3
Total property, plant and equipment	9,524.5	9,140.9
Accumulated depreciation	(1,561.2)	(1,424.2)
Property, plant and equipment, net	$ 7,963.3	$ 7,716.7

7. DEBT

Credit Facility

At June 30, 2010, we had no amounts outstanding under our Second Amended and Restated Credit Agreement, which we refer to as our Credit Facility, and letters of credit totaling $16.7 million. The amounts we may borrow under the terms of our Credit Facility are reduced by the principal amount of our commercial paper issuances and the balance of our letters of credit outstanding. At June 30, 2010, we could borrow $740.8 million under the terms of our Credit Facility, determined as follows:

	(in millions)
Total credit available under Credit Facility	$1,167.5
Less: Amounts outstanding under Credit Facility	—
Balance of letters of credit outstanding	16.7
Principal amount of commercial paper issuances	410.0
Total amount we could borrow at June 30, 2010	$ 740.8

Individual borrowings under the terms of our Credit Facility 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 Facility, which we accomplish by contemporaneously borrowing at the then current rate of interest and repaying the principal amount due. During the six month periods ended June 30, 2010 and 2009, we net settled borrowings of $915.0 million and $957.1 million, respectively, on a non-cash basis.

Commercial Paper

We have a commercial paper program that provides for the issuance of up to $600 million of commercial paper that is supported by our Credit Facility. We access the commercial paper market primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions when the available interest rates we can obtain are lower than the rates available under our Credit Facility. At June 30, 2010, we had $410.0 million of commercial paper outstanding at a weighted average interest rate of 0.44%, excluding the effect of our interest rate hedging activities. At December 31, 2009, we did not have any amounts of commercial paper outstanding. At June 30, 2010, we could issue an additional $190.0 million in principal of commercial paper under our commercial paper program. The commercial paper we can issue is limited by the credit available under our Credit Facility.

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

Senior Notes

In March 2010, we issued and sold $500 million in principal amount of our 5.20% senior notes due March 15, 2020, which we refer to as the Notes. We received net proceeds from the offering of approximately $496.1 million after underwriting discounts and commissions and payment of offering expenses. We used the net proceeds we received from this offering to repay a portion of our outstanding commercial paper and Credit Facility borrowings that we had previously used to finance a portion of our capital expansion projects. We temporarily invested a portion of the remaining proceeds, which we subsequently used to fund additional expenditures under our capital expansion programs. The Notes do not contain any covenants restricting our issuance of additional indebtedness and rank equally with all of our other existing and future unsecured and unsubordinated indebtedness. Interest on the Notes is payable semi-annually on March 15th and September 15th of each year and we may redeem the Notes for cash in whole or in part at any time at our option subject to a make-whole redemption premium.

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 Credit Facility borrowings approximate their fair values at June 30, 2010 and December 31, 2009 due to the short-term nature and frequent repricing of these obligations. 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, 2010		December 31, 2009	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Commercial paper	$ 410.0	$ 410.0	$ —	$ —
Credit Facility	—	—	765.0	765.0
9.150% First Mortgage Notes	62.0	68.5	62.0	69.9
7.900% Senior Notes due 2012	100.0	110.0	100.0	109.5
4.750% Senior Notes due 2013	199.9	206.2	199.9	201.2
5.350% Senior Notes due 2014	200.0	214.4	199.9	206.9
5.875% Senior Notes due 2016	299.8	330.9	299.8	315.0
7.000% Senior Notes due 2018	99.9	117.4	99.9	111.6
6.500% Senior Notes due 2018	398.3	455.7	398.2	433.2
9.875% Senior Notes due 2019	499.9	693.5	499.8	664.8
5.200% Senior Notes due 2020	499.8	512.9	—	—
7.125% Senior Notes due 2028	99.8	118.0	99.9	110.9
5.950% Senior Notes due 2033	199.7	200.8	199.7	188.8
6.300% Senior Notes due 2034	99.8	103.9	99.8	98.0
7.500% Senior Notes due 2038	398.9	474.0	398.9	449.5
8.050% Junior subordinated notes due 2067	399.5	392.9	399.4	381.8
Total	$3,967.3	$4,409.1	$3,822.2	$4,106.1

8. PARTNERS' CAPITAL

The following table sets forth our distributions, as approved by the Board of Directors of Enbridge Energy Management, L.L.C., which we refer to as Enbridge Management, during the six month period ended June 30, 2010.

Distribution Declaration Date	Record Date	Distribution Payment Date	Distribution per Unit	Cash available for distribution	Amount of Distribution of i-units to i-unit Holders[(1)]	Retained from General Partner[(2)]	Distribution of Cash
		(in millions, except per unit amounts)					
April 28, 2010	May 7, 2010	May 14, 2010	$1.0025	$134.9	$16.7	$0.4	$117.8
January 29, 2010	February 5, 2010	February 12, 2010	0.9900	131.7	16.2	0.3	115.2

(1) We issued 635,724 i-units to Enbridge Management, the sole owner of our i-units, during 2010 in lieu of cash distributions.

(2) We retained an amount equal to 2 percent of the i-unit distribution from our General Partner to maintain its 2 percent general partner interest in us.

The following table presents significant changes in partners' capital attributable to our general 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, 2010. The noncontrolling interest in the OLP arises from our joint funding arrangement with our General Partner and its affiliates 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 Project.

	For the three month period ended June 30, 2010	For the six month period ended June 30, 2010
	(in millions)	
General and limited partner interests		
Beginning balance	$3,805.5	$3,803.4
Proceeds from issuance of partnership interest, net of costs	15.1	15.1
Capital contribution	—	1.9
Net income	140.0	255.4
Distributions	(117.8)	(233.0)
Ending balance	$3,842.8	$3,842.8
Accumulated other comprehensive income		
Beginning balance	$ (68.1)	$ (74.6)
Net realized losses (gains) on changes in fair value of derivative financial instruments reclassified to earnings	9.0	18.9
Unrealized net gain (loss) on derivative financial instruments	(61.9)	(65.3)
Ending balance	$ (121.0)	$ (121.0)
Noncontrolling interest		
Beginning balance	$ 429.1	$ 341.1
Capital contributions	9.7	87.0
Comprehensive income:		
Net income	14.5	25.2
Ending balance	$ 453.3	$ 453.3
Total partners' capital at end of period	$4,175.1	$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 allows us to issue and sell our Class A common units at any time from the execution date of the agreement through January 28, 2012, at prices we deem appropriate for our Class A common units. The issue and sale of our Class A common units can be conducted on any day that is a trading day for the New York Stock Exchange, unless we have suspended sales under the EDA.

We issued 287,345 Class A common units at sales prices averaging $52.52 per unit, for proceeds of approximately $14.8 million, net of $0.3 million of commissions and issuance costs, during the three and six month period ended June 30, 2010. In addition, our General Partner contributed approximately $0.3 million to us to maintain its two percent general partner interest.

9. RELATED PARTY TRANSACTIONS

EUS Credit Agreement

In March 2010, we terminated our unsecured revolving credit agreement with Enbridge (U.S.) Inc. in accordance with the terms of the agreement and without penalty.

Light Sour Crude Oil Pipeline

Enbridge Pipelines (Southern Lights), L.L.C., which we refer to as Southern Lights, a wholly-owned subsidiary of our General Partner, incurred an additional $1.9 million of construction costs during the six month period ended June 30, 2010, associated with the light sour crude oil pipeline it transferred to us in exchange for Line 13, a 156-mile section of crude oil pipeline we previously owned. These additional costs increase the balance of our "Property, plant and equipment, net" and the capital account of our General Partner. Through June 30, 2010, we have recorded total costs for the light sour crude oil pipeline of $168.4 million, representing the $173.4 million of construction costs incurred by Southern Lights less the $5.0 million net book value of the Line 13 assets we exchanged.

In connection with the exchange, at the request of shippers and to ensure adequate southbound pipeline capacity prior to the completion of the Albert Clipper Project, we agreed to lease Line 13 from Southern Lights for monthly payments of $1.8 million. The transfer and lease, which became effective in February 2009, expired in April 2010. For the six month period ended June 30, 2010, we paid $5.4 million to Southern Lights to lease Line 13, which we expect to recover through the tariff that went into effect April 1, 2010. For the three month period ended June 30, 2010, we did not incur any additional lease costs related to our lease of Line 13.

Joint Funding Arrangement for Alberta Clipper Project

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

In March 2010, we refinanced $324.6 million of amounts we had outstanding and payable to our General Partner under the A1 Credit Agreement, a credit agreement between our General Partner and us to finance the Alberta Clipper Project, by issuing a promissory note payable to our General Partner, at which time we also terminated the A1 Credit Agreement. The promissory note payable, which we refer to as the A1 Term Note, matures on March 15, 2020, and 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 Project and is subordinate to all of our senior indebtedness. Under the terms of the A1 Term Note, we have the ability to increase the principal amount outstanding to finance the debt portion of the Alberta Clipper Project that our General Partner is obligated to make pursuant to the Alberta Clipper Joint Funding Arrangement, for any additional costs associated with our construction of the Alberta Clipper Project that we incur after the date the original A1 Term Note was issued. The increases we make to the principal balance of the A1 Term Note will also mature on March 15, 2020. Pursuant to the terms of the A1 Term Note, we are required to make semi-annual payments of principal and accrued interest. The semi-annual principal payments are based upon a straight-line amortization of the principal balance over a 30 year period as set forth in the approved terms of the cost of service recovery model associated with the Alberta Clipper Project. The approved terms for the Alberta Clipper Project are described in the

"Alberta Clipper U.S. Term Sheet," which is included as Exhibit I to the June 27, 2008 Offer of Settlement filed with the FERC by Enbridge Energy, Limited Partnership and approved on August 28, 2008 (Docket No. OR08-12-000). The following table presents in millions, the scheduled maturities of the A1 Term Note based upon the $340.9 million outstanding at June 30, 2010:

Year Following Completion of Alberta Clipper Project	Principal Repayment Amount
	(in millions)
Year 1	$ 11.4
Year 2	11.4
Year 3	11.4
Year 4	11.4
Year 5	11.4
Thereafter	283.9
Total	$340.9

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

We allocated earnings derived from operating the Alberta Clipper Project in the amounts of $14.5 million and $25.2 million to our General Partner for its 66.67 percent share of the earnings of the Alberta Clipper Project for the 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 Project in "Net income attributable to noncontrolling interest" on our consolidated statements of income.

10. COMMITMENTS AND CONTINGENCIES

Environmental Liabilities

We are subject to federal and state laws and regulations relating to the protection of the environment. Environmental risk is inherent to liquid hydrocarbon and natural gas pipeline operations, and we 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 associated with the Lakehead system assets through insurance, 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, and to date, no material environmental risks have been identified.

As of June 30, 2010 and December 31, 2009, we have recorded $6.4 million and $7.3 million, respectively, in "Accounts payable and other" and $3.8 million and $3.4 million in "Other long-term liabilities," respectively, 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 Line 2b Leak

On January 8, 2010, an unexpected release on Line 2b of our Lakehead system occurred in Pembina County, North Dakota. We immediately shut down our pipelines in the vicinity and dispatched emergency response crews to oversee containment, cleanup and repair of the pipeline. We completed the excavation and repairs and returned the line to service within five days. Line 2b was restarted January 13, 2010, once repairs on the pipeline were completed. The volume of oil released was approximately 3,000 barrels, which was largely contained in an area surrounding the pipeline leak. We continue to work with federal and state environmental and pipeline safety regulators to investigate the cause of the leak. We have the potential of incurring additional costs in connection with this incident, including expenditures necessary to remediate any operating condition that is determined to have caused the incident. On our consolidated statement of financial position as of June 30, 2010, we had $0.8 million accrued for additional cleanup and repair costs associated with the incident.

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. We believe that the outcome of these legal and regulatory proceedings and related actions will not, individually or in the aggregate, have a material adverse effect on our operating results, cash flows or financial position.

11. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

Our net income and cash flows are subject to volatility stemming from changes in interest rates on our variable rate debt obligations and fluctuations in commodity prices of natural gas, NGLs, condensate, crude oil and fractionation margins. Fractionation margins represent the relative difference between the price we receive from NGL 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 2014 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.

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-qualified. These non-qualified 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. We subsequently determined that a sub-group of physical natural gas sales contracts with terms allowing for economic net settlement did not qualify for the NPNS scope exception, and are being marked-to-market each period with the changes in fair value recorded in earnings. As a result, our operating income is subject to additional volatility associated with the changes in fair value of these contracts.
- **Crude Oil Contracts**—In our Liquids segment, we use forward contracts to hedge a portion of the crude oil length inherent in the operation of our pipelines, which we subsequently sell at market rates. In 2010, we executed derivative financial instruments for the current year which fixes the sales prices we receive in the future for this crude oil. We elected not to designate these derivative financial instruments as cash flow hedges due to the relatively small volumes involved. As a result, our operating income is subject to additional volatility associated with fluctuations in crude oil prices until the underlying transactions are settled or offset.

Interest Rate Risk Exposures:

- **Interest Rate Caps**—At the corporate level, our earnings and cash flows are affected by fluctuations in interest rates associated with our variable interest rate debt. Our variable interest rate borrowing cost is determined at the time of each borrowing or interest rate reset based upon a posted London Interbank Offered Rate, or LIBOR, for the period of borrowing or interest rate reset, increased by a defined credit spread. In order to mitigate the negative effect that increasing interest rates can have on our cash flows, we have entered into interest rate caps, which establish a ceiling averaging approximately 1.12% on the interest rates we pay on up to $400 million of our variable rate indebtedness. Although our interest rate caps protect us from the adverse effect of higher interest rates, they do not qualify for hedge accounting and, as a result, changes in the market value of these instruments creates additional volatility in our earnings.

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.

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 segment commodity-based derivatives—"Cost of natural gas"
- Liquids segment commodity-based derivatives—"Operating revenue"
- 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,	
	2010	2009	2010	2009
	(in millions)			
Liquids segment				
Non-qualified hedges	$ 1.6	$ —	$ 0.4	$ —
Natural Gas segment				
Hedge ineffectiveness	0.9	(0.4)	1.4	(0.6)
Non-qualified hedges	19.2	(2.6)	28.9	(12.4)
Marketing				
Non-qualified hedges	(3.9)	17.5	(4.3)	10.6
Commodity derivative fair value gains (losses)	17.8	14.5	26.4	(2.4)
Corporate				
Non-qualified interest rate hedges	—	2.4	(0.5)	2.4
Derivative fair value gains	$17.8	$16.9	$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, 2010	December 31, 2009
	(in millions)	
Other current assets	$ 27.6	$ 14.8
Other assets, net	29.8	43.7
Accounts payable and other	(31.1)	(59.2)
Other long-term liabilities	(86.1)	(50.5)
	$(59.8)	$(51.2)

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 and NGL sales and purchase agreements.

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 $0.8 million associated with derivative financial instruments that qualified for and were classified as cash flow hedges of forecasted commodity transactions that were subsequently de-designated. These losses are reclassified to earnings over the periods during which the originally hedged forecasted transactions affect earnings. We estimate that approximately $19.3 million, representing unrealized net losses from our cash flow hedging activities based on pricing and positions at June 30, 2010, will be reclassified from AOCI to earnings during the next 12 months.

In connection with our March 2010 issuance and sale of $500 million in principal amount of our 5.20% senior notes due March 15, 2020, we paid $13.2 million to settle treasury locks we entered to hedge the interest payments on a portion of these obligations through the 2020 maturity date of the senior notes. The $13.2 million is being amortized from AOCI to "Interest expense" over the 10-year term of the senior notes.

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

	June 30, 2010	December 31, 2009
	(in millions)	
Counterparty Credit Quality*		
AAA	$ —	$ —
AA	(19.2)	14.2
A	(48.6)	(63.1)
Lower than A	5.9	(3.2)
	(61.9)	(52.1)
Credit valuation adjustment	2.1	0.9
Total	$(59.8)	$(51.2)

* 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 ("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 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, 2010, we were in an overall net liability position of $59.8 million, which included assets of $57.4 million. Based on our forward positions at June 30, 2010, if our credit ratings were downgraded to BBB- by Standard & Poor's or Baa3 by Moody's Investors Service, we would be required to provide $60.1 million in the form of either cash collateral or letters of credit to satisfy the requirements of our ISDA® agreements.

At June 30, 2010 and December 31, 2009, we had credit concentrations in the following industry sectors, as presented below:

	June 30, 2010	December 31, 2009
	(in millions)	
U.S. financial institutions and investment banking entities	$ (5.1)	$(18.8)
Non-U.S. financial institutions	(62.9)	(30.2)
Small non-integrated energy companies	4.5	(3.4)
Integrated oil companies	3.7	1.2
	$(59.8)	$(51.2)

We are holding no cash collateral on our asset exposures, and we have provided letters of credit totaling $15.8 million and $13.1 million relating to our liability exposures pursuant to the margin thresholds in effect at June 30, 2010 and December 31, 2009, 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			Fair Value	
	Financial Position Location	June 30, 2010	December 31, 2009	Financial Position Location	June 30, 2010	December 31, 2009
			(in millions)			
Derivatives designated as hedging instruments						
Interest rate contracts	Other current assets	$ —	$ —	Accounts payable and other	$ (10.9)	$ (7.0)
Interest rate contracts	Other assets, net	—	38.7	Other long-term liabilities	(76.3)	(18.9)
Commodity contracts	Other current assets	17.1	15.7	Accounts payable and other	(24.8)	(47.3)
Commodity contracts	Other assets, net	28.9	17.8	Other long-term liabilities	(17.9)	(50.9)
		46.0	72.2		(129.9)	(124.1)
Derivatives not designated as hedging instruments						
Interest rate contracts	Other current assets	4.7	5.8	Accounts payable and other	(4.3)	(4.8)
Interest rate contracts	Other assets, net	8.0	5.6	Other long-term liabilities	(7.0)	(4.4)
Commodity contracts	Other current assets	35.0	22.0	Accounts payable and other	(20.4)	(28.8)
Commodity contracts	Other assets, net	21.3	12.1	Other long-term liabilities	(13.2)	(6.8)
		69.0	45.5		(44.9)	(44.8)
Total derivative instruments		$115.0	$117.7		$(174.8)	$(168.9)

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, 2010					
Interest rate contracts	$ (86.2)	Interest expense	$ (2.0)	Interest expense	$ —
Commodity contracts	—	Operating revenue	—	Operating revenue	—
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 three month period ended June 30, 2009					
Interest rate contracts	$ (14.2)	Interest expense	$ (1.8)	Interest expense	$ —
Commodity contracts	(69.0)	Cost of natural gas	9.7	Cost of natural gas	(0.4)
Total	$ (83.2)		$ 7.9		$(0.4)
For the six month period ended June 30, 2010					
Interest rate contracts	$(100.1)	Interest expense	$ (3.4)	Interest expense	$ —
Commodity contracts	—	Operating revenue	—	Operating revenue	—
Commodity contracts	67.2	Cost of natural gas	(15.5)	Cost of natural gas	1.4
Total	$ (32.9)		$(18.9)		$ 1.4
For the six month period ended June 30, 2009					
Interest rate contracts	$ (14.2)	Interest expense	$ (0.9)	Interest expense	$ —
Commodity contracts	(62.6)	Cost of natural gas	19.8	Cost of natural gas	(0.6)
Total	$ (76.8)		$ 18.9		$(0.6)

(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,		For the six month period ended June 30,	
		2010	2009	2010	2009
		Amount of Gain or (Loss) Recognized in Earnings[(1)]		Amount of Gain or (Loss) Recognized in Earnings[(1)]	
		(in millions)		(in millions)	
Interest rate contracts	Interest expense	$ —	$ 2.4	$ (0.5)	$ 2.4
Commodity contracts	Operating revenue	1.6	—	0.4	—
Commodity contracts	Cost of natural gas	15.3	14.9	24.6	(1.8)
Total		$16.9	$17.3	$24.5	$ 0.6

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

Gross to Net Presentation Reconciliation of Derivative Assets and Liabilities

	June 30, 2010			December 31, 2009		
	Assets	Liabilities	Total	Assets	Liabilities	Total
			(in millions)			
Fair value of derivatives—gross presentation	$115.0	$(174.8)	$(59.8)	$117.7	$(168.9)	$(51.2)
Effects of netting agreements	(57.6)	57.6	—	(59.2)	59.2	—
Fair value of derivatives—net presentation	$ 57.4	$(117.2)	$(59.8)	$ 58.5	$(109.7)	$(51.2)

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, 2010 and December 31, 2009. 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, 2010				December 31, 2009			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
		(in millions)				(in millions)		
Interest rate contracts	$—	$ (85.8)	$ —	$(85.8)	$—	$ 14.5	$ —	$ 14.5
Commodity contracts—financial	—	(24.1)	31.7	7.6	—	(63.2)	(7.5)	(70.7)
Commodity contracts—physical	—	—	8.9	8.9	—	—	(3.5)	(3.5)
Commodity options	—	(0.5)	10.0	9.5	—	(1.3)	9.3	8.0
Interest rate options	—	—	—	—	—	0.5	—	0.5
Total	$—	$(110.4)	$50.6	$(59.8)	$—	$(49.5)	$(1.7)	$(51.2)

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, 2010 to June 30, 2010. No transfers of assets between any of the Levels occurred during the period.

	2010			
	Commodity Financial Contracts	Commodity Physical Contracts	Commodity Options	Total
Beginning balance as of January 1	$ (7.5)	$ (3.5)	$ 9.3	$ (1.7)
Transfer out of Level 3[(1)]	—	—	—	—
Gains or losses				
Included in earnings (or changes in net assets)	11.8	11.5	(0.3)	23.0
Included in other comprehensive income	22.5	—	2.3	24.8
Purchases, issuances, sales and settlements				
Purchases[(2)]	—	—	—	—
Settlements[(3)]	4.9	0.9	(1.3)	4.5
Ending balance as of June 30	$31.7	$ 8.9	$10.0	$50.6
Amount of total gains included in earnings (or changes in net assets) attributable to the change in unrealized gains or losses related to assets still held at the reporting date	$31.9	$ 8.9	$ 2.0	$42.8
Amounts reported in operating revenue	$ 0.1	$ —	$ —	$ 0.1

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

(2) Purchases represent option premiums paid.

(3) 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, 2010 and December 31, 2009.

	At June 30, 2010						At December 31, 2009	
			Wtd. Average Price[2]		Fair Value[3]		Fair Value[3]	
	Commodity	Notional[1]	Receive	Pay	Asset	Liability	Asset	Liability
Portion of contracts maturing in 2010								
Swaps								
Receive variable/pay fixed	Natural Gas	3,500,621	$ 4.58	$ 5.54	$ —	$ (3.3)	$ 1.6	$ (3.1)
	NGL	184,000	30.86	24.18	1.4	(0.2)	3.4	—
Receive fixed/pay variable	Natural Gas	6,331,613	4.37	4.72	2.2	(4.4)	2.9	(16.0)
	NGL	1,977,616	37.81	37.97	9.4	(9.7)	9.7	(39.4)
	Crude Oil	558,060	73.57	76.08	2.3	(3.7)	3.1	(10.6)
Receive variable/pay variable	Natural Gas	55,179,975	4.59	4.52	5.8	(1.9)	13.0	(3.5)
Physical Contracts								
Receive fixed/pay variable	NGL	1,508,000	64.33	59.94	6.9	(0.3)	—	(4.0)
	Crude Oil	384,000	84.26	75.87	3.2	—	—	(1.6)
Receive variable/pay fixed	NGL	874,286	60.04	65.03	—	(4.4)	0.3	—
	Crude Oil	201,000	75.73	80.75	—	(1.0)	1.8	—
Receive variable/pay variable	Crude Oil	123,691	73.94	73.07	0.3	(0.2)	0.1	(0.1)
	NGL	3,275,951	53.07	52.68	1.7	(0.5)	—	—
	Natural Gas	11,760,444	4.56	4.51	0.6	—	—	—
Portion of contracts maturing in 2011								
Swaps								
Receive variable/pay fixed	Natural Gas	1,028,000	$ 5.15	$ 9.12	$ —	$ (4.0)	$ —	$ (3.1)
	NGL	120,000	69.60	47.67	2.6	—	3.2	—
Receive fixed/pay variable	Natural Gas	8,907,859	4.05	5.29	1.3	(12.2)	—	(19.3)
	NGL	1,535,190	57.20	50.56	12.0	(1.9)	6.1	(7.0)
	Crude Oil	780,650	73.11	79.59	1.2	(6.2)	—	(10.0)
Receive variable/pay variable	Natural Gas	20,717,675	5.15	5.03	3.0	(0.5)	2.9	(0.1)
Physical Contracts								
Receive variable/pay variable	Natural Gas	18,288,653	5.04	5.01	0.6	—	—	—
	NGL	845,524	43.37	42.19	1.1	(0.1)	—	—
Receive fixed/pay variable	NGL	100,000	58.95	57.26	0.2	—	—	—
Portion of contracts maturing in 2012								
Swaps								
Receive variable/pay fixed	Natural Gas	759,709	$ 5.53	$ 9.96	$ —	$ (3.3)	$ —	$ (2.6)
Receive fixed/pay variable	Natural Gas	2,327,500	4.90	5.71	1.1	(3.0)	0.3	(4.2)
	NGL	869,250	65.14	49.19	13.7	(0.1)	7.1	(0.9)
	Crude Oil	559,980	77.92	81.19	0.3	(2.1)	—	(5.3)
Receive variable/pay variable	Natural Gas	1,089,000	5.50	4.93	0.6	—	0.6	—
Physical Contracts								
Receive variable/pay variable	Natural Gas	11,858,120	4.96	4.93	0.4	—	—	—
	NGL	391,429	34.74	33.48	0.5	—	—	—
Portion of contracts maturing in 2013								
Swaps								
Receive fixed/pay variable	Natural Gas	730,000	$ 9.83	$ 5.64	$ 2.9	$ —	$ 2.3	$ —
	NGL	248,565	58.89	53.74	1.5	(0.2)	—	(1.0)
	Crude Oil	467,930	86.40	82.28	3.6	(1.8)	2.3	(3.6)
Physical Contracts								
Receive variable/pay variable	Natural Gas	7,076,216	4.96	4.93	0.2	—	—	—
Portion of contracts maturing in 2014								
Swaps								
Receive fixed/pay variable	Crude Oil	445,300	$88.03	$83.41	$ 1.9	$ —	$ —	$ (0.4)

(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.

(2) Weighted average prices received and paid 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, 2010 and December 31, 2009, 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 losses and $1.0 million of gains at June 30, 2010 and December 31, 2009, respectively.

The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity options at June 30, 2010 and December 31, 2009.

	At June 30, 2010						At December 31, 2009	
					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 2010								
Calls (written)	Natural Gas[4]	184,000	$ 4.31	$ 4.83	$ —	$(0.1)	$ —	$(0.6)
Puts (purchased)	Natural Gas[4]	184,000	3.40	4.83	—	—	—	—
	NGL	526,792	46.84	47.65	2.5	—	3.2	—
	Crude Oil	150,696	70.87	76.93	0.3	—	0.6	—
Portion of option contracts maturing in 2011								
Calls (written)	Natural Gas[4]	365,000	$ 4.31	$ 5.34	$ —	$(0.5)	$ —	$(0.8)
Puts (purchased)	Natural Gas[4]	365,000	3.40	5.34	—	—	—	—
	NGL	262,070	44.09	34.10	3.3	—	2.4	—
	Crude Oil	25,550	90.50	79.59	0.4	—	—	—
Portion of option contracts maturing in 2012								
Puts (purchased)	NGL	128,832	$66.80	$41.37	$3.7	$ —	$3.2	$ —

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

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

(3) The fair value is determined based on quoted market prices at June 30, 2010 and December 31, 2009, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values are presented in millions of dollars and exclude credit valuation adjustments of approximately $0.2 million of losses and $0.1 million of losses at June 30, 2010 and December 31, 2009, respectively.

(4) 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[3] at	
Date of Maturity & Contract Type	Accounting Treatment	Notional	Average Fixed Rate[1]	June 30, 2010	December 31, 2009
		(dollars in millions)			
Contracts maturing in 2010					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$250	1.68%	$ (1.2)	$ (2.5)
Interest Rate Caps	Non-qualifying	200	1.09%	—	0.2
Contracts maturing in 2011					
Interest Rate Caps	Non-qualifying	$200	1.14%	$ —	$ 0.3
Contracts maturing in 2013					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$600	4.15%	$(43.6)	$(16.9)
Interest Rate Swaps—Pay Fixed	Non-qualifying	125	4.35%	(11.6)	(9.2)
Interest Rate Swaps—Pay Float	Non-qualifying	125	4.75%	13.0	11.0
Contracts settling prior to maturity					
2010—Pre-issuance Hedges[2]	Cash Flow Hedge	$220	4.62%	$ —	$ (6.8)
2012—Pre-issuance Hedges	Cash Flow Hedge	600	4.57%	(33.4)	24.9
2013—Pre-issuance Hedges	Cash Flow Hedge	300	4.62%	(12.2)	14.1

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

(2) All 2010 Pre-issuance Hedges were settled in connection with our $500 million senior note debt issuance in March 2010.

(3) The fair value is determined from quoted market prices at June 30, 2010 and December 31, 2009, 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 $3.2 million of gains at June 30, 2010, with no such amounts at December 31, 2009.

12. SEGMENT INFORMATION

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

Each of our reportable segments is a business unit that offers different services and products that is managed separately, since each business segment requires different operating strategies. We have segregated our business activities into three distinct operating segments:

- Liquids;
- Natural Gas; and
- Marketing.

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

	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
Operating and administrative	65.2	67.9	2.0	1.2	136.3
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.

	For the three month period ended June 30, 2009				
	Liquids	Natural Gas	Marketing	Corporate[1]	Total
			(in millions)		
Total revenue	$228.4	$878.3	$503.9	$ —	$1,610.6
Less: Intersegment revenue	—	306.5	4.8	—	311.3
Operating revenue	228.4	571.8	499.1	—	1,299.3
Cost of natural gas	—	420.1	473.1	—	893.2
Operating and administrative	59.2	70.8	1.7	1.2	132.9
Power	29.8	—	—	—	29.8
Depreciation and amortization	34.6	31.1	0.4	—	66.1
Operating income	104.8	49.8	23.9	(1.2)	177.3
Interest expense	—	—	—	57.9	57.9
Other income	—	—	—	0.2	0.2
Income from continuing operations before income tax expense	104.8	49.8	23.9	(58.9)	119.6
Income tax expense	—	—	—	2.1	2.1
Net income	$104.8	$ 49.8	$ 23.9	$(61.0)	$ 117.5

(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
Operating and administrative	128.9	137.5	4.7	1.2	272.3
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.

	As of and for the six month period ended June 30, 2009				
	Liquids	Natural Gas	Marketing	Corporate[1]	Total
			(in millions)		
Total revenue	$ 448.1	$1,853.7	$1,153.2	$ —	$3,455.0
Less: Intersegment revenue	0.3	698.8	15.4	—	714.5
Operating revenue	447.8	1,154.9	1,137.8	—	2,740.5
Cost of natural gas	—	880.9	1,105.2	—	1,986.1
Operating and administrative	113.6	146.2	3.5	2.1	265.4
Power	63.2	—	—	—	63.2
Depreciation and amortization	64.0	61.7	0.8	—	126.5
Operating income	207.0	66.1	28.3	(2.1)	299.3
Interest expense	—	—	—	109.2	109.2
Other expense	—	—	—	0.3	0.3
Income from continuing operations before income tax expense	207.0	66.1	28.3	(111.6)	189.8
Income tax expense	—	—	—	4.1	4.1
Income from continuing operations	207.0	66.1	28.3	(115.7)	185.7
Income from discontinued operations	—	0.4	—	—	0.4
Net income	$ 207.0	$ 66.5	$ 28.3	$(115.7)	$ 186.1
Total assets	$4,512.1	$3,527.8	$ 207.2	$ 228.9	$8,476.0
Capital expenditures (excluding acquisitions)	$ 458.3	$ 77.4	$ —	$ 8.2	$ 543.9

(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.

13. REGULATORY MATTERS

Regulatory Accounting

We apply the authoritative accounting provisions for regulated operations to the operating activities associated with the crude oil pipeline and related assets we constructed to expand the capacity of our Lakehead system, which we refer to as the Southern Access Pipeline. During 2009 and the first quarter of 2010, we under collected revenue related to the operation of our Southern Access Pipeline in-part because actual volumes were lower than the forecasted volumes used to calculate the toll surcharge. As a result of the difference in transportation volumes, we recognized additional revenue and a regulatory receivable during 2009 and the first three months of 2010. Beginning April 1, 2010, we began to collect the previously recognized revenue when the annual update to our transportation rates became effective. We recognized $2.3 million of additional revenue on our consolidated statement of income in connection with the difference in transportation volumes of which we have collected $2.0 million through June 30, 2010. At June 30, 2010 and December 31, 2009, the regulatory receivable related to the differences in our transportation volumes was $7.8 million and $7.5 million, respectively, on our consolidated statements of financial position. We will continue to collect the additional revenue that we previously recorded through the first quarter of 2011.

We also apply the authoritative accounting provisions for regulated operations to the operating activities of our Alberta Clipper Project. Included in the balances of "Property, plant and equipment, net" on our consolidated statements of financial position are $26.9 million at June 30, 2010 and $12.6 at December 31, 2009, which we recorded in connection with construction of the Alberta Clipper Project and represents an allowance for equity during construction, or AEDC. We also recorded a corresponding $14.3 million of "Other income (expense)," in our consolidated statements of income for the six month period ended June 30, 2010, related to AEDC. For the three month period ended June 30, 2010, we did not record any additional income related to AEDC.

FERC Transportation Tariffs

Effective January 1, 2010, we increased the rates for transportation on our North Dakota system to include a new surcharge related to the recent completion of our Phase VI Expansion program, which increased capacity on the pipeline from 110,000 barrels per day, or Bpd, to 161,000 Bpd. This surcharge is applicable for the seven years immediately following the January 1, 2010 in-service date of the Phase VI Expansion program. The mainline expansion surcharge is applied to all mainline volumes with a destination of Clearbrook, Minnesota.

Effective April 1, 2010, we filed our annual tariff rate adjustment with the FERC to reflect true-ups for the difference between estimates and actual cost and throughput data for the prior year and our projected costs and throughput for 2010 related to our expansion projects. The projected costs for 2010 include two additional projects: the Alberta Clipper Project, which was placed into service on April 1, 2010, and the Line 3 conversion project. Filings in early 2010 by shippers requesting the FERC to delay the tariff were dismissed by the FERC in March 2010 in docket number IS10-139-000. This tariff filing increased the average transportation rate for crude oil movements from the Canadian border to Chicago, Illinois by approximately $0.52 per barrel, to an average of approximately $1.98 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.

Effective April 1, 2010, we extended the term of the looping surcharge, a component of the Phase V Expansion program of our North Dakota system, with the FERC by four years so that it now expires on December 31, 2016. The effect of the extended term reduced the looping surcharge from $0.70 per barrel to $0.38 per barrel for all volumes originating from Trenton, Missouri Ridge and Alexander, North Dakota delivered to Tioga, North Dakota.

Effective July 1, 2010, 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 March 2006, the FERC determined that the Producer Price Index For Finished Goods plus 1.3 percent (PPI + 1.3 percent) should be the oil pricing index for a five year period ending July 2011. The index is used to establish rate ceiling levels for oil pipeline rate changes. 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. Effective July 2010, we decreased the base tariff rates on our Lakehead system by an average of 1.3 percent to equal the indexed ceiling level allowed under the FERC's indexing methodology. On our Lakehead system, the new average rate for crude oil movements from the International Border near Neche, North Dakota to Chicago, Illinois is $1.97 per barrel, which reflects a $0.01 per barrel decrease over the rates filed effective April 1, 2010. In addition to the rates on our Lakehead system, we decreased the transportation rates on our North Dakota and Ozark systems 1.3 percent. The tariff rates for our Lakehead, North Dakota and Ozark systems are at the ceiling levels allowed under the FERC methodology.

14. SUBSEQUENT EVENTS

Class A common unit issuances

We issued 110,000 Class A common units in July 2010 under the terms of the EDA at sales prices averaging $53.01 per unit, for proceeds of approximately $5.7 million, net of $0.1 million of commissions and issuance costs within the period of July 1 and July 6, 2010. In addition, our General Partner contributed approximately $0.1 million to us to maintain its two percent general partner interest.

Distribution to Partners

On July 23, 2010, the board of directors of Enbridge Management declared a distribution payable to our partners on August 13, 2010. The distribution will be paid to unitholders of record as of August 5, 2010, of our available cash of $141.7 million at June 30, 2010, or $1.0275 per limited partner unit. Of this distribution, $123.8 million will be paid in cash, $17.5 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 23, 2010, 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 $17.2 million to the noncontrolling interest in the Series AC while $8.6 million will be paid to us.

Lakehead Line 6b Leak

On July 26, 2010, we experienced a crude oil release on Line 6b of our Lakehead system near Marshall, Michigan. We immediately shut down the pipeline and dispatched emergency response crews to oversee containment, cleanup and repair of the pipeline. We currently are investigating the cause of the release and, at this time, are unable to determine the economic impact this incident may have. We maintain commercial liability coverage that includes a deductible of approximately $5 million, excluding fines and penalties, and limits of coverage that we believe should be adequate to fund the resulting costs and liabilities.

15. 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,	
	2010	2009
	(in millions)	
Discount accretion	$ 0.3	$ 6.0
Environmental liabilities	4.3	0.9
Amortization of debt issuance and hedging costs	11.1	4.5
Deferred income taxes	0.6	0.7
Allowance for equity used during construction	(14.3)	—
Allowance for doubtful accounts	(4.0)	—
Other	0.6	1.9
	$ (1.4)	$14.0

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.

Our operating results for the three and six month periods ended June 30, 2010 surpassed our expectations, primarily due to the performance of our Liquids segment assets. Additionally, we continue to benefit from the cost containment measures we implemented during 2009 as well as the cash flows we derive from our stable platform of midstream energy assets. In July 2010, as a result of our continuing strong performance and cash flows derived from our new and existing assets, the board of directors of Enbridge Energy Management, L.L.C., or Enbridge Management, as delegate of our General Partner, announced a quarterly distribution that reflected a $0.025 per unit increase over the prior quarterly distribution rate which increased our distribution rate to $4.11 on an annualized basis. This increase is in addition to the $0.0125 per unit quarterly distribution rate increase, or $0.05 per unit on an annualized basis, that we announced in April 2010. While the completion of our historic capital expansion program and the additional cash flow generated by these assets supports the increase in our distribution rate, we continue to pursue opportunities for accretive acquisitions in or near areas in which we have a competitive advantage or in areas where we can deploy our successful operating strategy to enhance the value of our franchise and 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, 2010 and 2009. We have removed from "Income from continuing operations," for the three and six month periods ended June 30, 2009, the amounts comprising the operating results of non-core natural gas pipeline assets that we sold in November 2009 and presented the amounts in "Income from discontinued operations."

	For the three month period ended June 30,		For the six month period ended June 30,	
	2010	2009	2010	2009
	(unaudited; in millions)			
Operating Income				
Liquids	$171.5	$104.8	$300.2	$207.0
Natural Gas	58.9	49.8	95.5	66.1
Marketing	(2.6)	23.9	2.9	28.3
Corporate, operating and administrative	(1.2)	(1.2)	(1.2)	(2.1)
Total Operating Income	226.6	177.3	397.4	299.3
Interest expense	69.6	57.9	128.9	109.2
Other income (expense)	(0.1)	0.2	16.7	(0.3)
Income tax expense	2.4	2.1	4.6	4.1
Income from continuing operations	154.5	117.5	280.6	185.7
Income from discontinued operations	—	—	—	0.4
Net income	154.5	117.5	280.6	186.1
Less: Net income attributable to noncontrolling interest	14.5	—	25.2	—
Net income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$140.0	$117.5	$255.4	$186.1

Contractual arrangements in our Liquids, Natural Gas and Marketing segments expose us to market risk 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

Operating income from our Liquids segment increased for the three and six month periods ended June 30, 2010 from the same periods in 2009 primarily due to the following:

Transportation rate increases that went into effect on the following dates:

- July 2009 for the annual index rate ceiling adjustment;
- January 2010 for the completion and start-up of Phase VI of our North Dakota expansion project; and
- April 2010 on our Lakehead system associated with the completion of construction and start-up of the Alberta Clipper crude oil pipeline project, referred to as the Alberta Clipper Project, and cost of service true-ups associated with the Southern Access crude oil pipeline.

- Higher delivery volumes on both our Lakehead and North Dakota systems as a result of additional crude oil supplies from upstream production facilities and the completion of the North Dakota Phase VI expansion.

The above increases to operating income were partially offset by:

- An increase in power costs primarily associated with higher volumes of crude oil transported on our Lakehead and North Dakota systems; and
- Increased operating costs and depreciation associated with the additional assets we have placed into service.

Natural Gas

The following factors affected the operating income of our Natural Gas business for the three and six month periods ended June 30, 2010 as compared with the same periods of 2009:

- Unrealized, non-cash, mark-to-market net gains of $20.1 million for the three month period and $30.3 million for the six month period June 30, 2010, associated with derivative financial instruments that do not qualify for hedge accounting treatment under authoritative accounting guidance compared with $3.0 million and $13.0 million of net losses we experienced in the respective periods of 2009; and
- Lower natural gas and NGL volumes associated with reduced natural gas production in the areas we serve.

Marketing

Included in the operating results of our Marketing segment for the three and six month periods ended June 30, 2010 were unrealized, non-cash, mark-to-market net losses of $3.9 million and $4.3 million, respectively, associated with derivative financial instruments that do not qualify for hedge accounting treatment under authoritative accounting guidance, as compared to $17.5 million and $10.6 million, respectively of unrealized, non-cash, mark-to-market net gains for comparable periods in 2009. Further contributing to lower operating income for the three and six month periods ended June 30, 2010, was the tightening of locational pricing differentials (basis) around purchase and sale points.

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 segment commodity-based derivatives—“Cost of natural gas”
- Liquids segment commodity-based derivatives—“Operating revenue”
- 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,	
	2010	2009	2010	2009
	(unaudited; in millions)			
Liquids segment				
Non-qualified hedges	$ 1.6	$ —	$ 0.4	$ —
Natural Gas segment				
Hedge ineffectiveness	0.9	(0.4)	1.4	(0.6)
Non-qualified hedges	19.2	(2.6)	28.9	(12.4)
Marketing				
Non-qualified hedges	(3.9)	17.5	(4.3)	10.6
Commodity derivative fair value gains (losses)	17.8	14.5	26.4	(2.4)
Corporate				
Non-qualified interest rate hedges	—	2.4	(0.5)	2.4
Derivative fair value gains	$17.8	$16.9	$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,	
	2010	2009	2010	2009
	(unaudited; in millions)			
Operating Results				
Operating revenue	$319.8	$228.4	$581.6	$447.8
Operating and administrative	65.2	59.2	128.9	113.6
Power	36.5	29.8	68.8	63.2
Depreciation and amortization	46.6	34.6	83.7	64.0
Operating expenses	148.3	123.6	281.4	240.8
Operating Income	$171.5	$104.8	$300.2	$207.0
Operating Statistics				
Lakehead system:				
United States[(1)]	1,397	1,270	1,332	1,267
Province of Ontario[(1)]	345	336	351	345
Total Lakehead system deliveries[(1)]	1,742	1,606	1,683	1,612
Barrel miles (billions)	117	102	225	207
Average haul (miles)	736	698	737	709
Mid-Continent system deliveries[(1)]	204	238	205	239
North Dakota system:				
Trunkline, excluding gathering	161	103	157	103
Gathering	6	6	6	6
Total North Dakota system deliveries[(1)]	167	109	163	109
Total Liquids Segment Delivery Volumes[(1)]	2,113	1,953	2,051	1,960

(1) Average barrels per day in thousands.

Three month period ended June 30, 2010 compared with three month period ended June 30, 2009

Operating revenue of our Liquids segment increased for the three month period ended June 30, 2010 when compared to the same period in 2009 primarily due to increased average rates for transportation on all of our major systems, most notably those associated with our Alberta Clipper Project. Increases in average transportation rates on all three Liquids systems contributed approximately $64.8 million of additional operating revenue for the three month period ended June 30, 2010 when compared to the same period in 2009. The rate increases included the following:

- Effective July 1, 2009, we increased the average transportation rates on all three of our Liquids systems in connection with the annual index rate ceiling adjustment;
- Effective January 1, 2010, we increased the rates for transportation on our North Dakota system to include a new surcharge related to the recent completion of our Phase VI expansion program; and
- Effective April 1, 2010, we increased the rates for transportation on our Lakehead system in connection with the completion of our Alberta Clipper Project. We also increased the transportation rates on our Lakehead system for additional facilities we added for which we receive a cost-of-service return and a true-up for costs associated with both our Stage 1 and 2 Southern Access crude oil pipeline projects, which we refer to as the Southern Access Pipeline.

Further contributing to increased operating revenue on our Liquids segment were increases in average delivery volumes on our Lakehead and North Dakota systems that contributed approximately $23.7 million for the three month period ended June 30, 2010 when compared to the same period in 2009. Average delivery volumes on our Lakehead system increased approximately 8.5 percent, to 1.742 million barrels per day, or Bpd, for the three months ended June 30, 2010 from 1.606 million Bpd during the same period in 2009, contributing $15.9 million to operating revenue. The increase in average deliveries on our Lakehead system is primarily due to additional crude oil supplies from upstream production facilities associated with the ongoing development of the Alberta Oil Sands.

The average trunkline delivery volumes of our North Dakota system increased approximately 56 percent, to 161,000 Bpd for the three month period ended June 30, 2010 from 103,000 Bpd during the same period in 2009, while gathering volumes during these periods remained constant at 6,000 Bpd. The increase in average trunkline delivery volumes contributed an additional $7.8 million to operating revenue and is attributable to our completion in late 2009 of the Phase VI expansion of our North Dakota system, which increased the system's trunkline capacity to approximately 161,000 Bpd from the 110,000 Bpd that was previously available. While the capacity of our North Dakota trunkline approximates 161,000 Bpd, many variables, including changes in scheduled maintenance and other operational factors, can limit or increase our ability to operate at that level.

In March 2010, we began to use forward contracts to hedge a portion of the pipeline loss allowance volumes we expect to receive from our customers 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 will fix the sales price we will receive in the future for this crude oil. We elected not to designate these derivative financial instruments as cash flow hedges due to the relatively small volumes of crude oil involved. As a result of the change in the forward price of crude oil in the three month period ended June 30, 2010, we recognized $1.6 million of unrealized, non-cash, mark-to-market net gains related to these derivative financial instruments that do not qualify for hedge accounting.

Operating and administrative expenses for the Liquids segment increased $6.0 million for the three month period ended June 30, 2010 as compared with the same period in 2009 primarily due to the following:

- Increased workforce related costs associated with the operational, administrative, regulatory and compliance support necessary for our Liquids systems resulting from our recently completed expansions; and
- Higher property taxes associated with increased assessments on our Liquids assets as a result of the additional assets placed in service.

The increases in operating and administrative expenses were offset by lower rent costs as a result of the expiration of our lease of Line 13 from an affiliate of Enbridge Energy Company, Inc., our General Partner. The lease of Line 13 contributed $5.4 million to our costs during the three month period ended June 30, 2009, with no similar costs existing during the same period of 2010. We are currently recovering the cost of the lease through a tolling surcharge on our Lakehead system with the net effect on our cash flow expected to approximate zero.

Power costs increased $6.7 million for the three month period ended June 30, 2010, compared with the same period in 2009. The increase in power costs is primarily associated with the higher volumes of crude oil transported on our Lakehead and North Dakota systems.

The increase in depreciation expense of $12.0 million is directly attributable to the additional assets we have placed in service during 2010, the most significant of which are the North Dakota Phase VI Expansion and Alberta Clipper Project that we placed in service during the first and second quarters of 2010, respectively.

Six month period ended June 30, 2010 compared with six month period ended June 30, 2009

Our Liquids segment contributed $300.2 million of operating income during the six month period ended June 30, 2010, representing an of $93.2 million increase over the $207.0 million for the comparable period in 2009. The components comprising our operating income changed during the six month period ended June 30, 2010 compared to the same period in 2009, primarily for the same reasons as noted in our three-month analysis, in addition to the items noted below.

Our transportation tariffs allow our pipelines to deduct an allowance from our customers for the transportation of their crude oil. We recognize revenue for this allowance at the prevailing market price for crude oil. The average prices of crude oil during the six month period ended June 30, 2010 were substantially higher than the average prices for the same period of 2009. For example, the average price of West Texas Intermediate crude oil has increased approximately 52 percent for the six month period ended June 30, 2010, as compared with the same period in 2009. As a result of the increase in crude oil prices, we have experienced an approximate $11.7 million increase in allowance oil revenues.

Partially offsetting these increases in operating revenue was revenue we recognized in the six month period ended June 30, 2009 resulting from our joint tolling arrangement with Mustang that we did not recognize for the same period in 2010.

Future Prospects Update for Liquids

The following discussion provides an update to the status of projects that we and Enbridge Inc., or 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 fiscal year ended December 31, 2009.

Partnership Projects

North Dakota—Bakken Expansion

We are continuing to evaluate opportunities to further expand our footprint in the Bakken play to meet the demand and needs of producers. Opportunities could include between $400 million and $500 million of additional gathering and transportation lines to our existing North Dakota system.

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. The amounts we present have been revised to exclude the results of discontinued operations, which are discussed below in the section labeled *Other Matters*.

	For the three month period ended June 30,		For the six month period ended June 30,	
	2010	2009	2010	2009
	(unaudited; in millions)			
Operating revenue	$ 888.6	$ 571.8	$ 1,873.3	$ 1,154.9
Cost of natural gas	730.8	420.1	1,578.6	880.9
Operating and administrative	67.9	70.8	137.5	146.2
Depreciation and amortization	31.0	31.1	61.7	61.7
Operating expenses	829.7	522.0	1,777.8	1,088.8
Operating Income	$ 58.9	$ 49.8	$ 95.5	$ 66.1
Operating Statistics (MMBtu/d)				
East Texas	1,172,000	1,567,000	1,183,000	1,599,000
Anadarko	613,000	594,000	580,000	596,000
North Texas	359,000	388,000	353,000	398,000
Total	2,144,000	2,549,000	2,116,000	2,593,000

Three month period ended June 30, 2010 compared with three month period ended June 30, 2009

The following discussion presents the primary factors affecting the operating income of our Natural Gas business for the three month period ended June 30, 2010 as compared with the same period of 2009:

- A $23.1 million increase resulting from $20.1 million of 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 losses of $3.0 million for the same period of 2009;
- Lower volumes of natural gas on our systems, as a result of lower natural gas production associated with reduced drilling by natural gas producers in the areas we serve; and
- Declines in operating and administrative costs resulted from lower costs that are mostly variable with volumes and the continuing benefit from cost reduction measures we implemented in 2009.

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 in our Natural Gas business. Forward prices for natural gas increased during the second quarter of 2010, producing gains on the natural gas hedges used to fix the price of natural gas we purchase. Additionally, 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 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.

Comparatively, higher average forward NGL prices at June 30, 2009 relative to March 31, 2009, produced non-cash, mark-to-market net losses of $3.0 million for the three month period ended June 30, 2009 from the derivatives we use to hedge the sales prices of a portion of the NGLs we derive from processing natural gas. The average forward prices for natural gas were relatively stable at June 30, 2009 in relation to prices at March 31, 2009.

The following table depicts the effect that unrealized, non-cash, mark-to-market net gains and losses had on the operating results of our Natural Gas segment for the three month periods ended June 30, 2010 and 2009:

	For the three month period ended June 30,		For the six month period ended June 30,	
	2010	2009	2010	2009
	(unaudited; in millions)			
Hedge ineffectiveness	$ 0.9	$(0.4)	$ 1.4	$ (0.6)
Non-qualified hedges	19.2	(2.6)	28.9	(12.4)
Derivative fair value gains (losses)	$20.1	$(3.0)	$30.3	$(13.0)

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 10 to 25 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 margins generally increase when the prices of these commodities are rising and generally decrease when the prices are declining. Although processing natural gas to produce NGLs and condensate was profitable in both periods discussed below, the amount of profitability fluctuates based on the difference between natural gas and NGL commodity prices. During the three month period ended June 30, 2010, NGL and condensate prices decreased and natural gas prices increased, resulting in narrower fractionation margins than in the comparable period of 2009 when commodity prices for NGL and condensate increased while natural gas prices decreased, resulting in widening fractionation margins.

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 most recently the Haynesville Shale. During the three month period ended June 30, 2010, natural gas volumes on our systems decreased approximately 16 percent, in relation to the same period of 2009, resulting from declines in production and shut-in natural gas. However, we anticipate volumes will steadily recover as producers increase drilling activity. Active drilling rigs in the areas we serve have increased 27 percent during the three month period ended June 30, 2010 from levels that existed in the corresponding period in 2009. We have also seen active drilling rigs in the areas we serve increase by 35 percent from levels that existed at the end of 2009.

Although demand for natural gas has begun to stabilize, declining natural gas prices over the past year have caused some producers to reduce their output of natural gas, which has in turn resulted in lower volumes on our systems. We are positioned to capitalize on any future increases in natural gas production, in large part due to the expansions we have completed in recent years. Another factor that could lead to more demand for our services is the recent discovery of the Haynesville Shale in western Louisiana and eastern Texas. The Haynesville Shale has the potential of being the largest natural gas discovery in the United States. If proven, the discovery could create more drilling activity around our East Texas system, increasing the demand for our services. In February 2010, we announced an expansion project on our East Texas system to capitalize on the growth opportunities that exist in the Haynesville Shale area, referred to as the South Haynesville Shale expansion project. For a discussion of our South Haynesville Shale expansion project, see *Future Prospects for Natural Gas* below. In June 2010, we acquired natural gas pipeline assets for approximately $17 million that are complementary to our existing assets and planned expansion into the South Haynesville area. The acquisition is expected to increase utilization of our East Texas system by connecting a portion of our East Texas system to the expansions we have underway in the South Haynesville area.

A variable element of the operating results of our Natural Gas segment is derived from processing natural gas under keep-whole arrangements on our East Texas, North Texas and Anadarko systems. Operating revenue less the cost of natural gas derived from keep-whole processing arrangements for the three month period ended June 30, 2010 was $13.9 million, representing a decrease of $2.4 million from the $16.3 million we produced for the same period in 2009. The pricing environment that existed for NGLs and condensate for the three month period ended June 30, 2010 was less favorable when compared to the same period in 2009, slightly decreasing the operating income we derive from keep-whole processing arrangements.

Operating and administrative costs of our Natural Gas segment were $2.9 million lower for the three month period ended June 30, 2010 compared to the same period in 2009, primarily due to a reduction in costs associated with our systems that are mostly variable with volumes and the continuing benefit from cost reduction measures we implemented in 2009.

Six month period ended June 30, 2010 compared with six month period ended June 30, 2009

The components comprising our Natural Gas segment's operating income changed during the six month period ended June 30, 2010 compared to the same period in 2009 for the same reasons as noted in our three-month analysis.

Future Prospects for Natural Gas

The following discussion provides an update to the status of projects we and Enbridge are developing and should be read in conjunction with the information included in Item 7 of our Annual Report on Form 10-K for the fiscal year ended December 31, 2009.

Partnership Projects

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. In addition, we plan to construct a large diameter lateral pipeline from Shelby County to Carthage, Texas expanding our recently completed Shelby County Loop expansion. The expansion into the Haynesville Shale area is expected to increase utilization of 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 minimum bill contracts, acreage dedications and other contractual structures are more than sufficient to proceed with the project. Materials, pipeline routing and construction planning for the project are underway. Portions of the pipeline for the project were completed during the second quarter of 2010 and will continue to be completed through the second quarter of 2011. Future compression will be layered in, as needed, after the completion of the pipelines.

Anadarko Cryogenic Processing Facility

In April 2010, we announced plans to construct a cryogenic processing plant on our Anadarko natural gas gathering system. The processing facility 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 new plant, when operational, will increase our Anadarko natural gas gathering system's total processing capacity to more than 650 MMcf/d. The new plant is anticipated to be operational by the end of the first quarter of 2011.

Other Matters

2009 Asset Disposition

In November 2009, we sold non-core natural gas pipeline assets located predominantly outside of Texas. We have removed the operating results related to the divestiture of these assets from our historical operating results and included the results in "Income from discontinued operations" on our consolidated statements of income for the three and six month periods ended June 30, 2009. The following table presents the operating results of the discontinued operations of our natural gas pipeline assets that we derived from historical financial information:

	For the three month period ended June 30, 2009	For the six month period ended June 30, 2009
	(unaudited; in millions)	
Operating revenue	$52.4	$108.5
Operating expenses		
Cost of natural gas	43.4	90.1
Operating and administrative	5.2	10.4
Depreciation and amortization	3.9	7.7
	52.5	108.2
Operating income (loss)	(0.1)	0.3
Other income	0.1	0.1
Income from discontinued operations	$ —	$ 0.4

Marketing

The following table sets forth the operating results of our Marketing segment assets for the periods presented. The amounts have been revised to exclude the operating results associated with the non-core natural gas assets we sold in November 2009, as previously addressed in our Natural Gas segment discussion:

	For the three month period ended June 30,		For the six month period ended June 30,	
	2010	2009	2010	2009
	(unaudited; in millions)			
Operating revenue	$539.0	$499.1	$1,223.7	$1,137.8
Cost of natural gas	539.6	473.1	1,216.0	1,105.2
Operating and administrative	2.0	1.7	4.7	3.5
Depreciation and amortization	—	0.4	0.1	0.8
Operating expenses	541.6	475.2	1,220.8	1,109.5
Operating Income (Loss)	$ (2.6)	$ 23.9	$ 2.9	$ 28.3

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, 2010 compared with three month period ended June 30, 2009

Included in the operating results of our Marketing segment for the three month period ended June 30, 2010 were unrealized, non-cash, mark-to-market net losses of $3.9 million associated with derivative financial instruments and net-settled physical transactions that do not qualify for hedge accounting treatment under authoritative accounting guidance, as compared with the $17.5 million of unrealized non-cash, mark-to-market net gains for the same period in 2009. The non-cash, mark-to market, net losses during the three month period ended June 30, 2010 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. The non-cash, mark-to-market, net gains during the three month period ended June 30, 2009 resulted from the narrowing difference between forward prices for natural gas purchases and sales at primary market centers, which positively affected the values of derivative financial instruments we use to hedge our transportation positions. Further contributing to the lower operating income of our Marketing business was relatively stable natural gas prices during the three month period ended June 30, 2010 which limited opportunities to generate additional revenue by taking advantage of significant price differentials between market centers. Further contributing to the lower operating income for the three month period ended June 30, 2010 as compared with the three months ended June 30, 2009, was the income derived from the sale of natural gas from storage that occurred early in the second quarter of 2009.

Operating and administrative expenses for the three month period ended June 30, 2010 were $0.3 million higher when compared to the same period in 2009 due to increased corporate overhead allocations.

Six month period ended June 30, 2010 compared with six month period ended June 30, 2009

The results for the Marketing business for the six month period ended June 30, 2010 changed for the same reasons as noted in the three-month analysis above.

Corporate

Our interest cost for the three and six month periods ended June 30, 2010 and 2009 is comprised of the following:

	For the three month period ended June 30,		For the six month period ended June 30,	
	2010	**2009**	**2010**	**2009**
	(unaudited; in millions)			
Interest expense	$69.6	$57.9	$128.9	$109.2
Interest capitalized	0.8	5.5	5.6	18.4
Interest cost incurred	$70.4	$63.4	$134.5	$127.6
Weighted average interest rate	*6.8%*	*6.9%*	*6.5%*	*7.0%*

The increases in interest expense between both the three and six month periods ended June 30, 2010 and 2009, are primarily the result of a higher weighted average outstanding debt balance during the three month period ended June 30, 2010 as compared with the same periods in 2009 partially offset by a lower weighted average interest rates for the 2010 periods in relation to the 2009 periods. The increased weighted average outstanding debt balance was primarily a result of the following:

- Approximately $300 million of weighted average debt outstanding under the A1 Credit Agreement and the subsequent A1 Term Note, representing agreements between our General Partner and us to finance the Alberta Clipper Project; and
- The issuance and sale in March 2010 of $500 million of our 5.20% senior unsecured notes due 2020.

We are exposed to interest rate risk associated with changes in interest rates on our variable rate debt. Our variable interest rate borrowing cost is determined at the time of each borrowing or interest rate reset based upon a posted London Interbank Offered Rate, or LIBOR, for the period of borrowing or interest rate reset, plus a defined credit spread. In order to mitigate the negative effect increasing interest rates can have on our cash flows, we purchased interest rate caps, which establish a ceiling averaging approximately 1.12% on the interest rates we pay on up to $400 million of our variable rate indebtedness through January 2011. The interest rate caps do not qualify for hedge accounting and, as a result, the fair values of these derivative financial instruments are recorded as assets or liabilities on our consolidated statements of financial position with the changes in fair value recorded as corresponding increases or decreases in “Interest expense” on our consolidated statements of income. For the six month period ended June 30, 2010, we recorded $0.5 million of unrealized, non-cash, mark-to-market net losses associated with the changes in fair value of these derivatives that resulted from the increase in interest rates from December 31, 2009 to June 30, 2010. We did not record any unrealized, non-cash, mark-to-market gains or losses for the three month period ended June 30, 2010. For the three and six month periods ended June 30, 2009, we recorded $2.4 million of unrealized, non-cash, mark-to-market net gains associated with the changes in fair value of these derivatives that resulted from the increase in interest rates from the May 2009 date these derivative financial instruments were purchased to June 30, 2009.

Other Matters

Alberta Clipper Project Joint Funding Arrangement and Regulatory Accounting

In July 2009, we entered into a joint funding arrangement to finance construction of the United States segment of the Alberta Clipper Project with several of our affiliates and affiliates of Enbridge including our General Partner. The Alberta Clipper Project 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 Project in the amounts of $14.5 million and $25.2 million to our General Partner and its affiliate for its combined 66.67 percent interest in the earnings of the Alberta Clipper Project for the 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 Project in “Net income attributable to noncontrolling interest” on our consolidated statements of income.

In connection with our application of the regulatory accounting provisions to our Alberta Clipper Project we record an allowance for equity during construction, referred to as AEDC, in “Other income (expense)” on our consolidated statement of income. For the six month period ended June 30, 2010, we recorded $14.3 million of AEDC on our consolidated statements of income related to the Alberta Clipper Project. For the three month period ended June 30, 2010 as well as the three and six month periods ended June 30, 2009, we did not record any additional income related to AEDC.

LIQUIDITY AND CAPITAL RESOURCES

As set forth in the following table, we had in excess of $900 million of liquidity at June 30, 2010 to meet our ongoing operational, investment and financing needs as noted below.

	(in millions)
Availability under Credit Facility	$740.8
Cash and cash equivalents	207.2
Total	$948.0

General

Our primary operating cash requirements consist of normal operating expenses, core maintenance activities, distributions to our partners and payments associated with our derivative activities. We expect to fund our current and future short-term cash requirements from our operating cash flows. Margin requirements associated with our derivative transactions are generally supported by letters of credit issued under our Second Amended and Restated Credit Agreement, which we refer to as the Credit Facility.

Our current business strategy emphasizes developing and expanding our existing Liquids and Natural Gas segments through targeted acquisitions and limited organic growth. We expect to fund long-term cash requirements for acquisitions and organic growth projects from several sources including cash flows from operating activities, our commercial paper program, our Credit Facility and issuances of additional equity and debt securities. 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 projects. We have issued a balanced combination of debt and equity securities to fund our expansion projects. 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.

In March 2010, we successfully issued and sold $500 million in principal amount of our 5.20% senior unsecured notes due 2020 for net proceeds of approximately $496.1 million, after payment of underwriting discounts, commissions and offering expenses. We used the net proceeds to reduce a portion of our outstanding commercial paper and Credit Facility borrowings that we had previously used to finance a portion of our capital expansion projects. We temporarily invested a portion of the remaining proceeds which we later used to fund additional expenditures under our capital expansion programs.

Equity Distribution Agreement

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

We issued 287,345 Class A common units at sales prices averaging $52.52 per unit, for proceeds of approximately $14.8 million, net of $0.3 million of commissions and issuance costs during the three and six month periods ended June 30, 2010. In addition, our General Partner contributed approximately $0.3 million to us to maintain its two percent general partner interest.

Available Credit

Two primary sources of liquidity are provided by the commercial paper market and our Credit Facility. We have a $600 million commercial paper program that is supported by our long-term Credit Facility, which we access primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions when the interest rates available to us for commercial paper are more favorable than the rates available under our Credit Facility.

Credit Facility

At June 30, 2010, we had no amounts outstanding under our Credit Facility and letters of credit totaling $16.7 million. The amounts we may borrow under the terms of our Credit Facility are reduced by the principal amount of our commercial paper issuances and the balance of our letters of credit outstanding. At June 30, 2010, we could borrow $740.8 million under the terms of our Credit Facility, determined as follows:

	(in millions)
Total credit available under Credit Facility	$1,167.5
Less: Amounts outstanding under Credit Facility	—
Balance of letters of credit outstanding	16.7
Principal amount of commercial paper issuances	410.0
Total amount we could borrow at June 30, 2010	$ 740.8

Individual borrowings under the terms of our Credit Facility 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 Facility, which we accomplish by contemporaneously borrowing at the then current rate of interest and repaying the principal amount due. During the six month periods ended June 30, 2010 and 2009, we net settled borrowings of approximately $915.0 million and $957.1 million, respectively, on a non-cash basis.

Commercial Paper

At June 30, 2010 we had $410.0 million of commercial paper outstanding, at a weighted average interest rate of 0.44%, before the effect of our interest rate hedging activities. Under our commercial paper program, we had net borrowings of approximately $409.9 million during the six month period ended June 30, 2010, which include gross issuances of $1,674.6 million and gross repayments of $1,264.7 million. At June 30, 2010 we could issue an additional $190.0 million in principal amount under our commercial paper program. The commercial paper we can issue is limited by the credit available under our Credit Facility.

Joint Funding Arrangement for Alberta Clipper Project

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

In March 2010, we refinanced $324.6 million of amounts we had outstanding and payable to our General Partner under the A1 Credit Agreement by issuing a promissory note payable to our General Partner, at which time we also terminated the A1 Credit Agreement. The promissory note payable, which we refer to as the A1 Term Note, matures on March 15, 2020, bears interest at a fixed rate of 5.20% and has a maximum loan amount of $400 million. The terms of the A1 Term Note are similar to the terms of our senior notes, except that the A1 Term Note has recourse only to the assets of the United States portion of the Alberta Clipper Project. Under the terms of the A1 Term Note, we have the ability to increase the principal amount outstanding to finance the debt portion of the investment our General Partner is obligated to make pursuant to the Alberta Clipper Joint Funding Arrangement to finance any additional costs associated with our construction of our portion of the Alberta Clipper Project we incur after the date the original A1 Term Note was issued. The increases we make to the principal balance of the A1 Term Note will also mature on March 15, 2020. At June 30, 2010, we had approximately $340.9 million outstanding under the A1 Term Note.

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

We allocate earnings derived from operating the Alberta Clipper Project in the amounts of $14.5 million and $25.2 million to our General Partner for its 66.67 percent share of the earnings of the Alberta Clipper Project for the three month 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 Project in “Net income attributable to noncontrolling interest” on our consolidated statements of income.

Cash Requirements for Future Growth

Capital Spending

We expect to make additional expenditures during the next year for the acquisition and construction of natural gas and crude oil transportation infrastructure. In 2010, we expect to spend approximately $900.0 million on system enhancements, including the Alberta Clipper Project, and other projects associated with our liquids and natural gas systems with the expectation of realizing additional cash flows as projects are completed and placed into service. At June 30, 2010, we had approximately $141.3 million in outstanding purchase commitments attributable to capital projects for the construction of assets that will be recorded as property, plant and equipment during 2010.

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. We expect to pursue potential acquisitions with a focus on natural gas 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 asset acquisitions are anticipated 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 Facility and the issuance of additional debt and equity securities. All acquisitions are considered in the context of the practical financing constraints presented by the capital markets.

Forecasted Expenditures

We categorize our capital expenditures as either core maintenance or enhancement expenditures. Core maintenance expenditures are those expenditures that are necessary to maintain the service capability of our existing assets and includes the replacement of system components and equipment which is 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, 2010. Although we anticipate making the expenditures in 2010, these estimates may change due to factors beyond our control, including weather-related issues, construction timing, changes in supplier prices or poor economic conditions. 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 $356.2 million, including $26.4 million on core maintenance activities, for the six month period ended June 30, 2010. For the full year ending December 31, 2010, we anticipate our capital expenditures to approximate the following:

	Total Forecasted Expenditures
	(in millions)
System enhancements	$354
Core maintenance activities	90
South Haynesville	153
Alberta Clipper	303
	$900

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. We anticipate beginning a comprehensive program in 2010 to upgrade sections of our liquids petroleum pipeline system located in eastern Michigan that were installed in the late 1960s. This program will likely extend over several years and will require additional capital expenditures.

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, 2010 for each of the indicated calendar years:

	Notional	2010	2011	2012	2013	2014	Total[3]
			(dollars, in millions)				
Swaps							
Natural gas[1]	100,571,952	$(1.6)	$(12.4)	$ (4.6)	$2.9	$ —	$(15.7)
NGL[2]	4,934,621	0.9	12.7	13.6	1.3	—	28.5
Crude[2]	2,811,920	(1.4)	(5.0)	(1.8)	1.8	1.9	(4.5)
Options-calls							
Natural gas—calls written[1]	549,000	(0.1)	(0.5)	—	—	—	(0.6)
Options-puts							
Natural gas—puts purchased[1]	549,000	—	—	—	—	—	—
NGL—puts purchased[2]	917,694	2.5	3.3	3.7	—	—	9.5
Crude—puts purchased[2]	176,246	0.3	0.4	—	—	—	0.7
Forward contracts							
Crude[2]	708,691	2.3	—	—	—	—	2.3
Natural gas[1]	48,983,433	0.6	0.6	0.4	0.2	—	1.8
NGL[2]	6,995,190	3.4	1.2	0.5	—	—	5.1
Totals		$ 6.9	$ 0.3	$11.8	$6.2	$1.9	$ 27.1

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

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

(3) Fair values exclude credit adjustments of approximately $1.1 million of losses at June 30, 2010.

The following table provides summarized information about the timing and expected settlement amounts of our outstanding interest rate derivative instruments at June 30, 2010 for each of the indicated calendar years:

	Notional Amount	2010	2011	2012	2013	2014	Thereafter	Total[1]
				(dollars in millions)				
Interest Rate Derivatives								
Interest Rate Swaps:								
Floating to Fixed	$975.0	$(3.3)	$(23.8)	$(18.5)	$(10.8)	$—	$—	$(56.4)
Fixed to Floating	125.0	2.3	5.0	4.1	1.6	—	—	13.0
Pre-issuance hedges	900.0	—	—	(33.4)	(12.2)	—	—	(45.6)
Interest Rate Caps	400.0	—	—	—	—	—	—	—
		$(1.0)	$(18.8)	$(47.8)	$(21.4)	$—	$—	$(89.0)

(1) Fair values are presented in millions of dollars and exclude credit adjustments of approximately $3.2 million of gains at June 30, 2010.

Operating Activities

Net cash provided by our operating activities was $365.4 million for the six month period ended June 30, 2010, an increase of $6.0 million compared with the $359.4 million generated during the same period in 2009. The change in operating cash flow is directly attributable to the operating performance of our Liquids and Natural Gas systems and marketing activities as discussed above in the section *Results of Operations—By Segment*. The increase from operating performance is partially offset by lower cash flows associated with changes in our working capital accounts for the six month period ended June 30, 2010 compared to the same period of 2009 coupled with general timing differences in the collection on and payment of our current and related party accounts.

Investing Activities

Net cash used in our investing activities during the six month period ended June 30, 2010 was $383.1 million, a decrease of $194.2 million from the $577.3 million used during the same period of 2009. The decrease is primarily attributable to the $211.1 million reduction of amounts spent in 2010 on our construction projects as compared to the same period of 2009. The decrease in the amounts spent on our construction projects is primarily attributable to completion of the second stage of our Southern Access Project, our North Dakota phase VI expansion project, and the Alberta Clipper Project. Offsetting the reduction in net cash used in investing activities was the $17.0 million acquisition of natural gas assets in the South Haynesville area.

Financing Activities

The net cash provided by our financing activities during the six month period ended June 30, 2010 was $81.3 million, an increase of $70.6 million from the $10.7 million provided during the same period in 2009. The increase in cash provided by financing activities is primarily due to the following:

- $496.1 million of net proceeds related to the March 2010 issuance and sale of $500 million in principal amount of our 5.20% senior unsecured notes due 2020 compared with $175.0 million in principal amount of senior unsecured notes we repaid in the same period of 2009;
- Net commercial paper borrowings of $409.9 million in 2010. Similar borrowings were not made in the same period of 2009;
- $395.8 million we borrowed 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 Project;
- $87.0 million of capital contributions from our General Partner and its affiliate during 2010 for its ownership interest in the Alberta Clipper Project; and
- $14.8 million of proceeds related to Class A common units issued under the EDA and $0.3 million of contributions from the General Partner to maintain their two percent interest.

Offsetting the cash inflows from financing activities are $765 million of net repayments under our Credit Facility over the $376.2 million of net borrowings we made in the comparable period of 2009. Included in our net repayments under our Credit Facility for the six month period ended June 30, 2010 were gross borrowings of $995.0 million and gross repayments of $1,760.0 million, including $915.0 million of non-cash borrowings and repayments.

Also, for the six month period ended June 30, 2010 we had $46.5 million more in distributions to our partners due to a greater number of units outstanding, a higher distribution rate and corresponding increase in incentive distribution payments to our General Partner.

OFF-BALANCE SHEET ARRANGEMENTS

We have no significant off-balance sheet arrangements.

SUBSEQUENT EVENTS

Class A common unit issuances

We issued 110,000 Class A common units in July 2010 under the terms of the EDA at sales prices averaging $53.01 per unit, for proceeds of approximately $5.7 million, net of $0.1 million of commissions and issuance costs. In addition, our General Partner contributed approximately $0.1 million to us to maintain its two percent general partner interest.

Distribution to Partners

On July 23, 2010, the board of directors of Enbridge Management declared a distribution payable to our partners on August 13, 2010. The distribution will be paid to unitholders of record as of August 5, 2010, of our available cash of $141.7 million at June 30, 2010, or $1.0275 per limited partner unit. Of this distribution, $123.8 million will be paid in cash, $17.5 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 23, 2010, 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 $17.2 million to the noncontrolling interest in the Series AC while $8.6 million will be paid to us.

Lakehead Line 6b Leak

On July 26, 2010, we experienced a crude oil release on Line 6b of our Lakehead system near Marshall, Michigan. We immediately shut down the pipeline and dispatched emergency response crews to oversee containment, cleanup and repair of the pipeline. We currently are investigating the cause of the release and, at this time, are unable to determine the economic impact this incident may have. We maintain commercial liability coverage that includes a deductible of approximately $5 million, excluding fines and penalties, and limits of coverage that we believe should be adequate to fund the resulting costs and liabilities.

REGULATORY MATTERS

FERC Transportation Tariffs

Effective January 1, 2010, we increased the rates for transportation on our North Dakota system to include a new surcharge related to the recent completion of our Phase VI Expansion program, which increased capacity on the pipeline from 110,000 Bpd to 161,000 Bpd. This surcharge is applicable for the seven years immediately following the January 1, 2010 in-service date of the Phase VI Expansion program. The mainline expansion surcharge is applied to all mainline volumes with a destination of Clearbrook, Minnesota.

Effective April 1, 2010, we extended the term of the looping surcharge, a component of the Phase V Expansion program of our North Dakota system, with the FERC by four years so that it now expires on December 31, 2016. The effect of the extended term reduced the looping surcharge from $0.70 per barrel to $0.38 per barrel for all volumes originating from Trenton, Missouri Ridge and Alexander, North Dakota delivered to Tioga, North Dakota.

Effective April 1, 2010, we filed our annual tariff rate adjustment with the FERC to reflect true-ups for the difference between estimates and actual cost and throughput data for the prior year and our projected costs and throughput for 2010 related to our expansion projects. The projected costs for 2010 include two additional projects: the Alberta Clipper project, which was placed into service on April 1, 2010, and the Line 3 conversion project. Filings in early 2010 by shippers requesting the FERC to delay the tariff were dismissed by the FERC in March 2010 in docket number IS10-139-000. This tariff filing increased the average transportation rate for crude oil movements from the Canadian border to Chicago, Illinois, by approximately $0.52 per barrel, to an average of approximately $1.98 per barrel. We began to realize revenues in relation to this increased surcharge as crude oil is delivered from our pipeline.

Effective July 1, 2010, 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 March 2006, the FERC determined that the Producer Price Index For Finished Goods plus 1.3 percent (PPI + 1.3 percent) should be the oil pricing index for a five year period ending July 2011. The index is used to establish rate ceiling levels for oil pipeline rate changes. For our Lakehead system, indexing only applies to the base rates, and does not apply to the SEP II, Terrace and Facilities surcharges, which includes the Southern Access and Alberta Clipper Projects. Effective July 2010, we decreased the base tariff rates on our Lakehead system by an average of 1.3 percent to equal the indexed ceiling level allowed under the FERC's indexing methodology. On our Lakehead system, the new average rate for crude oil movements from the International Border near Neche, North Dakota to Chicago, Illinois is $1.97 per barrel, which reflects a $0.01 per barrel decrease over the rates filed effective April 1, 2010. In addition to the rates on our Lakehead system, we decreased the transportation rates on our North Dakota and Ozark systems 1.3 percent. The tariff rates for our Lakehead, North Dakota and Ozark systems are at the ceiling levels allowed under the FERC methodology.

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, 2009, in addition to information presented in Items 1 and 2 of this Quarterly Report on Form 10-Q. There have been no material changes to that information other than as presented below.

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

Interest Rate Derivatives

The table below provides information about our derivative financial instruments that we use to hedge the interest payments on our variable rate debt obligations that are sensitive to changes in interest rates and to lock in the interest rate on anticipated issuances of debt in the future. For interest rate swaps, the table presents notional amounts, the rates charged on the underlying notional and weighted average interest rates paid by expected maturity dates. Notional amounts are used to calculate the contractual payments to be exchanged under the contract. Weighted average variable rates are based on implied forward rates in the yield curve at June 30, 2010.

				Fair Value(3) at	
Date of Maturity & Contract Type	**Accounting Treatment**	**Notional**	**Average Fixed Rate(1)**	**June 30, 2010**	**December 31, 2009**
		(dollars in millions)			
Contracts maturing in 2010					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$250	1.68%	$(1.2)	$(2.5)
Interest Rate Caps	Non-qualifying	200	1.09%	—	0.2
Contracts maturing in 2011					
Interest Rate Caps	Non-qualifying	$200	1.14%	$ —	$ 0.3

Date of Maturity & Contract Type	Accounting Treatment	Notional	Average Fixed Rate[1]	Fair Value[3] at June 30, 2010	Fair Value[3] at December 31, 2009
		(dollars in millions)			
Contracts maturing in 2013					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$600	4.15%	$(43.6)	$(16.9)
Interest Rate Swaps—Pay Fixed	Non-qualifying	125	4.35%	(11.6)	(9.2)
Interest Rate Swaps—Pay Float	Non-qualifying	125	4.75%	13.0	11.0
Contracts settling prior to maturity					
2010—Pre-issuance Hedges[2]	Cash Flow Hedge	$220	4.62%	$ —	$ (6.8)
2012—Pre-issuance Hedges	Cash Flow Hedge	600	4.57%	(33.4)	24.9
2013—Pre-issuance Hedges	Cash Flow Hedge	300	4.62%	(12.2)	14.1

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

(2) All 2010 Pre-issuance Hedges were settled in connection with our $500 million senior note debt issuance in March 2010.

(3) The fair value is determined from quoted market prices at June 30, 2010 and December 31, 2009, 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 adjustments of approximately $3.2 million of gains at June 30, 2010, with no such gains and losses at December 31, 2009.

In connection with our March 2010 issuance and sale of $500 million in principal amount of 5.20% senior notes due March 15, 2020, we paid $13.2 million to settle treasury locks we entered to hedge the interest payments on a portion of these obligations through the maturity date of the senior notes maturing in 2020. The $13.2 million is being amortized from AOCI to "Interest expense" over the 10-year term of the senior notes.

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, 2010 and December 31, 2009.

	At June 30, 2010						At December 31, 2009	
			Wtd. Average Price[2]		Fair Value[3]		Fair Value[3]	
	Commodity	Notional[1]	Receive	Pay	Asset	Liability	Asset	Liability
Portion of contracts maturing in 2010								
Swaps								
Receive variable/pay fixed	Natural Gas	3,500,621	$ 4.58	$ 5.54	$ —	$ (3.3)	$ 1.6	$ (3.1)
	NGL	184,000	30.86	24.18	1.4	(0.2)	3.4	—
Receive fixed/pay variable	Natural Gas	6,331,613	4.37	4.72	2.2	(4.4)	2.9	(16.0)
	NGL	1,977,616	37.81	37.97	9.4	(9.7)	9.7	(39.4)
	Crude Oil	558,060	73.57	76.08	2.3	(3.7)	3.1	(10.6)
Receive variable/pay variable	Natural Gas	55,179,975	4.59	4.52	5.8	(1.9)	13.0	(3.5)
Physical Contracts								
Receive fixed/pay variable	NGL	1,508,000	64.33	59.94	6.9	(0.3)	—	(4.0)
	Crude Oil	384,000	84.26	75.87	3.2	—	—	(1.6)
Receive variable/pay fixed	NGL	874,286	60.04	65.03	—	(4.4)	0.3	—
	Crude Oil	201,000	75.73	80.75	—	(1.0)	1.8	—
Receive variable/pay variable	Crude Oil	123,691	73.94	73.07	0.3	(0.2)	0.1	(0.1)
	NGL	3,275,951	53.07	52.68	1.7	(0.5)	—	—
	Natural Gas	11,760,444	4.56	4.51	0.6	—	—	—
Portion of contracts maturing in 2011								
Swaps								
Receive variable/pay fixed	Natural Gas	1,028,000	$ 5.15	$ 9.12	$ —	$ (4.0)	$ —	$ (3.1)
	NGL	120,000	69.60	47.67	2.6	—	3.2	—
Receive fixed/pay variable	Natural Gas	8,907,859	4.05	5.29	1.3	(12.2)	—	(19.3)
	NGL	1,535,190	57.20	50.56	12.0	(1.9)	6.1	(7.0)
	Crude Oil	780,650	73.11	79.59	1.2	(6.2)	—	(10.0)
Receive variable/pay variable	Natural Gas	20,717,675	5.15	5.03	3.0	(0.5)	2.9	(0.1)
Physical Contracts								
Receive variable/pay variable	Natural Gas	18,288,653	5.04	5.01	0.6	—	—	—
	NGL	845,524	43.37	42.19	1.1	(0.1)	—	—
Receive fixed/pay variable	NGL	100,000	58.95	57.26	0.2	—	—	—

	At June 30, 2010						At December 31, 2009	
			Wtd. Average Price(2)		Fair Value(3)		Fair Value(3)	
	Commodity	Notional(1)	Receive	Pay	Asset	Liability	Asset	Liability
Portion of contracts maturing in 2012								
Swaps								
Receive variable/pay fixed	Natural Gas	759,709	$ 5.53	$ 9.96	$ —	$(3.3)	$ —	$(2.6)
Receive fixed/pay variable	Natural Gas	2,327,500	4.90	5.71	1.1	(3.0)	0.3	(4.2)
	NGL	869,250	65.14	49.19	13.7	(0.1)	7.1	(0.9)
	Crude Oil	559,980	77.92	81.19	0.3	(2.1)	—	(5.3)
Receive variable/pay variable	Natural Gas	1,089,000	5.50	4.93	0.6	—	0.6	—
Physical Contracts								
Receive variable/pay variable	Natural Gas	11,858,120	4.96	4.93	0.4	—	—	—
	NGL	391,429	34.74	33.48	0.5	—	—	—
Portion of contracts maturing in 2013								
Swaps								
Receive fixed/pay variable	Natural Gas	730,000	$ 9.83	$ 5.64	$ 2.9	$ —	$2.3	$ —
	NGL	248,565	58.89	53.74	1.5	(0.2)	—	(1.0)
	Crude Oil	467,930	86.40	82.28	3.6	(1.8)	2.3	(3.6)
Physical Contracts								
Receive variable/pay variable	Natural Gas	7,076,216	4.96	4.93	0.2	—	—	—
Portion of contracts maturing in 2014								
Swaps								
Receive fixed/pay variable	Crude Oil	445,300	$88.03	$83.41	$ 1.9	$ —	$ —	$(0.4)

(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.

(2) Weighted average prices received and paid 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, 2010 and December 31, 2009, 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 adjustments of approximately $0.9 million of losses and $1.0 million of gains at June 30, 2010 and December 31, 2009, respectively.

The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity options at June 30, 2010 and December 31, 2009.

	At June 30, 2010						At December 31, 2009	
					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 2010								
Calls (written)	Natural Gas(4)	184,000	$ 4.31	$ 4.83	$ —	$(0.1)	$ —	$(0.6)
Puts (purchased)	Natural Gas(4)	184,000	3.40	4.83	—	—	—	—
	NGL	526,792	46.84	47.65	2.5	—	3.2	—
	Crude Oil	150,696	70.87	76.93	0.3	—	0.6	—
Portion of option contracts maturing in 2011								
Calls (written)	Natural Gas(4)	365,000	$ 4.31	$ 5.34	$ —	$(0.5)	$ —	$(0.8)
Puts (purchased)	Natural Gas(4)	365,000	3.40	5.34	—	—	—	—
	NGL	262,070	44.09	34.10	3.3	—	2.4	—
	Crude Oil	25,550	90.50	79.59	0.4	—	—	—
Portion of option contracts maturing in 2012								
Puts (purchased)	NGL	128,832	$66.80	$41.37	$3.7	$ —	$3.2	$ —

(1) Volumes of Natural gas are measured in MMBtu, whereas volumes of NGL and Crude Oil are measured in Bbl.

(2) Strike and market prices are in $/MMBtu for Natural gas and in $/Bbl for NGL and Crude Oil.

(3) The fair value is determined based on quoted market prices at June 30, 2010 and December 31, 2009, 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 adjustments of approximately $0.2 million of losses and $0.1 million of losses at June 30, 2010 and December 31, 2009, respectively.

(4) 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, 2010	December 31, 2009
	(in millions)	
Counterparty Credit Quality*		
AAA	$ —	$ —
AA	(19.2)	14.2
A	(48.6)	(63.1)
Lower than A	5.9	(3.2)
	(61.9)	(52.1)
Credit valuation adjustment	2.1	0.9
Total	$(59.8)	$(51.2)

* 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 has evaluated the effectiveness of our disclosure controls and procedures as of June 30, 2010. 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, 2010.

PART II—OTHER INFORMATION

Item 1. Legal Proceedings

Refer to Part I, Item 1. Financial statements, Note 10—*Legal and Regulatory Proceedings,* 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, 2009.

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 27, 2010

By: /s/ STEPHEN J. J. LETWIN

Stephen J. J. Letwin
Managing Director
(Principal Executive Officer)

Date: July 27, 2010

By: /s/ MARK A. MAKI

Mark A. Maki
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, 2010 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 June 9, 2010).
3.1	Certificate of Limited Partnership of the Partnership (incorporated by reference to Exhibit 3.1 to the Partnership's Registration Statement on Form S-1 (No. 33-43425)).
3.2	Certificate of Amendment to Certificate of Limited Partnership of the Partnership, dated August 28, 2001 (incorporated by reference to Exhibit 3.2 to the Partnership's Second Amendment to Annual Report on Form 10-K/A for the year ended December 31, 2000, filed on October 9, 2001).
3.3	Fourth Amended and Restated Agreement of Limited Partnership of the Partnership, dated August 15, 2006 (incorporated by reference to Exhibit 3.1 of the Partnership's Current Report on Form 8-K, filed on August 16, 2006).
3.4	Amendment No. 1 to Fourth Amended and Restated Limited Partnership Agreement of the Partnership, dated December 28, 2007 (incorporated by reference to Exhibit 3.1 of the Partnership's Current Report on Form 8-K, filed on January 3, 2008).
3.5	Amendment No. 2 to Fourth Amended and Restated Agreement of Limited Partnership of the Partnership, dated August 6, 2008 (incorporated by reference to Exhibit 3.1 of the Partnership's Current Report on Form 8-K filed on August 7, 2008).
4.1	Form of Certificate representing Class A Common Units (incorporated by reference to Exhibit 4.1 to the Partnership's Second Amendment to Annual Report on Form 10-K/A for the year ended December 31, 2000, filed on October 9, 2001).
31.1*	Certification of Principal Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Principal Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of Principal Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification of Principal Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.