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 September 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 98,562,053 Class A common units outstanding as of October 29, 2010.

ENBRIDGE ENERGY PARTNERS, L.P.

TABLE OF CONTENTS

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

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

Our forward-looking statements are subject to risks and uncertainties pertaining to operating performance, regulatory parameters, weather, economic conditions, interest rates and commodity prices, including but not limited to, those risks and uncertainties discussed in this Quarterly Report on Form 10-Q and our other reports that we have filed or will file with the Securities and Exchange Commission. 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.

PART I—FINANCIAL INFORMATION

Item 1. Financial Statements

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF INCOME

	For the three month period ended September 30,		For the nine month period ended September 30,	
	2010	2009	2010	2009
	(unaudited; in millions, except per unit amounts)			
Operating revenue (Note 12)	$1,889.3	$1,363.7	$5,567.9	$4,104.2
Operating expenses				
Cost of natural gas (Notes 5 and 12)	1,455.6	943.2	4,250.2	2,929.3
Environmental costs (Note 11)	477.6	—	482.1	2.0
Operating and administrative	142.1	133.6	409.9	397.0
Power	36.7	33.7	105.5	96.9
Depreciation and amortization (Note 6)	79.7	65.2	225.2	191.7
Impairment charge (Note 6)	10.3	—	10.3	—
	2,202.0	1,175.7	5,483.2	3,616.9
Operating income (loss)	(312.7)	188.0	84.7	487.3
Interest expense (Note 12)	70.1	60.7	199.0	169.9
Other income (expense) (Note 14)	(0.6)	2.8	16.1	2.5
Income (loss) from continuing operations before income tax expense	(383.4)	130.1	(98.2)	319.9
Income tax expense	2.9	2.7	7.5	6.8
Income (loss) from continuing operations	(386.3)	127.4	(105.7)	313.1
Loss from discontinued operations, net of tax (Note 3)	—	(67.9)	—	(67.5)
Net income (loss)	(386.3)	59.5	(105.7)	245.6
Less: Net income attributable to noncontrolling interest (Notes 9 and 10)	20.1	2.3	45.3	2.3
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ (406.4)	$ 57.2	$ (151.0)	$ 243.3
Net income (loss) allocable to limited partner interests				
Income (loss) from continuing operations	$ (415.2)	$ 110.1	$ (195.7)	$ 267.6
Loss from discontinued operations	—	(66.5)	—	(66.2)
Net income (loss) allocable to limited partner interests	$ (415.2)	$ 43.6	$ (195.7)	$ 201.4
Basic and diluted earnings per limited partner unit (Note 2)				
Income (loss) from continuing operations	$ (3.49)	$ 0.94	$ (1.65)	$ 2.30
Loss from discontinued operations	—	(0.57)	—	(0.57)
Net income (loss) per limited partner unit (basic and diluted)	$ (3.49)	$ 0.37	$ (1.65)	$ 1.73
Weighted average limited partner units outstanding	119.0	117.0	118.4	116.0

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 September 30,		For the nine month period ended September 30,	
	2010	2009	2010	2009
	(unaudited; in millions, except per unit amounts)			
Net income (loss)	$(386.3)	$ 59.5	$(105.7)	$ 245.6
Other comprehensive loss, net of tax benefit of $0.5, $0.1, $0.2 and $0.5, respectively (Note 12)	(56.0)	(37.9)	(102.4)	(114.2)
Comprehensive income (loss)	(442.3)	21.6	(208.1)	131.4
Less: Comprehensive income attributable to noncontrolling interest (Notes 9 and 10)	20.1	2.3	45.3	2.3
Comprehensive income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$(462.4)	$ 19.3	$(253.4)	$ 129.1

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the nine month period ended September 30,	
	2010	2009
	(unaudited; in millions)	
Cash provided by operating activities		
Net income (loss)	$ (105.7)	$ 245.6
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization (Note 6)	225.2	203.3
Derivative fair value gains (Note 12)	(10.7)	(7.3)
Inventory market price adjustments (Note 5)	3.6	3.6
Impairment charge	10.3	66.1
Reserve for environmental obligations (Note 11)	481.5	2.9
Other (Note 16)	2.2	11.4
Changes in operating assets and liabilities, net of acquisitions:		
Receivables, trade and other	7.4	(40.8)
Due from General Partner and affiliates	(2.5)	11.7
Accrued receivables	(31.4)	189.0
Inventory (Note 5)	(82.5)	(31.3)
Current and long-term other assets (Note 12)	(5.1)	(42.3)
Due to General Partner and affiliates	14.6	21.8
Accounts payable and other (Notes 4 and 12)	23.2	(8.8)
Environmental liabilities (Note 11)	(147.3)	(1.4)
Accrued purchases	(9.2)	(89.5)
Interest payable	32.8	42.7
Property and other taxes payable	8.4	6.9
Settlement of interest rate derivatives (Note 12)	(3.0)	(0.7)
Net cash provided by operating activities	411.8	582.9
Cash used in investing activities		
Additions to property, plant and equipment (Note 6)	(529.1)	(813.3)
Changes in construction payables	(5.9)	(77.0)
Acquisitions (Note 3)	(703.1)	—
Other	(3.3)	(0.1)
Net cash used in investing activities	(1,241.4)	(890.4)
Cash provided by financing activities		
Net proceeds from unit issuances (Note 9)	52.2	—
Distributions to partners (Note 9)	(356.8)	(279.9)
Repayments of long-term debt	—	(389.7)
Repayment of loan from General Partner (Note 10)	(330.7)	—
Net proceeds from issuances of long-term debt (Note 8)	890.5	—
Net borrowings (repayments) under Credit Facility (Note 8)	(438.0)	463.2
Net commercial paper borrowings (Note 8)	594.8	—
Borrowings from General Partner (Note 10)	403.7	166.1
Contribution from noncontrolling interest (Notes 9 and 10)	96.6	203.0
Distributions to noncontrolling interest (Notes 9 and 10)	(17.2)	—
Other	(2.5)	(4.0)
Net cash provided by financing activities	892.6	158.7
Net increase (decrease) in cash and cash equivalents	63.0	(148.8)
Cash and cash equivalents at beginning of year	143.6	339.9
Cash and cash equivalents at end of period	$ 206.6	$ 191.1

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	September 30, 2010	December 31, 2009
	(unaudited; dollars in millions)	
ASSETS		
Current assets		
Cash and cash equivalents (Note 4)	$ 206.6	$ 143.6
Receivables, trade and other, net of allowance for doubtful accounts of $2.0 in 2010 and $6.8 in 2009	147.8	148.5
Due from General Partner and affiliates	20.5	18.0
Accrued receivables	483.9	440.4
Inventory (Note 5)	149.7	71.9
Other current assets (Note 12)	41.4	47.5
	1,049.9	869.9
Property, plant and equipment, net (Notes 6, 10 and 14)	8,532.7	7,716.7
Goodwill	246.7	246.7
Intangibles, net (Note 7)	274.9	82.9
Other assets, net (Note 12)	58.0	72.1
	$10,162.2	$8,988.3
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Due to General Partner and affiliates	$ 60.8	$ 46.2
Accounts payable and other (Notes 1, 4, and 12)	198.9	198.1
Environmental liabilities (Notes 1 and 11)	319.5	7.3
Accrued purchases	426.1	428.6
Interest payable	78.1	45.3
Property and other taxes payable	48.8	38.8
Loan from General Partner (Note 10)	11.4	269.7
Current maturities of long-term debt	31.0	31.0
	1,174.6	1,065.0
Long-term debt (Note 8)	4,846.8	3,791.2
Note payable to General Partner (Note 10)	331.3	—
Other long-term liabilities (Notes 11 and 12)	169.2	62.2
	6,521.9	4,918.4
Commitments and contingencies (Note 11)		
Partners' capital (Note 9)		
Class A common units (98,417,438 at September 30, 2010 and 97,443,352 at December 31, 2009)	2,476.3	2,884.9
Class B common units (3,912,750 at September 30, 2010 and December 31, 2009)	61.8	78.6
i-units (17,339,359 at September 30, 2010 and 16,388,867 at December 31, 2009)	562.0	588.8
General Partner	251.4	251.1
Accumulated other comprehensive income (Notes 9 and 12)	(177.0)	(74.6)
Total Enbridge Energy Partners, L.P. partners' capital	3,174.5	3,728.8
Noncontrolling interest (Notes 9 and 10)	465.8	341.1
Total partners' capital	3,640.3	4,069.9
	$10,162.2	$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 September 30, 2010; our results of operations for the three and nine month periods ended September 30, 2010 and 2009; and our cash flows for the nine month periods ended September 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 nine month periods ended September 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 and the effect of the leaks on Lines 6A and 6B of our Lakehead system. Our interim consolidated financial statements should be read in conjunction with our consolidated financial statements and notes thereto presented in our Annual Report on Form 10-K for the fiscal year ended December 31, 2009.

Comparative Amounts

We have made reclassifications to the amounts reported in our consolidated statement of financial position as of December 31, 2009 and our consolidated statement of cash flows as of September 30, 2009 to conform to our current year presentation. We reclassified $7.3 million from “Accounts payable and other” to “Environmental liabilities” in our December 31, 2009 consolidated statement of financial position and $2.9 million from “Other” to “Reserve for environmental obligations” in our September 30, 2009 consolidated statement of cash flows. We also reclassified $1.4 million from “Accounts payable and other” to “Environmental liabilities” in our consolidated statement of cash flows for the nine month period ended September 30, 2009. Additionally, we made a reclassification of $2.0 million from “Operating and administrative” to “Environmental costs” in our consolidated statement of income for the nine month period ended September 30, 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 September 30,		For the nine month period ended September 30,	
	2010	2009	2010	2009
	(in millions, except per unit amounts)			
Net income (loss)	$(386.3)	$ 59.5	$(105.7)	$ 245.6
Less: Net income attributable to noncontrolling interest	20.1	2.3	45.3	2.3
Net income (loss) attributable to general and limited partner interests in Enbridge Energy Partners, L.P.	(406.4)	57.2	(151.0)	243.3
Less: Loss from discontinued operations	—	(67.9)	—	(67.5)
Net income (loss) from continuing operations attributable to general and limited partner interests in Enbridge Energy Partners, L.P.	(406.4)	125.1	(151.0)	310.8
Less distributions paid:				
Incentive distributions to our general partner	(17.3)	(12.6)	(48.7)	(37.7)
Distributed earnings allocated to our general partner (2%)	(2.5)	(2.5)	(7.4)	(7.1)
Total distributed earnings to our general partner	(19.8)	(15.1)	(56.1)	(44.8)
Total distributed earnings to our limited partners (98%)	(123.2)	(116.2)	(363.5)	(346.0)
Total distributed earnings	(143.0)	(131.3)	(419.6)	(390.8)
Overdistributed earnings	$(549.4)	$ (6.2)	$(570.6)	$ (80.0)
Weighted average limited partner units outstanding	119.0	117.0	118.4	116.0
Basic and diluted earnings per unit:				
Distributed earnings per limited partner unit[1]	$ 1.04	$ 0.99	$ 3.07	$ 2.98
Overdistributed earnings per limited partner unit[2]	(4.53)	(0.05)	(4.72)	(0.68)
Net income (loss) from continuing operations attributable to our limited partner interests per limited partner unit	(3.49)	0.94	(1.65)	2.30
Loss from discontinued operations attributable to our limited partner interests per limited partner unit	—	(0.57)	—	(0.57)
Net income (loss) per limited partner unit (basic and diluted)	$ (3.49)	$ 0.37	$ (1.65)	$ 1.73

(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. ACQUISITIONS AND DISPOSITIONS

Elk City Natural Gas Gathering and Processing System Acquisition

On September 16, 2010, we acquired 100 percent ownership of the entities that comprise the Elk City Natural Gas Gathering and Processing System, or ECOP, for $686.1 million in cash, including the initial adjustment for working capital, subject to any final working capital adjustments. The ECOP assets extend from southwestern Oklahoma to Hemphill County in the Texas Panhandle. ECOP consists of approximately 800 miles of natural gas gathering and transportation pipelines, one carbon dioxide treating plant and three cryogenic processing plants with a total capacity of 370 million cubic feet per day, or MMcf/d, and a combined current natural gas liquid production capability of 20,000 barrels per day. The acquisition of ECOP complements our existing Anadarko natural gas system by providing additional processing capacity and expansion capability. We used the net proceeds from the September 2010 issuance and sale of our senior notes, detailed in Note 8—*Debt*, to pay for a portion of the acquisition. The results of operations of the ECOP assets have been included in our consolidated financial statements from the September 16, 2010 acquisition date within our Natural Gas segment. ECOP did not significantly impact the operating results of our Natural Gas business for the three and nine month periods ended September 30, 2010.

The following table presents the allocation of the purchase price to the assets acquired and the liabilities assumed, based on their fair values:

	September 16, 2010
	(in millions)
Other current assets	$ 3.9
Property, plant and equipment, net	489.5
Intangibles	189.2
Other assets	4.7
Total assets acquired	687.3
Other long-term liabilities	1.2
Net assets acquired	$686.1

South Haynesville Acquisition

In June 2010, we acquired natural gas pipeline assets for approximately $17 million that are complementary to our existing East Texas system assets and planned expansion into the South Haynesville area.

Natural Gas Pipeline Disposition

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 nine month periods ended September 30, 2009 in "Loss 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 September 30, 2009	For the nine month period ended September 30, 2009
	(in millions)	
Operating revenue	$ 43.1	$151.6
Operating expenses		
Cost of natural gas	34.8	124.9
Operating and administrative	6.1	16.5
Depreciation and amortization	3.9	11.6
	44.8	153.0
Operating loss	(1.7)	(1.4)
Other expense	(66.2)	(66.1)
Loss from discontinued operations	$(67.9)	$ (67.5)

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 $30.4 million at September 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:

	September 30, 2010	December 31, 2009
	(in millions)	
Materials and supplies	$ 5.3	$ 3.6
Crude oil inventory	8.3	4.1
Natural gas and NGL inventory	136.1	64.2
	$149.7	$71.9

Our consolidated statements of income include charges totaling $1.0 million and $3.6 million for the three and nine month periods ended September 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 nine month periods ended September 30, 2009 totaled $0.2 million and $3.6 million, respectively.

6. PROPERTY, PLANT AND EQUIPMENT

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

	September 30, 2010	December 31, 2009
	(in millions)	
Land	$ 35.9	$ 29.8
Rights-of-way	489.1	438.7
Pipelines	6,141.8	4,401.9
Pumping equipment, buildings and tanks	1,333.9	1,115.9
Compressors, meters and other operating equipment	1,386.9	1,337.8
Vehicles, office furniture and equipment	190.6	164.8
Processing and treating plants	328.4	325.7
Construction in progress	274.7	1,326.3
Total property, plant and equipment	10,181.3	9,140.9
Accumulated depreciation	(1,648.6)	(1,424.2)
Property, plant and equipment, net	$ 8,532.7	$ 7,716.7

In September 2010, our West Tulsa crude oil pipeline was abandoned and as a result we recognized a $10.3 million impairment charge during the third quarter of 2010 to reduce the carrying amount of the asset to zero.

7. INTANGIBLES

In connection with our September 2010 acquisition of the ECOP natural gas assets, we allocated $189.2 million of the purchase price to intangible assets. The intangible assets, which will be included in our Natural Gas segment, are comprised primarily of natural gas supply opportunities associated with the natural gas reserves underlying acreage dedication agreements we obtained through this acquisition. We recorded the intangible assets at the fair value associated with natural gas opportunities. We will amortize the intangibles associated with our ECOP acquisition on a straight-line basis over the estimated remaining life of the underlying reserves at the time of acquisition, which is approximately 30 years.

8. DEBT

Credit Facilities

On August 26, 2010, we established a new unsecured senior revolving credit agreement, with a group of lenders and an aggregate commitment amount of $350.0 million, which we plan to use for funding general activities and working capital needs. The new $350.0 million credit facility has terms consistent with our existing $1,167.5 million Second Amended and Restated Credit Agreement and has the same maturity date of April 4, 2013. The two credit agreements provide an aggregate amount of $1,517.5 million of bank credit and will be referred to as our Credit Facilities.

On September 30, 2010, our Credit Facilities were amended to modify the definition of Consolidated Earnings Before Income Taxes Depreciation and Amortization, or Consolidated EBITDA, used for debt covenant calculations. Consolidated EBITDA, as modified, will exclude those costs associated with the crude oil releases on Lines 6A and 6B of our Lakehead system, not to exceed an aggregate amount of $450.0 million. Specifically, the costs allowed to be excluded from Consolidated EBITDA are those for emergency response, environmental remediation, cleanup activities, costs to repair the pipelines, inspection costs, potential claims by third parties and lost revenue.

At September 30, 2010, we had $327.0 million outstanding under our Credit Facilities, and letters of credit totaling $53.6 million. The amounts we may borrow under the terms of our Credit Facilities are reduced by the principal amount of our commercial paper issuances and the balance of our letters of credit outstanding. At September 30, 2010, we could borrow $541.9 million under the terms of our Credit Facilities, determined as follows:

	(in millions)
Total credit available under Credit Facilities	$1,517.5
Less: Amounts outstanding under Credit Facilities	327.0
Balance of letters of credit outstanding	53.6
Principal amount of commercial paper issuances	595.0
Total amount we could borrow at September 30, 2010	$ 541.9

Individual borrowings under the terms of our Credit Facilities generally become due and payable at the end of each contract period, which is typically a period of three months or less. We have the option to repay these amounts on a non-cash basis by net settling with the parties to our Credit Facilities, which we accomplish by contemporaneously borrowing at the then current rate of interest and repaying the principal amount due. During the nine month periods ended September 30, 2010 and 2009, we net settled borrowings of $915.0 million and $1,447.1 million, respectively, on a non-cash basis.

Commercial Paper

We have a commercial paper program that provides for the issuance of up to an aggregate principal amount $600 million of commercial paper that is supported by our Credit Facilities. We access the commercial paper market primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions when the available interest rates we can obtain are lower than the rates available under our Credit

Facilities. At September 30, 2010, we had $595.0 million of commercial paper outstanding at a weighted average interest rate of 0.45%, excluding the effect of our interest rate hedging activities. At December 31, 2009, we did not have any amounts of commercial paper outstanding. At September 30, 2010, we could issue an additional $5.0 million in principal of commercial paper under our commercial paper program. The commercial paper we can issue is limited by the credit available under our Credit Facilities.

We have the ability and intent to refinance all of our commercial paper obligations on a long-term basis through borrowings under our unsecured, long-term Credit Facilities or permanent financing through the issuance of term debt or additional limited partner interests. Accordingly, such amounts have been classified as "Long-term debt" in our accompanying consolidated statements of financial position.

Senior Notes

In September 2010, we issued and sold $400 million in principal amount of our 5.50% senior notes due September 15, 2040, which we refer to as the 2040 Notes. We received net proceeds from the offering of approximately $394.4 million after underwriting discounts and commissions and payment of offering expenses. We temporarily invested the net proceeds we received from this offering, which we subsequently used to fund a portion of our ECOP acquisition discussed in Note 3—*Acquisitions and Dispositions*. The 2040 Notes do not contain any covenants restricting our issuance of additional unsecured indebtedness and rank equally in right of payment with all of our other existing and future unsecured and unsubordinated indebtedness. Interest on the 2040 Notes is payable semi-annually on March 15th and September 15th of each year and we may redeem the 2040 Notes for cash in whole or in part at any time at our option subject to a make-whole redemption premium.

Also, 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 2020 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 2020 Notes do not contain any covenants restricting our issuance of additional unsecured indebtedness and rank equally in right of payment with all of our other existing and future unsecured and unsubordinated indebtedness. Interest on the 2020 Notes is payable semi-annually on March 15th and September 15th of each year and we may redeem the 2020 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 borrowings on our Credit Facilities approximate their fair values at September 30, 2010 and December 31, 2009 due to the short-term nature and frequent repricing of these obligations. The fair value of our outstanding commercial paper and borrowings on our Credit Facilities are included with our long-term debt obligations below since we have the ability to refinance the amounts on a long-term basis. The approximate fair values of our long-term debt obligations are determined using a standard methodology that incorporates pricing points that are obtained from independent, third-party investment dealers who actively make markets in our debt securities. We use these pricing points to calculate the present value of the principal obligation to be repaid at maturity and all future interest payment obligations for any debt outstanding.

	September 30, 2010		December 31, 2009	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Commercial paper	$ 595.0	$ 595.0	$ —	$ —
Credit Facilities	327.0	327.0	765.0	765.0
9.150% First Mortgage Notes	62.0	65.8	62.0	69.9
7.900% Senior Notes due 2012	100.0	110.9	100.0	109.5
4.750% Senior Notes due 2013	199.9	210.5	199.9	201.2
5.350% Senior Notes due 2014	200.0	221.2	199.9	206.9
5.875% Senior Notes due 2016	299.8	347.7	299.8	315.0
7.000% Senior Notes due 2018	99.9	124.2	99.9	111.6
6.500% Senior Notes due 2018	398.3	481.6	398.2	433.2
9.875% Senior Notes due 2019	499.9	730.0	499.8	664.8
5.200% Senior Notes due 2020	499.8	549.9	—	—
7.125% Senior Notes due 2028	99.8	128.9	99.9	110.9
5.950% Senior Notes due 2033	199.7	221.4	199.7	188.8
6.300% Senior Notes due 2034	99.8	114.5	99.8	98.0
7.500% Senior Notes due 2038	398.9	520.4	398.9	449.5
5.500% Senior Notes due 2040	398.5	391.3	—	—
8.050% Junior subordinated notes due 2067	399.5	408.4	399.4	381.8
Total	$4,877.8	$5,548.7	$3,822.2	$4,106.1

9. PARTNERS' CAPITAL

Distribution to Partners

The following table sets forth our distributions, as approved by the Board of Directors of Enbridge Energy Management, L.L.C., the delegate of our General Partner and which we refer to as Enbridge Management, during the nine month period ended September 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)					
July 23, 2010	August 5, 2010	August 13, 2010	$1.0275	$141.7	$17.5	$0.4	$123.8
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 950,492 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.

Changes in Partners' Capital

The following table presents significant changes in partners' capital attributable to our General Partner and limited partners as well as the noncontrolling interest in our consolidated subsidiary, Enbridge Energy, Limited Partnership, or the OLP, for the three and nine month periods ended September 30, 2010. The noncontrolling interest in the OLP arises from the joint funding arrangement with our General Partner and its affiliates to finance construction of the U.S. portion of the Alberta Clipper crude oil pipeline and related facilities, which we refer to as the Alberta Clipper Project.

	For the three month periods ended September 30,		For the nine month periods ended September 30,	
	2010	2009	2010	2009
	(in millions)			
General and limited partner interests				
Beginning balance	$3,842.8	$3,879.0	$3,803.4	$3,714.0
Proceeds from issuance of partnership interests, net of costs	37.1	—	52.2	0.3
Capital contribution	1.8	3.7	3.7	168.8
Net income (loss)	(406.4)	57.2	(151.0)	243.3
Distributions	(123.8)	(93.4)	(356.8)	(279.9)
Ending balance	$3,351.5	$3,846.5	$3,351.5	$3,846.5
Accumulated other comprehensive income				
Beginning balance	$ (121.0)	$ (63.4)	$ (74.6)	$ 12.9
Net realized losses (gains) on changes in fair value of derivative financial instruments reclassified to earnings	3.6	(11.0)	22.5	(29.9)
Unrealized net loss on derivative financial instruments	(59.6)	(26.9)	(124.9)	(84.3)
Ending balance	$ (177.0)	$ (101.3)	$ (177.0)	$ (101.3)
Noncontrolling interest				
Beginning balance	$ 453.3	$ —	$ 341.1	$ —
Capital contributions	9.6	203.0	96.6	203.0
Comprehensive income:				
Net income	20.1	2.3	45.3	2.3
Distributions to noncontrolling interest	(17.2)	—	(17.2)	—
Ending balance	$ 465.8	$ 205.3	$ 465.8	$ 205.3
Total partners' capital at end of period	$3,640.3	$3,950.5	$3,640.3	$3,950.5

Equity Distribution Agreement

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

The following table presents the net proceeds from our Class A common unit issuances, pursuant to the EDA, during the nine month period ended September 30, 2010:

Three Month Period Ended	Number of Class A common units Issued	Average Offering Price per Class A common unit	Net Proceeds to the Partnership[1]	General Partner Contribution[2]	Net Proceeds Including General Partner Contribution
		(in millions, except units and per unit amounts)			
June 30, 2010	287,345	$52.52	$14.8	$0.3	$15.1
September 30, 2010	686,741	54.21	36.4	0.7	37.1
2010 Totals	974,086		$51.2	$1.0	$52.2

(1) Net of commissions and issuance costs of $0.3 million and $0.7 million for the three month periods ended June 30, 2010 and September 30, 2010, respectively.

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

10. 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 $3.7 million of construction costs during the nine month period ended September 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 that 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 September 30, 2010, we have recorded total costs for the light sour crude oil pipeline of $170.2 million, representing the $175.2 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 nine month period ended September 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 on April 1, 2010.

Joint Funding Arrangement for Alberta Clipper Project

In July 2009, we entered into a joint funding arrangement to finance construction of the U.S. segment of the Alberta Clipper Project with several of our affiliates and affiliates of Enbridge 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, 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 2020 Notes, except that the A1 Term Note has recourse only to the assets of the U.S. portion of the Alberta Clipper Project and is subordinate to all of our senior indebtedness. Under the terms of the A1 Term Note, we have the ability to increase the principal amount outstanding to finance the debt portion of the Alberta Clipper Project that our General Partner is obligated to make pursuant to the Alberta Clipper Joint Funding Arrangement for any additional costs associated with our construction of the

Alberta Clipper 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 the OLP and approved on August 28, 2008 (Docket No. OR08-12-000).

A summary of the cash activity for both the A1 Credit Agreement and A1 Term Note for the nine month period ended September 30, 2010 is as follows:

	A1 Credit Facility	A1 Term Note	Total
		(in millions)	
Balance at January 1, 2010	$ 269.7	$ —	$ 269.7
Borrowings	54.9	348.8	403.7
Repayments	(324.6)	(6.1)	(330.7)
Balance at September 30, 2010	$ —	$342.7	$ 342.7

The following table presents in millions, the scheduled maturities of the A1 Term Note based upon the $342.7 million outstanding at September 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	285.7
Total	$342.7

Our General Partner also made equity contributions totaling $96.6 million and $203.0 million to the OLP during the nine month periods ended September 30, 2010 and 2009, respectively, to fund its equity portion of the construction costs associated with the Alberta Clipper Project.

We allocated earnings derived from operating the Alberta Clipper Project in the amounts of $20.1 million and $45.3 million to our General Partner for its 66.67 percent share of the earnings of the Alberta Clipper Project for the three and nine month periods ended September 30, 2010, respectively, and $2.3 million for both the three and nine month periods ended September 30, 2009. We have presented the amounts we allocated to our General Partner for its share of the earnings of the Alberta Clipper Project in "Net income attributable to noncontrolling interest" on our consolidated statements of income.

Distribution to Series AC Interests

The board of directors of Enbridge Management, acting on behalf of Enbridge Pipelines (Lakehead) L.L.C., the managing general partner of the OLP and the Series AC, declared a distribution payable to the holders of the Series AC general and limited partner interests on July 23, 2010. The distribution was paid on August 13, 2010 by the OLP to our General Partner and its affiliate representing the noncontrolling interest in the Series AC, and to us in the amounts of $17.2 million and $8.6 million, respectively.

11. COMMITMENTS AND CONTINGENCIES

Environmental Liabilities

We are subject to federal and state laws and regulations relating to the protection of the environment. Environmental risk is inherent to liquid hydrocarbon and natural gas pipeline operations, and we could, at times, be subject to environmental cleanup and enforcement actions. We manage this environmental risk through appropriate environmental policies and practices to minimize any impact our operations may have on the environment. To the extent that we are unable to recover environmental liabilities through insurance or other potentially responsible parties, we will be responsible for payment of liabilities arising from environmental incidents associated with the operating activities of our crude oil and natural gas businesses. Our General Partner has agreed to indemnify us from and against any costs relating to environmental liabilities associated with the Lakehead system assets prior to the transfer of these assets to us in 1991. This excludes any liabilities resulting from a change in laws after such transfer. We continue to voluntarily investigate past leak sites on our systems for the purpose of assessing whether any remediation is required in light of current regulations.

Lakehead Lines 6A & 6B Leaks

Line 6B Leak

On July 26, 2010, a release of crude oil on Line 6B of our Lakehead system was reported near Marshall, Michigan. We initially estimated 19,500 barrels of crude oil were leaked at the site, a portion of which reached the Talmadge Creek, a waterway that feeds the Kalamazoo River. We shut down our pipelines in the vicinity, notified the appropriate federal, state and local officials, and dispatched emergency response crews to oversee the containment of the released crude oil and cleanup of the affected areas. The released crude oil affected approximately 38 miles of area along the Talmadge Creek and Kalamazoo River waterways, including residential areas, businesses, farmland and marshland between Marshall and downstream of Battle Creek, Michigan. In response to the leak, a unified command structure was established under the jurisdiction of the Environmental Protection Agency, or EPA, the Michigan Department of Natural Resources and Environment, or MDNRE, and other federal, state and local agencies. The cause of the release remains the subject of an investigation by the National Transportation Safety Board, or NTSB, and other federal and state regulatory agencies.

Pursuant to an administrative order issued by the EPA under the Clean Water Act, we were directed to clean up the released crude oil and remediate and restore the affected areas, a process we had begun upon discovering the release. In connection with this incident, we estimate that, before insurance recoveries, we will incur aggregate costs of approximately $430 million, excluding fines and penalties, and approximately $13 million of lost revenue. These costs include the emergency response, environmental remediation and cleanup activities associated with the crude oil release and related pipeline inspection costs. The foregoing estimate is based on currently available information and will be updated as considered necessary to incorporate material new information as it becomes available. The actual costs we incur may differ from the foregoing estimate due to variations in any or all of the categories described above including modified or revised requirements from regulatory agencies. We expect to pay approximately 90 percent of the estimated costs by the end of 2011.

For purposes of estimating our expected losses associated with the Line 6B leak, those costs that we considered probable and could be reasonably estimated at September 30, 2010 were included. Our estimates do not include amounts we have capitalized or any unasserted claims associated with the leak that may later become evident.

The following table includes the material components underlying our estimated loss for the cleanup, remediation and restoration associated with the Line 6B leak:

	(in millions)
Equipment and other resources	$111
Field response personnel	154
Professional, regulatory and other	165
Total	$430

We anticipate the majority of the effort to clean up, remediate and restore the areas affected by the Line 6B leak will be completed by the end of 2010. We expect to make payments for additional costs associated with remediation and restoration of the area, air and groundwater monitoring, along with other legal, professional and regulatory costs through future periods. All the initiatives we will undertake in the monitoring and restoration phase are intended to restore the incident area as closely as possible to its pre-spill condition. Where applicable, the assumptions includes estimates of the expected number of days the associated services will be required and rates that we have obtained from contracts negotiated for the respective service and equipment providers. As invoices are received for the actual personnel, equipment and services, our estimates will be further refined. Our estimates also consider currently available facts, existing technology and presently enacted laws and regulations. These amounts also consider our and other companies' prior experience remediating contaminated sites and data released by government organizations. Despite the efforts we have made to ensure the reasonableness of our estimates, changes to the recorded amounts associated with this leak are reasonably possible over the next twelve months as more reliable information becomes available.

We believe we have met the September 27, 2010 deadline established by the EPA for remediating all areas along the Talmadge Creek, Kalamazoo River and Morrow Lake, including the shoreline that was affected by the leak. We have the potential of incurring additional costs in connection with this incident, including fines and penalties as well as expenditures associated with litigation. This includes the EPA's requirement that submerged crude oil be removed from affected waterways by October 31, 2010. A number of governmental agencies and regulators have initiated investigations into the Line 6B incident. Eight actions or claims have been filed against us and our affiliates, in state and federal courts in connection with this incident. Additionally, a number of government agencies have initiated investigations into the Line 6B incident however no penalties or fines have been assessed against us. We are evaluating all claims and intend to defend ourselves against any lawsuits.

The removal and replacement of the Line 6B pipeline segment was completed under the supervision of the United States Department of Transportation's Pipeline and Hazardous Materials Safety Administration, or PHMSA, which required us to perform specific tasks to ensure the safety of the pipeline before returning it to service. The excavation and replacement of the pipeline segment in the vicinity of the leak site was completed and regulatory approval of our pipeline restart plan was obtained from PHMSA. On September 27, 2010 the pipeline was safely brought back into service.

Line 6A Leak

A release of crude oil from Line 6A of our Lakehead system was reported in an industrial area of Romeoville, Illinois on September 9, 2010. We immediately shut down the pipeline in the vicinity and dispatched emergency response crews to oversee containment, cleanup and the replacement of the pipeline segment. We estimate approximately 9,000 barrels of crude oil was released. Some of the released crude oil went onto a roadway, into a storm sewer, waste water treatment facility and then into a nearby retention pond. All but a small amount of the crude oil has been recovered. We completed excavation and replacement of the pipeline segment and returned it to service on September 17, 2010. The cause of the crude oil release remains subject to investigation by federal and state environmental and pipeline safety regulators.

In connection with this incident, we estimate that before insurance recoveries we will incur aggregate costs of approximately $45 million, excluding fines and penalties, and approximately $3 million of lost revenues. These costs include the emergency response, environmental remediation and cleanup activities associated with the crude oil release and related pipeline inspection costs. The foregoing estimate is based on currently available information and will be updated as considered necessary to incorporate material new information as it becomes available. The actual costs we incur may differ from the foregoing estimate due to variations in any or all of the categories described above including modified or revised requirements from regulatory agencies. We expect to pay approximately 90 percent of the estimated costs by the end of 2011.

We included those costs we considered probable and that we could reasonably estimate for purposes of determining our expected losses associated with the Line 6A leak. Our estimates do not include consideration for any unasserted claims associated with the leak that may later become evident, nor have we considered any potential recoveries from third-parties that may later be determined to have contributed to the leak. The following table includes the material components underlying our estimated loss for the cleanup, remediation and restoration associated with the Line 6A leak:

	(in millions)
Equipment and other resources	$10
Field response personnel	12
Professional, regulatory and other	23
Total	$45

The cleanup, remediation and restoration for the Line 6A leak is expected to be substantially completed before year-end, representing three-quarters of our total expected costs. We expect to make payments for additional costs associated with the leak for air and groundwater monitoring, along with other professional and legal fees into future periods. Where applicable, the assumptions includes estimates of the expected number of days the associated services will be required and rates that we have obtained from contracts negotiated for the respective services and equipment. As invoices are received for the actual personnel, equipment and services, our estimates will be further refined. Our estimates also consider currently available facts, existing technology and presently enacted laws and regulations. These amounts also consider our and other companies' prior experience remediating contaminated sites and data released by government organizations. Despite the efforts we have made to ensure the reasonableness of our estimates, changes to the recorded amounts associated with this leak are reasonably possible over the next twelve months as more reliable information becomes available.

We have the potential of incurring additional costs in connection with this incident, including fines and penalties as well as expenditures associated with litigation. A number of governmental agencies and regulators have initiated investigations into the Line 6A incident. One action or claim has been filed against us and our affiliates, in state and federal courts in connection with this incident.

Lines 6A & 6B Fines and Penalties

Our estimated environmental costs for both the Line 6A and Line 6B leaks do not include an estimate for fines and penalties at September 30, 2010, which may be imposed by the EPA and PHMSA in addition to other state and local governmental agencies. Several factors remain outstanding at the end of the period that we consider critical in estimating the amount of fines and penalties that we may be assessed.

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

Insurance Recoveries

We maintain commercial liability insurance coverage for costs associated with environmental incidents such as those we have incurred for the leaks from Lines 6A and 6B, excluding costs for fines and penalties. We maintain limits that we consider sufficient to fund the resulting insured costs and liabilities, subject to a deductible of approximately $5 million per incident. We do not maintain insurance coverage for interruption of our operations except for water crossings, and therefore, we will not recover the approximately $16 million of revenues lost while Lines 6A and 6B were not in service. Apart from the amounts for which we are not insured, we anticipate that substantially all of the costs we have incurred from the leaks will ultimately be recoverable under our existing insurance policies. We expect to record a receivable for any amounts we claim for recovery pursuant to our insurance policies during the period realization of the claim for recovery is deemed probable.

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 the NTSB which is leading the federal and state environmental and pipeline safety regulators' investigation into 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. The total costs related to the Line 2B leak were $4.0 million of which we have paid $3.3 million as of September 30, 2010. On our consolidated statement of financial position as of September 30, 2010, we had $0.7 million accrued for additional cleanup and repair costs associated with the incident.

PHMSA Fine on Line 3

In September of 2010, we paid a $2.4 million fine issued by PHMSA related to the unexpected release and fire on Line 3 of our Lakehead system that occurred in November 2007 during planned maintenance near our Clearbrook, Minnesota terminal.

Pipeline Integrity Commitment

In connection with the restart of Line 6B of our Lakehead system with PHMSA, we committed to accelerate a process we had initiated prior to the leak to perform additional inspections, testing and refurbishment of Line 6B within and beyond the immediate area of the July 26, 2010 incident. Pursuant to this agreement, we will remediate ahead of our original schedule those pipeline anomalies identified by us between the years 2007 and 2009 that were scheduled for refurbishment including anomalies identified for action in a July 2010 PHMSA notification. We have agreed to complete all required work within 180 days of the September 27, 2010 restart of Line 6B. In addition to the required integrity measures, we also agreed to replace a 3,600 foot section of the Line 6B pipeline that lies underneath the St. Clair River in Michigan within one year of the restart of Line 6B, subject to obtaining required permits. The total cost associated with these integrity measures and pipeline replacement is estimated to approximate $110 million. Additional significant integrity expenditures may be required after this initial remediation program. The total cost of these integrity measures is separate from the environmental liabilities discussed above. The pipeline integrity and replacement costs will be capitalized or expensed in accordance with our capitalization policies as these costs are incurred, the majority of which are expected to be capital in nature. Costs we incur for in-line inspection, crack detection, tool runs and hydrostatic testing to verify the integrity of the pipeline will be expensed as incurred. We are currently discussing with our customers recovery of these costs through the tolls on our Lakehead system.

Legal and Regulatory Proceedings

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

A number of governmental agencies and regulators have initiated investigations into the Line 6A and Line 6B incidents. Eight actions or claims have been filed against us and our affiliates, in state and federal courts in connection with the Line 6B incident, including direct actions, actions seeking class status, and actions seeking derivative status. With respect to the Line 6B incident, no penalties or fines have been assessed against us to-date. Governmental agencies and regulators have also initiated investigations into the Line 6A incident. One action or claim has been filed against us and our affiliates, in state court in connection with this incident, and we believe this action or claim has been resolved pursuant to an agreed interim order. We have accrued a provision for future legal costs associated with the Line 6A and Line 6B incidents as described above in the section titled ***Lakehead Lines 6A & 6B Leaks*** of this footnote.

12. 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 2015 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-qualifying. These non-qualifying derivative financial instruments are marked-to-market each period with the change in fair value, representing unrealized gains and losses, included in "Cost of natural gas," "Operating revenue" or "Interest expense" in our consolidated statements of income. These mark-to-market adjustments produce a degree of earnings volatility that can often be significant from period to period, but have no cash flow impact relative to changes in market prices. The cash flow impact occurs when the underlying physical transaction takes place in the future and the associated financial instrument contract settlement is made.

The following transaction types do not qualify for hedge accounting and contribute to the volatility of our income and cash flows:

Commodity Price Exposures:

- **Transportation**—In our Marketing segment, when we transport natural gas from one location to another, the pricing index used for natural gas sales is usually different from the pricing index used for natural gas purchases, which exposes us to market price risk relative to changes in those two indices. By entering into a basis swap, where we exchange one pricing index for another, we can effectively lock in the margin, representing the difference between the sales price and the purchase price, on the combined natural gas purchase and natural gas sale, removing any market price risk on the physical transactions. Although this represents a sound economic hedging strategy, the derivative financial instruments (i.e., the basis swaps) we use to manage the commodity price risk associated with these transportation contracts do not qualify for hedge accounting, since only the future margin has been fixed and not the future cash flow. As a result, the changes in fair value of these derivative financial instruments are recorded in earnings.

- **Storage—**In our Marketing segment, we use derivative financial instruments (i.e., natural gas swaps) to hedge the relative difference between the injection price paid to purchase and store natural gas and the withdrawal price at which the natural gas is sold from storage. The intent of these derivative financial instruments is to lock in the margin, representing the difference between the price paid for the natural gas injected and the price received upon withdrawal of the natural gas from storage in a future period. We do not pursue cash flow hedge accounting treatment for these storage transactions since the underlying forecasted injection or withdrawal of natural gas may not occur in the period as originally forecast. This can occur because we have the flexibility to make changes in the underlying injection or withdrawal schedule, based on changes in market conditions. In addition, since the physical natural gas is recorded at the lower of cost or market, timing differences can result when the derivative financial instrument is settled in a period that is different from the period the physical natural gas is sold from storage. As a result, derivative financial instruments associated with our natural gas storage activities can create volatility in our earnings.
- **Natural Gas Collars—**In our Natural Gas segment, we previously entered into natural gas collars to hedge the sales price of natural gas. The natural gas collars were based on a New York Mercantile Exchange, or NYMEX, pricing index, while the physical gas sales were based on a different index. To better align the index of the natural gas collars with the index of the underlying sales, we de-designated the original cash flow hedging relationship with the intent of contemporaneously re-designating the natural gas collars as hedges of forecasted physical natural gas sales with a NYMEX pricing index. However, because the fair value of these derivative instruments was a liability to us at re-designation, they are considered net written options and, pursuant to the authoritative accounting guidance, do not qualify for hedge accounting. These derivatives are being marked-to-market, with the changes in fair value from the date of de-designation recorded to earnings each period. As a result, our operating income is subject to greater volatility due to movements in the prices of natural gas until the underlying long-term transactions are settled.
- **Optional Natural Gas Processing Volumes—**In our Natural Gas segment, we use derivative financial instruments to hedge the volumes of NGLs produced from our natural gas processing facilities. Some of our natural gas contracts allow us the choice of processing natural gas when it is economical and to cease doing so when processing becomes uneconomic. We have entered into derivative financial instruments to fix the sales price of a portion of the NGLs that we produce at our discretion and to fix the associated purchase price of natural gas required for processing. We typically designate derivative financial instruments associated with NGLs we produce per contractual processing requirements as cash flow hedges when the processing of natural gas is probable of occurrence. However, we are precluded from designating the derivative financial instruments as qualifying hedges of the respective commodity price risk when the discretionary processing volumes are subject to change. As a result, our operating income is subject to increased volatility due to fluctuations in NGL prices until the underlying transactions are settled or offset.
- **NGL Forward Contracts—**In our Natural Gas segment, we use forward contracts to fix the price of NGLs we purchase and store in inventory and to fix the price of NGLs that we sell from inventory to meet the demands of our customers that sell and purchase NGLs. Prior to April 1, 2009, these forward contracts were not treated as derivative financial instruments pursuant to the normal purchase normal sale, or NPNS, exception allowed under authoritative accounting guidance, since the forward contracts resulted in physical receipt or delivery of NGLs. However, evolving markets for NGLs have increased opportunities for a portion of our forward contracts to be settled net rather than physically receiving or delivering the NGLs. Accordingly, we have revoked the NPNS election on certain forward contracts associated with the liquids marketing operations of Dufour Petroleum, L.P., our wholly-owned subsidiary, executed after April 1, 2009. The forward contracts for which we have revoked the NPNS election do not qualify for hedge accounting and are being marked-to-market each period with the changes in fair value recorded in earnings. As a result, our operating income is subject to additional volatility associated with fluctuations in NGL prices until the forward contracts are settled.

- **Natural Gas Forward Contracts**—In our Marketing segment, we use forward contracts to sell natural gas to our customers. Historically, we have not considered these contracts to be derivatives under the NPNS exception allowed by authoritative accounting guidance. 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 September 30,		For the nine month period ended September 30,	
	2010	2009	2010	2009
	(in millions)			
Liquids segment				
Non-qualified hedges	$ (0.3)	$ —	$ 0.1	$ —
Natural Gas segment				
Hedge ineffectiveness	3.1	(0.1)	4.5	(0.7)
Non-qualified hedges	(18.9)	(0.2)	10.0	(12.6)
Marketing				
Non-qualified hedges	1.3	9.0	(3.0)	19.6
Commodity derivative fair value gains (losses)	(14.8)	8.7	11.6	6.3
Corporate				
Non-qualified interest rate hedges	(0.4)	(1.4)	(0.9)	1.0
Derivative fair value gains (losses)	$(15.2)	$ 7.3	$10.7	$ 7.3

Derivative Positions

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

	September 30, 2010	December 31, 2009
	(in millions)	
Other current assets	$ 14.6	$ 14.8
Other assets, net	14.5	43.7
Accounts payable and other	(39.8)	(59.2)
Other long-term liabilities	(131.6)	(50.5)
	$(142.3)	$(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 $0.7 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 $27.3 million, representing unrealized net losses from our cash flow hedging activities based on pricing and positions at September 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 2020 Notes, we paid $13.2 million to settle treasury locks we entered into to hedge the interest payments on a portion of these obligations through the 2020 maturity date of the 2020 Notes. We received $10.2 million to settle treasury locks associated with our September 2010 issuance and sale of our 2040 Notes that were entered into to hedge the interest payments on a portion of the obligations through the 2040 maturity date of the 2040 Notes. Both the $13.2 million and $10.2 million settlement amounts are being amortized from AOCI to "Interest expense" over the 10- and 30-year terms, respectively, of the 2020 and 2040 Notes.

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

	September 30, 2010	December 31, 2009
	(in millions)	
Counterparty Credit Quality*		
AAA	$ —	$ —
AA	(68.6)	14.2
A	(83.7)	(63.1)
Lower than A	5.7	(3.2)
	(146.6)	(52.1)
Credit valuation adjustment	4.3	0.9
Total	$(142.3)	$(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 September 30, 2010, we were in an overall net liability position of $142.3 million, which included assets of $29.1 million. Based on our forward positions at September 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 $118.7 million in the form of either cash collateral or letters of credit to satisfy the requirements of our ISDA® agreements.

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

	September 30, 2010	December 31, 2009
	(in millions)	
U.S. financial institutions and investment banking entities	$ (59.3)	$(18.8)
Non-U.S. financial institutions	(86.6)	(30.2)
Small non-integrated energy companies	1.3	(3.4)
Integrated oil companies	2.3	1.2
	$(142.3)	$(51.2)

We are holding no cash collateral on our asset exposures, and we have provided letters of credit totaling $52.7 million and $13.1 million relating to our liability exposures pursuant to the margin thresholds in effect at September 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	September 30, 2010	December 31, 2009	Financial Position Location	September 30, 2010	December 31, 2009
	(in millions)					
Derivatives designated as hedging instruments						
Interest rate contracts	Other current assets	$ —	$ —	Accounts payable and other	$ (17.0)	$ (7.0)
Interest rate contracts	Other assets, net	1.8	38.7	Other long-term liabilities	(122.5)	(18.9)
Commodity contracts	Other current assets	13.2	15.7	Accounts payable and other	(23.1)	(47.3)
Commodity contracts	Other assets, net	23.1	17.8	Other long-term liabilities	(24.5)	(50.9)
		38.1	72.2		(187.1)	(124.1)
Derivatives not designated as hedging instruments						
Interest rate contracts	Other current assets	3.7	5.8	Accounts payable and other	(3.4)	(4.8)
Interest rate contracts	Other assets, net	9.8	5.6	Other long-term liabilities	(8.8)	(4.4)
Commodity contracts	Other current assets	29.3	22.0	Accounts payable and other	(27.8)	(28.8)
Commodity contracts	Other assets, net	10.3	12.1	Other long-term liabilities	(6.4)	(6.8)
		53.1	45.5		(46.4)	(44.8)
Total derivative instruments		$91.2	$117.7		$(233.5)	$(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 September 30, 2010					
Interest rate contracts . . .	$ (50.4)	Interest expense	$ (1.9)	Interest expense	$ 0.2
Commodity contracts . . .	—	Operating revenue	—	Operating revenue	—
Commodity contracts . . .	(13.9)	Cost of natural gas	(1.7)	Cost of natural gas	3.1
Total	$ (64.3)		$ (3.6)		$ 3.3
For the three month period ended September 30, 2009					
Interest rate contracts . . .	$ (32.7)	Interest expense	$ (0.7)	Interest expense	$ —
Commodity contracts . . .	(5.9)	Cost of natural gas	11.7	Cost of natural gas	(0.1)
Total	$ (38.6)		$ 11.0		$(0.1)
For the nine month period ended September 30, 2010					
Interest rate contracts . . .	$(150.5)	Interest expense	$ (5.3)	Interest expense	$ 0.2
Commodity contracts . . .	—	Operating revenue	—	Operating revenue	—
Commodity contracts . . .	53.3	Cost of natural gas	(17.2)	Cost of natural gas	4.5
Total	$ (97.2)		$(22.5)		$ 4.7
For the nine month period ended September 30, 2009					
Interest rate contracts . . .	$ (46.9)	Interest expense	$ (1.6)	Interest expense	$ —
Commodity contracts . . .	(68.5)	Cost of natural gas	31.5	Cost of natural gas	(0.7)
Total	$(115.4)		$ 29.9		$(0.7)

(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 September 30, 2010	For the three month period ended September 30, 2009	For the nine month period ended September 30, 2010	For the nine month period ended September 30, 2009
		Amount of Gain or (Loss) Recognized in Earnings[1] (in millions)		Amount of Gain or (Loss) Recognized in Earnings[1] (in millions)	
Interest rate contracts . .	Interest expense	$ (0.4)	$(1.4)	$(0.9)	$1.0
Commodity contracts . .	Operating revenue	(0.3)	—	0.1	—
Commodity contracts . .	Cost of natural gas	(17.6)	8.8	7.0	7.0
Total		$(18.3)	$ 7.4	$ 6.2	$8.0

(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

	September 30, 2010 Assets	September 30, 2010 Liabilities	September 30, 2010 Total	December 31, 2009 Assets	December 31, 2009 Liabilities	December 31, 2009 Total
			(in millions)			
Fair value of derivatives—gross presentation	$ 91.2	$(233.5)	$(142.3)	$117.7	$(168.9)	$(51.2)
Effects of netting agreements	(62.1)	62.1	—	(59.2)	59.2	—
Fair value of derivatives—net presentation	$ 29.1	$(171.4)	$(142.3)	$ 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 September 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.

	September 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	$—	$(136.3)	$ —	$(136.3)	$—	$ 14.5	$ —	$ 14.5
Commodity contracts—financial	—	(28.0)	7.0	(21.0)	—	(63.2)	(7.5)	(70.7)
Commodity contracts—physical	—	—	3.5	3.5	—	—	(3.5)	(3.5)
Commodity options	—	(0.2)	11.7	11.5	—	(1.3)	9.3	8.0
Interest rate options	—	—	—	—	—	0.5	—	0.5
Total	$—	$(164.5)	$22.2	$(142.3)	$—	$(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 September 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)	2.5	11.1	(0.6)	13.0
Included in other comprehensive income	9.3	—	5.4	14.7
Purchases, issuances, sales and settlements				
Purchases	—	—	—	—
Settlements[(2)]	2.8	(4.2)	(2.4)	(3.8)
Ending balance as of September 30	$ 7.1	$ 3.4	$11.7	$22.2
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	$ 3.8	$ 3.5	$ 4.8	$12.1
Amounts reported in operating revenue	$ —	$ —	$ —	$ —

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

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

Fair Value Measurements of Commodity Derivatives

The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity based swaps and physical contracts at September 30, 2010 and December 31, 2009.

	At September 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	2,161,079	$ 3.77	$ 5.27	$ —	$ (3.3)	$ 1.6	$ (3.1)
	NGL	367,000	85.01	78.24	2.5	—	3.4	—
	Crude Oil	730,000	81.30	77.03	3.2	(0.1)	—	—
Receive fixed/pay variable	Natural Gas	3,212,347	4.41	3.87	2.3	(0.6)	2.9	(16.0)
	NGL	1,627,808	52.24	57.04	3.1	(10.9)	9.7	(39.4)
	Crude Oil	1,037,944	76.70	80.70	1.1	(5.2)	3.1	(10.6)
Receive variable/pay variable	Natural Gas	30,123,758	3.74	3.66	3.5	(1.0)	13.0	(3.5)
Physical Contracts								
Receive fixed/pay variable	NGL	1,179,811	55.29	59.06	0.1	(4.6)	—	(4.0)
	Crude Oil	513,950	75.95	80.90	0.1	(2.6)	—	(1.6)
Receive variable/pay fixed	NGL	429,286	55.84	51.30	2.0	—	0.3	—
	Crude Oil	414,950	80.72	74.89	2.4	—	1.8	—
Receive variable/pay variable	Crude Oil	35,719	75.37	73.96	0.1	—	0.1	(0.1)
	NGL	2,251,560	68.58	67.45	3.2	(0.7)	—	—
	Natural Gas	10,643,789	3.68	3.65	0.3	—	—	—
Portion of contracts maturing in 2011								
Swaps								
Receive variable/pay fixed	Natural Gas	1,166,445	$ 4.28	$ 8.60	$ —	$ (5.0)	$ —	$ (3.1)
	NGL	205,000	81.29	61.20	4.1	—	3.2	—
Receive fixed/pay variable	Natural Gas	9,377,229	4.07	4.38	2.9	(5.8)	—	(19.3)
	NGL	4,318,510	46.47	47.31	7.8	(11.4)	6.1	(7.0)
	Crude Oil	1,207,335	76.03	84.47	0.1	(10.3)	—	(10.0)
Receive variable/pay variable	Natural Gas	34,547,885	4.24	4.14	3.8	(0.3)	2.9	(0.1)
Physical Contracts								
Receive variable/pay fixed	NGL	80,000	58.48	53.66	0.4	—	—	—
Receive variable/pay variable	Natural Gas	25,566,657	4.17	4.13	1.0	—	—	—
	NGL	1,666,095	59.64	58.33	2.5	(0.3)	—	—
Receive fixed/pay variable	NGL	240,000	56.73	62.51	—	(1.4)	—	—
	Crude Oil	25,000	78.01	82.70	—	(0.1)	—	—
Portion of contracts maturing in 2012								
Swaps								
Receive variable/pay fixed	Natural Gas	827,195	$ 4.93	$ 9.58	$ —	$ (3.8)	$ —	$ (2.6)
Receive fixed/pay variable	Natural Gas	2,327,500	4.90	5.04	1.7	(2.1)	0.3	(4.2)
	NGL	1,315,770	59.82	53.70	10.5	(2.5)	7.1	(0.9)
	Crude Oil	733,830	79.70	87.30	—	(5.5)	—	(5.3)
Receive variable/pay variable	Natural Gas	17,869,000	4.98	4.95	0.6	—	0.6	—
Physical Contracts								
Receive variable/pay variable	Natural Gas	14,963,301	5.00	4.96	0.5	—	—	—
	NGL	391,429	39.44	38.19	0.5	—	—	—
Portion of contracts maturing in 2013								
Swaps								
Receive variable/pay fixed	Natural Gas	58,765	$ 5.15	$ 5.38	$ —	$ —	$ —	$ —
Receive fixed/pay variable	Natural Gas	730,000	9.83	5.06	3.4	—	2.3	—
	NGL	541,660	63.89	65.26	0.6	(1.3)	—	(1.0)
	Crude Oil	750,805	86.32	88.32	2.6	(4.1)	2.3	(3.6)
Receive variable/pay variable	Natural Gas	16,740,000	5.20	5.21	—	(0.1)	—	—
Physical Contracts								
Receive variable/pay variable	Natural Gas	6,612,450	5.26	5.23	0.2	—	—	—
Portion of contracts maturing in 2014								
Swaps								
Receive fixed/pay variable	Crude Oil	618,675	$87.82	$89.16	$ 0.2	$ (1.0)	$ —	$ (0.4)
	NGL	171,550	75.42	78.39	—	(0.5)	—	—
Receive variable/pay fixed	Natural Gas	14,490	5.52	5.38	—	—	—	—
Receive variable/pay variable	Natural Gas	3,600,000	5.60	5.62	—	(0.1)	—	—
Portion of contracts maturing in 2015								
Swaps								
Receive fixed/pay variable	Crude Oil	177,025	$89.06	$90.33	$ —	$ (0.2)	$ —	$ —

(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 September 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 \$0.1 million of gains and \$1.0 million of gains at September 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 September 30, 2010 and December 31, 2009.

	At September 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]	92,000	\$ 4.31	\$ 3.95	\$ —	\$ —	\$ —	\$(0.6)
Puts (purchased)	Natural Gas[4]	92,000	3.40	3.95	—	—	—	—
	NGL	263,396	46.84	54.27	1.0	—	3.2	—
	Crude Oil	75,348	70.87	81.41	—	—	0.6	—
Portion of option contracts maturing in 2011								
Calls (written)	Natural Gas[4]	365,000	\$ 4.31	\$ 4.44	\$ —	\$(0.2)	\$ —	\$(0.8)
Puts (purchased)	Natural Gas[4]	365,000	3.40	4.44	—	—	—	—
	NGL	364,270	47.18	43.48	4.4	—	2.4	—
	Crude Oil	43,800	86.87	84.83	0.1	—	—	—
Portion of option contracts maturing in 2012								
Puts (purchased)	NGL	284,382	\$65.90	\$57.98	\$6.4	\$ —	\$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 September 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 September 30, 2010 and December 31, 2009, respectively.

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

Fair Value Measurements of Interest Rate Derivatives

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

				Fair Value[3] at	
Date of Maturity & Contract Type	Accounting Treatment	Notional	Average Fixed Rate[1]	September 30, 2010	December 31, 2009
		(dollars in millions)			
Contracts maturing in 2010					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	\$250	1.68%	\$ (0.7)	\$ (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%	\$(56.4)	\$(16.9)
Interest Rate Swaps—Pay Fixed	Non-qualifying	125	4.35%	(12.5)	(9.2)
Interest Rate Swaps—Pay Float	Non-qualifying	125	4.75%	13.8	11.0
Contracts maturing in 2015					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	\$300	2.43%	\$ (0.4)	\$ —
Contracts settling prior to maturity					
2010—Pre-issuance Hedges[2]	Cash Flow Hedge	\$220	4.62%	\$ —	\$ (6.8)
2011—Pre-issuance Hedges	Cash Flow Hedge	300	2.92%	1.9	—
2012—Pre-issuance Hedges	Cash Flow Hedge	600	4.57%	(61.9)	24.9
2013—Pre-issuance Hedges	Cash Flow Hedge	300	4.62%	(24.7)	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 2020 Notes issuance in March 2010 and our 2040 Notes issuance in September 2010.

(3) The fair value is determined from quoted market prices at September 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 $4.5 million of gains at September 30, 2010, with no such amounts at December 31, 2009.

13. SEGMENT INFORMATION

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

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

- Liquids;
- Natural Gas; and
- Marketing.

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

	For the three month period ended September 30, 2010				
	Liquids	Natural Gas	Marketing	Corporate[1]	Total
			(in millions)		
Total revenue	$ 301.4	$1,385.6	$599.7	$ —	$2,286.7
Less: Intersegment revenue	0.3	388.7	8.4	—	397.4
Operating revenue	301.1	996.9	591.3	—	1,889.3
Cost of natural gas	—	869.1	586.5	—	1,455.6
Environmental costs	477.6	—	—	—	477.6
Operating and administrative	59.4	78.3	2.3	2.1	142.1
Power	36.7	—	—	—	36.7
Depreciation and amortization	48.0	31.6	0.1	—	79.7
Impairment charge	10.3	—	—	—	10.3
Operating income (loss)	(330.9)	17.9	2.4	(2.1)	(312.7)
Interest expense	—	—	—	70.1	70.1
Other expense	—	—	—	0.6	0.6
Income (loss) from continuing operations before income tax expense	(330.9)	17.9	2.4	(72.8)	(383.4)
Income tax expense	—	—	—	2.9	2.9
Net income (loss)	(330.9)	17.9	2.4	(75.7)	(386.3)
Less: Net income attributable to the noncontrolling interest	—	—	—	20.1	20.1
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$(330.9)	$ 17.9	$ 2.4	$(95.8)	$ (406.4)

(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 September 30, 2009				
	Liquids	Natural Gas	Marketing	Corporate[(1)]	Total
			(in millions)		
Total revenue	$262.1	$939.8	$466.3	$ —	$1,668.2
Less: Intersegment revenue	—	301.4	3.1	—	304.5
Operating revenue	262.1	638.4	463.2	—	1,363.7
Cost of natural gas	—	491.4	451.8	—	943.2
Operating and administrative	61.2	69.7	1.8	0.9	133.6
Power	33.7	—	—	—	33.7
Depreciation and amortization	34.5	30.3	0.4	—	65.2
Operating income	132.7	47.0	9.2	(0.9)	188.0
Interest expense	—	—	—	60.7	60.7
Other income	—	—	—	2.8	2.8
Income from continuing operations before income tax expense	132.7	47.0	9.2	(58.8)	130.1
Income tax expense	—	—	—	2.7	2.7
Income from continuing operations	132.7	47.0	9.2	(61.5)	127.4
Loss from discontinued operations	—	(67.9)	—	—	(67.9)
Net income (loss)	132.7	(20.9)	9.2	(61.5)	59.5
Less: Net income attributable to the noncontrolling interest	—	—	—	2.3	2.3
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$132.7	$ (20.9)	$ 9.2	$(63.8)	$ 57.2

(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 nine month period ended September 30, 2010				
	Liquids	Natural Gas	Marketing	Corporate[(1)]	Total
			(in millions)		
Total revenue	$ 883.6	$4,022.8	$1,842.5	$ —	$ 6,748.9
Less: Intersegment revenue	0.9	1,152.6	27.5	—	1,181.0
Operating revenue	882.7	2,870.2	1,815.0	—	5,567.9
Cost of natural gas	—	2,447.7	1,802.5	—	4,250.2
Environmental costs	482.1	—	—	—	482.1
Operating and administrative	183.8	215.8	7.0	3.3	409.9
Power	105.5	—	—	—	105.5
Depreciation and amortization	131.7	93.3	0.2	—	225.2
Impairment charge	10.3	—	—	—	10.3
Operating income (loss)	(30.7)	113.4	5.3	(3.3)	84.7
Interest expense	—	—	—	199.0	199.0
Other income	—	—	—	16.1	16.1
Income (loss) from continuing operations before income tax expense	(30.7)	113.4	5.3	(186.2)	(98.2)
Income tax expense	—	—	—	7.5	7.5
Net income (loss)	(30.7)	113.4	5.3	(193.7)	(105.7)
Less: Net income attributable to the noncontrolling interest	—	—	—	45.3	45.3
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ (30.7)	$ 113.4	$ 5.3	$(239.0)	$ (151.0)
Total assets	$5,399.9	$4,308.3	$ 205.0	$ 249.0	$10,162.2
Capital expenditures (excluding acquisitions)	$ 317.2	$ 206.2	$ —	$ 5.7	$ 529.1

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

	As of and for the nine month period ended September 30, 2009				
	Liquids	Natural Gas	Marketing	Corporate[1]	Total
			(in millions)		
Total revenue	$ 710.2	$2,793.5	$1,619.5	$ —	$5,123.2
Less: Intersegment revenue	0.3	1,000.2	18.5	—	1,019.0
Operating revenue	709.9	1,793.3	1,601.0	—	4,104.2
Cost of natural gas	—	1,372.3	1,557.0	—	2,929.3
Environmental costs	0.9	1.1	—	—	2.0
Operating and administrative	173.9	214.8	5.3	3.0	397.0
Power	96.9	—	—	—	96.9
Depreciation and amortization	98.5	92.0	1.2	—	191.7
Operating income	339.7	113.1	37.5	(3.0)	487.3
Interest expense	—	—	—	169.9	169.9
Other income	—	—	—	2.5	2.5
Income from continuing operations before income tax expense	339.7	113.1	37.5	(170.4)	319.9
Income tax expense	—	—	—	6.8	6.8
Income from continuing operations	339.7	113.1	37.5	(177.2)	313.1
Loss from discontinued operations	—	(67.5)	—	—	(67.5)
Net income	339.7	45.6	37.5	(177.2)	245.6
Less: Net income attributable to the noncontrolling interest	—	—	—	2.3	2.3
Net income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 339.7	$ 45.6	$ 37.5	$(179.5)	$ 243.3
Total assets	$4,737.4	$3,478.3	$ 158.9	$ 280.0	$8,654.6
Capital expenditures (excluding acquisitions)	$ 695.6	$ 106.2	$ —	$ 11.5	$ 813.3

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

14. 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 $2.8 million through September 30, 2010. At September 30, 2010 and December 31, 2009, the regulatory receivable related to the differences in our transportation volumes was $7.0 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 September 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 nine month period ended September 30, 2010 related to AEDC. For the three month period ended September 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.

15. SUBSEQUENT EVENTS

Class A common unit issuances

We issued 144,615 Class A common units in October 2010 under the terms of the EDA at sales prices averaging $55.70 per unit, for proceeds of approximately $7.9 million, net of $0.2 million of commissions and issuance costs within the period of October 1 and October 5, 2010. In addition, our General Partner contributed approximately $0.2 million to us to maintain its two percent general partner interest.

Distribution to Partners

On October 27, 2010, the board of directors of Enbridge Management declared a distribution payable to our partners on November 12, 2010. The distribution will be paid to unitholders of record as of November 4, 2010, of our available cash of $143.0 million at September 30, 2010, or $1.0275 per limited partner unit. Of this distribution, $124.8 million will be paid in cash, $17.9 million will be distributed in i-units to our i-unitholder and $0.3 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 October 27, 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 $21.4 million to the noncontrolling interest in the Series AC, while $10.7 million will be paid to us.

16. SUPPLEMENTAL CASH FLOWS INFORMATION

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

	For the nine month period ended September 30,	
	2010	2009
	(in millions)	
Discount accretion	$ 0.3	$ 0.5
Amortization of debt issuance and hedging costs	15.7	8.8
Deferred income taxes	1.9	1.5
Allowance for equity used during construction	(14.3)	(2.4)
Allowance for doubtful accounts	(4.0)	1.0
Other	2.6	2.0
	$ 2.2	$11.4

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

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

In July 2010, the board of directors of Enbridge Energy Management, L.L.C. 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.

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 nine month periods ended September 30, 2010 and 2009. We have removed from "Income from continuing operations," for the three and nine month periods ended September 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 "Loss from discontinued operations."

	For the three month period ended September 30,		For the nine month period ended September 30,	
	2010	2009	2010	2009
	(unaudited; in millions)			
Operating Income (Loss)				
Liquids	$(330.9)	$132.7	$ (30.7)	$339.7
Natural Gas	17.9	47.0	113.4	113.1
Marketing	2.4	9.2	5.3	37.5
Corporate, operating and administrative	(2.1)	(0.9)	(3.3)	(3.0)
Total Operating Income (Loss)	(312.7)	188.0	84.7	487.3
Interest expense	70.1	60.7	199.0	169.9
Other income (expense)	(0.6)	2.8	16.1	2.5
Income tax expense	2.9	2.7	7.5	6.8
Income (loss) from continuing operations	(386.3)	127.4	(105.7)	313.1
Loss from discontinued operations	—	(67.9)	—	(67.5)
Net income (loss)	(386.3)	59.5	(105.7)	245.6
Less: Net income attributable to noncontrolling interest	20.1	2.3	45.3	2.3
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$(406.4)	$ 57.2	$(151.0)	$243.3

Contractual arrangements in our Liquids, Natural Gas and Marketing segments expose us to market risks associated with changes in commodity prices where we receive crude oil, natural gas or NGLs in return for the services we provide or where we purchase natural gas or NGLs. Our unhedged commodity position is fully exposed to fluctuations in commodity prices. These fluctuations can be significant if commodity prices experience significant volatility. We employ derivative financial instruments to hedge a portion of our commodity position and to reduce our exposure to fluctuations in crude oil, natural gas and NGL prices. Some of these derivative financial instruments do not qualify for hedge accounting under the provisions of authoritative accounting guidance, which can create volatility in our earnings that can be significant. However, these fluctuations in earnings do not affect our cash flow. Cash flow is only affected when we settle the derivative instrument.

Summary Analysis of Operating Results

Liquids

The operating losses of our Liquids segment for the three and nine month periods ended September 30, 2010 resulted from the overall impact of the crude oil releases on Lines 6A and 6B of our Lakehead system. In connection with these incidents, we estimate that, before insurance recoveries, the costs for the emergency response, environmental remediation and cleanup activities associated with the crude oil release, and related pipeline inspection costs were approximately $475 million, excluding fines and penalties, for the three and nine month periods ended September 30, 2010. In addition, during the period the pipelines were shut down for the replacement of the pipeline segments, our operating revenues were lower by approximately $16 million as a result of the volumes that we were unable to transport. We do not maintain insurance coverage for interruption of our operations, except for water crossing, and therefore we will not recover the revenues lost while Lines 6A and 6B were not in service. The operating losses that resulted from the incidents on Lines 6A and 6B were partially offset by transportation rate increases that went into effect in January and April 2010 and higher delivered volumes on our North Dakota system as a result of the completion of the North Dakota Phase VI expansion in the first quarter of 2010.

Natural Gas

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

- Unrealized, non-cash, mark-to-market net losses of $15.8 million associated with derivative financial instruments that do not qualify for hedge accounting treatment under authoritative accounting guidance compared with $0.3 million of net losses for the comparable period of 2009; and
- Increased operating and administrative costs due to the increased costs associated with work-force, maintenance activities, and our September 2010 natural gas acquisition.

For the nine month period ended September 30, 2010 we had non-cash, mark-to-market net gains of $14.5 million compared with $13.3 million of non-cash, mark-to-market net losses for the comparable period of 2009.

Marketing

Included in the operating results of our Marketing segment for the three and nine month periods ended September 30, 2010 were unrealized, non-cash, mark-to-market net gains of $1.3 million and net losses of $3.0 million, respectively, associated with derivative financial instruments that do not qualify for hedge accounting treatment under authoritative accounting guidance, as compared with $9.0 million and $19.6 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 nine month periods ended September 30, 2010 were relatively stable natural gas prices during these periods, which limited our opportunities to benefit from significant price differentials between market centers.

Derivative Transactions and Hedging Activities

We use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the risks associated with market fluctuations in commodity prices and interest rates and to reduce variability in our cash flows. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on commodity prices or interest rates. We record all derivative instruments in our consolidated financial statements at fair market value pursuant to the requirements of applicable authoritative accounting guidance. We record changes in the fair value of our derivative financial instruments that do not qualify for hedge accounting in our consolidated statements of income as follows:

- Natural Gas and Marketing 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 September 30,		For the nine month period ended September 30,	
	2010	2009	2010	2009
	(unaudited; in millions)			
Liquids segment				
Non-qualified hedges	$ (0.3)	$ —	$ 0.1	$ —
Natural Gas segment				
Hedge ineffectiveness	3.1	(0.1)	4.5	(0.7)
Non-qualified hedges	(18.9)	(0.2)	10.0	(12.6)
Marketing				
Non-qualified hedges	1.3	9.0	(3.0)	19.6
Commodity derivative fair value gains (losses)	(14.8)	8.7	11.6	6.3
Corporate				
Non-qualified interest rate hedges	(0.4)	(1.4)	(0.9)	1.0
Derivative fair value gains (losses)	$(15.2)	$ 7.3	$10.7	$ 7.3

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 September 30,		For the nine month period ended September 30,	
	2010	**2009**	**2010**	**2009**
	(unaudited; in millions)			
Operating Results				
Operating revenue	$ 301.1	$262.1	$882.7	$709.9
Environmental costs	477.6	—	482.1	0.9
Operating and administrative	59.4	61.2	183.8	173.9
Power	36.7	33.7	105.5	96.9
Depreciation and amortization	48.0	34.5	131.7	98.5
Impairment charge	10.3	—	10.3	—
Operating expenses	632.0	129.4	913.4	370.2
Operating Income (Loss)	$(330.9)	$132.7	$ (30.7)	$339.7
Operating Statistics				
Lakehead system:				
United States[(1)]	1,271	1,351	1,311	1,296
Province of Ontario[(1)]	326	350	343	346
Total Lakehead system deliveries[(1)]	1,597	1,701	1,654	1,642
Barrel miles (billions)	105	108	329	316
Average haul (miles)	713	688	729	706
Mid-Continent system deliveries[(1)]	215	241	208	239
North Dakota system:				
Trunkline, excluding gathering	158	101	158	102
Gathering	6	6	6	6
Total North Dakota system deliveries[(1)]	164	107	164	108
Total Liquids Segment Delivery Volumes[(1)]	1,976	2,049	2,026	1,989

(1) Average barrels per day in thousands.

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

Operating revenue of our Liquids segment increased for the three month period ended September 30, 2010 when compared to the same period in 2009 primarily due to the 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 $49.5 million of additional operating revenue for the three month period ended September 30, 2010 when compared to the same period in 2009. The changes to our transportation rates included the following:

- 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;

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

Further contributing to the overall increase in operating revenue on our Liquids segment was an increase in average delivery volumes on our North Dakota system that contributed an approximate $8.1 million of additional operating revenue for the three month period ended September 30, 2010 when compared to the same period in 2009. The average trunkline delivery volumes of our North Dakota system increased approximately 56 percent, to 158,000 Bpd for the three month period ended September 30, 2010 from 101,000 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 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.

Offsetting the improved operating revenue for our Liquids segment during the three month period ended September 30, 2010 is approximately $16 million of lost operating revenue associated with the temporary shutdowns of Lines 6A and 6B of our Lakehead system resulting from the crude oil releases from these pipelines. The average delivery volumes on our Lakehead system decreased approximately six percent, to 1.597 million Bpd for the three month period ended September 30, 2010 from 1.701 million Bpd during the same period in 2009. Prior to the occurrence of the leaks, Lines 6A and 6B were operating at approximately 450,000 Bpd and 190,000 Bpd, respectively. Lines 6A and 6B were temporally shut down for eight and 63 days, respectively, before they were returned to service. Excluding the impact of the leaks on our Lakehead system average delivery volumes would have been approximately 1.766 million Bpd for the three month period ended September 30, 2010. The lower volumes and related revenue associated with the leaks on Lines 6A and 6B were partially offset by greater use of other pipelines on the Lakehead system to facilitate the transportation and delivery of crude oil from the oil sands.

The Liquids business for the three month period ended September 30, 2010 incurred approximately $475.0 million of costs for the emergency response, environmental remediation, cleanup activities and pipeline inspection costs associated with the crude oil releases from Lines 6A and 6B, excluding fines and penalties. Our estimated costs for these incidents are based on currently available information and will be updated as considered necessary to incorporate material new information as it becomes available. We expect the cleanup, remediation and restoration for the Line 6A and 6B leaks to be substantially completed by the end of 2010. We expect to pay approximately 90 percent of the estimated $475 million of costs related to the Line 6A and 6B incidents by the end of 2011, but air, ground water monitoring, along with other professional and legal fees are expected to continue into future periods.

The environmental costs for the crude oil releases on Lines 6A and 6B that we have included in operating income for our Liquids business do not include costs for fines and penalties we expect will be imposed on us by the federal, state and local regulatory authorities. We expect to recognize such expenses when sufficient information becomes available that will allow us to compute a reasonable estimate for these costs, which amounts could be material to our operating results.

We maintain commercial liability insurance coverage for costs associated with environmental incidents such as those we have incurred for the leaks from Lines 6A and 6B, excluding costs for fines and penalties. We maintain limits that we consider sufficient to fund the resulting insured costs and liabilities, subject to a deductible of approximately $5 million per incident. We do not maintain insurance coverage for interruption of our operations except for water crossings, and therefore, we will not recover the approximately $16 million of revenues lost while Lines 6A and 6B were not in service. Apart from the amounts for which we are not insured, we anticipate that substantially all of the costs we have incurred from the leaks will ultimately be recoverable under our existing insurance policies. We expect to record a receivable for any amounts we claim for recovery pursuant to our insurance policies during the period realization of the claim for recovery is deemed probable.

Operating and administrative expenses for the Liquids segment decreased $1.8 million from the three month period ended September 30, 2010 when compared to the same period in 2009 due to lower rent costs associated with the termination of our lease of Line 13 from an affiliate of our general partner coupled with declines in costs for outside services. The decline in operating and administrative expenses was partially offset by increased workforce costs associated with our expanded systems.

Power costs increased $3.0 million for the three month period ended September 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 North Dakota system coupled with utility rate increases on power used on our Lakehead system. Offsetting the increases in power costs was a decline in power used by our Lakehead system from the fewer volumes being shipped as a result of the leaks on Lines 6A and 6B.

The increase in depreciation expense of $13.5 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 the Alberta Clipper Project that we placed in service during the first and second quarters of 2010, respectively.

In September 2010, our West Tulsa crude oil pipeline was abandoned due to a significant decrease in throughput on the pipeline and as a result we recognized a $10.3 million impairment charge during the third quarter of 2010 to reduce the carrying amount of the asset to zero.

Nine month period ended September 30, 2010 compared with nine month period ended September 30, 2009

Operating income for our Liquids segment declined $370.4 million to an operating loss of $30.7 million for the nine month period ended September 30, 2010 compared to the $339.7 million of operating income for the same period in 2009. The components comprising our operating loss changed during the nine month period ended September 30, 2010 as compared with the same period in 2009, for primarily 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 nine month period ended September 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 36% percent for the nine month period ended September 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 $13.1 million increase in allowance oil revenues.

Partially offsetting these increases was $13.5 million of revenue we recognized in the nine month period ended September 30, 2009 resulting from an expired joint tolling arrangement with Mustang Pipe Line, LLC 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

Bakken Pipeline Expansion and Portal Reversal Expansion Project

In August 2010, we announced the Bakken Pipeline Expansion project, or the Bakken Project, a joint crude oil pipeline expansion project with an affiliate of Enbridge in the Bakken and Three Forks formations located in Montana, North Dakota, and Saskatchewan and Manitoba, Canada. The Bakken Project will follow our and

Enbridge Income Fund's existing rights of way to terminate and deliver to the Enbridge mainline terminal at Cromer, Manitoba, Canada. The U.S. portion of the Bakken Project will expand the U.S. portion of Line 26 by constructing two new pumping stations to be constructed in Kenaston and Lignite, North Dakota, and replacing an 11-mile segment of the existing 12-inch diameter pipeline that runs from these two locations. Also the project calls for an expansion at Enbridge's existing terminal and station in Berthold, North Dakota. Prior to the Bakken Project, the Portal Reversal Expansion Project, or PREP, will reactivate and reverse the flow of the existing idled Line 26 pipeline between Berthold, North Dakota and Steelman, Saskatchewan. Both projects when completed will increase the takeaway capacity from this region by 145,000 Bpd, with further expansion available to increase the takeaway capacity to 325,000 Bpd. The U.S. portion of the Bakken Project will have an estimated cost of approximately $370 million with an expected in-service date in the first quarter of 2013 while PREP will have an estimated cost of approximately $9 million and will be complete in early 2011. Currently, the Bakken Project has received long-term shipping commitments sufficient to allow the project to proceed and has extended the binding open season to November 30, 2010 to provide an opportunity for additional shippers to utilize the pipeline.

Pipeline Integrity Plan—Line 6B

In connection with the restart of Line 6B of our Lakehead system with the United States Department of Transportation's Pipeline and Hazardous Materials Safety Administration, or PHMSA, we committed to accelerate a process we had initiated prior to the leak to perform additional inspections, testing and refurbishment of Line 6B within and beyond the immediate area of the July 26, 2010 incident. Pursuant to this agreement, we will remediate ahead of our original schedule those pipeline anomalies identified by us between the years 2007 and 2009 that were scheduled for refurbishment including anomalies identified for action in a July 2010 PHMSA notification. We have agreed to complete all required work within 180 days of the September 27, 2010 restart of Line 6B. In addition to the required integrity measures, we also agreed to replace a 3,600 foot section of the Line 6B pipeline that lies underneath the St. Clair River in Michigan within one year of the restart of Line 6B, subject to obtaining required permits. The total cost associated with these integrity measures and pipeline replacement is estimated to approximate $110 million. Additional significant integrity expenditures may be required after this initial remediation program. The pipeline integrity and replacement costs will be capitalized or expensed in accordance with our capitalization policies as these costs are incurred, the majority of which are expected to be capital in nature. Costs we incur for in-line inspection, crack detection, tool runs and hydrostatic testing to verify the integrity of the pipeline will be expensed as incurred. We are currently discussing with our customers recovery of these costs through the tolls on our Lakehead 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 September 30,		For the nine month period ended September 30,	
	2010	**2009**	**2010**	**2009**
	(unaudited; in millions)			
Operating revenue	$ 996.9	$ 638.4	$ 2,870.2	$ 1,793.3
Cost of natural gas	869.1	491.4	2,447.7	1,372.3
Environmental costs	—	—	—	1.1
Operating and administrative	78.3	69.7	215.8	214.8
Depreciation and amortization	31.6	30.3	93.3	92.0
Operating expenses	979.0	591.4	2,756.8	1,680.2
Operating Income	$ 17.9	$ 47.0	$ 113.4	$ 113.1
Operating Statistics (MMBtu/d)				
East Texas	1,332,000	1,346,000	1,233,000	1,515,000
Anadarko	694,000	570,000	618,000	587,000
North Texas	355,000	382,000	354,000	393,000
Total[1]	2,381,000	2,298,000	2,205,000	2,495,000

(1) Average daily volumes for the three and nine month periods ended September 30, 2010 do not include volumes associated with our acquisition of the Elk City Natural Gas Gathering and Processing System, referred to as ECOP.

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

The primary factors affecting the operating income of our Natural Gas business for the three month period ended September 30, 2010 as compared with the same period of 2009 are as follows:

- $15.5 million of additional unrealized, non-cash, mark-to-market net losses from derivative instruments that do not qualify for hedge accounting treatment under authoritative accounting guidance, as compared with the same period of 2009; and
- Increases in operating and administrative costs associated with the expansion of our systems, maintenance activities, and additional costs related to our September 2010 acquisition.

Changes in the average forward prices of natural gas, NGLs and condensate from June 30, 2010 to September 30, 2010 produced unrealized, non-cash, mark-to-market net losses of $15.8 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. As a result of higher NGL forward prices and lower natural gas forward prices during the three month period ended September 30, 2010, 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, widened. The widening of fractionation margins produced unrealized, non-cash mark-to-market net losses on the derivatives that we use to hedge our fractionation margins. Additionally, as a result of the decline in forward natural gas prices during the third quarter of 2010, we experienced losses from the natural gas derivatives we use to fix the price of natural gas we purchase. Partially offsetting the losses were unrealized mark-to market net gains on derivatives we use to fix the price of natural gas we sell, that resulted from the decrease in forward natural gas prices.

Comparatively, higher average forward NGL prices at September 30, 2009 relative to June 30, 2009, produced non-cash, mark-to-market net losses of $0.3 million for the three month period ended September 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 September 30, 2009 in relation to prices at June 30, 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 September 30, 2010 and 2009:

	For the three month period ended September 30,		**For the nine month period ended September 30,**	
	2010	**2009**	**2010**	**2009**
	(unaudited; in millions)			
Hedge ineffectiveness	$ 3.1	$(0.1)	$ 4.5	$ (0.7)
Non-qualified hedges	(18.9)	(0.2)	10.0	(12.6)
Derivative fair value gains (losses)	$(15.8)	$(0.3)	$14.5	$(13.3)

Revenue for our Natural Gas business is derived from the fees or commodities we receive from the gathering, transportation, processing and treating of natural gas and NGLs for our customers. We are exposed to fluctuations in commodity prices in the near term on approximately 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. 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 September 30, 2010, natural gas volumes on our systems increased approximately 3.6 percent, in relation to the same period of 2009 primarily due to production increases in the granite wash. Active drilling rigs in the areas we serve have increased 50 percent during the three month period ended September 30, 2010 from levels that existed in the corresponding period in 2009. Also, active drilling rigs in the areas we serve increased by 41 percent from levels that existed at the end of 2009. As a result of the increased drilling activity in the areas we serve, we expect our volumes to continue to increase in future periods.

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 relative to historical highs, particularly on our East Texas and North Texas 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. We anticipate the recent discovery of the Haynesville Shale in western Louisiana and eastern Texas could result in greater demand for our services. 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 September 30, 2010 was $13.5 million, representing a decrease of $7.1 million from the $20.6 million we produced for the same period in 2009. However the decline in margin derived from keep-whole contracts was mostly offset by an increase in margin derived by our percent of liquids, or POL, type contracts. We also continue to experience a trend of replacing or renegotiating some of our exiting keep-whole contracts with POL type contracts and other similar arrangements. This trend may reduce our exposure to commodity price risk along with a portion of the operating income we derive from processing natural gas under keep-whole arrangements.

Operating and administrative costs of our Natural Gas segment were $8.6 million higher for the three month period ended September 30, 2010 compared to the same period in 2009, primarily due to an increase in workforce-related costs associated with the expansion of our systems, maintenance activities, and additional costs related to our September 2010 ECOP acquisition, discussed below in *Other Matters*.

Nine month period ended September 30, 2010 compared with nine month period ended September 30, 2009

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

The average forward and daily prices for natural gas and NGLs at September 30, 2010 were lower relative to natural gas and NGL prices at December 31, 2009, resulting in unrealized, non-cash, mark-to-market net gains of $14.5 million for the nine months ended September 30, 2010. The lower prices for natural gas and NGLs relative to the prices that existed at December 31, 2010, resulted in unrealized, mark-to-market net gains from the derivative instruments we use to fix the price of the natural gas and NGLs we sell. Additionally, as a result of the reduction of forward natural gas prices during the nine month period ended September 30, 2010, the natural gas derivatives we use to fix the price of natural gas we purchase for processing resulted in losses. Comparatively, the average forward and daily prices for natural gas at December 31, 2008 were higher relative to natural gas prices at September 30, 2009, resulting in unrealized, non-cash, mark-to-market net losses of $13.3 million for the nine month period ended September 30, 2009 from the derivative instruments we use to fix the price of the natural gas we purchase for processing. These net losses were compounded by unrealized, non-cash, mark-to-market net losses associated with the derivatives we use to fix the sales price of NGLs we derive from processing natural gas that resulted from higher average forward and daily NGL prices at September 30, 2009 as compared with the prices at December 31, 2008.

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 demand payments, 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. We completed construction of a portion of the pipeline for the project during the second quarter of 2010 and we expect construction of the facilities will continue through the second quarter of 2011. Future compression will be layered in, as needed, after the completion of the facilities.

Allison Cryogenic Processing Plant

In April 2010, we announced plans to construct a cryogenic processing plant on our Anadarko natural gas gathering system, which we refer to as the Allison Plant. The Allison Plant will have a planned capacity of 150

MMcf/d and is intended to accommodate the resurgence of horizontal drilling activity that exists in the Granite Wash Formation in the Texas Panhandle, where our Anadarko system is located. The Allsion Plant, when operational, will increase our Anadarko natural gas gathering system's total processing capacity to more than 650 MMcf/d. The Allison Plant is anticipated to be in service by late 2011.

Other Matters

2010 Gathering and Processing Natural Gas System Acquisition

Furthering our growth strategy to expand our Natural Gas business, on September 16, 2010, we acquired ECOP for $686.1 million in cash, including the initial adjustment for working capital, subject to any final working capital adjustments. The ECOP assets extend from southwestern Oklahoma to Hemphill County in the Texas Panhandle. The ECOP system consists of approximately 800 miles of natural gas gathering and transportation pipelines, one carbon dioxide treating plant and three cryogenic processing plants with a total capacity of 370 million cubic feet per day, or MMcf/d, and a combined current NGL production capability of 20,000 Bpd. The acquisition of ECOP complements our existing Anadarko natural gas system by providing additional processing capacity and expansion capability allowing us to further capitalize on growing volumes of natural gas from the Granite Wash Formation. We used the net proceeds from the September 2010 issuance and sale of our senior notes to pay for a portion of the acquisition. The results of operations of the ECOP assets have been included in our consolidated financial statements since the September 16, 2010 acquisition date within our Natural Gas segment. ECOP did not significantly affect the operating income of our Natural Gas business for the three and nine month periods ended September 30, 2010.

The following table presents the allocation of the purchase price to the assets acquired and the liabilities assumed, based on their fair values:

	September 16, 2010
	(in millions)
Other current assets	$ 3.9
Property, plant and equipment, net	489.5
Intangibles	189.2
Other assets	4.7
Total assets acquired	687.3
Other long-term liabilities	1.2
Net assets acquired	$686.1

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 "Loss from discontinued operations" on our consolidated statements of income for the three and nine month periods ended September 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 September 30, 2009	For the nine month period ended September 30, 2009
	(unaudited; in millions)	
Operating revenue	$ 43.1	$151.6
Operating expenses		
Cost of natural gas	34.8	124.9
Operating and administrative	6.1	16.5
Depreciation and amortization	3.9	11.6
	44.8	153.0
Operating loss	(1.7)	(1.4)
Other expense	(66.2)	(66.1)
Loss from discontinued operations	$(67.9)	$ (67.5)

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 September 30,		For the nine month period ended September 30,	
	2010	2009	2010	2009
	(unaudited; in millions)			
Operating revenue	$591.3	$463.2	$1,815.0	$1,601.0
Cost of natural gas	586.5	451.8	1,802.5	1,557.0
Operating and administrative	2.3	1.8	7.0	5.3
Depreciation and amortization	0.1	0.4	0.2	1.2
Operating expenses	588.9	454.0	1,809.7	1,563.5
Operating Income	$ 2.4	$ 9.2	$ 5.3	$ 37.5

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

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

Included in the operating results of our Marketing segment for the three month period ended September 30, 2010 were unrealized, non-cash, mark-to-market net gains of $1.3 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 $9.0 million of unrealized non-cash, mark-to-market net gains for the same period in 2009. For the three month period ended September 30, 2010, the non-cash, mark-to-market, net gains primarily related to our financial instruments that we use to hedge our storage positions. The net gains on these derivative instruments resulted from the narrowing difference between the natural gas injection price paid to purchase and store natural gas and the withdrawal price at which the natural gas is sold from storage. Comparatively, during the three month period ended September 30, 2009, the narrowing difference between forward prices for natural gas purchases and sales at primary market centers, positively affected the values of the derivative financial instruments we use to hedge our transportation positions resulting in unrealized, mark-to-market net gains.

Contributing to the lower operating income of our Marketing business were relatively stable natural gas prices during the three month period ended September 30, 2010, which limited opportunities to benefit from significant price differentials between market centers. This decrease for the three month period ended September 30, 2010 as compared with the three months ended September 30, 2009 was partially offset by income derived from the increased sales of natural gas from storage that occurred early in the third quarter of 2010.

Operating and administrative expenses for the three month period ended September 30, 2010 were $0.5 million higher when compared to the same period in 2009 due to increased corporate overhead allocations.

Nine month period ended September 30, 2010 compared with nine month period ended September 30, 2009

The components comprising our operating income changed during the nine month period ended September 30, 2010 compared to the same period in 2009, primarily for the same reasons as in the three-month analysis, in addition to the items noted below.

The non-cash, mark-to market, net losses of $3.0 million during the nine month period ended September 30, 2010 resulted from the widening of the difference between forward natural gas purchase and sales prices between market centers, which negatively impacted the values of derivative financial instruments we use to hedge our transportation positions. Conversely, during the nine month period ended September 30, 2009, we had unrealized, mark-to-market net gains of $19.6 million resulting from narrower transportation differentials from the increases in the forward and daily market prices of natural gas from December 31, 2008.

Corporate

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

	For the three month period ended September 30,		For the nine month period ended September 30,	
	2010	2009	2010	2009
	(unaudited; in millions)			
Interest expense	$70.1	$60.7	$199.0	$169.9
Interest capitalized	1.5	6.9	7.1	25.3
Interest cost incurred	$71.6	$67.6	$206.1	$195.2
Weighted average interest rate	*6.5%*	*7.1%*	*6.5%*	*7.0%*

The increases in interest expense between both the three and nine month periods ended September 30, 2010 and 2009 are primarily the result of a higher weighted average outstanding debt balance during the three month period ended September 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;
- The issuance and sale in March 2010 of $500 million of our 5.20% senior unsecured notes due 2020; and
- The issuance and sale in September 2010 of $400 million of our 5.50% senior unsecured notes due 2040.

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 three and nine month periods ended September 30, 2010, we recorded $0.4 million and $0.9 million, respectively, of unrealized, non-cash, mark-to-market net losses associated with the changes in fair value of these derivatives that resulted from the decrease in interest rates from December 31, 2009 to September 30, 2010. For the three and nine month periods ended September 30, 2009, we recorded $1.4 million of unrealized, non-cash, mark-to-market net losses and $1.0 million of net gains, respectively, associated with the changes in fair value of these derivatives that resulted from the changes in interest rates from the May 2009 date these derivative financial instruments were purchased to September 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 U.S. 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 $20.1 million and $45.3 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 nine month periods ended September 30, 2010, respectively, and $2.3 million for both the three and nine month periods ended September 30, 2009. 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 recorded an allowance for equity during construction, referred to as AEDC, in “Other income (expense)” on our consolidated statement of income. For the nine month period ended September 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 September 30, 2010 as well as the three and nine month periods ended September 30, 2009, we did not record any additional income related to AEDC.

LIQUIDITY AND CAPITAL RESOURCES

Available Liquidity

As set forth in the following table, we had in excess of $700 million of liquidity available to us at September 30, 2010 to meet our ongoing operational, investment and financing needs as well as the funding requirements associated with the environmental costs resulting from the crude oil releases on Lines 6A and 6B.

	(in millions)
Availability under Credit Facilities[1]	$541.9
Cash and cash equivalents	206.6
Total	$748.5

[1] Our Credit Facilities consist of our Second Amended and Restated Credit Agreement along with the $350 million unsecured senior revolving credit agreement established in August 2010.

Impact of Lines 6A and 6B Crude Oil Releases

During the three month period ended September 30, 2010 our cash flows were adversely affected by the approximate $140 million we paid for the emergency response, environmental remediation, and cleanup activities resulting from the crude oil releases occurring on Lines 6A and 6B of our Lakehead system. The estimated costs for the emergency response, environmental remediation and cleanup activities associated with the crude oil releases and related pipeline inspection costs were approximately $475 million for the three and nine month periods ended September 30, 2010. We expect to pay approximately 90 percent of the estimated costs by the end of 2011. The estimated environmental cost for the leaks does not include amounts for fines and penalties we expect will be imposed on us by the federal, state and local regulators and such amounts are not covered under our insurance policies. Apart from amounts that are not insured, we anticipate that substantially all of the costs we have incurred from the leaks will ultimately be recoverable under our existing insurance policies. We expect to record a receivable for any amounts we claim for recovery pursuant to our insurance policies during the period realization of the claim for recovery is deemed probable. We do not maintain insurance coverage for interruption of our operations, except for water crossings, and therefore we will not recover the approximately $16 million of revenues lost while Lines 6A and 6B were not in service.

In spite of the challenges posed by the crude oil releases on our Lakehead system, we believe we have sufficient liquidity to fund our operating activities and environmental remediation obligations while maintaining our present distribution rate to our unitholders.

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 Credit Facilities.

Our current business strategy emphasizes developing and expanding our existing Liquids and Natural Gas businesses 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 Facilities 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 activities.

We have issued a balanced combination of debt and equity securities to fund our expansion projects and acquisitions. Our internal growth projects and targeted acquisitions may require additional permanent capital and require us to bear the cost of constructing and acquiring assets before we begin to realize a return on them. If market conditions change and capital markets again become constrained, our ability and willingness to complete future debt and equity offerings may be limited. The timing of any future debt and equity offerings will depend on various factors, including prevailing market conditions, interest rates, our financial condition and our credit rating at the time.

In September 2010, we issued and sold $400 million in principal amount of our 5.50% senior notes due September 15, 2040, which we refer to as the 2040 Notes. We received net proceeds from the offering of approximately $394.4 million after underwriting discounts and commissions and payment of offering expenses. We used the net proceeds we received from this offering to fund a portion of our ECOP acquisition discussed in *Natural Gas—Future Prospects for Natural Gas—Other Matters* above.

In March 2010, we issued and sold $500 million in principal amount of our 5.20% senior unsecured notes due March 15, 2020, which we refer to as the 2020 Notes, 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. The following table presents the net proceeds from our Class A common unit issuances, resulting from the EDA, during the nine month period ended September 30, 2010:

Three Month Period Ended	Number of Class A common units Issued	Offering Price per Class A common unit	Net Proceeds to the Partnership[1]	General Partner Contribution[2]	Net Proceeds Including General Partner Contribution
		(in millions, except units and per unit amounts)			
June 30, 2010	287,345	$52.52	$14.8	$0.3	$15.1
September 30, 2010	686,741	54.21	36.4	0.7	37.1
2010 Totals	974,086		$51.2	$1.0	$52.2

(1) Net of commissions and issuance costs of $0.3 million and $0.7 million for the three month periods ended June 30, 2010 and September 30, 2010, respectively.

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

Available Credit

Our two primary sources of liquidity are provided by our commercial paper program and our $1,517.5 million Credit Facilities. We have a $600 million commercial paper program that is supported by our long-term Credit Facilities, which we access primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions when the interest rates available to us for commercial paper are more favorable than the rates available under our Credit Facilities.

Credit Facilities

On August 26, 2010, we established a new unsecured senior revolving credit agreement, with a group of lenders and an aggregate commitment amount of $350.0 million, which we plan to use for funding general activities and working capital needs. The new $350.0 million credit facility has terms consistent with our existing $1,167.5 million Second Amended and Restated Credit Agreement and has the same maturity date of April 4, 2013. The two credit agreements provide an aggregate amount of $1,517.5 million of bank credit and will be referred to as our Credit Facilities.

On September 30, 2010, our Credit Facilities were amended to modify the definition of Consolidated Earnings Before Income Taxes, Depreciation and Amortization, or Consolidated EBITDA, used for debt covenant calculations. Consolidated EBITDA, as modified, will exclude those costs associated with the crude oil releases on Lines 6A and 6B of our Lakehead system, not to exceed an aggregate amount of $450.0 million. Specifically, the costs allowed to be excluded from Consolidated EBITDA are those for emergency response, environmental remediation, cleanup activities, costs to repair the pipelines, inspection costs, potential claims by third parties and lost revenue.

At September 30, 2010, we had $327.0 million outstanding under our Credit Facilities, and letters of credit totaling $53.6 million. The amounts we may borrow under the terms of our Credit Facilities are reduced by the principal amount of our commercial paper issuances and the balance of our letters of credit outstanding. At September 30, 2010, we could borrow $541.9 million under the terms of our Credit Facilities, determined as follows:

	(in millions)
Total credit available under Credit Facilities	$1,517.5
Less: Amounts outstanding under Credit Facilities	327.0
Balance of letters of credit outstanding	53.6
Principal amount of commercial paper issuances	595.0
Total amount we could borrow at September 30, 2010	$ 541.9

Individual borrowings under the terms of our Credit Facilities generally become due and payable at the end of each contract period, which is typically a period of three months or less. We have the option to repay these amounts on a non-cash basis by net settling with the parties to our Credit Facilities, which we accomplish by contemporaneously borrowing at the then current rate of interest and repaying the principal amount due. During the nine month periods ended September 30, 2010 and 2009, we net settled borrowings of $915.0 million and $1,447.1 million, respectively, on a non-cash basis.

Commercial Paper

At September 30, 2010 we had $595.0 million in principal amount of our commercial paper outstanding, at a weighted average interest rate of 0.45%, before the effect of our interest rate hedging activities. Under our commercial paper program, we had net borrowings of approximately $594.8 million during the nine month period ended September 30, 2010, which include gross issuances of $3,329.2 million and gross repayments of $2,734.4 million. At September 30, 2010 we could issue an additional $5.0 million in principal amount under our commercial paper program. The commercial paper we can issue is limited by the credit available under our Credit Facilities.

Joint Funding Arrangement for Alberta Clipper Project

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

In March 2010, we refinanced $324.6 million of amounts we had outstanding and payable to our General Partner under the A1 Credit Agreement by issuing a promissory note payable to our General Partner, at which time we also terminated the A1 Credit Agreement. The promissory note payable, which we refer to as the A1 Term Note, matures on March 15, 2020, bears interest at a fixed rate of 5.20% and has a maximum loan amount of $400 million. The terms of the A1 Term Note are similar to the terms of our senior notes, except that the A1

Term Note has recourse only to the assets of the U.S. portion of the Alberta Clipper Project. Under the terms of the A1 Term Note, we have the ability to increase the principal amount outstanding to finance the debt portion of the investment our General Partner is obligated to make pursuant to the Alberta Clipper Joint Funding Arrangement to finance any additional costs associated with the construction of our portion of the Alberta Clipper Project we incur after the date the original A1 Term Note was issued. The increases we make to the principal balance of the A1 Term Note will also mature on March 15, 2020. At September 30, 2010, we had approximately $342.7 million outstanding under the A1 Term Note.

Our General Partner also made equity contributions totaling $96.6 million and $203.0 million to the OLP, during the nine month periods ended September 30, 2010 and 2009, to fund its equity portion of the construction costs associated with the Alberta Clipper Project. The OLP paid a distribution of $17.2 million to our General Partner and its affiliate for their noncontrolling interest in the Series AC.

We allocated earnings derived from operating the Alberta Clipper Project in the amounts of $20.1 million and $45.3 million to our General Partner for its 66.67 percent share of the earnings of the Alberta Clipper Project for the three month and nine month periods ended September 30, 2010, respectively, and $2.3 million for both the three and nine month periods ended September 30, 2009. 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 remainder of the year for the acquisition and construction of natural gas and crude oil transportation infrastructure. In 2010, we expect to spend approximately $950 million on system enhancements and other projects associated with our liquids and natural gas systems with the expectation of realizing additional cash flows as projects are completed and placed into service. At September 30, 2010, we had approximately $255.7 million in outstanding purchase commitments attributable to capital projects for the construction of assets that will be recorded as property, plant and equipment during 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 them. 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 we anticipate making asset acquisitions in and around our existing natural gas business. We expect to obtain the funds needed to make acquisitions through a combination of cash flows from operating activities, borrowings under our credit facilities and the issuance of additional debt and equity securities. All acquisitions are considered in the context of the practical financing constraints presented by the capital markets.

Forecasted Expenditures

We categorize our capital expenditures as either core maintenance or enhancement expenditures. Core maintenance expenditures are those expenditures that are necessary to maintain the service capability of our existing assets and includes the replacement of system components and equipment which are worn, obsolete or completing its useful life. We also include a portion of our expenditures for connecting natural gas wells, or well-connects, to our natural gas gathering systems as core maintenance expenditures. Enhancement expenditures include our capital expansion projects and other projects that improve the service capability of our existing assets, extend asset useful lives, increase capacities from existing levels, reduce costs or enhance revenues and enable us to respond to governmental regulations and developing industry standards.

We estimate our capital expenditures based upon our strategic operating and growth plans, which are also dependent upon our ability to produce or otherwise obtain the financing necessary to accomplish our growth objectives. The following table sets forth our estimates of capital expenditures we expect to make for system enhancement and core maintenance for the year ending December 31, 2010. Although we anticipate making these 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 which may adversely affect our ability to access the capital markets. Additionally, our estimates may also change as a result of decisions made at a later date to revise the scope of a project or undertake a particular capital program or an acquisition of assets. We made capital expenditures of $529.1 million, including $45.1 million on core maintenance activities, for the nine month period ended September 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	$375
Line 6B integrity plan per CAO	40
Core maintenance activities	75
Haynesville projects	200
Alberta Clipper	260
	$950

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

Under our capitalization policy, expenditures that replace major components of property or extend the useful lives of existing assets are capital in nature while expenditures to inspect and test our pipelines are usually considered operating expenses. The capital components of our programs have increased over time as our pipeline systems age.

In connection with the restart of Line 6B of our Lakehead system with PHMSA, we committed to accelerate a process we had initiated prior to the leak to perform additional inspections, testing and refurbishment of Line 6B within and beyond the immediate area of the July 26, 2010 incident. Pursuant to this agreement, we will remediate ahead of our original schedule those pipeline anomalies identified by us between the years 2007 and 2009 that were scheduled for refurbishment, including anomalies identified for action in a July 2010 PHMSA notification. We have agreed to complete all required work within 180 days of the September 27, 2010 restart of Line 6B. In addition to the required integrity measures, we also agreed to replace a 3,600 foot section of the Line 6B pipeline that lies underneath the St. Clair River in Michigan within one year of the restart of Line 6B, subject to obtaining required permits. The total cost associated with these integrity measures and pipeline replacement is estimated to approximate $110 million. Additional significant integrity expenditures may be required after this initial remediation program. The pipeline integrity and replacement costs will be capitalized or expensed in accordance with our capitalization policies as these costs are incurred, the majority of which are expected to be capital in nature. Costs we incur for in-line inspection, crack detection, tool runs and hydrostatic testing to verify the integrity of the pipeline will be expensed as incurred. We are currently discussing with our customers recovery of these costs through the tolls on our Lakehead system.

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 September 30, 2010 for each of the indicated calendar years:

	Notional	2010	2011	2012	2013	2014	Thereafter	Total[3]
			(dollars, in millions)					
Swaps								
Natural gas[1]	122,755,693	$ 0.9	$ (4.4)	$(3.6)	$ 3.3	$(0.1)	$ —	$ (3.9)
NGL[2]	8,547,298	(5.3)	0.5	8.0	(0.7)	(0.5)	—	2.0
Crude[2]	5,255,614	(1.0)	(10.2)	(5.5)	(1.5)	(0.8)	(0.2)	(19.2)
Options								
Natural gas—puts purchased[1]	457,000	—	—	—	—	—	—	—
Natural gas—calls written[1]	457,000	—	(0.2)	—	—	—	—	(0.2)
NGL—puts purchased[2]	912,048	1.0	4.4	6.4	—	—	—	11.8
Crude—puts purchased[2]	119,148	—	0.1	—	—	—	—	0.1
Forward contracts								
Crude[2]	989,619	(0.0)	(0.1)	—	—	—	—	(0.1)
Natural gas[1]	57,786,197	0.3	1.0	0.5	0.2	—	—	2.0
NGL[2]	6,238,181	—	1.2	0.5	—	—	—	1.7
Totals		$(4.1)	$ (7.7)	$ 6.3	$ 1.3	$(1.4)	$(0.2)	$ (5.8)

(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 $0.1 million of losses at September 30, 2010.

The following table provides summarized information about the timing and expected settlement amounts of our outstanding interest rate derivative instruments at September 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	$1,275.0	$(1.6)	$(27.2)	$(23.8)	$(17.0)	$(0.5)	$0.1	$ (70.0)
Fixed to Floating	125.0	1.0	5.6	5.0	2.2	—	—	13.8
Pre-issuance hedges	1,200.0	—	1.9	(61.9)	(24.7)	—	—	(84.7)
		$(0.6)	$(19.7)	$(80.7)	$(39.5)	$(0.5)	$0.1	$(140.9)

(1) Fair values are presented in millions of dollars and exclude credit adjustments of approximately $4.5 million of gains at September 30, 2010.

Operating Activities

Net cash provided by our operating activities was $411.8 million for the nine month period ended September 30, 2010, a decrease of $171.1 million compared with the $582.9 million generated during the same period in 2009. During the nine month period ended September 30, 2010 our cash flows were adversely affected by the approximate $140 million we paid for the emergency response, environmental remediation and cleanup activities resulting from the crude oil releases occurring on Lines 6A and 6B of our Lakehead system. In addition, cash flows associated with changes in our working capital accounts were lower for the nine month period ended September 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 nine month period ended September 30, 2010 was $1,241.4 million, an increase of $351.0 million from the $890.4 million used during the same period of 2009. The increase is primarily attributable to the $686.1 million acquisition of the ECOP natural gas system and the $17.0 million acquisition of the natural gas assets in the South Haynesville area. Offsetting the increase in net cash used in investing activities was the $280.3 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.

Financing Activities

The net cash provided by our financing activities during the nine month period ended September 30, 2010 was $892.6 million, an increase of $733.9 million from the $158.7 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 our 2020 Notes and $394.4 million of net proceeds related to the September 2010 issuance and sale of our 2040 Notes 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 $594.8 million in 2010. Similar borrowings were not made in the same period of 2009;
- $403.7 million we borrowed from our General Partner in 2010 which we used to repay $330.7 million we borrowed on the A1 Credit Facility and to fund $79.1 million of additional costs incurred for the construction of the Alberta Clipper Project. We borrowed $166.1 million in the same period of 2009;
- $214.7 million we repaid of our zero coupon notes in the first nine months of 2009. Similar payments were not made in the same period of 2010; and
- $51.2 million of proceeds related to Class A common units issued under the EDA and $1.0 million of contributions from the General Partner to maintain its two percent interest.

Offsetting the cash inflows from financing activities are $438.0 million of net repayments under our Credit Facilities over the $463.2 million of net borrowings we made in the comparable period of 2009. Included in our net repayments under our Credit Facilities for the nine month period ended September 30, 2010 were gross borrowings of $432.0 million and gross repayments of $870.0 million, including $915.0 million of non-cash borrowings and repayments.

We also had $96.6 million of capital contributions from and $17.2 million in distributions to our General Partner and its affiliate for the nine month period ended September 30, 2010 for its ownership interest in the Alberta Clipper Project compared to $203 million of capital contribution for the same period in 2009.

Also, for the nine month period ended September 30, 2010 we had $76.9 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 144,615 Class A common units in October 2010 under the terms of the EDA at sales prices averaging $55.70 per unit, for proceeds of approximately $7.9 million, net of $0.2 million of commissions and issuance costs within the period of October 1 and October 5, 2010. In addition, our General Partner contributed approximately $0.2 million to us to maintain its two percent general partner interest.

Distribution to Partners

On October 27, 2010, the board of directors of Enbridge Management declared a distribution payable to our partners on November 12, 2010. The distribution will be paid to unitholders of record as of November 4, 2010, of our available cash of $143.0 million at September 30, 2010, or $1.0275 per limited partner unit. Of this distribution, $124.8 million will be paid in cash, $17.9 million will be distributed in i-units to our i-unitholder and $0.3 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 October 27, 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 $21.4 million to the noncontrolling interest in the Series AC while $10.7 million will be paid to us.

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 September 30, 2010.

				Fair Value[3] at	
Date of Maturity & Contract Type	**Accounting Treatment**	**Notional**	**Average Fixed Rate[1]**	**September 30, 2010**	**December 31, 2009**
	(dollars in millions)				
Contracts maturing in 2010					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$250	1.68%	$ (0.7)	$ (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%	$(56.4)	$(16.9)
Interest Rate Swaps—Pay Fixed	Non-qualifying	125	4.35%	(12.5)	(9.2)
Interest Rate Swaps—Pay Float	Non-qualifying	125	4.75%	13.8	11.0
Contracts maturing in 2015					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$300	2.43%	$ (0.4)	$ —
Contracts settling prior to maturity					
2010—Pre-issuance Hedges[2]	Cash Flow Hedge	$220	4.62%	$ —	$ (6.8)
2011—Pre-issuance Hedges	Cash Flow Hedge	300	2.92%	1.9	—
2012—Pre-issuance Hedges	Cash Flow Hedge	600	4.57%	(61.9)	24.9
2013—Pre-issuance Hedges	Cash Flow Hedge	300	4.62%	(24.7)	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 and $400 million senior note debt issuance in September 2010.

(3) The fair value is determined from quoted market prices at September 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 $4.5 million of gains at September 30, 2010, with no such gains and losses at December 31, 2009.

In connection with our March 2010 issuance and sale of the 2020 Notes, 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. We received $10.2 million to settle treasury locks associated with our September 2010 issuance and sale of the 2040 Notes that were entered into to hedge the interest payments on a portion of the obligations through the 2040 maturity date of the senior notes. Both the $13.2 million and $10.2 million settlement amounts are being amortized from AOCI to "Interest expense" over the 10 and 30-year terms, respectively, of the 2020 and 2040 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 September 30, 2010 and December 31, 2009.

	At September 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	2,161,079	$ 3.77	$ 5.27	$ —	$ (3.3)	$ 1.6	$ (3.1)
	NGL	367,000	85.01	78.24	2.5	—	3.4	—
	Crude Oil	730,000	81.30	77.03	3.2	(0.1)	—	—
Receive fixed/pay variable	Natural Gas	3,212,347	4.41	3.87	2.3	(0.6)	2.9	(16.0)
	NGL	1,627,808	52.24	57.04	3.1	(10.9)	9.7	(39.4)
	Crude Oil	1,037,944	76.70	80.70	1.1	(5.2)	3.1	(10.6)
Receive variable/pay variable	Natural Gas	30,123,758	3.74	3.66	3.5	(1.0)	13.0	(3.5)
Physical Contracts								
Receive fixed/pay variable	NGL	1,179,811	55.29	59.06	0.1	(4.6)	—	(4.0)
	Crude Oil	513,950	75.95	80.90	0.1	(2.6)	—	(1.6)
Receive variable/pay fixed	NGL	429,286	55.84	51.30	2.0	—	0.3	—
	Crude Oil	414,950	80.72	74.89	2.4	—	1.8	—
Receive variable/pay variable	Crude Oil	35,719	75.37	73.96	0.1	—	0.1	(0.1)
	NGL	2,251,560	68.58	67.45	3.2	(0.7)	—	—
	Natural Gas	10,643,789	3.68	3.65	0.3	—	—	—
Portion of contracts maturing in 2011								
Swaps								
Receive variable/pay fixed	Natural Gas	1,166,445	$ 4.28	$ 8.60	$ —	$ (5.0)	$ —	$ (3.1)
	NGL	205,000	81.29	61.20	4.1	—	3.2	—
Receive fixed/pay variable	Natural Gas	9,377,229	4.07	4.38	2.9	(5.8)	—	(19.3)
	NGL	4,318,510	46.47	47.31	7.8	(11.4)	6.1	(7.0)
	Crude Oil	1,207,335	76.03	84.47	0.1	(10.3)	—	(10.0)
Receive variable/pay variable	Natural Gas	34,547,885	4.24	4.14	3.8	(0.3)	2.9	(0.1)
Physical Contracts								
Receive variable/pay fixed	NGL	80,000	58.48	53.66	0.4	—	—	—
Receive variable/pay variable	Natural Gas	25,566,657	4.17	4.13	1.0	—	—	—
	NGL	1,666,095	59.64	58.33	2.5	(0.3)	—	—
Receive fixed/pay variable	NGL	240,000	56.73	62.51	—	(1.4)	—	—
	Crude Oil	25,000	78.01	82.70	—	(0.1)	—	—
Portion of contracts maturing in 2012								
Swaps								
Receive variable/pay fixed	Natural Gas	827,195	$ 4.93	$ 9.58	$ —	$ (3.8)	$ —	$ (2.6)
Receive fixed/pay variable	Natural Gas	2,327,500	4.90	5.04	1.7	(2.1)	0.3	(4.2)
	NGL	1,315,770	59.82	53.70	10.5	(2.5)	7.1	(0.9)
	Crude Oil	733,830	79.70	87.30	—	(5.5)	—	(5.3)
Receive variable/pay variable	Natural Gas	17,869,000	4.98	4.95	0.6	—	0.6	—
Physical Contracts								
Receive variable/pay variable	Natural Gas	14,963,301	5.00	4.96	0.5	—	—	—
	NGL	391,429	39.44	38.19	0.5	—	—	—
Portion of contracts maturing in 2013								
Swaps								
Receive variable/pay fixed	Natural Gas	58,765	$ 5.15	$ 5.38	$ —	$ —	$ —	$ —
Receive fixed/pay variable	Natural Gas	730,000	9.83	5.06	3.4	—	2.3	—
	NGL	541,660	63.89	65.26	0.6	(1.3)	—	(1.0)
	Crude Oil	750,805	86.32	88.32	2.6	(4.1)	2.3	(3.6)
Receive variable/pay variable	Natural Gas	16,740,000	5.20	5.21	—	(0.1)	—	—
Physical Contracts								
Receive variable/pay variable	Natural Gas	6,612,450	5.26	5.23	0.2	—	—	—
Portion of contracts maturing in 2014								
Swaps								
Receive fixed/pay variable	Crude Oil	618,675	$87.82	$89.16	$ 0.2	$ (1.0)	$ —	$ (0.4)
	NGL	171,550	75.42	78.39	—	(0.5)	—	—
Receive variable/pay fixed	Natural Gas	14,490	5.52	5.38	—	—	—	—
Receive variable/pay variable	Natural Gas	3,600,000	5.60	5.62	—	(0.1)	—	—
Portion of contracts maturing in 2015								
Swaps								
Receive fixed/pay variable	Crude Oil	177,025	$89.06	$90.33	$ —	$ (0.2)	$ —	$ —

(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 September 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 $0.1 million of gains and $1.0 million of gains at September 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 September 30, 2010 and December 31, 2009.

	At September 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)	92,000	$ 4.31	$ 3.95	$ —	$ —	$ —	$(0.6)
Puts (purchased)	Natural Gas(4)	92,000	3.40	3.95	—	—	—	—
	NGL	263,396	46.84	54.27	1.0	—	3.2	—
	Crude Oil	75,348	70.87	81.41	—	—	0.6	—
Portion of option contracts maturing in 2011								
Calls (written)	Natural Gas(4)	365,000	$ 4.31	$ 4.44	$ —	$(0.2)	$ —	$(0.8)
Puts (purchased)	Natural Gas(4)	365,000	3.40	4.44	—	—	—	—
	NGL	364,270	47.18	43.48	4.4	—	2.4	—
	Crude Oil	43,800	86.87	84.83	0.1	—	—	—
Portion of option contracts maturing in 2012								
Puts (purchased)	NGL	284,382	$65.90	$57.98	$6.4	$ —	$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 September 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 September 30, 2010 and December 31, 2009, respectively.

(4) Indicate 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).

	September 30, 2010	December 31, 2009
	(in millions)	
Counterparty Credit Quality*		
AAA	$ —	$ —
AA	(68.6)	14.2
A	(83.7)	(63.1)
Lower than A	5.7	(3.2)
	(146.6)	(52.1)
Credit valuation adjustment	4.3	0.9
Total	$(142.3)	$(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, with the participation of our principal executive and principal financial officers, has evaluated the effectiveness of our disclosure controls and procedures as of September 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 September 30, 2010.

PART II—OTHER INFORMATION

Item 1. Legal Proceedings

Refer to Part I, Item 1. Financial statements, Note 11—*Commitments and Contingencies,* which is incorporated herein by reference.

Item 1A. Risk Factors

There have been no material changes to risk factors as previously disclosed in our Annual Report on Form 10-K for the fiscal year ended December 31, 2009.

Item 5. Other Information

William M. Ramos, 50, was elected to serve as Controller of Enbridge Energy Company, Inc., referred to as the General Partner, the general partner of Enbridge Energy Partners, L.P., or the Partnership, and of Enbridge Energy Management, L.L.C., or Enbridge Management, effective October 27, 2010. Prior to his election he served as Assistant Controller and in other managerial roles of the General Partner with responsibility for financial accounting, reporting and control from April 2005.

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: October 29, 2010

By: /S/ MARK A. MAKI

Mark A. Maki
President
(Principal Executive Officer)

Date: October 29, 2010

By: /S/ STEPHEN J. NEYLAND

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

Index of Exhibits

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

Exhibit Number	Description
3.1	Certificate of Limited Partnership of the Partnership (incorporated by reference to Exhibit 3.1 to the Partnership's Registration Statement on Form S-1 (No. 33-43425)).
3.2	Certificate of Amendment to Certificate of Limited Partnership of the Partnership, dated August 28, 2001 (incorporated by reference to Exhibit 3.2 to the Partnership's Second Amendment to Annual Report on Form 10-K/A for the year ended December 31, 2000, filed on October 9, 2001).
3.3	Fourth Amended and Restated Agreement of Limited Partnership of the Partnership, dated August 15, 2006 (incorporated by reference to Exhibit 3.1 of the Partnership's Current Report on Form 8-K, filed on August 16, 2006).
3.4	Amendment No. 1 to Fourth Amended and Restated Limited Partnership Agreement of the Partnership, dated December 28, 2007 (incorporated by reference to Exhibit 3.1 of the Partnership's Current Report on Form 8-K, filed on January 3, 2008).
3.5	Amendment No. 2 to Fourth Amended and Restated Agreement of Limited Partnership of the Partnership, dated August 6, 2008 (incorporated by reference to Exhibit 3.1 of the Partnership's Current Report on Form 8-K, filed on August 7, 2008).
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).
10.1	Eleventh Supplemental Indenture, dated September 13, 2010, between the Partnership, as Issuer, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.2 of the Partnership's Current Report on Form 8-K, filed on September 13, 2010).
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.