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, 2009

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 (§ 232.406 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☐ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer ☒	Accelerated Filer ☐
Non-Accelerated Filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The registrant had 97,443,352 Class A common units outstanding as of November 3, 2009.

ENBRIDGE ENERGY PARTNERS, L.P.

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In this report, unless the context requires otherwise, references to "we," "us," "our" or the "Partnership" are intended to mean Enbridge Energy Partners, L.P. and its consolidated subsidiaries. This Quarterly Report on Form 10-Q contains forward-looking statements. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. They use words such as "anticipate," "believe," "continue," "estimate," "expect," "forecast," "intend," "may," "plan," "position," "projection," "strategy," "could," "should," "would," or "will" or the negative of those terms or other variations of them or by comparable terminology. In particular, statements, expressed or implied, concerning future actions, conditions or events or future operating results or the ability to generate revenue, income or cash flow or to make distributions are forward-looking statements. Forward-looking statements are not guarantees of performance. They involve risks, uncertainties and assumptions. Future actions, conditions or events and future results of operations may differ materially from those expressed in these forward-looking statements. Many of the factors that will determine these results are beyond our ability to control or predict. For additional discussion of risks, uncertainties and assumptions, see "Risk Factors" included in Part I, Item 1A of our Annual Report on Form 10-K for the fiscal year ended December 31, 2008 and in Part II, Item 1A of our Quarterly Reports on Form 10-Q.

PART I—FINANCIAL INFORMATION

Item 1. Financial Statements

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF INCOME

	For the three months ended September 30,		For the nine months ended September 30,	
	2009	2008	2009	2008
	(unaudited; in millions, except per unit amounts)			
Operating revenue	$1,363.7	$2,770.2	$4,104.2	$8,044.7
Operating expenses				
Cost of natural gas (Notes 5 and 11)	943.2	2,376.2	2,929.3	7,019.6
Operating and administrative	133.6	135.2	399.0	363.3
Power	33.7	35.0	96.9	104.6
Depreciation and amortization (Note 6)	65.2	54.8	191.7	153.3
	1,175.7	2,601.2	3,616.9	7,640.8
Operating income	188.0	169.0	487.3	403.9
Interest expense	60.7	50.7	169.9	129.6
Other income	2.8	0.2	2.5	1.5
Income from continuing operations before income tax expense	130.1	118.5	319.9	275.8
Income tax expense	2.7	1.9	6.8	5.0
Income from continuing operations	127.4	116.6	313.1	270.8
Income (loss) from discontinued operations, net of tax (Note 3)	(67.9)	2.8	(67.5)	10.5
Net income	59.5	119.4	245.6	281.3
Less: Net income attributable to noncontrolling interest	2.3	—	2.3	—
Net income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 57.2	$ 119.4	$ 243.3	$ 281.3
Net income allocable to limited partner units				
Income from continuing operations	$ 110.1	$ 100.2	$ 267.6	$ 235.9
Income (loss) from discontinued operations	(66.5)	1.4	(66.2)	10.3
Net income allocable to limited partner units	$ 43.6	$ 101.6	$ 201.4	$ 246.2
Basic and diluted earnings per limited partner unit (Note 2)				
Income from continuing operations	$ 0.94	$ 1.03	$ 2.30	$ 2.47
Income (loss) from discontinued operations	(0.57)	0.01	(0.57)	0.11
Net income per limited partner unit (basic and diluted)	$ 0.37	$ 1.04	$ 1.73	$ 2.58
Weighted average limited partner units outstanding	117.0	96.9	116.0	95.3

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 months ended September 30,		For the nine months ended September 30,	
	2009	**2008**	**2009**	**2008**
	(unaudited; in millions)			
Net income	$ 59.5	$119.4	$ 245.6	$281.3
Other comprehensive income (loss), net of tax benefit (expense) of $0.1, $(1.5), $0.5 and $(0.4), respectively (Note 11)	(37.9)	257.1	(114.2)	66.6
Comprehensive income	21.6	376.5	131.4	347.9
Less: Comprehensive income attributable to noncontrolling interest	2.3	—	2.3	—
Comprehensive income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 19.3	$376.5	$ 129.1	$347.9

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the nine months ended September 30,	
	2009	2008
	(unaudited; in millions)	
Cash provided by operating activities		
Net income	$ 245.6	$ 281.3
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization (Notes 3 and 6)	203.3	163.1
Derivative fair value gains (Notes 11)	(7.3)	(17.5)
Inventory market price adjustments (Note 5)	3.6	8.3
Impairment charge (Note 3)	66.1	—
Other	14.3	20.1
Changes in operating assets and liabilities, net of acquisitions:		
Receivables, trade and other	(40.8)	(49.2)
Due from General Partner and affiliates (Note 9)	11.7	2.1
Accrued receivables	189.0	21.1
Inventory (Note 5)	(31.3)	(98.6)
Current and long term other assets (Note 11)	(42.3)	(9.1)
Due to General Partner and affiliates (Note 9)	21.8	35.4
Accounts payable and other (Notes 4 and 11)	(10.2)	(10.5)
Accrued purchases	(89.5)	78.1
Interest payable	42.7	55.9
Property and other taxes payable	6.9	14.8
Settlement of interest rate derivatives	(0.7)	(22.1)
Net cash provided by operating activities	582.9	473.2
Cash used in investing activities		
Additions to property, plant and equipment (Note 6)	(813.3)	(1,000.2)
Changes in construction payables	(77.0)	(56.0)
Changes in restricted cash (Note 4 and 7)	0.1	(10.0)
Other	(0.2)	(13.0)
Net cash used in investing activities	(890.4)	(1,079.2)
Cash provided by financing activities		
Net proceeds from unit issuances	—	221.8
Distributions to partners (Notes 8 and 14)	(279.9)	(211.8)
Repayments of long-term debt (Note 7)	(389.7)	—
Net proceeds from issuances of long-term debt (Note 7)	—	790.2
Net borrowings (repayments) under Credit Facility (Note 7)	463.2	(13.7)
Net commercial paper repayments (Note 7)	—	(79.4)
Net borrowings from General Partner and affiliates	166.1	—
Contribution from noncontrolling interest (Note 9)	203.0	—
Other	(4.0)	—
Net cash provided by financing activities	158.7	707.1
Net increase (decrease) in cash and cash equivalents	(148.8)	101.1
Cash and cash equivalents at beginning of year	339.9	50.5
Cash and cash equivalents at end of period	$ 191.1	$ 151.6

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	September 30, 2009	December 31, 2008
	(unaudited; dollars in millions)	
ASSETS		
Current assets		
Cash and cash equivalents (Note 4)	$ 191.1	$ 339.9
Restricted cash (Note 4 and 7)	—	0.1
Receivables, trade and other, net of allowance for doubtful accounts of $2.8 in 2009 and $2.6 in 2008	143.0	103.0
Due from General Partner and affiliates (Note 9)	28.8	40.5
Accrued receivables	317.9	507.3
Inventory (Note 5)	80.7	53.0
Assets held for sale (Note 3)	151.4	—
Other current assets (Note 11)	53.5	80.7
	966.4	1,124.5
Property, plant and equipment, net (Note 6)	7,295.6	6,722.9
Goodwill	246.6	256.5
Intangibles, net	84.1	88.7
Other assets, net (Note 11)	61.9	108.3
	$8,654.6	$8,300.9
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Due to General Partner and affiliates (Note 9)	$ 64.0	$ 42.2
Accounts payable and other (Notes 4, 10 and 11)	125.8	225.3
Accrued purchases	291.6	381.2
Interest payable	76.7	34.0
Property and other taxes payable	39.7	32.8
Current maturities of long-term debt (Note 7)	31.0	420.7
	628.8	1,136.2
Long-term debt (Note 7)	3,687.1	3,223.4
Loans from General partner and affiliates	296.1	130.0
Other long-term liabilities (Notes 10 and 11)	92.1	84.4
	4,704.1	4,574.0
Commitments and contingencies (Note 10)		
Partners' capital (Note 8)		
Class A common units (76,088,834 at September 30, 2009 and December 31, 2008, respectively)	2,009.1	2,104.0
Class B common units (3,912,750 at September 30, 2009 and December 31, 2008)	80.5	85.0
Class C units (21,333,276 and 19,688,968 at September 30, 2009 and December 31, 2008, respectively)	922.3	886.5
i-units (16,052,739 and 14,763,055 at September 30, 2009 and December 31, 2008, respectively)	580.7	553.8
General Partner	253.9	84.7
Accumulated other comprehensive income (loss) (Note 11)	(101.3)	12.9
Total Enbridge Energy Partners, L.P. partners' capital	3,745.2	3,726.9
Noncontrolling interest (Note 9)	205.3	—
Total partners' capital	3,950.5	3,726.9
	$8,654.6	$8,300.9

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, 2009 and December 31, 2008, and our results of operations and cash flows for the three and nine month periods ended September 30, 2009 and 2008. We derived our consolidated statement of financial position as of December 31, 2008 from the audited financial statements included in our 2008 Annual Report on Form 10-K. Our results of operations for the three and nine month periods ended September 30, 2009 should not be taken as indicative of the results to be expected for the full year due to 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 certain derivative financial instruments that are accounted for using mark-to-market accounting. 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, 2008.

2. NET INCOME PER LIMITED PARTNER AND GENERAL PARTNER UNIT

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, Enbridge Energy Company, Inc. 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 net income per limited partner unit as follows:

	For the three months ended September 30,		For the nine months ended September 30,	
	2009	2008	2009	2008
	(in millions, except per unit amounts)			
Net income	$ 59.5	$ 119.4	$ 245.6	$ 281.3
Less: Net income attributable to noncontrolling interest	2.3	—	2.3	—
Net income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	57.2	119.4	243.3	281.3
Less: Net income (loss) from discontinued operations	(67.9)	2.8	(67.5)	10.5
Net income from continuing operations attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	125.1	116.6	310.8	270.8
Less distributions paid:				
Incentive distributions to General Partner	(12.6)	(10.6)	(37.7)	(30.1)
Distributed earnings allocated to General Partner (2%)	(2.5)	(1.9)	(7.1)	(5.8)
Total distributed earnings to General Partner	(15.1)	(12.5)	(44.8)	(35.9)
Total distributed earnings to limited partners (98%)	(116.2)	(96.3)	(346.0)	(283.1)
Total distributed earnings	(131.3)	(108.8)	(390.8)	(319.0)
Underdistributed (overdistributed) earnings	$ (6.2)	$ 7.8	$ (80.0)	$ (48.2)
Weighted average limited partner units outstanding	117.0	96.9	116.0	95.3
Basic and diluted earnings per unit:				
Distributed earnings per limited partner unit[(1)]	$ 0.99	$ 0.99	$ 2.98	$ 2.97
Underdistributed (overdistributed) earnings per limited partner unit[(2)]	(0.05)	0.04	(0.68)	(0.50)
Net income from continuing operations attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P. per limited partner unit	0.94	1.03	2.30	2.47
Net income (loss) from discontinued operations per limited partner unit	(0.57)	0.01	(0.57)	0.11
Net income per limited partner unit (basic and diluted)	$ 0.37	$ 1.04	$ 1.73	$ 2.58

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

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

3. DISCONTINUED OPERATIONS

In September 2009, we committed to sell certain of our non-core natural gas pipeline assets located predominantly outside of Texas. We have classified these assets as "Assets held for sale" in our consolidated statement of financial position at September 30, 2009 and have presented in "Income from discontinued operations" the income and losses we derived from these assets for the three and nine month periods ended September 30, 2009 and 2008. Also included in "Income from discontinued operations" for the three and nine month periods ended September 30, 2009 is an impairment charge of approximately $66.1 million we recorded to reduce the carrying value of "Assets held for sale" to our estimate of the fair value of these assets. The natural gas pipeline assets are primarily intrastate and interstate natural gas transmission systems and related facilities, which serve onshore and offshore markets in the southeastern United States and along the Gulf Coast. The natural gas pipeline assets include over 1,400 miles of pipeline with diameters ranging from 2 to 30 inches. The areas in which the natural gas pipeline assets operate are not strategic to the ongoing central operations of our core Natural Gas segment assets.

The following table presents in millions of dollars a summary of the assets and liabilities of our discontinued operations at September 30, 2009, excluding any intercompany accounts that we eliminate in consolidation.

Assets:	
Inventory	$ 0.5
Property, plant and equipment	151.4
Total assets	$151.9
Liabilities:	
Other long-term liabilities	$ 2.0
Total liabilities	$ 2.0

The following table presents the operating results of the discontinued operations of our held for sale natural gas pipeline assets that we derived from historical financial information and have segregated from our continuing operations in our consolidated statements of income:

	For the three months ended September 30,		For the nine months ended September 30,	
	2009	**2008**	**2009**	**2008**
	(in millions)			
Operating revenue	$ 43.1	$100.8	$151.6	$303.8
Operating expenses				
Cost of natural gas	34.8	89.6	124.9	269.3
Operating and administrative	6.1	4.7	16.5	15.1
Depreciation and amortization	3.9	3.8	11.6	9.8
	44.8	98.1	153.0	294.2
Operating income (loss)	(1.7)	2.7	(1.4)	9.6
Interest expense	—	—	—	(0.1)
Other income (expense)[1]	(66.2)	0.1	(66.1)	1.0
Income (loss) from discontinued operations, net of income taxes	$(67.9)	$ 2.8	$ (67.5)	$ 10.5

(1) Includes an impairment charge of $66.1 million for the three and nine month periods ended September 30, 2009.

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 issued check payments that have not yet been presented to the financial institution totaling approximately $22.6 million at September 30, 2009 and $30.5 million at December 31, 2008 are included in "Accounts payable and other" on our consolidated statements of financial position.

Bank of America, N.A., as administrative agent to our Second Amended and Restated Credit Agreement, which we refer to as the Credit Facility, previously required us to provide cash collateral for a portion of the letters of credit outstanding under the terms of our Credit Facility that would have been obligations of Lehman Brothers Bank, FSB, which we refer to as Lehman BB. The amount of cash collateral we provided was $0.1 million at December 31, 2008. On March 31, 2009, we amended our Credit Facility to remove Lehman BB as a lender, which eliminated the cash collateral requirement imposed on us by Bank of America, N.A., as administrative agent. At September 30, 2009, no cash collateral was required and none of our cash and cash equivalents was restricted for use.

5. INVENTORY

Inventory is comprised of the following:

	September 30, 2009	December 31, 2008
	(in millions)	
Materials and supplies	$ 4.2	$ 3.9
Crude oil inventory	2.1	7.1
Natural gas and NGL inventory	74.4	42.0
	$80.7	$53.0

The "Cost of natural gas" on our consolidated statements of income includes charges totaling $0.2 million and $3.6 million for the three and nine month periods ended September 30, 2009, respectively, that we recorded to reduce the cost basis of our natural gas and natural gas liquids, or NGLs, inventory to reflect market value.

6. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is comprised of the following:

	September 30, 2009	December 31, 2008
	(in millions)	
Land	$ 32.7	$ 17.9
Rights-of-way	439.0	437.1
Pipelines	4,362.3	4,327.8
Pumping equipment, buildings and tanks	1,137.3	995.4
Compressors, meters and other operating equipment	1,338.2	639.3
Vehicles, office furniture and equipment	162.3	153.0
Processing and treating plants	325.6	343.1
Construction in progress	863.6	1,057.0
Total property, plant and equipment	8,661.0	7,970.6
Accumulated depreciation	(1,365.4)	(1,247.7)
Property, plant and equipment, net[1]	$ 7,295.6	$ 6,722.9

[1] We reclassified approximately $205.9 million, before impairment charges to property, plant and equipment associated with the discontinued operations of certain non-core natural gas pipeline assets, to "Assets held for sale" on our consolidated statement of financial position as of September 30, 2009. Information regarding our discontinued operations are discussed in Note 3—*Discontinued Operations*.

7. DEBT

Credit Facility

On March 31, 2009, we amended our Credit Facility to remove Lehman BB as a lender, which effectively reduced the amounts available to us under our Credit Facility. The removal of Lehman BB permanently reduced both the amount we may borrow under the terms of our Credit Facility to $1,167.5 million as well as the number of committed lenders to 13. The amendment to our Credit Facility did not result in any changes to the pricing, fees or other commercial terms.

At September 30, 2009, we had $630.0 million outstanding under our Credit Facility at a weighted average interest rate of 0.57% and outstanding letters of credit totaling $11.7 million. The amounts we may borrow under the terms of our Credit Facility are reduced by the balance of our outstanding letters of credit.

At September 30, 2009, we could borrow $525.8 million under the terms of our Credit Facility, determined as follows:

	(in millions)
Total credit available under Credit Facility	$1,167.5
Less: Amounts outstanding under Credit Facility	630.0
Balance of letters of credit outstanding	11.7
Total amount we could borrow at September 30, 2009	$ 525.8

Individual borrowings under the terms of our Credit Facility generally become due and payable at the end of each contract period, which typically is a period of three months or less. We have the option to repay these amounts on a non-cash basis by net settling with the parties to our Credit Facility by contemporaneously borrowing at the then current rate of interest and repaying the principal amount due. During the nine month periods ended September 30, 2009 and 2008, we net settled borrowings of approximately $1,447.1 million and $490.0 million, respectively, on a non-cash basis.

Senior Notes

In January 2009, we repaid at face value $175.0 million in principal amount of our 4.0% Senior Notes that matured on January 15, 2009.

Zero Coupon Senior Notes

In August 2009, we repaid the holder of our senior, unsecured zero coupon notes due 2022 the full amount of the outstanding balance of approximately $222.3 million. The amount repaid includes $22.3 million of interest that we accreted to the original $200 million of principal of the zero coupon notes, including approximately $7.6 million of interest that we accreted during the nine months ended September 30, 2009.

364-day Credit Facilities

In April 2009, we entered into two unsecured and non-guaranteed revolving credit facility agreements totaling $350 million for funding our general activities and working capital, which we refer to as the 364-day Credit Facilities. The 364-day Credit Facilities include a $200 million agreement with Barclays Bank PLC, as administrative agent, and Barclays Bank PLC and Export Development Canada as lenders, which we refer to as the Barclays Agreement, and a $150 million affiliate credit agreement, or the EUS Agreement, with Enbridge (U.S.) Inc., a wholly-owned subsidiary of Enbridge Inc., or Enbridge. We entered into each agreement concurrently with an initial maturity date of April 7, 2010 and a one-year extension, for a fee, exercisable at our option. Amounts we may borrow under the agreements comprising the 364-day Credit Facilities have the same terms, which are summarized below; however, amounts we borrow under the EUS Agreement are subordinate to amounts we borrow under the Barclays Agreement.

Under our 364-day Credit Facilities, borrowings can be funded through either a “Fixed Period Eurodollar Rate Loan” or “Base Rate Loan,” as those terms are defined in the agreements. Borrowings drawn under the Fixed Period Eurodollar Rate Loan bear interest at a rate per annum equal to the British Bankers’ Association London Interbank Offered Rate, or BBA LIBOR. Under the Base Rate Loan borrowings, interest will be at a rate per annum that is equal to the greater of (a) the Federal Funds Rate plus 0.5%; (b) the prime rate as determined by Barclays Bank PLC; or (c) the Fixed Period Eurodollar Rate plus 1.0%.

Our 364-day Credit Facilities contain restrictive covenants that require us to maintain a maximum leverage ratio of 5.25 to 1.0 for periods ending on or before March 31, 2010 and a ratio of 5.00 to 1.0 for periods ending June 30, 2010 and following. At September 30, 2009, our leverage ratio was approximately 3.6 as computed pursuant to the terms of our 364-day Credit Facilities. Our 364-day Credit Facilities also place limitations on the debt that our subsidiaries may incur directly. Accordingly, we are expected to provide debt financing to our subsidiaries as necessary.

Any repayments on the 364-day Credit Facilities must be made pro-rata between the Barclays Agreement and the EUS Agreement, until such time as the Barclays Agreement is repaid. At September 30, 2009, we had no amounts outstanding under our 364-day Credit Facilities and the full amount remains available for our use. Both the Barclays Agreement and EUS Agreement rank equally to our Credit Facility and senior indebtedness and senior to our current and future junior notes.

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 Credit Facility borrowings approximate their fair values at September 30, 2009 and December 31, 2008 due to the short-term nature and frequent repricing of these obligations. The approximate fair values of our long-term debt obligations are determined using a standard methodology that incorporates pricing points that are obtained from independent third-party investment dealers who actively make markets in our debt securities. We use these pricing points to calculate the present value of the principal obligation to be repaid at maturity and all future interest payment obligations for any debt outstanding.

	September 30, 2009		December 31, 2008	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Credit Facility	$ 630.0	$ 630.0	$ 166.8	$ 166.8
9.150% First Mortgage Notes	93.0	99.8	93.0	93.8
5.358% Senior unsecured zero coupon notes due 2022	—	—	214.7	211.0
4.000% Senior Notes due 2009	—	—	175.0	175.2
7.900% Senior Notes due 2012	100.0	110.1	99.9	93.7
4.750% Senior Notes due 2013	199.9	200.8	199.9	163.4
5.350% Senior Notes due 2014	199.9	206.1	199.9	151.3
5.875% Senior Notes due 2016	299.8	314.0	299.8	234.5
7.000% Senior Notes due 2018	99.9	112.1	99.9	81.9
6.500% Senior Notes due 2018	398.2	434.0	398.0	317.7
9.875% Senior Notes due 2019	499.8	670.2	499.7	500.4
7.125% Senior Notes due 2028	99.8	112.7	99.8	72.7
5.950% Senior Notes due 2033	199.7	192.2	199.7	119.7
6.300% Senior Notes due 2034	99.8	99.8	99.8	62.3
7.500% Senior Notes due 2038	398.9	457.8	398.9	289.2
8.050% Junior subordinated notes due 2067	399.4	381.9	399.3	209.3
Total	$3,718.1	$4,021.5	$3,644.1	$2,942.9

8. PARTNERS' CAPITAL

The following table sets forth the distributions, as approved by the Board of Directors of Enbridge Energy Management, L.L.C., which we refer to as Enbridge Management, during the nine month period ended September 30, 2009:

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)	Amount of Distribution of Class C units to Class C unit Holders(2)	Retained from General Partner(3)	Distribution of Cash
		(in millions, except per unit amounts)						
July 24, 2009	August 6, 2009	August 14, 2009	$0.990	$130.3	$15.5	$20.7	$0.7	$93.4
April 30, 2009	May 7, 2009	May 15, 2009	0.990	129.2	15.1	20.1	0.7	93.3
January 30, 2009	February 5, 2009	February 13, 2009	0.990	128.0	14.6	19.5	0.7	93.2

(1) During 2009, in lieu of cash distributions, we issued 1,289,684 i-units to Enbridge Management.

(2) During 2009, in lieu of cash distributions, we issued 1,644,308 Class C units to our Class C unitholders.

(3) We retain an amount equal to 2 percent of the i-unit and Class C unit distribution from the General Partner in respect of its 2 percent general partner interest.

On October 14, 2009, the Class C units converted to Class A common units on a one-for-one basis. See Note 15 *Subsequent Events*.

9. RELATED PARTY TRANSACTIONS

UTOS Disposition

In January 2009, we sold the member interests of our UTOS system for minimal consideration to Enbridge Offshore (Gas Transportation), L.L.C., a wholly-owned subsidiary of Enbridge. The UTOS system transports natural gas from offshore platforms on a fee for service basis to other pipelines onshore for further delivery and does not have long-term contracts. The UTOS system was not considered strategic to our ongoing operations, but is strategically aligned with Enbridge's offshore operations.

Purchase of Line Pipe

We, our general partner and Enbridge Pipelines Inc., which we refer to as Enbridge Pipelines, a subsidiary of Enbridge, regularly collaborate on construction projects that are mutually beneficial to our respective customers and operations. Examples of such projects include the Southern Access and Alberta Clipper crude oil pipeline projects where we have constructed and are constructing the U.S. portion of the projects and Enbridge Pipelines has constructed and is constructing the Canadian portion. In March 2009, we acquired, for $27.0 million, approximately 25 miles of 36-inch diameter line pipe from our general partner for our use in constructing the Alberta Clipper crude oil pipeline project, referred to as the Alberta Clipper Project. The line pipe was initially obtained by our general partner for use in constructing the Southern Access extension, which has been delayed due to a protracted regulatory process. This transaction was previously approved by the Enbridge Management Board of Directors.

Line 13 Exchange and Lease

In connection with the development of a diluent pipeline being constructed by Enbridge Pipelines (Southern Lights), L.L.C., or Southern Lights, a wholly-owned subsidiary of our general partner, we completed the transfer of a 156-mile section of pipeline, which we refer to as Line 13, from our Lakehead system to Southern Lights in exchange for a newly constructed pipeline for transporting light sour crude oil. In connection with the exchange, at the request of shippers and to ensure adequate southbound pipeline capacity prior to the completion of the Alberta Clipper Project, we agreed to lease Line 13 from Southern Lights for monthly payments of $1.8 million. The transfer and lease became effective February 20, 2009, which was the in-service date for the light sour pipeline. The lease of Line 13 will be effective until the earliest of (i) July 1, 2010, (ii) upon the transfer of the Canadian portion of Line 13 from Enbridge Pipelines to Enbridge Southern Lights LP, a wholly-owned subsidiary of Enbridge Pipelines or (iii) early termination of the lease. We are able to terminate the lease at any time during the term by providing Southern Lights with written notice, at which time we would be required to return Line 13 to Southern Lights. The costs associated with the lease are being recovered through a tolling surcharge on our Lakehead system and the net effect on our cash flow over the life of the transaction is expected to approximate zero. The exchange resulted in a $168.8 million increase in "Property, plant and equipment" and the capital account of our general partner included in "Partners' capital" on our September 30, 2009 consolidated statement of financial position, representing the $173.8 million cost of the light sour pipeline that was in excess of the $5.0 million net book value of the Line 13 assets we exchanged. Subsequent to the initial exchange, an additional $8.1 million of costs were incurred by Southern Lights through September 30, 2009 that have been transferred to us through the capital account of our general partner, which are included in the $173.8 million cost presented above. The light sour pipeline is newer and has a slightly higher capacity than Line 13, which will allow us to transport additional volumes of light sour crude oil on our Lakehead system with less integrity and maintenance costs, although depreciation and property tax expense is anticipated to increase in future periods due to the higher book value associated with these assets.

EUS Credit Facility

In April 2009, we entered into a $150 million unsecured and non-guaranteed revolving credit facility agreement with Enbridge (U.S.) Inc., as discussed in Note 7—Debt—*364-day Credit Facilities.*

Purchase of Spearhead Pipeline

In May 2009, we purchased a portion of a crude oil pipeline system from CCPS Transportation, L.L.C., a wholly-owned subsidiary of our general partner, for $75.0 million, representing the carrying value in the records of our general partner. The portion of the system, which we refer to as Spearhead North, includes approximately seven storage tanks and 75 miles of pipeline that our general partner reversed to provide northbound service from Flanagan, Illinois to Griffith, Indiana. The acquisition of Spearhead North will serve to complement the existing operations of our Lakehead system, as our newly-constructed Southern Access pipeline ends in Flanagan where it connects to Spearhead North. The transaction was previously approved by the Enbridge Management Board of Directors.

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. This joint funding arrangement is pursuant to a Contribution Agreement by and among Enbridge Energy Company, Inc., Enbridge Pipelines (Alberta Clipper) L.L.C., Enbridge Energy, Limited Partnership, Enbridge Energy Partners, L.P., Enbridge Pipelines (Lakehead) L.L.C., and Enbridge Pipelines (Wisconsin) Inc. Under the terms of the Contribution Agreement, the parties have agreed to jointly fund, construct and operate the Alberta Clipper Project. To effect the provisions of the Contribution Agreement, the limited partnership agreement for Enbridge Energy, Limited Partnership, which we refer to as the OLP, was amended and restated to establish two distinct series of partnership interests. All the assets, liabilities and operations related to the Alberta Clipper Project are designated specifically by the Series AC interests while all other assets and operations of the OLP are designated by the Series LH interests. Liabilities of the OLP have recourse to both the Series AC and Series LH assets. In exchange for a 66.67 percent ownership interest in the Series AC interests, Enbridge, through our general partner, is funding approximately two-thirds of both the debt financing and equity requirement for the Alberta Clipper Project in return for approximately two-thirds of the Alberta Clipper Project's earnings and cash flows. For our 33.33 percent ownership of the Series AC interests we are funding approximately one-third of the debt financing and required equity of the Alberta Clipper Project, for which we are entitled to approximately one-third of the project's earnings and cash flows. We and our general partner each have a right of first refusal on the other's investment in the Alberta Clipper Project, and we retain the right to fund up to 100 percent of any expansion of the Alberta Clipper Project, which would result in a corresponding adjustment of our general partner's interest.

The funding of the construction costs for the Alberta Clipper Project provided by our general partner are facilitated through a newly established credit facility with us, which we refer to as the A1 Credit Agreement, as well as capital contributions directly by the Series AC holders. The A1 Credit Agreement will be used to fund Enbridge's debt portion of project costs during construction. The A1 Credit Agreement is an unsecured, non-revolving credit facility with a capacity of $400 million and will be utilized for the purpose of funding capital expenditures that are directly related to the Alberta Clipper Project and to refinance the existing indebtedness previously incurred to fund such costs.

Under the A1 Credit Agreement, project expenditures are funded through either a Base Rate Loan or Fixed Period Eurodollar Rate Loan as those terms are defined in the A1 Credit Agreement. Funds drawn under the Base Rate Loan bear interest at a base rate that is equal to the greater of (a) the Federal Funds Rate plus one half of one percent or (b) the "Prime rate" as determined by Bank of America, N.A., from time to time. Funds drawn under Fixed Period Eurodollar Rate Loans will bear interest at a rate per annum equal to the BBA LIBOR plus an additional rate per annum based on the credit rating of our senior unsecured long-term debt as determined by S&P and Moody's. Any interest incurred and outstanding is due on the last business day of March, June, September and December and the maturity date for both the Based Rate and Fixed Period Eurodollar Rate loans.

The A1 Credit Agreement contains restrictive covenants that require us to maintain a maximum leverage ratio of 5.25 to 1.0 for periods ending on or before March 31, 2010 and a maximum ratio of 5.0 to 1.0 for periods ending June 30, 2010 and thereafter. At September 30, 2009, our leverage ratio was approximately 3.6 as computed pursuant to the terms of the A1 Credit Agreement. The A1 Credit Agreement also places limitations on the debt that our subsidiaries may incur directly. Accordingly, we are expected to provide debt financing to our subsidiaries as necessary.

The maturity date of the A1 Credit Agreement is the earlier of July 1, 2011 or the date that is 180 days following the in-service date of the U.S. portion of the Alberta Clipper crude oil pipeline. At points of time either shortly before or shortly after the in-service date for the Alberta Clipper Project, we must use commercially reasonable efforts to issue debt in one or more capital market transactions, the proceeds of which will be used to refinance the loans we make to the OLP on substantially the same terms as the debt issued in the capital market transactions. On the same date, our general partner will refinance its loans with respect to the project on substantially the same terms as we refinanced our loan to the OLP. Repayment of any principal amount outstanding on the A1 Credit Agreement is required on the maturity date. The A1 Credit Agreement allows for the prepayment of borrowings prior to the scheduled maturity date without penalty. The A1 Credit Agreement is limited in recourse only to the Series AC assets. At September 30, 2009, we had $166.1 million outstanding under the A1 Credit Agreement bearing interest at a weighted average rate of 0.578% per annum. Our general partner also made equity contributions totaling $203.0 million to the OLP for both the three and nine month periods ended September 30, 2009, to fund construction costs associated with the Alberta Clipper Project.

10. COMMITMENTS AND CONTINGENCIES

Environmental Liabilities

We are subject to federal and state laws and regulations relating to the protection of the environment. Environmental risk is inherent to liquid hydrocarbon and natural gas pipeline operations, and we could, at times, be subject to environmental cleanup and enforcement actions. We manage this environmental risk through appropriate environmental policies and practices to minimize any impact that our operations may have on the environment. To the extent that we are unable to recover environmental liabilities associated with the Lakehead system assets through insurance, our general partner has agreed to indemnify us from and against any costs relating to environmental liabilities associated with the Lakehead system assets prior to the transfer of these assets to us in 1991. This excludes any liabilities resulting from a change in laws after such transfer. We continue to voluntarily investigate past leak sites on our systems for the purpose of assessing whether any remediation is required in light of current regulations, and, to date, no material environmental risks have been identified.

As of September 30, 2009 and December 31, 2008, we have recorded $7.3 million and $5.5 million, respectively, in "Accounts payable and other" and $2.4 million and $2.8 million, respectively, in "Other long-term liabilities," primarily to address remediation of contaminated sites, asbestos-containing materials, management of hazardous waste material disposal, outstanding air quality measures for certain of our liquids and natural gas assets and penalties we have been or expect to be assessed.

Legal and Regulatory Proceedings

We are a participant in various legal and regulatory proceedings arising in the ordinary course of business. Some of these proceedings are covered, in whole or in part, by insurance. We are also, directly, or indirectly, subject to challenges by special interest groups to regulatory approvals and permits for certain of our expansion projects. We believe that the outcome of these legal and regulatory proceedings and related actions will not, individually or in the aggregate, have a material adverse effect on our financial condition.

11. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

Our net income and cash flows are subject to volatility stemming from changes in interest rates on our variable rate debt obligations and fluctuations in commodity prices of natural gas, NGLs, condensate 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 does not exist within any of our segments, but exists at the corporate level where our variable rate debt obligations are issued. Our exposure to commodity price risk exists within our Natural Gas and Marketing 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 natural gas and NGL sales and purchases and changes in interest rates on our variable rate debt through 2014 in accordance with our risk management policies.

Accounting Treatment

We record all derivative financial instruments in our consolidated financial statements at fair market value, which we adjust each period for changes in the fair market value, which we 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 use actively traded external market quotes and indices to value substantially all of the derivative financial instruments we utilize.

In accordance with the authoritative accounting guidance, if a derivative financial instrument does not qualify as a hedge, or is not designated as a hedge, the derivative is marked-to-market each period with the increases and decreases in fair market value recorded in our consolidated statements of income as increases and decreases in "Cost of natural gas" for our commodity-based derivatives and "Interest expense" for our interest rate derivatives. Cash flow is only impacted to the extent the actual derivative contract is settled by making or receiving a payment to or from the counterparty or by making or receiving a payment for entering into a contract that exactly offsets the original derivative contract. Typically, we settle our derivative contracts when the physical transaction that underlies the derivative financial instrument occurs.

If a derivative financial instrument qualifies and is designated as a cash flow hedge, which is a hedge of a forecasted transaction or future cash flows, any unrealized mark-to-market gain or loss is deferred in "Accumulated other comprehensive income," also referred to as AOCI, a component of "Partners' capital," until the underlying hedged transaction occurs. To the extent that the hedge instrument is effective in offsetting the transaction being hedged, there is no impact to the income statement. At inception and on a quarterly basis, we formally assess whether the hedge contract is highly effective in offsetting changes in cash flows of hedged items. Any ineffective portion of a cash flow hedge's change in fair market value is recognized each period in earnings. Realized gains and losses on derivative financial instruments that are designated as hedges and qualify for hedge accounting are included in "Cost of natural gas" for commodity hedges and "Interest expense" for interest rate hedges in the period in which the hedged transaction occurs. Gains and losses deferred in AOCI related to cash flow hedges for which hedge accounting has been discontinued remain in AOCI until the underlying physical transaction occurs unless it is probable that the forecasted transaction will not occur by the end of the originally specified time period or within an additional two-month period of time thereafter. Generally, our preference is for our derivative financial instruments to receive hedge accounting treatment whenever possible to mitigate the non-cash earnings volatility that arises from recording the changes in fair value of our derivative financial instruments through earnings. To qualify for cash flow hedge accounting treatment as set forth in the authoritative accounting guidance, very specific requirements must be met in terms of hedge structure, hedge objective and hedge documentation.

If a derivative financial instrument is designated and qualifies as a hedge of the change in fair market value of an underlying asset or liability, the gain or loss resulting from the change in fair market value of the derivative financial instrument is recorded in earnings and is adjusted by the gain or loss resulting from the change in fair market value of the underlying asset or liability. Any ineffective portion of a fair value hedge's change in fair market value is recorded in earnings as the amount that is not offset by the gain or loss on the change in fair market value of the underlying asset or liability. Although we do not presently hold any derivative financial instruments designated as fair value hedges, in the past we have designated derivatives as fair value hedges of fixed rate debt in periods of high interest rates to achieve effectively lower variable rates. We include the gains and losses associated with derivative financial instruments designated and qualifying as fair value hedges of our debt obligations in "Interest expense" on our consolidated statements of income. Similar to derivative financial instruments designated as cash flow hedges, to qualify as a fair value hedge very specific requirements must be met in terms of hedge structure, hedge objective and hedge documentation.

Non-Qualified Hedges

Many of our derivative financial instruments qualify for hedge accounting treatment as set forth in the authoritative accounting guidance. However, we have transaction types associated with our commodity and interest rate derivative financial instruments where the hedge structure does not meet the requirements to apply hedge accounting. As a result, these derivative financial instruments do not qualify for hedge accounting and are referred to as "non-qualified." These non-qualified derivative financial instruments are marked-to-market each period with the change in fair value, representing unrealized gains and losses, included in "Cost of natural gas" 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 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 had previously entered into natural gas collars to hedge the sales price of natural gas. The natural gas collars were based on a NYMEX price, 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 will be 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. Our natural gas contracts allow us the option of processing natural gas when it is economical and ceasing to do 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 purchases of natural gas required for processing. We will typically designate derivative financial instruments associated with NGLs we produce at our discretion as cash flow hedges when the processing of natural gas is probable of occurrence. However, we are precluded from designating the derivative financial instruments entered to manage the respective commodity price risk when we are unable to accurately forecast the NGLs to be processed at our discretion. As a result, our operating income will be subject to increased volatility due to fluctuations in NGL prices until the underlying transactions are settled or offset.

- **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, 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 exception 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 will be subject to additional volatility associated with fluctuations in NGL prices until the forward contracts are settled.

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 LIBOR rate 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 will create additional volatility in our earnings.

In all instances related to the commodity price exposures described above, the underlying physical purchase, storage and sale of natural gas and NGLs are accounted for on a historical cost or market basis rather than on the mark-to-market basis we employ for the derivative financial instruments we use 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.

The following table presents the unrealized gains and losses associated with changes in the fair value of our derivatives, which are recorded as an element of "Cost of natural gas" and "Interest expense" in our consolidated statements of income and disclosed as a reconciling item on our consolidated statements of cash flows:

	For the three months ended September 30,		For the nine months ended September 30,	
	2009	2008	2009	2008
	(in millions)			
Natural Gas segment				
Hedge ineffectiveness	$(0.1)	$ 0.1	$ (0.7)	$ (1.1)
Non-qualified hedges	(0.2)	36.5	(12.6)	42.5
Marketing				
Non-qualified hedges	9.0	11.0	19.6	(23.9)
Commodity derivative fair value gains	8.7	47.6	6.3	17.5
Corporate				
Non-qualified interest rate hedges	(1.4)	—	1.0	—
Derivative fair value gains	$ 7.3	$47.6	$ 7.3	$ 17.5

Derivative Positions

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

	September 30, 2009	December 31, 2008
	(in millions)	
Other current assets	$ 23.1	$ 70.6
Other assets, net	26.7	75.7
Accounts payable and other	(26.2)	(40.6)
Other long-term liabilities	(78.3)	(71.0)
	$(54.7)	$ 34.7

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 that were in gain positions 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 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 $1.2 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. For the three and nine month periods ended September 30, 2008, we reclassified from AOCI to "Cost of natural gas" on our consolidated statements of income unrealized net losses of $52.1 million and $112.4 million, respectively. We estimate that approximately $9.9 million, representing unrealized net losses from our cash flow hedging activities based on pricing and positions at September 30, 2009, will be reclassified from AOCI to earnings during the next twelve months.

As of September 30, 2009, we have provided letters of credit totaling $9.9 million in lieu of providing cash collateral to our counterparties pursuant to the terms of our International Securities Dealers Association ("ISDA®") agreements.

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

	September 30, 2009	December 31, 2008
	(in millions)	
Counterparty Credit Quality*		
AAA	$ —	$ —
AA	(3.0)	(39.6)
A	(51.3)	73.3
Lower than A	(1.5)	(1.2)
	(55.8)	32.5
Credit valuation adjustment	1.1	2.2
Total	$(54.7)	$ 34.7

* As determined by nationally recognized statistical ratings organizations.

As the net receivable 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 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 each counterparty's credit rating. 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, but the agreements do not contain additional triggers or automatic termination clauses relating to credit downgrades. 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, 2009, we were in an overall net liability position of $54.7 million, which included assets of $49.8 million. Based on our forward positions at September 30, 2009, 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 an additional $15.8 million in the form of either cash collateral or letters of credit to satisfy the requirements of our ISDA® agreements.

Counterparties to our derivative financial instruments include credit concentrations with U.S. financial institutions, international financial institutions, investment banking entities and, to a lesser extent, international integrated oil companies. At September 30, 2009, approximately $8.9 million of receivables were payable to us from U.S. financial institutions, including investment banks. We are in net liability positions of $2.1 million, $60.9 million and $0.6 million with integrated oil companies, non-U.S. financial institutions and small non-integrated energy companies, respectively, representing amounts payable by us. We are holding no cash collateral on our asset exposures and we have provided letters of credit totaling $9.9 million relating to our liability exposure pursuant to the margin thresholds in effect at September 30, 2009 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. 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 these schedules presented at gross values rather than the net amounts we present in our other derivative schedules, is also provided below.

Effect of Derivative Instruments on the Consolidated Statements of Financial Position

	September 30, 2009			
	Asset Derivatives		Liability Derivatives	
	Financial Position Location	Fair Value	Financial Position Location	Fair Value
	(in millions)			
Derivatives designated as hedging instruments under SFAS No. 133				
Interest rate contracts	Other current assets	$ —	Accounts payable and other	$ (3.7)
Interest rate contracts	Other assets, net	—	Other long-term liabilities	(43.2)
Commodity contracts	Other current assets	26.8	Accounts payable and other	(35.4)
Commodity contracts	Other assets, net	26.8	Other long-term liabilities	(47.0)
		53.6		(129.3)
Derivatives not designated as hedging instruments under SFAS No. 133				
Interest rate contracts	Other current assets	5.7	Accounts payable and other	(4.8)
Interest rate contracts	Other assets, net	7.4	Other long-term liabilities	(5.5)
Commodity contracts	Other current assets	26.8	Accounts payable and other	(18.6)
Commodity contracts	Other assets, net	18.8	Other long-term liabilities	(8.8)
		58.7		(37.7)
Total derivative instruments		$112.3		$(167.0)

Effect of Derivative Instruments on the Consolidated Statements of Income and Accumulated Other Comprehensive Income

For the three months ended September 30, 2009					
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)*	Amount of gain (loss) recognized in earnings on derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)*
		(in millions)			
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)

* 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.

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)*	Amount of gain (loss) recognized in earnings on derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)*
	For the nine months ended September 30, 2009				
	(in millions)				
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)

* 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.

The amount of loss recognized in earnings represents $0.7 million related to the ineffective portion of the hedging relationships.

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 months ended September 30, 2009	For the nine months ended September 30, 2009
		Amount of Gain or (Loss) Recognized in Earnings*	
		(in millions)	
Interest rate contracts	Interest expense	$(1.4)	$1.0
Commodity contracts	Cost of natural gas	8.8	7.0
Total		$ 7.4	$8.0

* 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, 2009		
	Assets	Liabilities	Total
		(in millions)	
Fair value of derivatives—gross presentation	$112.3	$(167.0)	$(54.7)
Effects of netting agreements	(62.5)	62.5	—
Fair value of derivatives—net presentation	$ 49.8	$(104.5)	$(54.7)

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, 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. We have reclassified the fair value of derivative financial instruments that we value using pricing inputs derived from observable data to Level 2 in the following table after determining the pricing inputs used to value these financial instruments are not directly observable from prices quoted by an exchange.

	September 30, 2009				December 31, 2008			
Recurring fair value measures	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
				(in millions)				
Assets:								
Derivative instruments, net	$—	$ 8.1	$47.8	$ 55.9	$—	$ 20.4	$119.6	$ 140.0
Liabilities:								
Derivative instruments, net	—	(105.9)	(4.7)	(110.6)	—	(77.5)	(27.8)	(105.3)
Total	$—	$ (97.8)	$43.1	$ (54.7)	$—	$(57.1)	$ 91.8	$ 34.7

The table below provides a reconciliation of changes in the fair value of our Level 3 financial assets and liabilities from January 1, 2009 to September 30, 2009 and from January 1, 2008 to September 30, 2008, for the respective periods. Interest rate swaps totaling $1.8 million were reclassified to Level 2 following our evaluation of the inputs used to compute fair value for these financial instruments and determination that the valuation inputs are more closely correlated with those that meet the qualifications for Level 2 classification as the values are derived from observable inputs, but are not directly observable.

	2009	**2008**
	(in millions)	
Beginning balance as of January 1	$ 91.8	$(160.6)
Realized and unrealized net losses	(49.4)	(44.3)
Purchases	(1.7)	(2.5)
Transfer out of Level 3	(1.8)	—
Balance as of June 30	38.9	(207.4)
Realized and unrealized net gains	2.1	123.6
Purchases	2.1	1.0
Transfer out of Level 3	—	—
Balance as of September 30	$ 43.1	$ (82.8)
Change in unrealized net gains (losses) relating to instruments still held at September 30:		
For the three months ended September 30	$ 27.1	$ 95.9
For the nine months ended September 30	$(11.8)	$ 4.6

Fair Value Measurements of Commodity Derivatives

The following table provides summarized information about the fair values of our outstanding commodity derivative instruments at September 30, 2009 and December 31, 2008.

	At September 30, 2009						At December 31, 2008	
			Wtd. Average Price[2]		Fair Value[3]		Fair Value[3]	
	Commodity	Notional[1]	Receive	Pay	Asset	Liability	Asset	Liability
Contracts maturing in 2009								
Swaps								
Receive variable/pay fixed	Natural Gas	4,900,031	$ 4.57	$ 6.15	$ 0.9	$ (8.7)	$ 2.5	$(56.0)
	NGL	82,454	43.60	52.55	—	(0.7)	—	(6.5)
Receive fixed/pay variable	Natural Gas	4,214,846	5.14	4.71	4.0	(2.1)	38.7	(19.6)
	NGL	1,250,894	40.81	37.45	6.0	(1.8)	70.0	—
	Crude Oil	187,364	66.62	71.06	0.7	(1.5)	5.8	(0.6)
Receive variable/pay variable	Natural Gas	34,406,444	4.43	4.34	5.4	(2.3)	8.9	(12.8)
Options								
Calls (written)	Natural Gas	92,000	4.31	4.80	—	(0.1)	—	(0.6)
Puts (written)	Natural Gas	—	5.79	9.22	—	—	—	(1.2)
Puts (purchased)	Natural Gas	92,000	4.80	3.40	—	—	—	—
	NGL	328,164	37.54	36.57	1.1	—	9.3	—
	Crude Oil	64,400	71.06	64.86	—	—	—	—
Physical Contracts								
Receive variable/pay fixed	NGL	145,000	50.33	48.66	0.2	—	—	—
Receive fixed/pay variable	NGL	828,747	48.12	50.36	0.4	(2.3)	—	—
Contracts maturing in 2010								
Swaps								
Receive variable/pay fixed	Natural Gas	5,353,464	$ 5.91	$ 6.88	$ 1.3	$ (6.5)	$ 2.5	$ (6.5)
	NGL	120,000	61.73	45.30	2.0	—	—	(1.3)
Receive fixed/pay variable	Natural Gas	10,380,620	4.49	6.12	2.0	(18.9)	2.2	(27.5)
	NGL	2,947,010	42.69	41.08	17.0	(12.3)	28.0	—
	Crude Oil	720,790	71.95	74.38	4.2	(5.9)	5.5	(0.5)
Receive variable/pay variable	Natural Gas	79,751,813	5.95	5.87	8.8	(2.0)	0.8	(3.1)
Options								
Calls (written)	Natural Gas	365,000	4.31	6.21	—	(0.7)	—	(1.0)
Puts (purchased)	Natural Gas	365,000	4.80	3.40	—	—	—	—
	NGL	971,995	44.30	42.85	8.0	—	5.2	—
	Crude Oil	298,935	74.52	70.87	1.8	—	—	—
Physical Contracts								
Receive fixed/pay variable	NGL	126,283	42.96	46.51	—	(0.5)	—	—
	Crude Oil	5,055	—	67.25	—	(0.4)	—	—
Contracts maturing in 2011								
Swaps								
Receive variable/pay fixed	Natural Gas	878,475	$ 6.66	$ 9.78	$ —	$ (2.7)	$ 2.6	$ (3.4)
	NGL	120,000	64.25	47.67	2.0	—	—	—
Receive fixed/pay variable	Natural Gas	7,513,500	3.74	6.87	—	(23.1)	1.1	(28.1)
	NGL	581,810	55.84	43.33	8.8	(1.6)	13.0	(0.3)
	Crude Oil	676,625	71.76	77.38	1.5	(5.2)	3.3	(0.8)
Receive variable/pay variable	Natural Gas	15,885,000	6.86	6.76	1.6	(0.1)	—	(1.0)
Options								
Calls (written)	Natural Gas	365,000	4.31	6.87	—	(1.0)	—	(1.0)
Puts (purchased)	Natural Gas	365,000	4.80	3.40	—	—	—	—
	NGL	83,220	63.34	39.55	2.3	—	2.7	—
Contracts maturing in 2012								
Swaps								
Receive variable/pay fixed	Natural Gas	759,709	$ 6.82	$ 9.96	$ —	$ (2.2)	$ 0.8	$ (2.1)
	NGL	—	—	—	—	—	—	(0.9)
Receive fixed/pay variable	Natural Gas	1,274,000	3.57	7.47	—	(4.8)	—	(5.8)
	NGL	458,598	69.11	45.61	10.4	(0.1)	15.7	—
	Crude Oil	402,600	75.98	79.32	—	(1.3)	0.8	—
Receive variable/pay variable	Natural Gas	1,089,000	6.81	6.38	0.4	—	—	—
Options								
Puts (purchased)	NGL	128,832	66.80	42.58	3.8	—	4.4	—
Contracts maturing in 2013								
Swaps								
Receive fixed/pay variable	Natural Gas	730,000	$ 9.83	$ 6.73	$ 2.1	$ —	$ 2.0	$ —
	NGL	90,155	35.68	40.16	—	(0.4)	—	—
	Crude Oil	328,500	85.91	81.24	2.9	(1.5)	3.4	—
Contracts maturing in 2014								
Swaps								
Receive fixed/pay variable	Crude Oil	36,500	$86.00	$83.31	$ 0.1	$ —	$ —	$ —

(1) Volumes of Natural gas are measured in millions of British Thermal Units, or MMBtu, whereas volumes of NGL and Crude Oil are measured in barrels, or Bbl.

(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, 2009 and December 31, 2008, 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.

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.

		Partnership			Fair Value	
	Notional Principal	Pays	Receives	Maturity Date	September 30, 2009	December 31, 2008
	(dollars in millions)				(dollars in millions)	
Interest Rate Swaps						
Floating to Fixed:						
	$ 50.0	4.6175%	LIBOR[2]	January 15, 2009	$ —	$ —
	$ 50.0	4.6130%	LIBOR	January 29, 2009	—	—
	$ 50.0	4.6525%	LIBOR	February 13, 2009	—	(0.1)
	$ 50.0	4.5875%	LIBOR	February 20, 2009	—	(0.2)
	$ 50.0	1.6510%	LIBOR	December 2, 2010	(0.4)	—
	$ 50.0	1.6570%	LIBOR	December 5, 2010	(0.4)	—
	$ 50.0	1.6870%	LIBOR	December 12, 2010	(0.4)	—
	$ 50.0	1.7040%	LIBOR	December 14, 2010	(0.4)	—
	$ 50.0	1.7180%	LIBOR	December 18, 2010	(0.4)	—
	$ 50.0	4.3700%	LIBOR-21 bps[1]	June 1, 2013	(4.2)	(5.3)
	$ 50.0	4.3425%	LIBOR-21 bps	June 1, 2013	(4.2)	(5.2)
	$ 25.0	4.3100%	LIBOR-25 bps	June 1, 2013	(2.1)	(2.7)
	$ 50.0	4.1160%	LIBOR	December 2, 2013	(1.5)	—
	$ 50.0	4.1250%	LIBOR	December 4, 2013	(1.5)	—
	$ 50.0	4.1320%	LIBOR	December 8, 2013	(1.5)	—
	$ 50.0	4.1270%	LIBOR	December 10, 2013	(1.5)	—
	$ 50.0	4.1570%	LIBOR	December 12, 2013	(1.5)	—
	$ 50.0	4.1720%	LIBOR	December 14, 2013	(1.6)	—
	$ 75.0	4.1380%	LIBOR	December 15, 2013	(2.2)	—
	$ 50.0	4.1740%	LIBOR	December 18, 2013	(1.6)	—
	$ 50.0	4.1920%	LIBOR	December 22, 2013	(1.6)	—
	$125.0	4.1680%	LIBOR	December 31, 2013	(3.9)	—
Fixed to Floating:						
	$ 25.0	LIBOR-25 bps	4.7500%	June 1, 2013	2.5	3.1
	$ 50.0	LIBOR-21 bps	4.7500%	June 1, 2013	4.9	6.1
	$ 50.0	LIBOR-21 bps	4.7500%	June 1, 2013	4.9	6.1
Rate Locks:						
	$ 20.0	4.6230%	LIBOR	June 30, 2020	(1.4)	—
	$200.0	4.6190%	LIBOR	June 30, 2020	(13.9)	—
	$300.0	4.5150%	LIBOR	December 14, 2022	(3.4)	—
	$100.0	4.6060%	LIBOR	December 14, 2022	(1.8)	—
	$200.0	4.6190%	LIBOR	December 14, 2022	(3.8)	—
	$150.0	4.6650%	LIBOR	December 13, 2023	(2.0)	—
	$150.0	4.5800%	LIBOR	December 13, 2023	(1.0)	—
Interest Rate Caps:						
	$ 25.0	1.0900%	LIBOR	December 17, 2010	0.1	—
	$ 50.0	1.1500%	LIBOR	December 22, 2010	0.1	—
	$125.0	1.0700%	LIBOR	December 31, 2010	0.3	—
	$ 50.0	1.1450%	LIBOR	January 4, 2011	0.1	—
	$ 25.0	1.1500%	LIBOR	January 8, 2011	0.1	—
	$ 50.0	1.1150%	LIBOR	January 10, 2011	0.1	—
	$ 75.0	1.1500%	LIBOR	January 15, 2011	0.2	—

(1) A bps refers to a basis point. One basis point is equivalent to 1/100th of 1 percent.

(2) LIBOR refers to the one-month or three-month U.S. London Interbank Offered Rate.

12. SEGMENT INFORMATION

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

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

- Liquids;
- Natural Gas; and
- Marketing.

The following tables present financial information about our business segments:

	For the three months 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
Capital expenditures (excluding acquisitions)	$237.3	$ 28.2	$ —	$ 3.3	$ 268.8

(1) Corporate consists of interest expense, interest income and certain other costs such as franchise and income taxes, which are not allocated to our business segments.

	For the three months ended September 30, 2008				
	Liquids	Natural Gas	Marketing	Corporate[1]	Total
			(in millions)		
Total revenue	$209.3	$2,190.9	$1,352.8	$ —	$3,753.0
Less: Intersegment revenue	0.1	928.5	54.2	—	982.8
Operating revenue	209.2	1,262.4	1,298.6	—	2,770.2
Cost of natural gas	—	1,091.4	1,284.8	—	2,376.2
Operating and administrative	52.0	79.1	2.5	1.6	135.2
Power	35.0	—	—	—	35.0
Depreciation and amortization	26.7	27.7	0.4	—	54.8
Operating income	95.5	64.2	10.9	(1.6)	169.0
Interest expense	—	—	—	50.7	50.7
Other income	—	—	—	0.2	0.2
Income from continuing operations before income tax expense	95.5	64.2	10.9	(52.1)	118.5
Income tax expense	—	—	—	1.9	1.9
Income from continuing operations	95.5	64.2	10.9	(54.0)	116.6
Income from discontinued operations	—	2.8	—	—	2.8
Net income	$ 95.5	$ 67.0	$ 10.9	$(54.0)	$ 119.4
Capital expenditures (excluding acquisitions)	$261.1	$ 62.7	$ —	$ 4.3	$ 328.1

(1) Corporate consists of interest expense, interest income and certain other costs such as franchise and income taxes, which are not allocated to our business segments.

	As of and for the nine months 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
Operating and administrative	174.8	215.9	5.3	3.0	399.0
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 and certain other costs such as franchise and income taxes, which are not allocated to our business segments.

	As of and for the nine months ended September 30, 2008				
	Liquids	Natural Gas	Marketing	Corporate[1]	Total
			(in millions)		
Total revenue	$ 555.5	$6,252.7	$4,025.8	$ —	$10,834.0
Less: Intersegment revenue	0.3	2,582.9	206.1	—	2,789.3
Operating revenue	555.2	3,669.8	3,819.7	—	8,044.7
Cost of natural gas	—	3,201.8	3,817.8	—	7,019.6
Operating and administrative	130.8	220.7	7.1	4.7	363.3
Power	104.6	—	—	—	104.6
Depreciation and amortization	73.0	79.0	1.3	—	153.3
Operating income (loss)	246.8	168.3	(6.5)	(4.7)	403.9
Interest expense	—	—	—	129.6	129.6
Other income	—	—	—	1.5	1.5
Income (loss) from continuing operations before income tax expense	246.8	168.3	(6.5)	(132.8)	275.8
Income tax expense	—	—	—	5.0	5.0
Income (loss) from continuing operations	246.8	168.3	(6.5)	(137.8)	270.8
Income from discontinued operations	—	10.5	—	—	10.5
Net income (loss)	$ 246.8	$ 178.8	$ (6.5)	$(137.8)	$ 281.3
Total assets	$3,709.9	$3,692.5	$ 353.1	$ 225.6	$ 7,981.1
Capital expenditures (excluding acquisitions)	$ 762.8	$ 226.6	$ —	$ 10.8	$ 1,000.2

(1) Corporate consists of interest expense, interest income and certain other costs such as franchise and income taxes, which are not allocated to our business segments.

13. UNRECORDED REVENUES

The OLP was party to a joint tariff agreement with Mustang Pipe Line, LLC, or Mustang, which owns a 100,000 barrel per day, or Bpd, crude oil pipeline that connects with our Lakehead system at Lockport, Illinois and transports crude oil to the Patoka, Illinois area. Mustang is 70% owned by a major integrated oil company that also serves as the operator and is 30% owned by Enbridge. The Mustang joint tariff arrangement is an unusual structure within our liquids pipeline system, since we have no other arrangements where neither we nor Enbridge are the billing carrier or operator of the pipeline with which we have a joint tariff arrangement.

Our joint tariff agreement with Mustang that was in place from October 2005 through March 2009 allowed for shippers on our Lakehead system to reach markets downstream of Chicago at a discounted transportation rate for their commitments to transport crude oil on our Lakehead system and then on the Mustang pipeline. Since October 2005, we incorrectly invoiced a shipper on our Lakehead system, which was not a committed shipper, at the discounted transportation rate. Additionally, we continued to invoice two other shippers whose commitments expired in September 2008 at discounted transportation rates rather than the undiscounted non-committed shipper rates. Due to our incorrectly invoicing these shippers, we understated approximately $13.5 million of operating revenues on our Lakehead system from October 2005 through December 2008. We invoiced and collected the previously unbilled amounts from these shippers in the first quarter of 2009. We have included the entire $13.5 million as revenue in our consolidated statement of income for the nine month period ended September 30, 2009 following our determination that the previously unbilled amounts were not material to any prior period financial statements.

In connection with the invoicing errors noted above, we have also identified differences between the volumes we measured as delivered to the Mustang pipeline system at Lockport for five committed shippers and the volumes that Mustang reported as delivered at Patoka for the same committed shippers. We continue to investigate these volume discrepancies with the operator of Mustang to ascertain whether additional amounts may be due to us for unbilled transportation services we have provided to transport between nine million and 11 million barrels of crude oil on our Lakehead system, which could result in up to $12 million of additional revenue. Regardless of the outcome of our investigation into these volumetric differences, we can provide no assurance that we will be able to collect any amounts that we may determine are due to us.

14. REGULATORY MATTERS

Regulatory Accounting

Certain of our liquids and natural gas transportation services are subject to regulation by the Federal Energy Regulatory Commission, referred to as the FERC, and various state authorities. Regulatory bodies exercise statutory authority over matters such as construction, rates and underlying accounting practices and ratemaking agreements with customers. Accordingly, we record certain assets and liabilities that result from the regulated ratemaking process that would not be recorded for non-regulated entities under U.S. GAAP. In April 2009, we began applying the authoritative accounting provisions applicable to the regulated operations of our Southern Access Project, when the facilities rate surcharge associated with the project was both approved by the FERC and uncontested by any of our customers. The rates for the Southern Access Project are based on a cost-of-service recovery model that follows the FERC's authoritative guidance and is subject to annual filing requirements with the FERC. Under our cost-of-service tolling methodology we calculate tolls based on forecast volumes and costs. A difference between forecast and actual results causes an under or over collection of revenue in any given year. During 2009 we have under collected revenue related to our Southern Access Project in-part because actual volumes have been lower than the forecast volumes used to calculate the toll surcharge. Under the authoritative accounting provisions applicable to our regulated operations, over or under collections of revenue are recognized in the financial statements currently and these amounts are realized or settled as cash the following year. This accounting model matches earnings to the period with which they relate and conforms to how we recover our costs associated with these expansions through the annual cost-of-service filings with our customers and the regulator. For the three and nine month periods ended September 30, 2009, we recognized $7.4 million of additional revenue on our consolidated statements of income, along with a corresponding regulatory receivable on our consolidated statement of financial position at September 30, 2009 related to the difference in transportation volumes. These revenues were earned during 2009, but will not be realized as cash until 2010 when we update our transportation rates to account for the lower actual delivered volume than estimated.

On August 20, 2009, our Alberta Clipper Project received the Presidential Border Crossing Permit from the U.S. Department of State, which will allow crude oil that will be shipped on the mainline system in Canada to cross the international border near Neche, North Dakota and be transported on the Alberta Clipper pipeline into the United States. The permit enables our planned construction of the Alberta Clipper Project to continue and ultimately, when completed, allows us to institute a cost-of-service model to recover the costs of construction from our customers through the transportation rates we will charge. As a result, we began applying the authoritative accounting provisions applicable to the regulated activities of our Alberta Clipper Project. We are permitted to capitalize and recover costs for rate-making purposes that include an allowance for equity costs during construction, referred to as AEDC. In connection with construction of the Alberta Clipper Project, we recorded $2.4 million of AEDC in "Property, plant and equipment" on our consolidated statement of financial position at September 30, 2009, and a corresponding $2.4 million of "Other income," in our consolidated statements of income for the three and nine month periods ended September 30, 2009.

FERC Transportation Tariffs-Liquids

Effective April 1, 2009, 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 2009 related to our expansion projects. The projected costs for 2009 include three additional projects, the most significant being the Southern Lights replacement capacity project. The projected costs also include a rate update for two existing projects including the Hartsdale tanks charge and the Southern Access Project for the inclusion of the recently completed Stage 2 of the project. This filing increased the average transportation rate for crude oil movements from the Canadian border to Chicago by approximately $0.15 per barrel, to an average of approximately $1.41 per barrel. In May 2009 we began realizing revenues in relation to this increased surcharge as crude oil was delivered from our pipeline.

Effective May 1, 2009, we filed a tariff with the FERC to reflect the addition of Flanagan, Illinois as a delivery point on our Lakehead system. The new delivery point is a component of the Southern Access Project. Notwithstanding the new rates for the delivery point in Flanagan, all rates in this tariff filing remain unchanged from the tariff filing effective April 1, 2009, discussed above. The average transportation rate for crude oil movements from the Canadian border to Flanagan will be approximately $1.41 per barrel, which is the same as other points in the Chicago region.

Effective July 1, 2009, we increased the rates for transportation on our Lakehead, North Dakota and Ozark systems in compliance with the indexed rate ceilings allowed by the FERC. In 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 Southern Access Project. Effective July 2009, we increased the base tariff rates on our Lakehead system by an average of 7.6 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 $1.46 per barrel, which reflects a $0.05 per barrel increase over the rates filed effective April 1, 2009. In addition to the rates on our Lakehead system, we increased the transportation rates on our North Dakota and Ozark systems 7.6 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

We have evaluated events subsequent to September 30, 2009 through November 4, the date we issued these financial statements, and identified the events disclosed below.

Class C Unit Conversion

On October 14, 2009, we effected the conversion of all our outstanding Class C units into Class A common units in accordance with the terms of our partnership agreement. The conversion became effective upon the determination by our general partner that the converted Class C units would have, as a substantive matter, like intrinsic economic and federal income tax characteristics, in all material respects, to the intrinsic economic and federal income tax characteristics of our outstanding Class A common units. Our general partner made this determination after adjustments were made to the capital accounts of our limited partners in connection with the private placement of Class A common units described below.

The Class C units converted on a one-for-one basis, resulting in the issuance of 21,333,273 Class A common units and a cash payment of $123.21 for the 2.608092 remaining fractional units. In order to facilitate the conversion of the Class C units described above, on October 14, 2009, we issued and sold 21,245 Class A common units to our general partner in a private placement for an aggregate purchase price of approximately $1 million, or $47.07 per unit, the closing price of the Class A common units on the New York Stock Exchange on October 13, 2009.

Sale of Natural Gas Pipeline Assets

In November 2009, we completed the sale of our non-core natural gas pipeline assets that are presented as "Assets held for sale" on our consolidated statement of financial position and are discussed in Note 3—*Discontinued Operations*. The sale did not significantly affect our financial position or results of operations beyond what has been presented in our consolidated financial statements. The sales price of our non-core natural gas pipeline assets was $150.8 million in cash, and will be subject to adjustments for working capital items subsequent to the closing of the transaction.

Distribution to Partners

On October 29, 2009, the Board of Directors of Enbridge Management declared a distribution payable to our partners on November 13, 2009. The distribution will be paid to unitholders of record as of November 5, 2009, of our available cash of $131.3 million at September 30, 2009, or $0.990 per common unit. Of this distribution, $115.1 million will be paid in cash, $15.9 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 distributions.

16. RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

Accounting Standards Update—Measuring Liabilities at Fair Value

In August 2009, the Financial Accounting Standards Board, or FASB, issued an accounting update to supplement and amend the guidance surrounding fair value measurements and disclosures. The accounting standards update was issued to clarify how an entity should measure the fair value of liabilities. If a quoted price in an active market for the identical liability is available, it represents a Level 1 fair value measurement. In circumstances where a quoted price in an active market for the identical liability is not available, an entity must measure fair value using one or more of the following techniques:

- A valuation technique that uses the quoted price of the identical liability when traded as an asset;
- A valuation technique that uses the quoted price for similar liabilities or similar liabilities when traded as assets; and
- Another valuation technique that is consistent with the principles of fair value measurements, such as an income approach or market approach.

The accounting update is effective for the first reporting period beginning after August 2009, with early application being permitted for financial statements for earlier periods that have not been issued. We did not adopt the provisions of this pronouncement early. We do not expect our adoption of this pronouncement to have a material effect on our financial statements other than modifications to our existing fair value disclosures.

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 should be read together with our consolidated financial statements and the accompanying notes included in "Item 1. Financial Statements" of this report.

Additionally, this quarterly report on Form 10-Q should be read in conjunction with our Annual Report on Form 10-K for the year ended December 31, 2008.

IMPACT OF CURRENT ECONOMIC CONDITIONS

We have taken several tangible steps to enhance our liquidity position since the end of 2008. First, we continue to limit our capital expenditure activities to those projects strategic to us. We have also enhanced liquidity in the form of our $350 million 364-day Credit Facilities, as discussed below. Most significantly, we recently announced a joint funding arrangement for our Alberta Clipper expansion project, referred to as the Alberta Clipper Project, through which our general partner and other affiliates of ours and Enbridge Inc., or Enbridge, participate jointly in financing the United States portion of the construction project. Following our announcement of the Alberta Clipper joint funding arrangement, both Standard & Poor's Ratings Services and Moody's Investors Service revised their ratings outlook on our senior unsecured debt to stable from negative. Standard & Poor's also raised our short-term rating to A-2 from A-3, which allows us to once again access the commercial paper market. Lastly, in September 2009, in an effort to further satisfy our financing needs, we committed to sell certain of our non-core natural gas pipeline assets located predominantly outside of Texas (see below, Results of Operations, *Natural Gas—Other Matters*).

The steps we have taken as described above are intended to maintain sufficient liquidity to fund our remaining growth programs and sustain the present distribution rate to our unitholders, while preserving our credit rating. Maintaining adequate liquidity may also involve the issuance of debt and equity and could involve the additional sale of additional non-core assets, further asset partnership or joint venture arrangements or other strategies to limit the amount of external funding required for our growth projects.

RESULTS OF OPERATIONS—OVERVIEW

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

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

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

The following table reflects our operating income by business segment and corporate charges for the three and nine month periods ended September 30, 2009 and 2008. We have removed from "Income from continuing operations" for each of the periods presented the amounts comprising the operating results of certain non-core natural gas pipeline assets that we committed to sell, which amounts are presented in "Income (loss) from discontinued operations."

	For the three months ended September 30,		For the nine months ended September 30,	
	2009	2008	2009	2008
	(unaudited; in millions)			
Operating Income				
Liquids	$132.7	$ 95.5	$339.7	$246.8
Natural Gas	47.0	64.2	113.1	168.3
Marketing	9.2	10.9	37.5	(6.5)
Corporate, operating and administrative	(0.9)	(1.6)	(3.0)	(4.7)
Total Operating Income	188.0	169.0	487.3	403.9
Interest expense	60.7	50.7	169.9	129.6
Other income	2.8	0.2	2.5	1.5
Income tax expense	2.7	1.9	6.8	5.0
Income from continuing operations	127.4	116.6	313.1	270.8
Income (loss) from discontinued operations	(67.9)	2.8	(67.5)	10.5
Net income	59.5	119.4	245.6	281.3
Less: Net income attributable to noncontrolling interest	2.3	—	2.3	—
Net income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 57.2	$119.4	$243.3	$281.3

Contractual arrangements in our Natural Gas and Marketing segments expose us to market risk associated with changes in commodity prices where we receive 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 very significant as evidenced by commodity prices during 2008. We employ derivative financial instruments to hedge a portion of our commodity position and to reduce our exposure to fluctuations in natural gas, NGL and crude oil prices. Some of these derivative financial instruments do not qualify for hedge accounting under the provisions of authoritative accounting guidance, which can create volatility in our earnings that can be significant. However, these fluctuations in earnings do not affect our cash flow. Cash flow is only affected when we settle the derivative instrument.

Summary Analysis of Operating Results

Liquids

The operating income of our Liquids segment for the three and nine month periods ended September 30, 2009, as compared with the same periods in 2008, was affected by the following:

- Transportation rate increases that went into effect in January, April and July 2009, which include increases in our tolls associated with the annual index rate ceiling adjustments, additional facilities added and a true-up of prior year transportation rate surcharges;
- Completion and start-up of the second stage of our Southern Access expansion project, referred to as the Southern Access Project, and the Phase V expansion of our North Dakota system;
- Higher delivered volumes on our Lakehead system;
- Revenue recognized in the third quarter of 2009 resulting from our application of regulatory accounting to our Southern Access Project and Alberta Clipper Project; and

- Additional spot storage fee revenue generated by our Mid-Continent storage terminal system.

The above increases to operating income were partially offset by:

- Lower prices associated with the allowance oil we receive; and
- Increased operating costs and depreciation associated with the additional assets we have placed into service.

Natural Gas

In September 2009, we committed to sell certain of our non-core natural gas pipeline assets located predominantly outside of Texas. We have presented in “Income from discontinued operations” the income and loss we derived from these assets for the three and nine month periods ended September 30, 2009 and 2008. We recorded an impairment charge of $66.1 million in the three and nine month periods ended September 30, 2009 to reduce the carrying amount of the natural gas pipeline assets we classified as held for sale to our estimate of the fair value of these assets.

The following factors affected the operating income of our Natural Gas business for the three month period ended September 30, 2009 compared to the same period of 2008:

- A $36.9 million decrease resulting from $0.3 million of unrealized, non-cash, mark-to-market losses from derivative instruments that do not qualify for hedge accounting treatment under authoritative accounting guidance, as compared with gains of $36.6 million for the same period of 2008;
- An approximate $7 million reduction in revaluation losses with respect to our in-kind natural gas imbalances due to less volatile commodities markets during the three months of 2009 when compared to same period in 2008;
- Decline in transportation volumes associated with lower natural gas production in the areas we serve;
- The operational disruptions related to hurricanes Gustav and Ike as well as measurement losses that existed in 2008 were not present during the same periods of 2009; and
- Overall improvement in operating and administrative costs as a result of our cost reduction measures, partially offset by increased depreciation associated with our completed expansion projects.

For the nine month period ended September 30, 2009, in addition to the factors discussed above, we had $13.3 million of unrealized, non-cash, mark-to-market losses associated with derivative financial instruments that do not qualify for hedge accounting treatment under authoritative accounting guidance compared with $41.4 million of gains we experienced in the same period of 2008.

Marketing

The operating results of our Marketing segment for the three month period ended September 30, 2009 compared to the same period in 2008 were affected by the following:

- A reduction in operating revenues and additional margin from the sale of natural gas to our customers as a result of lower natural gas prices;
- $2.0 million decline in unrealized, non-cash, mark-to-market net gains of $9.0 million in 2009 from $11.0 million in the same period of 2008 associated with derivative financial instruments that do not qualify for hedge accounting treatment under authoritative accounting guidance;
- Continued narrowing of natural gas transportation differentials between market centers, which benefited our hedged transportation positions; and
- Revaluation losses with respect to our in-kind natural gas imbalances of $5.9 million in 2008 that were not present during the same period in 2009.

The operating results of our Marketing segment for the nine month period ended September 30, 2009 were positively affected by $19.6 million of unrealized, non-cash, mark-to-market gains associated with derivative financial instruments that do not qualify for hedge accounting treatment under authoritative accounting guidance. The gains for the nine month period ended September 30, 2009 resulted primarily from our hedged transportation positions which benefitted from the narrowing of the differences between the purchase and sales prices of natural gas. Conversely, the operating results for the nine month period ended September 30, 2008 were negatively impacted by $23.9 million of unrealized, non-cash, mark-to-market losses associated with derivative financial instruments. The non-cash, mark-to-market losses resulted from increases in the forward and daily market prices of natural gas from December 31, 2007 to September 30, 2008.

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 interest rates and commodity prices and minimize 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 interest rates or commodity prices. We record all derivative instruments in our consolidated financial statements at fair market value pursuant to the requirements of applicable authoritative accounting guidance. For those derivative instruments that do not qualify for hedge accounting, we record all changes in fair market value through our consolidated statements of income each period.

The following table presents the unrealized gains and losses associated with changes in the fair value of our derivative instruments, which are recorded as an element of “Cost of natural gas” or “Interest expense” in our consolidated statements of income and disclosed as a reconciling item on our consolidated statements of cash flows:

	For the three months ended September 30,		For the nine months ended September 30,	
	2009	2008	2009	2008
	(unaudited; in millions)			
Natural Gas segment				
Hedge ineffectiveness	$(0.1)	$ 0.1	$ (0.7)	$ (1.1)
Non-qualified hedges	(0.2)	36.5	(12.6)	42.5
Marketing				
Non-qualified hedges	9.0	11.0	19.6	(23.9)
Commodity derivative fair value gains	8.7	47.6	6.3	17.5
Corporate				
Non-qualified interest rate hedges	(1.4)	—	1.0	—
Derivative fair value gains	$ 7.3	$47.6	$ 7.3	$ 17.5

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 months ended September 30,		For the nine months ended September 30,	
	2009	2008	2009	2008
	(unaudited; in millions)			
Operating Results				
Operating revenues	$262.1	$209.2	$709.9	$555.2
Operating and administrative	61.2	52.0	174.8	130.8
Power	33.7	35.0	96.9	104.6
Depreciation and amortization	34.5	26.7	98.5	73.0
Operating expenses	129.4	113.7	370.2	308.4
Operating Income	$132.7	$ 95.5	$339.7	$246.8
Operating Statistics				
Lakehead system:				
United States(1)	1,351	1,233	1,296	1,242
Province of Ontario(1)	350	331	346	344
Total Lakehead system deliveries(1)	1,701	1,564	1,642	1,586
Barrel miles (billions)	108	105	316	317
Average haul (miles)	688	730	706	729
Mid-Continent system deliveries(1)	241	227	239	238
North Dakota system:				
Trunkline	107	101	108	103
Gathering	6	6	6	6
Total North Dakota system deliveries(1)	113	107	114	109
Total Liquids Segment Delivery Volumes(1)	2,055	1,898	1,995	1,933

(1) Average barrels per day, or Bpd in thousands.

Three months ended September 30, 2009 compared with three months ended September 30, 2008

Our Liquids segment accounted for $132.7 million of operating income during the three months ended September 30, 2009, an increase of $37.2 million from the $95.5 million generated during the same period in 2008. The favorable results are primarily attributable to transportation rate increases that went into effect during 2009, increased volumes on our Lakehead system, partially offset by higher operating and administrative costs, and depreciation.

Operating revenue for the three months ended September 30, 2009 increased by $52.9 million to $262.1 million from $209.2 million for the same period in 2008. The increase in operating revenue is due to the following:

- Increased average rates for transportation on all of our major systems as noted below;
- Higher delivered volumes on our Lakehead system;
- Additional revenue recognized in the third quarter of 2009 resulting from our application of the provisions of regulatory accounting; and
- Additional storage fee revenue generated by our Mid-Continent storage terminal system.

These increases in operating revenue were partially offset by lower average crude oil prices associated with the allowance oil we receive in connection with our transportation services.

Increases in average transportation rates on all three Liquids systems contributed approximately $33.8 million of additional operating revenue. The rate increases included the following:

- Effective January 1, 2009, we increased the rates for transportation on our North Dakota system to include an updated calculation of the two surcharges related to the Phase V Expansion program;
- Effective April 1, 2009, we increased the rates for transportation on our Lakehead system in connection with the completion of Stage 2 of our Southern Access 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 our Southern Access Stage 1 project; and
- Effective July 1, 2009, we increased the average transportation rates on all three of our Liquids systems in connection with the annual index rate ceiling adjustment.

Average delivery volumes on our Lakehead system increased approximately 8.8 percent, to 1.701 million Bpd for the three months ended September 30, 2009 from 1.564 million Bpd during the same period in 2008, contributing $14.2 million to operating revenue. The increase in average deliveries on our Lakehead system is primarily due to increases of crude oil supplies from upstream production facilities associated with the ongoing development of the Alberta Oil Sands.

For the three months ended September 30, 2009, we recognized $7.4 million of revenue and a corresponding regulatory receivable for amounts we expect to recover in the future due to fewer volumes being transported on our system than anticipated when our current rates were established under the cost-of-service recovery model. These revenues were earned during 2009, but will not be realized as cash until 2010 when we update our transportation rates to account for the lower actual delivered volume than estimated. In April 2009, we applied the provisions of regulatory accounting to the operations of our Southern Access Project when the facilities rate surcharge associated with the project was both approved by the Federal Energy Regulatory Commission, referred to as the FERC, and uncontested by any of our customers. The rates for the Southern Access Project are based on a cost-of-service recovery model that follows the FERC's authoritative guidance and is subject to the annual filing requirements with the FERC. The rates we are allowed to charge shippers associated with our Southern Access Project include an allowance that provides a rate of return to our partners.

Also contributing to the increase in revenues for the three months ended September 30, 2009, was an approximately $3.7 million increase in storage fees generated by our Mid-Continent system due to wider storage spreads in the market coupled with increased spot storage fee revenue.

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 three months ended September 30, 2009 are substantially lower than the average prices for the same period of 2008. For example, the average daily price of West Texas Intermediate crude oil has decreased approximately 42 percent for the three months ended September 30, 2009 as compared with the same period in 2008. As a result of the decrease in crude oil prices, we have experienced an approximate $6.8 million decrease in allowance oil revenues.

Operating and administrative expenses for the Liquids segment increased $9.2 million for the three months ended September 30, 2009, compared with the same period in 2008. The increase in these costs is primarily attributable to the following:

- Higher operating costs associated with our lease of Line 13 from an affiliate of our general partner which contributed $5.4 million to our costs and which we are recovering through a tolling surcharge on our Lakehead system with the net effect on our cash flow expected to approximate zero;
- Increased workforce related costs associated with the operational, administrative, regulatory, and compliance support necessary for our existing systems; and
- Slightly increased operating costs associated with pigging batches at our Flanagan terminal.

These increases in operating and administrative expenses were slightly offset by decreased property taxes. We revised our estimate for 2009 property taxes in the third quarter of 2009, resulting in a lower property tax expense as compared with the same period of 2008, which did not include a similar revision.

Power costs decreased $1.3 million in the three months ended September 30, 2009, compared with the same period in 2008. The decline in power costs is primarily associated with the additional capacity provided by our Southern Access Project that has enabled us to more efficiently utilize our pipelines to transport crude oil.

The increase in depreciation expense of $7.8 million is attributable to the additional assets we have placed in service during the last quarter of 2008 and the first nine months of 2009, primarily the second stage of the Southern Access Project assets which we placed in service on April 1, 2009.

Nine months ended September 30, 2009 compared with nine months ended September 30, 2008

Our Liquids segment accounted for $339.7 million of operating income during the nine months ended September 30, 2009, representing a $92.9 million increase over the $246.8 million for the same period in 2008. In addition to the factors explaining the changes noted in our three month analysis, operating income for the nine month period ended September 30, 2009 as compared with the nine month period ended September 30, 2008 was affected by approximately $13.5 million of previously unbilled operating revenues on our Lakehead system that resulted from incorrectly invoicing shippers at one of our delivery points from October 2005 through December 2008 that we recorded in March 2009.

We also experienced less favorable oil measurement adjustments which occur as part of the normal operations associated with our Liquids systems and contributed an approximately $12.8 million increase in our operating expenses for the nine months ended September 30, 2009, as compared with the same period in 2008. Our oil measurement expense level, while less favorable than 2008, is within acceptable industry tolerances. The three types of oil measurement adjustments that normally occur on our systems include:

- Physical, which results from evaporation, shrinkage, differences in measurement between receipt and delivery locations and other operational incidents;
- Degradation, which results from mixing at the interface between higher quality light crude oil and lower quality heavy crude oil; and
- Revaluation, which is a function of crude oil prices, the level of our carriers' inventory and the inventory positions of customers.

Other Matters

Line 13 Exchange and Lease

In connection with the development of a diluent pipeline being constructed by Enbridge Pipelines (Southern Lights), L.L.C., or Southern Lights, a wholly-owned subsidiary of our general partner, we completed the transfer of a 156-mile section of pipeline, which we refer to as Line 13, from our Lakehead system to Southern Lights, in exchange for a newly constructed pipeline for transporting light sour crude oil. In connection with the exchange, at the request of shippers and to ensure adequate southbound pipeline capacity prior to the completion of the Alberta Clipper Project, we agreed to lease Line 13 from Southern Lights for monthly payments of $1.8 million. The transfer and lease became effective February 20, 2009, which was the in-service date for the light sour pipeline. The lease of Line 13 will be effective until the earliest of (i) July 1, 2010, (ii) upon the transfer of the Canadian portion of Line 13 from Enbridge Pipelines to Enbridge Southern Lights LP, a wholly-owned subsidiary of Enbridge Pipelines or (iii) early termination of the lease. We are able to terminate the lease at any time during the term by providing Southern Lights with written notice, at which time we would only be required to return Line 13 to Southern Lights. The costs associated with the lease are being recovered through a tolling surcharge on our Lakehead system and the net effect on our cash flow over the life of the transaction is expected to approximate zero. The exchange resulted in a $168.8 million increase in "Property, plant and equipment" and the capital account of our general partner included in "Partners' capital" on our September 30, 2009 consolidated statement of financial position, representing the $173.8 million cost of the light sour pipeline that was in excess of the $5.0 million net book value of the Line 13 assets we exchanged. Subsequent to the initial exchange, an additional $8.1 million of costs were incurred by Southern Lights through September 30, 2009 that have been transferred to us through the capital account of our general partner. The light sour pipeline is newer and has a slightly higher capacity than Line 13, which will allow us to transport additional volumes of light sour crude oil on our Lakehead system with less integrity and maintenance costs, although depreciation and property tax expense is anticipated to increase in future periods due to the higher book value associated with these assets.

Mustang Joint Tariff Revenue

The OLP was party to a joint tariff agreement with Mustang Pipe Line, LLC, or Mustang, which owns a 100,000 Bpd crude oil pipeline that connects with our Lakehead system at Lockport, Illinois and transports crude oil to the Patoka, Illinois area. Mustang is 70% owned by a major integrated oil company that also serves as the operator and is 30% owned by Enbridge. The Mustang joint tariff arrangement is an unusual structure within our liquids pipeline system, since we have no other arrangements where neither we nor Enbridge are the billing carrier or operator of the pipeline with which we have a joint tariff arrangement.

Our joint tariff agreement with Mustang that was in place from October 2005 through March 2009 allowed for shippers on our Lakehead system to reach markets downstream of Chicago at a discounted transportation rate for their commitments to transport crude oil on our Lakehead system and then on the Mustang pipeline. Since October 2005, we incorrectly invoiced a shipper on our Lakehead system, which was not a committed shipper, at the discounted transportation rate. Additionally, we continued to invoice two other shippers whose commitments expired in September 2008 at discounted transportation rates rather than the undiscounted non-committed shipper rates. Due to our incorrectly invoicing these shippers, we understated approximately $13.5 million of operating revenues on our Lakehead system from October 2005 through December 2008. We invoiced and collected the previously unbilled amounts from these shippers in the first quarter of 2009. We have included the entire $13.5 million as revenue in our consolidated statement of income for the nine month period ended September 30, 2009 following our determination that the previously unbilled amounts were not material to any prior period financial statements.

In addition to the approximate $13.5 million of additional revenue included in our operating results for the nine month period ended September 30, 2009 that resulted from incorrectly invoicing shippers in prior periods, we have also identified differences between the volumes we measured as delivered to the Mustang pipeline system at Lockport for five committed shippers that are party to a joint tariff agreement with the OLP and Mustang Pipe Line, LLC and the volumes that Mustang reported as delivered at Patoka for the same committed shippers. We continue to investigate these volume discrepancies with the operator of Mustang to ascertain whether additional amounts may be due to us for unbilled transportation services we have provided to transport between nine million and 11 million barrels of crude oil on our Lakehead system, which could result in up to $12 million of additional revenue. Regardless of the outcome of our investigation into these volume discrepancies, we can provide no assurance that we will be able to collect any amounts that we may determine are due to us.

Future Prospects Update for Liquids

We and Enbridge are actively working with our customers to develop transportation options that will allow Canadian crude oil greater access to markets throughout the United States. The following discussion provides an update to the status of projects that 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 year ended December 31, 2008.

Partnership Projects

Southern Access

We completed the second and final stage of our Southern Access Project and placed it into service on April 1, 2009. The related tolling surcharge has been adjusted to include costs of this phase of the expansion and became effective April 1, 2009. This stage provides additional upstream pumping capacity and a new pipeline from Delavan, Wisconsin to Flanagan, Illinois. Completion of the total Southern Access Project created a 42-inch, 454-mile pipeline with approximately 400,000 Bpd of incremental capacity on our Lakehead system, which can be further expanded to 1.2 million Bpd with expenditures for additional pumping equipment. The commercial structure for this expansion is a cost-of-service based surcharge that has been added to the existing transportation rates. We anticipate that cash flows associated with this project will be approximately $230 million to $250 million annually in the first full year that both stages of the Southern Access Project are fully operational.

Alberta Clipper

The Alberta Clipper Project involves construction of a new 36-inch diameter, 1,000-mile heavy crude oil pipeline from Hardisty, Alberta to Superior, Wisconsin, generally within or adjacent to our and Enbridge's existing rights-of-way. We will construct approximately 330 miles of the new pipeline from the International Border near Neche, North Dakota to Superior, a delivery connection at Clearbrook, Minnesota and additional tankage at Superior. The Alberta Clipper pipeline will have an initial capacity of 450,000 Bpd and allows for expansions up to 800,000 Bpd by adding pump stations. In addition, complementary capacity on the Southern Access 42-inch pipeline from Superior to Flanagan was obtained by installing additional pump stations. We anticipate that our share of the construction cost for the U.S. segment of the project will approximate $1.2 billion. The Alberta Clipper pipeline will be a common carrier line fully integrated with the Enbridge/Lakehead mainline systems for tolling purposes. We and Enbridge are progressing with the project, which is expected to be in service by mid-2010. On August 20, 2009, we received the Presidential Border Crossing Permit from the U.S. Department of State, authorizing construction of the United States portion of the project which allows for crude oil that is shipped on the mainline system in Canada to cross the international border near Neche, North Dakota and be transported on the Alberta Clipper pipeline into the United States. Construction on the United States portion of the Alberta Clipper Project commenced in August shortly after receiving the Presidential Border Crossing Permit. The commercial structure for this expansion is a cost-of-service based surcharge that will be added to the existing transportation rates. We anticipate financing the $1.2 billion of expected construction costs for the United States portion of the project through our recently announced joint funding arrangement through which our general partner and other affiliates of ours and Enbridge participate jointly in financing a portion of the construction project in return for an interest in approximately two-thirds of the earnings and cash flows. The joint funding arrangement also contemplates our issuance of additional term debt in one or more capital markets transactions, following the in-service date of the project, to refinance our initial debt financing of the project. Our general partner will refinance its portion of its initial debt financing of the project on the same terms. We anticipate that the first full year cash flows resulting from the completion of this project will approximate $170 million.

North Dakota

We have commenced an approximate $0.15 billion additional expansion consisting of upgrades to existing pump stations, additional tankage, as well as extensive use of drag reducing agents, or DRA, that are injected into the pipeline. This expansion of our North Dakota system, referred to as Phase VI, is expected to increase system capacity to 161,000 Bpd from the 110,000 Bpd that is currently available. The commercial structure for this expansion is a cost-of-service based surcharge that will be added to the existing transportation rates. The proposed tolling methodology is similar to the structure being used on the recently completed Phase V expansion project and was approved by the FERC in October 2008. All necessary permits and approvals have been received and the Phase VI expansion is expected to be in service in early 2010.

Enbridge and Other Projects

Spearhead Pipeline

The Spearhead pipeline has operated at or near its capacity of 125,000 Bpd since it was acquired and reversed by Enbridge. In the first half of 2007, Enbridge successfully concluded a binding open season for expansion of the pipeline to 193,300 Bpd, with binding commitments for capacity of 30,000 Bpd. In December 2007, the FERC issued a favorable declaratory order effectively approving the tolling methodology and priority service for shippers with binding commitments. Construction on the 68,300 Bpd expansion was completed on schedule in early 2009 and was placed into service in May 2009. The Spearhead pipeline is complementary to our Lakehead system as western Canadian crude oil is carried on our Lakehead system as far as Chicago, Illinois and then transferred to the Spearhead pipeline.

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 and exclude the results of our discontinued operations, which are discussed below under *Other Matters*.

	For the three months ended September 30,		For the nine months ended September 30,	
	2009	2008	2009	2008
	(unaudited; in millions)			
Operating revenues	$ 638.4	$ 1,262.4	$ 1,793.3	$ 3,669.8
Cost of natural gas	491.4	1,091.4	1,372.3	3,201.8
Operating and administrative	69.7	79.1	215.9	220.7
Depreciation and amortization	30.3	27.7	92.0	79.0
Operating expenses	591.4	1,198.2	1,680.2	3,501.5
Operating Income	$ 47.0	$ 64.2	$ 113.1	$ 168.3
Operating Statistics (MMBtu/d)				
East Texas	1,346,000	1,443,000	1,515,000	1,431,000
Anadarko	570,000	682,000	587,000	648,000
North Texas	382,000	388,000	393,000	383,000
Total(1)(2)	2,298,000	2,513,000	2,495,000	2,462,000

(1) In January 2009, we sold the member interests of our UTOS asset, which contributed average daily volumes of approximately 96,000 MMBtu/d and 157,000 MMBtu/d for the three and nine months ended September 30, 2008 and have been excluded.

(2) In September 2009, we initiated a process to sell certain of our non-core natural gas pipeline assets located predominantly outside of Texas. We have excluded the average daily volumes of these natural gas pipeline assets from the table above. The average daily volumes not included in the table above are 528,000 MMBtu/d and 477,000 MMBtu/d for the three month periods ended September 30, 2009 and 2008, respectively, and 551,000 MMBtu/d and 499,000 MMBtu/d for the six month periods ended September 30, 2009 and 2008, respectively.

Three months ended September 30, 2009 compared with the three months ended September 30, 2008

Our Natural Gas segment contributed $47.0 million of operating income for the three months ended September 30, 2009, a decrease of $17.2 million from the $64.2 million contributed in the corresponding period of 2008. The following discussion presents the primary factors affecting the operating income of our Natural Gas business for the three months ended September 30, 2009 as compared with the same period of 2008:

- A $36.9 million decrease resulting from $0.3 million of 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 gains of $36.6 million for the same period of 2008;
- An approximate $7 million reduction in revaluation losses with respect to our inventories and in-kind natural gas imbalances due to less volatile commodity prices during the three months of 2009 when compared to same period in 2008;
- Lower transportation volumes as a result of reduced drilling by natural gas producers in the areas we serve;
- Operational disruptions related to hurricanes Gustav and Ike as well as measurement losses that occurred in 2008 were not present during the same period in 2009; and
- Decreased operating and administrative costs associated with our cost reduction efforts, partially offset by higher depreciation associated with our system growth.

Higher average forward and daily NGL prices at September 30, 2009 relative to June 30, 2009, produced unrealized, non-cash, mark-to-market net losses of $0.3 million for the three months ended September 30, 2009 from the derivatives we use to hedge the sales prices of a portion of the NGLs that we derive from processing natural gas. The average forward and daily prices for natural gas were relatively stable at September 30, 2009 in relation to prices at June 30, 2009. Comparatively, at September 30, 2008, the average forward and daily prices for both natural gas and NGLs were significantly lower than the prices at June 30, 2008, which produced $36.6 million of unrealized, non-cash, mark-to-market net gains for the derivative instruments we used to fix the price of the natural gas purchased for processing and for the derivatives we used to hedge the sales prices of a portion of the NGLs derived from processing natural gas.

The following table depicts the effect that unrealized, non-cash, mark-to-market gains and losses had on the operating results of our Natural Gas segment for the three and nine months ended September 30, 2009 and 2008:

	For the three months ended September 30,		For the nine months ended September 30,	
	2009	2008	2009	2008
	(unaudited; in millions)			
Hedge ineffectiveness	$(0.1)	$ 0.1	$ (0.7)	$ (1.1)
Non-qualified hedges	(0.2)	36.5	(12.6)	42.5
Derivative fair value gains (losses)	$(0.3)	$36.6	$(13.3)	$41.4

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. During the three months ended September 30, 2009, NGL and condensate prices increased, while natural gas prices declined, creating a favorable environment for processing NGL and condensate. Comparatively, during the three months ended September 30, 2008, commodity prices for NGL, condensate and natural gas experienced significant price erosion. The rapid decline in commodity prices during the three months ended September 30, 2008, led to $4.8 million of revaluation losses with respect to our in-kind natural gas imbalances as well as $2.2 million of non-cash charges to reduce the cost basis of our natural gas inventory to fair market value. Although commodity prices were significantly lower for the three month period ended September 30, 2009, when compared to the same period in 2008, a rapid decline in commodity prices did not occur and as a result we did not incur similar revaluation losses and non-cash charges in the 2009 period.

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 and Granite Wash areas. During the three months ended September 30, 2009, natural gas production decreased relative to the same period in 2008. Due to the significant decline in natural gas prices over the past several months, producers have slowed down drilling activity levels compared to 2008. The number of approved drilling permits for the three months ended September 30, 2009 has declined 59% from the same period in 2008. Existing active drilling rigs in the areas we serve have also declined 66% during the three months ended September 30, 2009 from levels that existed in the corresponding period in 2008. Our margin growth may be tempered since our customers and certain of our assets may experience continued volume declines relative to 2008. Weak demand together with low commodity prices may lead to the inability or unwillingness of natural gas producers to commit the necessary capital to engage in new projects, which could decrease the amount of new natural gas production in the areas we serve. A decrease in new natural gas production has the potential to adversely affect the margins we derive from our Natural Gas business. The volume decline experienced on our East Texas system for the three month period ended September 30, 2009 compared with levels that existed for the three months ended September 30, 2008 include volumes that contributed lower levels of margin to our overall natural gas operating results.

A variable element of our Natural Gas segment's operating income is derived from processing natural gas under keep-whole arrangements on our East Texas, North Texas and Anadarko systems. Operating income derived from keep-whole processing arrangements for the three months ended September 30, 2009 was $20.6 million, representing an increase of $2.2 million, or 12 percent, from the $18.4 million we produced for the same period in 2008. The increase in operating income derived from keep-whole processing arrangements for the three months ended September 30, 2009 is largely due to wider differences between the price of natural gas we purchase for processing and the NGLs produced from our processing activities when compared with the same period in 2008.

Natural gas measurement losses occur as part of the normal operating conditions associated with our natural gas pipelines. The quantification and resolution of measurement losses is complicated by several factors including varying qualities of natural gas in the streams gathered and processed through our systems, changes in weather, temperatures and variances in measurement that are inherent in metering technologies. During the three months ended September 30, 2009 we recognized approximately $7 million fewer losses related to measurement than in the same period for 2008. We made a focused effort to more closely monitor and improve the operating conditions on our gathering systems, which produced the reduced level of measurement losses.

During the third quarter of 2008, we experienced operational disruptions to our onshore and offshore natural gas facilities as a result of hurricanes Gustav and Ike. Our facilities sustained minimal physical damage from the hurricanes, although some of our natural gas systems had lower throughput and revenues in the month of September due to the inability of third-party downstream facilities to receive deliveries of our natural gas and NGLs. These temporary disruptions curtailed our ability to gather unprocessed natural gas at our processing plants and transport natural gas to markets in the Texas and Louisiana regions. Approximately $8 million of lost revenue associated with the hurricanes occurred during the three months ended September 30, 2008. A similar disruption to our natural gas operations was not experienced during the three months ended September 30, 2009.

Operating and administrative costs of our Natural Gas segment were $9.4 million lower for the three months ended September 30, 2009 compared to the same period in 2008, primarily due to the implementation of enhanced cost reduction measures. Our efforts to more closely monitor costs have yielded positive results by reducing the costs associated with material and supplies purchases and alleviating unnecessary repairs and maintenance when compared to the three month period ended September 30, 2008. Depreciation expense for our Natural Gas segment was higher for the three months ended September 30, 2009 as compared to the same period in 2008, as a result of the capital projects completed and placed into service in the last half of 2008.

Nine months ended September 30, 2009 compared with nine months ended September 30, 2008

Our Natural Gas segment accounted for $113.1 million of operating income during the nine months ended September 30, 2009, representing a $55.2 million decrease from the $168.3 million for the same period in 2008. In addition to the factors explaining the changes noted in our three month analysis, some of the components comprising our operating income changed unfavorably during the nine months ended September 30, 2009 compared with the nine months ended September 30, 2008, which are described below.

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 months 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. Comparatively, at December 31, 2007 the average forward and daily prices for natural gas were lower than the prices at September 30, 2008, which produced $41.4 million of unrealized, non-cash, mark-to-market net gains on the derivative instruments used to fix the price of the natural gas we purchase for processing. These net gains were partially offset by unrealized, non-cash, mark-to-market net losses associated with the derivatives we use to fix the sales prices of a portion of the NGLs we derive from processing natural gas that resulted from higher average forward and daily NGL prices at September 30, 2008 relative to prices at December 31, 2007.

Operating income we derive from keep-whole processing arrangements for the nine months ended September 30, 2009 was $48.7 million, representing a decrease of $17.7 million, or 27 percent, from the $66.5 million we produced for the same period in 2008. The favorable pricing environment that existed for NGLs and condensate for the nine months ended September 30, 2008, did not exist for the same period in 2009 significantly reducing the operating income we derive from our keep-whole processing arrangements.

Future Prospects Update 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, 2008.

Partnership Projects

Shelby County Loop and Compression

We commenced construction during the third quarter of 2008 to add compression at the Carthage Hub and on the Shelby County lateral sections of our East Texas system. We have also initiated construction to increase the capacity of the East Texas system in the area by installing approximately 26 miles of 20-inch pipeline. Commercial terms for this project predominately involve firm volume commitments from customers. During the second quarter of 2009, construction on the approximately $60 million project was substantially completed with additional compression added in the third quarter of 2009.

Enbridge Projects

LaCrosse Pipeline

The proposed interstate natural gas pipeline, known as the LaCrosse Pipeline, will run from our Carthage Hub in Panola County, Texas to the Sonat Pipeline in Washington Parish, Louisiana. The 300-mile pipeline, which is expected to have a capacity of at least one billion cubic feet per day, is designed to provide an outlet for increasing supplies of natural gas originating in the East Texas and Fort Worth producing basins and in the growing Haynesville Shale Play. The pipeline would interconnect with pipelines accessing the Perryville, Louisiana Hub as well as Louisiana industrial markets and pipelines serving southeastern U.S. markets. The pipeline would provide our customers with additional markets and options when transporting their natural gas. In May 2009, Enbridge conducted a successful non-binding open season for the proposed pipeline. The next stage of the project involves confirming customer interest and the expected cost of the new construction.

Other Matters

In September 2009, we committed to sell certain of our non-core natural gas pipeline assets located predominantly outside of Texas. We have classified these assets as "Assets held for sale" in our consolidated statement of financial position at September 30, 2009 and have presented in "Income from discontinued operations" the income we derived from these assets for the three and nine month periods ended September 30, 2009 and 2008. Also included in "Income from discontinued operations" for the three and nine month periods ended September 30, 2009 is an impairment charge of approximately $66.1 million we recorded to reduce the carrying value of "Assets held for sale" to our estimate of the fair value of these assets. The natural gas pipeline assets are primarily intrastate and interstate natural gas transmission systems and related facilities, which serve onshore and offshore markets in the southeastern United States and the Gulf Coast. The natural gas pipeline assets include over 1,400 miles of pipeline with diameters ranging from 2 to 30 inches. The areas in which the natural gas pipeline assets operate are not strategic to the ongoing central operations of our core Natural Gas segment assets.

The following table presents the operating results of our natural gas pipeline assets that we have designated as "Assets held for sale," which we derived from historical financial information and have segregated from our continuing operations on our consolidated statements of income:

	For the three months ended September 30,		For the nine months ended September 30,	
	2009	2008	2009	2008
	(in millions)			
Operating revenue	$ 43.1	$100.8	$151.6	$303.8
Operating expenses				
Cost of natural gas	34.8	89.6	124.9	269.3
Operating and administrative	6.1	4.7	16.5	15.1
Depreciation and amortization	3.9	3.8	11.6	9.8
	44.8	98.1	153.0	294.2
Operating income (loss)	(1.7)	2.7	(1.4)	9.6
Interest expense	—	—	—	(0.1)
Other income (expense)	(66.2)	0.1	(66.1)	1.0
Income (loss) from discontinued operations, net of income taxes	$(67.9)	$ 2.8	$ (67.5)	$ 10.5

Marketing

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

	For the three months ended September 30,		For the nine months ended September 30,	
	2009	2008	2009	2008
	(unaudited; in millions)			
Operating revenues	$463.2	$1,298.6	$1,601.0	$3,819.7
Cost of natural gas	451.8	1,284.8	1,557.0	3,817.8
Operating and administrative	1.8	2.5	5.3	7.1
Depreciation and amortization	0.4	0.4	1.2	1.3
Operating expenses	454.0	1,287.7	1,563.5	3,826.2
Operating Income (Loss)	$ 9.2	$ 10.9	$ 37.5	$ (6.5)

A majority of the operating income of our Marketing segment is derived from selling natural gas received from producers on our Natural Gas segment pipeline assets to customers who need natural gas. As a result of our natural gas system expansions and other initiatives, our Marketing business now has access to several additional downstream natural gas pipelines, which it can use to transport natural gas to primary markets where it can be sold at more favorable prices.

Three months ended September 30, 2009 compared with three months ended September 30, 2008

The operating income we derive from the sale of natural gas declined as a result of lower natural gas prices for the three month period ended September 30, 2009 as compared with the same period in 2008. Although the volumes that our Marketing business received from our Natural Gas segment assets remained relatively stable when compared to the three month period ended September 30, 2008, the revenue and related margin from the sale of those natural gas volumes declined. The volatility existing in the overall commodities markets during the three month period ended September 30, 2008, resulted in more opportunities for us to benefit from differences between the purchase and sales prices of natural gas, which resulted in higher operating income. The less volatile pricing environment existing during the three month period ended September 30, 2009 reduced the differences between the purchase and sales prices of natural gas which in turn reduced our operating income for the period.

The operating results of our Marketing segment for the three months ended September 30, 2009 were positively affected by unrealized, non-cash, mark-to-market net gains of $9.0 million associated with derivative financial instruments that do not qualify for hedge accounting treatment under authoritative accounting guidance. The non-cash, mark-to-market net gains during the three months ended September 30, 2009 resulted from the continued narrowing of natural gas purchase and sales prices between market centers, which benefited our hedged transportation positions. During the three months ended September 30, 2008, declines in the forward and daily market prices of natural gas produced $11.0 million of non-cash, mark-to-market net gains in our portfolio of derivative instruments. We expect all net mark-to-market gains to be offset when the related physical transactions are settled.

Operating income for the three months ended September 30, 2009, was not affected by $5.9 million of non-cash charges that we recorded for the same period in 2008 to reduce the cost basis of our natural gas inventory to fair market value. The reduction of non-cash charges to our natural gas inventory was a direct result of a less volatile commodity price environment during the third quarter of 2009 when compared to the same period in 2008. During the three month period ended September 30, 2008, the average daily price of natural gas as published by Platt's Gas Daily for Henry Hub decreased approximately 43%. A similar decline in the average daily price of natural gas did not occur during the three months ended September 30, 2009.

Operating and administrative costs for our Marketing segment were $0.7 million lower for the three month period ended September 30, 2009 compared to the same period in 2008. The reduction in operating and administrative costs resulted in an improvement in operating income.

Nine months ended September 30, 2009 compared with nine months ended September 30, 2008

Similar to the three month analysis, operating income of our Marketing segment improved to $37.5 million for the nine month period ended September 30, 2009 from a loss of $6.5 million for the corresponding period in 2008. In addition to the factors explaining the changes noted in our three month analysis, for the first nine months of 2009 we had approximately $19.6 million of unrealized, non-cash, mark-to-market gains associated with derivative financial instruments that do not qualify for hedge accounting treatment, which is a $43.5 million increase from the $23.9 million of unrealized, non-cash, mark-to-market losses for the comparable period of 2008. The unrealized, mark-to-market gains for the nine months ended September 30, 2009 resulted primarily from narrower transportation differentials, while the unrealized, non-cash, mark-to-market losses of $23.9 million for the nine months ended September 30, 2008 resulted from the increases in the forward and daily market prices of natural gas from December 31, 2007.

Corporate

Interest expense was $60.7 million and $169.9 million for the three and nine months ended September 30, 2009, compared with $50.7 million and $129.6 million for the corresponding periods in 2008. The increases are primarily the result of a higher weighted average outstanding debt balance in 2009 as compared with 2008, along with higher commitment fees related to our credit facilities and increased debt issuance cost amortization. The debt issuances that impacted the entire nine month period ended September 30, 2009 are as follows:

- $400 million of our 6.5% Senior Notes in April 2008;
- $400 million of our 7.5% Senior Notes in April 2008; and
- $500 million of our 9.875% Senior Notes in December 2008.

Our weighted average interest rates are 7.06% and 7.04% for the three and nine month periods ended September 30, 2009, respectively, as compared with our weighted average interest rates of 6.61% and 6.24% for the same periods in 2008.

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, rate for the period of borrowing or interest rate reset, plus a defined credit spread. In order to mitigate the negative effect high interest rates 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, 2009, we recorded $1.4 million of unrealized, non-cash, mark-to-market net losses and $1.0 million of unrealized, non-cash, mark-to-market net gains, respectively, associated with the changes in fair value of these derivatives that resulted from the increase in interest rates from the May 2009 date these derivative financial instruments were purchased to September 30, 2009.

The increase in interest expense for the nine month period ended September 30, 2009 was attributable to a $5.9 million reduction of capitalized interest when compared to the same period in 2008. For the three and nine month periods ended September 30, 2009 and 2008, our interest cost is comprised of the following:

	For the three months ended September 30,		For the nine months ended September 30,	
	2009	2008	2009	2008
	(unaudited; in millions)			
Interest expense	$60.7	$50.7	$169.9	$129.6
Interest capitalized	6.9	6.2	25.3	31.2
Interest cost incurred	$67.6	$56.9	$195.2	$160.8

* Interest expense for the three and nine months ended September 30, 2009 includes $1.4 million of unrealized, non-cash, mark-to-market losses and $1.0 million of unrealized, non-cash, mark-to-market gains, respectively, associated with our interest rate caps.

Other Matters

Joint Funding Arrangement for Alberta Clipper Project 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. In exchange for a 66.67 percent ownership interest in the Alberta Clipper project, Enbridge, through our general partner, is funding approximately two-thirds of both the debt financing and equity requirement for the project in return for approximately two-thirds of the earnings and cash flows. For our 33.33 percent ownership of the Alberta Clipper project, we are funding approximately one-third of the debt financing and required equity of the project, for which we will be entitled to approximately one-third of the project's earnings and cash flows. As a result of this joint funding arrangement, 66.67 percent of earnings associated with the Alberta Clipper project are attributable to our general partner and presented as "Noncontrolling interest" in our consolidated statements of income and consolidated statement of financial position. For further details on our Alberta Clipper joint funding arrangement please refer to the *Capital Resources—Joint Funding Arrangement* discussion below under *Liquidity and Capital Resources*.

In August 2009, we applied the provisions of regulatory accounting to our Alberta Clipper Project when the project received its Presidential Border Crossing Permit from the U.S. Department of State. In conjunction with our application of the provisions of regulatory accounting, we recorded an allowance for equity during construction, referred to as AEDC, of $2.4 million, for the three and nine month periods ended September 30, 2009. We also recorded an allowance for interest during construction, or AIDC, that was $1.0 million greater than the interest cost incurred by the Alberta Clipper Project on the specific debt used to fund the construction for the three and nine month periods ended September 30, 2009. These amounts together represent the $3.4 million in earnings of the Alberta Clipper project for the three and nine months ended September 30, 2009, of which we have allocated $2.3 million to noncontrolling interest representing our general partner's 66.67 percent ownership interest in the project.

LIQUIDITY AND CAPITAL RESOURCES

Impact of Current Economic Conditions

In response to the financial crisis, we have taken several tangible steps to enhance our liquidity position since the end of 2008. Liquidity constraints have begun to recede within the capital markets of the United States and around the world. We continue to believe that we will be able to obtain the capital necessary to fund our growth programs and maintain our credit rating, although the prices at which we can access capital could be higher than the prices we incurred for similar capital in recent years. Our cost for both debt and equity capital could become high if the capital markets become constrained once again. We expect to selectively access the capital markets as necessary to fund our internal growth projects and continue to explore alternative means of financing our projects. For example, we recently announced a joint funding arrangement through which our general partner and other affiliates of ours and Enbridge Inc. participating jointly in financing our portion of the construction of the Alberta Clipper Project. Following our announcement of this arrangement, both Standard & Poor's Ratings Services and Moody's Investors Service revised their ratings outlook on our senior unsecured debt to stable from negative. Standard & Poor's also raised our short-term rating to A-2 from A-3, which allows us to once again access the commercial paper market. In September 2009, in an effort to further satisfy our equity financing needs, we initiated the process to sell certain of our non-core natural gas pipeline assets located predominantly outside of Texas (see Results of Operations, *Natural Gas—Other Matters*). We continue to focus on maintaining sufficient liquidity to fund our remaining growth programs and sustain the present distribution rate to our unitholders, while preserving our credit rating.

As computed in the following table , we have in excess of $1.5 billion of liquidity at September 30, 2009 to meet our ongoing operational, investment and finance needs, excluding the $233.9 million we have available from our general partner to fund the Alberta Clipper Project, as noted below:

	(in millions)
Availability under Credit Facility	$ 525.8
Available under Enbridge (U.S.) Credit Agreement	500.0
Available under 364-Day Credit Facilities	350.0
Cash and cash equivalents	191.1
Total	$1,566.9

General

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

Our current business strategy emphasizes developing and expanding our existing Liquids and Natural Gas businesses with less focus on acquisitions. Our need for investment capital to fund our expansion projects, make acquisitions of new assets and businesses and to retire maturing or callable debt obligations is expected to be funded from several sources. We anticipate initially funding long-term cash requirements for expansion projects and acquisitions first from operating cash flows, second, from borrowings under our Credit Facility and from borrowings under our credit agreement with Enbridge (U.S.) Inc., or Enbridge U.S., a wholly-owned subsidiary of Enbridge and from other potential sources of capital. Likewise, we anticipate initially retiring our maturing debt with similar borrowings on these existing facilities and possibly debt and equity financings through the capital market. We expect to obtain permanent financing 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 financing will be available on favorable terms, if at all.

Enbridge, as the ultimate parent of our general partner, has been and continues to be supportive of our efforts in executing our significant capital expenditure program as some of these projects are beneficial to our mutual customers and operational asset bases. In addition to Enbridge's recent liquidity support and investment through our general partner, , Enbridge has the capacity to provide further support in the form of participation in public and private equity transactions, and other non-traditional forms of investments in our operations.

Capital Resources

Joint Funding Arrangement

In July 2009, we announced a joint funding arrangement with our general partner and other affiliates of ours and Enbridge to participate in financing construction of the United States portion of our $1.2 billion Alberta Clipper Project being constructed by Enbridge Energy, Limited Partnership, which we refer to as the OLP. Enbridge, through our general partner, is funding approximately two-thirds of the debt financing for the project and approximately two-thirds of the project's equity financing requirements directly into the OLP. We are funding approximately one-third of the debt and equity financing required for the project. Enbridge, through our general partner, is entitled to approximately two-thirds of the earnings and cash flows that the OLP generates from the project. We are be entitled to approximately one-third of the project's earnings and cash flows. We and our general partner each have a right of first refusal on the other's investment in the project and we retain the right to fund up to 100 percent of any expansion of the project, which would result in a corresponding adjustment to our general partner's interest.

Equity and Debt Securities

Execution of our growth strategy and completion of our planned construction projects contemplate our accessing the public and private equity and credit markets to obtain the capital necessary to fund these projects. We have issued securities generating proceeds in excess of $4 billion over the past three years through the issuance of a balanced combination of debt and equity securities to fund our expansion projects. Our planned internal growth projects will require additional permanent capital and continue to require us to bear the cost of constructing these new assets before we begin to realize a return on them. If market conditions change and capital markets again become constrained, our ability and willingness to complete future debt and equity offerings may be limited. The timing of any future debt and equity offerings will depend on various factors, including prevailing market conditions, interest rates, our financial condition and our credit rating at the time.

Available Credit

Historically our two primary sources of liquidity have been the commercial paper market and our Credit Facility. From November 2008 until July 2009 we were unable to access the commercial paper market due to a downgrade in our short-term credit rating by Standard and Poor's to A-3 from A-2 and used our Credit Facility as our primary source of liquidity. In July 2009, Standard and Poor's revised their ratings on our short-term credit to A-2 from A-3, which allows us to once again make use of our $600 million commercial paper program, depending on market conditions. We will continue to use our Credit Facility primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions and access the commercial paper market for similar temporary financing as economic conditions warrant. In addition to our Credit Facility and commercial paper program we have available a $500 million revolving credit agreement from Enbridge (U.S.). Additionally, in April 2009 we entered into 364-day revolving credit facilities totaling $350 million with Barclays Bank PLC, Export Development Canada and Enbridge (U.S.).

Credit Facility

On March 31, 2009, we amended our Credit Facility to remove Lehman BB as a lender, which effectively reduced the amounts available to us under our Credit Facility. The removal of Lehman BB permanently reduced both the amount we may borrow under the terms of our Credit Facility to $1,167.5 million as well as the number of committed lenders to 13. The amendment to our Credit Facility did not result in any changes to the pricing, fees or other commercial terms.

At September 30, 2009, we had $630.0 million outstanding under our Credit Facility at a weighted average interest rate of 0.57% and outstanding letters of credit totaling $11.7 million. The amounts we may borrow under the terms of our Credit Facility are reduced by the balance of our outstanding letters of credit.

At September 30, 2009, we could borrow $525.8 million under the terms of our Credit Facility, determined as follows:

	(in millions)
Total credit available under Credit Facility	$1,167.5
Less: Amounts outstanding under Credit Facility	630.0
Balance of letters of credit outstanding	11.7
Total amount we could borrow at September 30	$ 525.8

Individual borrowings under the terms of our Credit Facility generally become due and payable at the end of each contract period, which typically is a period of three months or less. We have the option to repay these amounts on a non-cash basis by net settling with the parties to our Credit Facility by contemporaneously borrowing at the then current rate of interest and repaying the principal amount due. During the nine month periods ended September 30, 2009 and 2008, we net settled borrowings of approximately $1,447.1 million and $490.0 million, respectively, on a non-cash basis.

364-day Credit Facilities

In April 2009, we entered into two unsecured and non-guaranteed revolving credit facility agreements totaling $350 million for funding our general activities and working capital. The credit facility agreements include a $200 million agreement with Barclays Bank PLC, as administrative agent, and Barclays Bank PLC and Export Development Canada as lenders; and a $150 million affiliate credit agreement with Enbridge U.S. Both credit facilities mature 364 days from the closing date of the agreements and include one-year extensions for a fee, exercisable at our option. The $150 million Enbridge U.S. facility is on the same terms as the $200 million facility with third parties.

EUS Credit Agreement

In addition to our Credit Facility and the 364-day Credit Facilities, we have access to an unsecured revolving credit agreement with Enbridge U.S., which we refer to as the EUS Credit Agreement. The EUS Credit Agreement provides us with access to an additional $500 million of financing on substantially the same terms as our Credit Facility and matures in December 2010. The amounts available to us under the EUS Credit Agreement remain undrawn at September 30, 2009 and available for our use.

Cash Requirements for Future Growth

Capital Spending

We expect to make additional expenditures during the next year for the construction of additional natural gas and crude oil transportation infrastructure primarily for the Alberta Clipper Project. Anticipated growth in western Canadian oil sands production and the need to reach new markets has prompted the Southern Access, Alberta Clipper and related projects associated with our Liquids systems. In 2009, we expect to spend approximately $1.3 billion on these and other projects with the expectation of realizing additional cash flows as projects are completed and placed into service. At September 30, 2009, we had approximately $532.4 million in outstanding purchase commitments attributable to capital projects for the construction of assets that will be recorded as property, plant and equipment during 2009.

Forecast Expenditures

We categorize our capital expenditures as either core maintenance or enhancement expenditures. Core maintenance expenditures are those expenditures that are necessary to maintain the service capability of our existing assets and includes the replacement of system components and equipment which is worn, obsolete or completing its useful life. We also began including a portion of our well-connects capital associated with our Natural Gas system assets as core maintenance expenditures beginning in 2009 which totaled $12.3 million for the nine months ended September 30, 2009. 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 forecast expenditures based upon our strategic operating and growth plans, which are also dependent upon our ability to produce or otherwise obtain the capital necessary to accomplish our growth objectives. The following table sets forth our estimates of capital required for system enhancement and core maintenance expenditures through December 31, 2009. Although we anticipate making the expenditures in 2009, these estimates may change due to factors beyond our control, including weather-related issues, construction timing, changes in supplier prices or poor economic conditions. Additionally, our estimates may also change as a result of decisions made at a later date to revise the scope of a project or undertake a particular capital program. We made capital expenditures of $813.3 million, including $50.4 million on core maintenance activities, for the nine months ended September 30, 2009.

For the full year ending December 31, 2009, we anticipate our capital expenditures to approximate the following:

	Total Forecasted Expenditures
	(in billions)
System enhancements	$0.3
Core maintenance activities	0.1
Southern Access expansion	0.2
Alberta Clipper	0.7
	$1.3

Major Construction Projects

The following table includes our active major construction projects and additional information regarding our projected cost, actual expenditures through September 30, 2009, the incremental capacity that will or has become available upon completion of the project and the periods we expect to complete the construction. The projected amounts included in this table may change due to modifications of the scope of the project, increases in materials and construction costs and other factors that are outside of our direct control.

	Capital Expenditures		Estimated Incremental Capacity	
	Estimated Total Cost	Actual Expenditures through September 30, 2009	Oil	Expected Completion
	(in billions)		(Kbpd)[1]	
Southern Access expansion (Lakehead)	$2.1	$2.1	400	Completed-April 2009
Alberta Clipper	1.2	0.5	450	Mid-2010
North Dakota Phase VI expansion	0.2	0.1	50	Early 2010
Total	$3.5	$2.7	900	

(1) Thousands of barrels per day (Kbpd).

Including major expansion projects and excluding acquisitions, ongoing capital expenditures are expected to moderate over the next 12 months as we progress and complete our Alberta Clipper and North Dakota projects. Core maintenance capital is anticipated to increase over that period of time due to growth in our pipeline systems and aging of infrastructure.

We anticipate funding our portions of the system enhancement capital expenditures temporarily through borrowing under the terms of our Credit Facility, with permanent debt and equity funding being obtained when appropriate, or through asset partnership or joint venture arrangements. As previously discussed, we intend to finance construction of the Alberta Clipper crude oil pipeline through a joint funding arrangement with Enbridge through our general partner and other affiliates of ours and Enbridge. Core maintenance expenditures are expected to be funded by operating cash flows.

We expect to incur continuing annual capital and operating expenditures for pipeline integrity measures to ensure both regulatory compliance and to maintain the overall integrity of our pipeline systems. Expenditure levels have continued to increase as pipelines age and require higher levels of inspection or maintenance; however, these are viewed to be consistent with industry trends.

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 instruments at September 30, 2009:

	Notional	2009	2010	2011	2012	2013	2014	Total
			(dollars, in millions)					
Swaps								
Natural gas[1]	167,136,902	$(2.8)	$(15.3)	$(24.3)	$ (6.6)	$ 2.1	$ —	$(46.9)
NGL[2]	5,650,921	3.5	6.7	9.2	10.3	(0.4)	—	29.3
Crude[2]	2,352,379	(0.8)	(1.7)	(3.7)	(1.3)	1.4	0.1	(6.0)
Options-calls								
Natural gas—calls written[1]	822,000	(0.1)	(0.7)	(1.0)	—	—	—	(1.8)
Options-puts								
Natural gas—puts purchased[1]	822,000	—	—	—	—	—	—	—
NGL—puts purchased[2]	1,512,211	1.1	8.0	2.3	3.8	—	—	15.2
Crude—puts purchased[2]	363,335	—	1.8	—	—	—	—	1.8
Forward contracts								
Crude[2]	5,055	—	(0.4)	—	—	—	—	(0.4)
NGL[2]	1,100,030	(1.7)	(0.5)	—	—	—	—	(2.2)
Totals		$(0.8)	$ (2.1)	$(17.5)	$ 6.2	$ 3.1	$0.1	$(11.0)

(1) Notional amounts for natural gas are recorded in MMBtu.

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

The following table provides summarized information about the timing and expected settlement amounts of our outstanding interest rate derivative instruments at September 30, 2009:

	Notional Amount	2009	2010	2011	2012	2013	Thereafter	Total
				(dollars in millions)				
Interest Rate Derivatives								
Interest Rate Swaps:								
Floating to Fixed	$1,175.0	$—	$(2.0)	$ —	$—	$(28.9)	$ —	$(30.9)
Fixed to Floating	125.0	—	—	—	—	12.3	—	12.3
Rate Locks	1,120.0	—	—	—	—	—	(27.3)	(27.3)
Interest Rate Caps	400.0	—	0.5	0.5	—	—	—	1.0
		$—	$(1.5)	$0.5	$—	$(16.6)	$(27.3)	$(44.9)

Operating Activities

Net cash provided by operating activities for the nine months ended September 30, 2009 was $582.9 million, an increase of $109.7 million from the $473.2 million generated during the same period in 2008. The increase in operating cash flow is directly attributable to higher net income resulting from the improved operating performance of our Liquids and Natural Gas systems. Net cash provided by operating activities also increased due to the general timing differences in the collection on and payment of our current and related party accounts.

Investing Activities

We used $188.8 million less in our investing activities during the nine months ended September 30, 2009 in relation to the same period in 2008. The decrease is primarily attributable to the $165.9 million reduction of amounts spent in the first nine months of 2009 on our construction projects as compared to the same period of 2008. The decrease in the amounts spent on our construction projects is primarily attributable to completion of the first and second stages of our Southern Access Project.

Financing Activities

Net cash provided by financing activities during the nine months ended September 30, 2009 was $158.7 million, compared with net cash provided by financing activities of $707.1 million for the corresponding period in 2008. The reduction in the amount of cash provided by financing activities is due primarily to the lower amount of cash generated from our unit issuances as well as no capital market debt financings compared to the $800 million of Senior Note offerings in the first nine months of 2008. Additionally, in the first nine months of 2009 we repaid $175.0 million of our senior notes and $214.7 million of our zero coupon notes and had additional distributions of $68.1 million as compared with the same period of 2008.

Partially offsetting the cash out flows from financing activities are $722.5 million of increases in short-term financing over the $93.1 million of repayments in the comparable period of 2008. We also had a $203.0 million contribution from non-controlling interest during the third quarter of 2009 that was not present for the same period in 2008. For the nine months ended September 30, 2009, we had gross borrowings of $3,307.1 million under our Credit Facility and gross repayments of $2,834.9 million, including $1,447.1 million of non-cash borrowings and repayments.

OFF-BALANCE SHEET ARRANGEMENTS

We have no significant off-balance sheet arrangements.

SUBSEQUENT EVENTS

We have evaluated events subsequent to September 30, 2009 through November 4, 2009, the date we issued these financial statements, and identified the events disclosed below.

Class C Unit Conversion

On October 14, 2009, we effected the conversion of all of our outstanding Class C units into Class A common units in accordance with the terms of our partnership agreement. The conversion became effective upon the determination by our general partner that the converted Class C units would have, as a substantive matter, like intrinsic economic and federal income tax characteristics, in all material respects, to the intrinsic economic and federal income tax characteristics of our outstanding Class A common units. Our general partner made this determination after adjustments were made to the capital accounts of our limited partners in connection with the private placement of Class A common units described below.

The Class C units converted on a one-for-one basis, resulting in the issuance of 21,333,273 Class A common units and a cash payment of $123.21 for the 2.608092 remaining fractional units. In order to facilitate the conversion of the Class C units described above, on October 14, 2009, we issued and sold 21,245 Class A common units to our general partner in a private for an aggregate purchase price of approximately $1 million, or $47.07 per unit, the closing price of the Class A common units on the New York Stock Exchange on October 13, 2009.

Sale of Natural Gas Pipeline Assets

In November 2009, we completed the sale of our non-core natural gas pipeline assets that are presented as "Assets held for sale" on our consolidated statement of financial position as discussed in Note 3—*Discontinued Operations*. The sale did not significantly affect our financial position or results of operations beyond what has been presented in our consolidated financial statements. The sales price of our non-core natural gas pipeline assets was $150.8 million in cash, and will be subject to adjustments for working capital items subsequent to the closing of the transaction.

Distribution to Partners

On October 29, 2009, the Board of Directors of Enbridge Management declared a distribution payable to our partners on November 13, 2009. The distribution will be paid to unitholders of record as of November 5, 2009, of our available cash of $131.3 million at September 30, 2009, or $0.990 per common unit. Of this distribution, $115.1 million will be paid in cash, $15.9 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 distributions.

REGULATORY MATTERS

FERC Transportation Tariffs—Liquids

Effective April 1, 2009, 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 2009 related to our expansion projects. The projected costs for 2009 include three additional projects, the most significant being the Southern Lights replacement capacity project. The projected costs also include a rate update for two existing projects including the Hartsdale tanks charge and the Southern Access Project for the inclusion of the recently completed Stage 2 of the project. This filing increased the average transportation rate for crude oil movements from the Canadian border to Chicago by approximately $0.15 per barrel, to an average of approximately $1.41 per barrel. We will begin to realize revenues in relation to this increased surcharge as crude oil is delivered from our pipeline, generally the month following the effective date of the tariff.

Effective May 1, 2009, we filed a tariff with the FERC to reflect the addition of Flanagan as a delivery point on our Lakehead system. The new delivery point is a component of the Southern Access Project expansion. Notwithstanding the new rates for the delivery point in Flanagan, all rates in this tariff filing remain unchanged from the tariff filing effective April 1, 2009, discussed above. The average transportation rate for crude oil movements from the Canadian border to Flanagan will be approximately $1.41 per barrel, which is the same as other points in the Chicago region.

Effective July 1, 2009, we increased the rates for transportation on our Lakehead, North Dakota and Ozark systems in compliance with the indexed rate ceilings allowed by the FERC. In 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 Southern Access Project. Effective July 2009, we increased the base tariff rates on our Lakehead system by an average of 7.6 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 $1.46 per barrel, which reflects a $0.05 per barrel increase over the rates filed effective April 1, 2009. In addition to the rates on our Lakehead system, we increased the transportation rates on our North Dakota and Ozark systems 7.6 percent. The tariff rates for our Lakehead, North Dakota and Ozark systems are at the ceiling levels allowed under the FERC methodology.

Regulatory Accounting

Certain of our liquids and natural gas transportation services are subject to regulation by the FERC and various state authorities. Regulatory bodies exercise statutory authority over matters such as construction, rates and underlying accounting practices and ratemaking agreements with customers. Accordingly, we record certain assets and liabilities that result from the regulated ratemaking process that would not be recorded for non-regulated entities under U.S. GAAP. In April 2009, we began applying the authoritative accounting provisions applicable to the regulated operations of our Southern Access Project when the facilities rate surcharge associated with the project was both approved by the FERC and uncontested by any of our customers. The rates for the Southern Access Project are based on a cost-of-service recovery model that follows the FERC's authoritative guidance and is subject to annual filing requirements with the FERC. Under our cost-of-service tolling methodology we calculate tolls based on forecast volumes and costs. A difference between forecast and actual results causes an under or over collection of revenue in any given year. During 2009 we have under collected revenue related to our Southern Access Project in-part because actual volumes have been lower than the forecast volumes used to calculate the toll surcharge. Under the authoritative accounting provisions applicable to our regulated operations, over or under collections of revenue are recognized in the financial statements currently and these amounts are realized or settled as cash the following year. This accounting model matches earnings to the period with which they relate and conforms to how we recover our costs associated with these expansions through the annual cost-of-service filings with our customers and the regulator. For the three and nine month periods ended September 30, 2009, we recognized $7.4 million of additional revenue on our consolidated statements of income, along with a corresponding regulatory receivable on our consolidated statement of financial position at September 30, 2009 related to the difference in transportation volumes. These revenues were earned during 2009, but will not be realized as cash until 2010 when we update our transportation rates to account for the lower actual delivered volume than estimated.

In August 2009 our Alberta Clipper Project received the Presidential Border Crossing Permit from the U.S. Department of State, which will allow heavy crude oil that will be shipped on the mainline system in Canada to cross the international border near Neche, North Dakota and be transported on the Alberta Clipper pipeline into the United States. The permit enables our planned construction of the Alberta Clipper Project to continue and ultimately, when completed, allows us to institute a cost-of-service model to recover the costs of construction from our customers through the transportation rates we will charge. As a result, we began applying the authoritative accounting provisions applicable to the regulated activities of our Alberta Clipper Project. We are permitted to capitalize and recover costs for rate-making purposes that include an allowance for equity costs during construction, referred to as AEDC. In connection with construction of the Alberta Clipper Project, we recorded $2.4 million of AEDC in "Property, plant and equipment" on our consolidated statement of financial position at September 30, 2009, and a corresponding $2.4 million of "Other income," in our consolidated statements of income for the three and nine month periods ended September 30, 2009.

RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

Accounting Standards Update—Measuring Liabilities at Fair Value

In August 2009, the Financial Accounting Standards Board, or FASB, issued an accounting update to supplement and amend the guidance surrounding fair value measurements and disclosures. The accounting standards update was issued to clarify how an entity should measure the fair value of liabilities. If a quoted price in an active market for the identical liability is available, it represents a Level 1 fair value measurement. In circumstances where a quoted price in an active market for the identical liability is not available, an entity must measure fair value using one or more of the following techniques:

- A valuation technique that uses the quoted price of the identical liability when traded as an asset;

- A valuation technique that uses the quoted price for similar liabilities or similar liabilities when traded as assets; and
- Another valuation technique that is consistent with the principles of fair value measurements, such as an income approach or market approach.

The accounting update is effective for the first reporting period beginning after August 26, 2009, with early application being permitted for financial statements for earlier periods that have not been issued. We did not adopt the provisions of this pronouncement early. We do not expect our adoption of this pronouncement to have a material effect on our financial statements other than modifications to our existing fair value disclosures.

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, 2008, 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 our Natural Gas and Marketing 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/or forecasted transaction and are not entered into with the objective of speculating on interest rates or commodity prices.

Commodity Price Derivatives

The following tables provides information about our derivative instruments at September 30, 2009 and December 31, 2008, with respect to our commodity price risk management activities for natural gas and NGLs, including condensate:

	At September 30, 2009						At December 31, 2008	
			Wtd. Average Price[2]		Fair Value[3]		Fair Value[3]	
	Commodity	Notional[1]	Receive	Pay	Asset	Liability	Asset	Liability
Contracts maturing in 2009								
Swaps								
Receive variable/pay fixed	Natural Gas	4,900,031	$ 4.57	$ 6.15	$ 0.9	$ (8.7)	$ 2.5	$(56.0)
	NGL	82,454	43.60	52.55	—	(0.7)	—	(6.5)
Receive fixed/pay variable	Natural Gas	4,214,846	5.14	4.71	4.0	(2.1)	38.7	(19.6)
	NGL	1,250,894	40.81	37.45	6.0	(1.8)	70.0	—
	Crude Oil	187,364	66.62	71.06	0.7	(1.5)	5.8	(0.6)
Receive variable/pay variable	Natural Gas	34,406,444	4.43	4.34	5.4	(2.3)	8.9	(12.8)
Options								
Calls (written)	Natural Gas	92,000	4.31	4.80	—	(0.1)	—	(0.6)
Puts (written)	Natural Gas	—	5.79	9.22	—	—	—	(1.2)
Puts (purchased)	Natural Gas	92,000	4.80	3.40	—	—	—	—
	NGL	328,164	37.54	36.57	1.1	—	9.3	—
	Crude Oil	64,400	71.06	64.86	—	—	—	—
Physical Contracts								
Receive variable/pay fixed	NGL	145,000	50.33	48.66	0.2	—	—	—
Receive fixed/pay variable	NGL	828,747	48.12	50.36	0.4	(2.3)	—	—
Contracts maturing in 2010								
Swaps								
Receive variable/pay fixed	Natural Gas	5,353,464	$ 5.91	$ 6.88	$ 1.3	$ (6.5)	$ 2.5	$ (6.5)
	NGL	120,000	61.73	45.30	2.0	—	—	(1.3)
Receive fixed/pay variable	Natural Gas	10,380,620	4.49	6.12	2.0	(18.9)	2.2	(27.5)
	NGL	2,947,010	42.69	41.08	17.0	(12.3)	28.0	—
	Crude Oil	720,790	71.95	74.38	4.2	(5.9)	5.5	(0.5)
Receive variable/pay variable	Natural Gas	79,751,813	5.95	5.87	8.8	(2.0)	0.8	(3.1)
Options								
Calls (written)	Natural Gas	365,000	4.31	6.21	—	(0.7)	—	(1.0)
Puts (purchased)	Natural Gas	365,000	4.80	3.40	—	—	—	—
	NGL	971,995	44.30	42.85	8.0	—	5.2	—
	Crude Oil	298,935	74.52	70.87	1.8	—	—	—
Physical Contracts								
Receive fixed/pay variable	NGL	126,283	42.96	46.51	—	(0.5)	—	—
	Crude Oil	5,055	—	67.25	—	(0.4)	—	—
Contracts maturing in 2011								
Swaps								
Receive variable/pay fixed	Natural Gas	878,475	$ 6.66	$ 9.78	$ —	$ (2.7)	$ 2.6	$ (3.4)
	NGL	120,000	64.25	47.67	2.0	—	—	—
Receive fixed/pay variable	Natural Gas	7,513,500	3.74	6.87	—	(23.1)	1.1	(28.1)
	NGL	581,810	55.84	43.33	8.8	(1.6)	13.0	(0.3)
	Crude Oil	676,625	71.76	77.38	1.5	(5.2)	3.3	(0.8)
Receive variable/pay variable	Natural Gas	15,885,000	6.86	6.76	1.6	(0.1)	—	(1.0)
Options								
Calls (written)	Natural Gas	365,000	4.31	6.87	—	(1.0)	—	(1.0)
Puts (purchased)	Natural Gas	365,000	4.80	3.40	—	—	—	—
	NGL	83,220	63.34	39.55	2.3	—	2.7	—
Contracts maturing in 2012								
Swaps								
Receive variable/pay fixed	Natural Gas	759,709	$ 6.82	$ 9.96	$ —	$ (2.2)	$ 0.8	$ (2.1)
	NGL	—	—	—	—	—	—	(0.9)
Receive fixed/pay variable	Natural Gas	1,274,000	3.57	7.47	—	(4.8)	—	(5.8)
	NGL	458,598	69.11	45.61	10.4	(0.1)	15.7	—
	Crude Oil	402,600	75.98	79.32	—	(1.3)	0.8	—
Receive variable/pay variable	Natural Gas	1,089,000	6.81	6.38	0.4	—	—	—
Options								
Puts (purchased)	NGL	128,832	66.80	42.58	3.8	—	4.4	—
Contracts maturing in 2013								
Swaps								
Receive fixed/pay variable	Natural Gas	730,000	$ 9.83	$ 6.73	$ 2.1	$ —	$ 2.0	$ —
	NGL	90,155	35.68	40.16	—	(0.4)	—	—
	Crude Oil	328,500	85.91	81.24	2.9	(1.5)	3.4	—
Contracts maturing in 2014								
Swaps								
Receive fixed/pay variable	Crude Oil	36,500	$86.00	$83.31	$ 0.1	$ —	$ —	$ —

(1) Volumes of Natural gas are measured in MMBtu, whereas volumes of NGL and Crude Oil are measured in 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, 2009 and December 31, 2008, 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.

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 in millions of dollars (negative amounts represent our net obligations to pay the counterparty).

	September 30, 2009	December 31, 2008
	(in millions)	
Counterparty Credit Quality*		
AAA	$ —	$ —
AA	(3.0)	(39.6)
A	(51.3)	73.3
Lower than A	(1.5)	(1.2)
	(55.8)	32.5
Credit valuation adjustment	1.1	2.2
Total	$(54.7)	$ 34.7

* As determined by nationally recognized statistical ratings organizations.

Interest Rate Derivatives

The following table provides information about our current interest rate derivatives for the specified periods.

		Partnership			Fair Value	
	Notional Principal	Pays	Receives	Maturity Date	September 30, 2009	December 31, 2008
	(dollars in millions)				(dollars in millions)	
Interest Rate Swaps Floating to Fixed:						
	$ 50.0	4.6175%	LIBOR[2]	January 15, 2009	$ —	$ —
	$ 50.0	4.6130%	LIBOR	January 29, 2009	—	—
	$ 50.0	4.6525%	LIBOR	February 13, 2009	—	(0.1)
	$ 50.0	4.5875%	LIBOR	February 20, 2009	—	(0.2)
	$ 50.0	1.6510%	LIBOR	December 2, 2010	(0.4)	—
	$ 50.0	1.6570%	LIBOR	December 5, 2010	(0.4)	—
	$ 50.0	1.6870%	LIBOR	December 12, 2010	(0.4)	—
	$ 50.0	1.7040%	LIBOR	December 14, 2010	(0.4)	—
	$ 50.0	1.7180%	LIBOR	December 18, 2010	(0.4)	—
	$ 50.0	4.3700%	LIBOR-21bps[1]	June 1, 2013	(4.2)	(5.3)
	$ 50.0	4.3425%	LIBOR-21 bps	June 1, 2013	(4.2)	(5.2)
	$ 25.0	4.3100%	LIBOR-25 bps	June 1, 2013	(2.1)	(2.7)
	$ 50.0	4.1160%	LIBOR	December 2, 2013	(1.5)	—
	$ 50.0	4.1250%	LIBOR	December 4, 2013	(1.5)	—
	$ 50.0	4.1320%	LIBOR	December 8, 2013	(1.5)	—
	$ 50.0	4.1270%	LIBOR	December 10, 2013	(1.5)	—
	$ 50.0	4.1570%	LIBOR	December 12, 2013	(1.5)	—
	$ 50.0	4.1720%	LIBOR	December 14, 2013	(1.6)	—
	$ 75.0	4.1380%	LIBOR	December 15, 2013	(2.2)	—
	$ 50.0	4.1740%	LIBOR	December 18, 2013	(1.6)	—
	$ 50.0	4.1920%	LIBOR	December 22, 2013	(1.6)	—
	$125.0	4.1680%	LIBOR	December 31, 2013	(3.9)	—
Fixed to Floating:						
	$ 25.0	LIBOR-25 bps	4.7500%	June 1, 2013	2.5	3.1
	$ 50.0	LIBOR-21 bps	4.7500%	June 1, 2013	4.9	6.1
	$ 50.0	LIBOR-21 bps	4.7500%	June 1, 2013	4.9	6.1
Rate Locks:						
	$ 20.0	4.6230%	LIBOR	June 30, 2020	(1.4)	—
	$200.0	4.6190%	LIBOR	June 30, 2020	(13.9)	—
	$300.0	4.5150%	LIBOR	December 14, 2022	(3.4)	—
	$100.0	4.6060%	LIBOR	December 14, 2022	(1.8)	—
	$200.0	4.6190%	LIBOR	December 14, 2022	(3.8)	—
	$150.0	4.6650%	LIBOR	December 13, 2023	(2.0)	—
	$150.0	4.5800%	LIBOR	December 13, 2023	(1.0)	—
Interest Rate Caps:						
	$ 25.0	1.0900%	LIBOR	December 17, 2010	0.1	—
	$ 50.0	1.1500%	LIBOR	December 22, 2010	0.1	—
	$125.0	1.0700%	LIBOR	December 31, 2010	0.3	—
	$ 50.0	1.1450%	LIBOR	January 4, 2011	0.1	—
	$ 25.0	1.1500%	LIBOR	January 8, 2011	0.1	—
	$ 50.0	1.1150%	LIBOR	January 10, 2011	0.1	—
	$ 75.0	1.1500%	LIBOR	January 15, 2011	0.2	—

(1) A bps refers to a basis point. One basis point is equivalent to 1/100th of 1 percent.

(2) LIBOR refers to the one-month or three-month U.S. London Interbank Offered Rate.

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 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 s rules and forms of the Securities and Exchange Commission. These disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure. Our management has evaluated the effectiveness of our disclosure controls and procedures as of September 30, 2009. 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, 2009.

PART II—OTHER INFORMATION

Item 1. Legal Proceedings

Refer to Part I, Item 1. Financial statements, Note 10—*Legal and Regulatory Proceedings,* which is incorporated herein by reference.

Item 1A. Risk Factors

The risk factors presented below update and should be considered in addition to the risk factors as previously disclosed in our Annual Report on Form 10-K for the fiscal year ended December 31, 2008 and Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2009.

TAX RISKS TO COMMON UNITHOLDERS

The anticipated after-tax economic benefit of an investment in our units depends largely on our being treated as a partnership for federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If we were to be treated as a corporation for federal income tax purposes or we were to become subject to additional amounts of entity-level taxation for state tax purposes, then our cash available for distribution to unitholders could be substantially reduced.

As long as we qualify to be treated as a partnership for federal income tax purposes, we are not subject to federal income tax. Although a publicly traded limited partnership is generally treated as corporation for federal income tax purposes, a publicly traded partnership such as us can qualify to be treated as a partnership for federal income tax purposes under current law so long as for each taxable year at least 90% of its gross income is derived from specified investments and activities. We believe that we qualify to be treated as partnership for federal income tax purposes because we believe that at least 90% of our gross income for each taxable year has been and is derived from such specified investments and activities. Although we intend to meet this gross income requirement, we may not find it possible, regardless of our efforts, to meet this gross income requirement or may inadvertently fail to meet this gross income requirement. If we do not meet this gross income requirement for any taxable year and the Internal Revenue Services (the "IRS") does not determine that such failure was inadvertent, we would be treated as a corporation for such taxable year and each taxable year thereafter. We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or certain other matters affecting us.

Additionally, current law may change so as to cause us to be treated as a corporation for federal income tax purposes without regard to our sources of income or otherwise subject us to entity-level taxation. Legislation has been proposed that would eliminate partnership tax treatment for certain publicly traded partnerships. Although such legislation would not apply to us as currently proposed, it could be amended prior to enactment in a manner that does apply to us. We are unable to predict whether any of these changes or other proposals will ultimately be enacted. Moreover, any modification to the federal income tax laws and interpretations thereof may be applied retroactively.

If we were to be treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%. Under current law, distributions to unitholders would generally be taxed as corporate distributions, and no income, gain, loss, or deduction would flow through to our unitholders. If we were treated as a corporation at the state level, we may also be subject to the income tax provisions of certain states. Moreover, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise, or other forms of taxation.

If we become subject to federal income tax and additional state taxes, the additional taxes we pay will reduce the amount of cash we can distribute each quarter to the holders of our Class A and B common units and the number of i-units that we will distribute quarterly. Therefore, our treatment as a corporation for federal income tax purposes or becoming subject to a material amount of additional state taxes could result in a material reduction in the anticipated cash flow and after-tax return to our unitholders, likely causing a substantial reduction in the value of our units. Moreover, our payment of additional federal and state taxes could materially and adversely affect our ability to make payments on our debt securities.

If the IRS contests our curative tax allocations or other federal income tax positions we take, the market for our Class A common units may be impacted and the cost of any IRS contest will reduce our cash available for distribution or payments on our debt securities.

Our partnership agreement allows curative allocations of income, deduction, gain and loss by us to account for differences between the tax basis and fair market value of property at the time the property is contributed or deemed contributed to us and to account for differences between the fair market value and book basis of our assets existing at the time of issuance of any Class A common units. If the IRS does not respect our curative allocations, ratios of taxable income to cash distributions received by the holders of Class A common units will be materially higher than previously estimated.

The IRS may adopt positions that differ from the positions we have taken or may take on certain tax matters. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we have taken or may take. A court may not agree with some or all of the positions we have taken or may take. Any contest with the IRS may materially and adversely impact the market for our Class A Common Units and the price at which they trade. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders and our general partner because the costs will reduce our cash available for distribution or payments on our debt securities.

The tax liability of our unitholders could exceed their distributions or proceeds from sales of Class A common units.

Because our unitholders will generally be treated as partners to whom we will allocate taxable income which could be different in amount than the cash we distribute, our unitholders will be required to pay any federal income tax and, in some cases, state and local income taxes on their allocable share of our income, even if they do not receive cash distributions from us. Unitholders will not necessarily receive cash distributions equal to the tax on their allocable share of our taxable income.

Tax gain or loss on the disposition of our Class A common units could be more or less than expected.

If a unitholder disposes of Class A common units, the unitholder will recognize a gain or loss equal to the difference between the amount realized and the unitholder's tax basis in those Class A common units. Because distributions in excess of a unitholder's allocable share of our net taxable income decrease the unitholder's tax basis in their Class A common units, the amount, if any, of such prior excess distributions with respect to their Class A common units sold will, in effect, become taxable income to the unitholder if the Class A common units are sold at a price greater than the unitholder's tax basis in those Class A common units, even if the price the unitholder receives is less than the unitholder's original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder's share of our nonrecourse liabilities, if a unitholder sells Class A common units, the unitholder may incur a tax liability in excess of the amount of cash received from the sale.

As a result of investing in our Class A common units, a unitholder may become subject to state and local taxes and return filing requirements in the states where we or our subsidiaries own property and conduct business.

In addition to federal income taxes, a unitholder will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we or our subsidiaries conduct business or own property now or in the future, even if such unitholder does not live in any of those jurisdictions. Our unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. We or our subsidiaries conduct business in the states of Alabama, Arkansas, Florida, Georgia, Illinois, Indiana, Kansas, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, New York, South Carolina, North Carolina, North Dakota, Oklahoma, Tennessee, Texas and Wisconsin. Most of these states impose an income tax on individuals, corporations, and other entities. As we make acquisitions or expand our business, we may acquire property or conduct business in additional states or in foreign jurisdictions that impose a personal income tax. It is the responsibility of each unitholder to file all required U.S. federal, foreign, state and local tax returns.

Ownership of Class A common units raises issues for tax-exempt entities and other investors.

An investment in our Class A common units by tax-exempt entities, such as employee benefit plans, individual retirement accounts (known as IRAs), Keogh plans and other retirement plans, regulated investment companies and foreign persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be "unrelated business taxable income" and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file U.S. federal tax returns and pay tax on their share of our taxable income. Tax-exempt entities and non-U.S. persons should consult their tax adviser before investing in our Class A common units.

We adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between the general partner and our unitholders. The IRS may challenge this treatment, which could adversely affect the value of the Class A Common Units.

When we issue additional Class A common units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and our general partner, which may be unfavorable to such unitholders. Moreover, under our valuation methods, subsequent purchasers of Class A common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between the general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders' sale of Class A common units and could have a negative impact on the value of the Class A common units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in our termination as a partnership for federal income tax purposes.

We will be considered to have been terminated for federal tax purposes if there are sales or exchanges which, in the aggregate, constitute 50% or more of the total interests in our capital and profits within a twelve-month period. Our termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1) for one fiscal year and could result in a significant deferral of depreciation deductions available in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in such unitholder's taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but instead, we would be treated as a new partnership for federal tax purposes. If treated as a new partnership for federal tax purposes, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred.

We treat each purchaser of Class A common units as having the same tax benefits without regard to the actual Class A common units purchased. The IRS may challenge this treatment, which could result in a unitholder owing more tax and may adversely affect the value of the Class A common units.

Because we cannot match transferors and transferees of our Class A common units and to maintain the uniformity of the economic and tax characteristics of our Class A common units, we have adopted certain depreciation and amortization positions that may not conform to all aspects of existing Treasury regulations. These positions may result in an understatement of deductions and losses and an overstatement of income and gain to our unitholders. For example, we do not amortize certain goodwill assets, the value of which has been attributed to certain of our outstanding Class A common units. A subsequent holder of those Class A common units is entitled to an amortization deduction attributable to that goodwill under Internal Revenue Code Section 743(b). However, because we cannot identify these Class A common units once they are traded by the initial holder, we do not give any subsequent holder of a Class A common unit any such amortization deduction. This approach understates deductions available to those unitholders who own those Class A common units and results in a reduction in the tax basis of those Class A common units by the amount of the deductions that were allowable but were not taken.

The IRS may challenge the manner in which we calculate our unitholder's basis adjustment under Internal Revenue Code Section 743(b). If so, because neither we nor a unitholder can identify the Class A common units to which this issue relates once the initial holder has traded them, the IRS may assert adjustments to all unitholders selling Class A common units within the period under audit as if all unitholders owned Class A common units with respect to which allowable deductions were not taken. Any position we take that is inconsistent with applicable Treasury regulations may have to be disclosed on our federal income tax return. This disclosure increases the likelihood that the IRS will challenge our positions and propose adjustments to some or all of our unitholders. A successful IRS challenge to this position or other positions we may take could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain from a unitholder's sale of Class A common units and could have a negative impact on the value of the Class A common units or result in audit adjustments to our unitholders' tax returns.

A unitholder whose Class A common units are loaned to a "short seller" to cover a short sale of Class A common units may be considered as having disposed of those Class A common units. If so, such unitholder would no longer be treated for tax purposes as a partner with respect to those Class A common units during the period of the loan and may recognize gain or loss from the disposition.

Because a unitholder whose Class A common units are loaned to a "short seller" to cover a short sale of Class A common units may be considered as having disposed of those Class A common units, such unitholder may no longer be treated as a partner with respect to those Class A common units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those Class A common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those Class A common units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their Class A common units.

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: November 4, 2009

By: /s/ STEPHEN J. J. LETWIN
Stephen J. J. Letwin
Managing Director
(Principal Executive Officer)

Date: November 4, 2009

By: /s/ MARK A. MAKI
Mark A. Maki
Vice President—Finance
(Principal Financial Officer)

Index of Exhibits

Each exhibit identified below is filed as a part of this quarterly report. 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. Exhibits designated with a "+" constitute a management contract or compensatory plan arrangement required to be filed as an exhibit to this report.

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 (incorporated by reference to Exhibit 3.2 to the Partnership's 2000 Form 10-K/A 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 our Current Report on Form 8-K filed on August 16, 2006).
3.4	Amendment No. 1 to Fourth Amended and Restated Agreement of Limited Partnership of the Partnership, dated December 28, 2007 (incorporated by reference to Exhibit 3.1 of our 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 our 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 2000 Form 10-K/A filed on October 9, 2001).
10.1	Third Amended and Restated Agreement of Limited Partnership of Enbridge Energy, Limited Partnership, dated July 31, 2009, by and among Enbridge Pipelines (Lakehead) L.L.C., Enbridge Pipelines (Wisconsin) Inc., Enbridge Energy Company, Inc., Enbridge Pipelines (Alberta Clipper) L.L.C. and Enbridge Energy Partners, L.P. (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed on August 5, 2009).
10.2	A1 Credit Agreement dated July 31, 2009, by and among Enbridge Energy Partners, L.P. and Enbridge Energy Company, Inc. (incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K filed on August 5, 2009).
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.