UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended March 31, 2008

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 and 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 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.

Large Accelerated Filer ☒	Non-Accelerated Filer ☐ (Do not check if a smaller reporting company)
Accelerated Filer ☐	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 59,838,834 Class A common units outstanding as of April 29, 2008.

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," "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 revenues, 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, 2007 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

	Three months ended March 31,	
	2008	2007
	(unaudited; in millions, except per unit amounts)	
Operating revenue	$2,435.3	$1,712.7
Operating expenses		
Cost of natural gas (Notes 9 and 10)	2,098.8	1,484.3
Operating and administrative	116.7	97.7
Power	38.3	30.1
Depreciation and amortization	49.2	36.5
	2,303.0	1,648.6
Operating income	132.3	64.1
Interest expense	27.6	25.3
Other income (expense)	(0.3)	1.4
Income before income tax expense	104.4	40.2
Income tax expense	1.3	1.1
Net income	$ 103.1	$ 39.1
Net income allocable to limited partner units (Note 2)	$ 91.8	$ 31.4
Net income per limited partner unit (basic and diluted) (Note 2)	$ 0.99	$ 0.40
Weighted average limited partner units outstanding (millions)	92.6	77.8

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three months ended March 31,	
	2008	2007
	(unaudited; in millions)	
Net income	$103.1	$ 39.1
Other comprehensive loss net of tax benefit of $1.8 and $1.3, respectively (Notes 9 and 10)	(26.3)	(40.3)
Comprehensive income (loss)	$ 76.8	$ (1.2)

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

ENBRIDGE ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three months ended March 31,	
	2008	2007
	(unaudited; in millions)	
Cash provided by operating activities		
Net income	$ 103.1	$ 39.1
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	49.2	36.5
Derivative fair value (gains) losses (Notes 9 and 10)	(13.7)	16.3
Other	5.5	(1.4)
Changes in operating assets and liabilities, net of cash acquired:		
Receivables, trade and other	20.7	45.5
Due from General Partner and affiliates	0.6	(13.2)
Accrued receivables	(63.8)	28.2
Inventory (Note 4)	21.1	61.1
Current and long-term other assets (Notes 9 and 10)	1.0	(0.2)
Due to General Partner and affiliates	(1.9)	(3.3)
Accounts payable and other (Notes 3, 9 and 10)	(0.3)	(28.9)
Accrued purchases	118.5	(53.1)
Interest payable	28.4	23.5
Current income tax payable	1.1	1.1
Property and other taxes payable	6.7	1.6
Net cash provided by operating activities	276.2	152.8
Cash used in investing activities		
Additions to property, plant and equipment	(373.5)	(399.3)
Changes in construction payables	(63.2)	63.9
Other	(5.3)	0.4
Net cash used in investing activities	(442.0)	(335.0)
Cash provided by financing activities		
Net proceeds from unit issuances (Note 7)	221.8	—
Distributions to partners (Note 7)	(66.0)	(57.6)
Net Credit Facility borrowings (Note 6)	130.0	—
Net commercial paper (repayments) issuances (Note 6)	(44.7)	139.4
Net cash provided by financing activities	241.1	81.8
Net increase (decrease) in cash and cash equivalents	75.3	(100.4)
Cash and cash equivalents at beginning of year	50.5	184.6
Cash and cash equivalents at end of period	$ 125.8	$ 84.2

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	March 31, 2008	December 31, 2007
	(unaudited; in millions)	
ASSETS		
Current assets		
Cash and cash equivalents (Note 3)	$ 125.8	$ 50.5
Receivables, trade and other, net of allowance for doubtful accounts of $1.8 in 2008 and 1.9 in 2007	137.3	157.8
Due from General Partner and affiliates	26.6	27.2
Accrued receivables	662.6	598.8
Inventory (Note 4)	89.5	110.6
Other current assets (Notes 9 and 10)	12.6	14.8
	1,054.4	959.7
Property, plant and equipment, net (Note 5)	5,883.7	5,554.9
Goodwill	256.5	256.5
Intangibles, net	91.9	91.5
Other assets, net (Notes 9 and 10)	28.9	29.0
	$7,315.4	$6,891.6
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Due to General Partner and affiliates	$ 43.9	$ 45.8
Accounts payable and other (Notes 3, 9 and 10)	343.8	400.4
Accrued purchases	722.3	603.8
Interest payable	49.3	20.9
Property and other taxes payable	30.3	22.5
Current maturities of long-term debt	231.0	31.0
	1,420.6	1,124.4
Long-term debt (Note 6)	2,751.4	2,862.9
Environmental liabilities (Note 8)	2.1	2.8
Notes payable to affiliate	130.0	130.0
Other long-term liabilities (Notes 9 and 10)	207.2	200.0
	4,511.3	4,320.1
Commitments and contingencies (Note 8)		
Partners' capital (Note 7)		
Class A common units (59,838,834 at March 31, 2008 and 55,238,834 at December 31, 2007, respectively)	1,550.2	1,340.7
Class B common units (3,912,750 in 2008 and 2007)	78.9	72.9
Class C units (18,415,008 at March 31, 2008 and 18,073,367 at December 31, 2007, respectively)	891.4	874.1
i-units (13,815,388 at March 31, 2008 and 13,564,086 at December 31, 2007, respectively)	535.3	515.3
General Partner	69.0	62.9
Accumulated other comprehensive loss (Notes 9 and 10)	(320.7)	(294.4)
	2,804.1	2,571.5
	$7,315.4	$6,891.6

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 March 31, 2008 and December 31, 2007; and the results of operations and cash flows for the three month periods ended March 31, 2008 and 2007. We derived the consolidated statement of financial position as of December 31, 2007, from the audited financial statements included in our 2007 Annual Report on Form 10-K. The results of operations for the three month period ended March 31, 2008, should not be taken as indicative of the results to be expected for the full year due to seasonality of portions of the 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. The interim consolidated financial statements should be read in conjunction with our consolidated financial statements and notes presented in our Annual Report on Form 10-K for the fiscal year ended December 31, 2007.

2. NET INCOME PER LIMITED PARTNER UNIT

Net income per limited partner unit is computed by dividing net income, after deducting our allocation to Enbridge Energy Company, Inc. (the "General Partner"), by the weighted average number of our limited partner units outstanding. The General Partner's allocation is equal to an amount based upon its general partner interest, adjusted to reflect an amount equal to its incentive distributions and an amount required to reflect depreciation on the General Partner's historical cost basis for assets contributed on formation of the Partnership. We have no dilutive securities. Net income per limited partner unit was determined as follows:

	Three months ended March 31,	
	2008	2007
	(in millions, except per unit amounts)	
Net income	$103.1	$ 39.1
Allocations to the General Partner:		
Net income allocated to the General Partner	(2.1)	(0.8)
Incentive income allocated to the General Partner	(9.2)	(6.8)
Historical cost depreciation adjustments	—	(0.1)
	(11.3)	(7.7)
Net income allocable to limited partner units	$ 91.8	$ 31.4
Net income per limited partner unit (basic and diluted)	$ 0.99	$ 0.40
Weighted average limited partner units outstanding	92.6	77.8

3. CASH AND CASH EQUIVALENTS

We extinguish liabilities when a creditor has relieved us of our obligation, which occurs when our financial institution honors a check that the creditor has presented for payment. Accordingly, obligations for which we have issued check payments that have not yet been presented to the financial institution of approximately $36.5 million at March 31, 2008 and $38.5 million at December 31, 2007, are included in Accounts payable and other on our Consolidated Statements of Financial Position.

4. INVENTORY

Inventory is comprised of the following:

	March 31, 2008	December 31, 2007
	(in millions)	
Material and supplies	$ 3.9	$ 3.9
Liquids inventory	13.0	6.7
Natural gas and natural gas liquids inventory	72.6	100.0
	$ 89.5	$110.6

5. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is comprised of the following:

	March 31, 2008	December 31, 2007
	(in millions)	
Land	$ 14.3	$ 14.3
Rights-of-way	367.3	345.8
Pipelines	2,883.0	2,703.2
Pumping equipment, buildings and tanks	911.7	854.7
Compressors, meters, and other operating equipment	568.1	536.1
Vehicles, office furniture and equipment	130.4	123.3
Processing and treating plants	297.5	200.4
Construction in progress	1,792.7	1,813.9
Total property, plant and equipment	6,965.0	6,591.7
Accumulated depreciation	(1,081.3)	(1,036.8)
Property, plant and equipment, net	$ 5,883.7	$ 5,554.9

6. DEBT

Credit Facility

In March 2008, we requested and received approval from the parties named as lenders to our Credit Facility for a one year extension of the maturity date from April 4, 2012 to April 4, 2013.

At March 31, 2008, we had $530 million outstanding under our Credit Facility at a weighted average interest rate of 3.27% and letters of credit totaling $177.5 million. The amounts we may borrow under the terms of our Credit Facility are reduced by the principal amount of our commercial paper issuances and the balance of our letters of credit outstanding. At March 31, 2008 we could borrow $317.5 million under the terms of our Credit Facility, determined as follows:

	March 31, 2008
	(in millions)
Total credit available under Credit Facility	$1,250.0
Less: Amounts outstanding under Credit Facility	(530.0)
Balance of letters of credit outstanding	(177.5)
Principal amount of commercial paper issuances	(225.0)
Total amount we could borrow at March 31, 2008	$ 317.5

Individual borrowings under the terms of our Credit Facility generally become due and payable at the end of each contract period, typically a period of three months or less. We have the option to repay these amounts on a non-cash basis by net settling with the parties to our Credit Facility by contemporaneously borrowing at the then current rate of interest and repaying the amounts due. During the quarter ended March 31, 2008, we net settled borrowings of approximately $390 million on a non-cash basis.

Commercial Paper Program

We have a commercial paper program that provides for the issuance of up to $600 million of commercial paper that is supported by our Credit Facility. We access the commercial paper market primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions, at rates that are generally lower than the rates available under our Credit Facility. At March 31, 2008 and December 31, 2007, respectively, we had $224.2 million and $268.5 million of commercial paper outstanding, net of unamortized discount of $0.8 million and $1.5 million, at weighted average interest rates of 3.53% and 5.36%. At March 31, 2008 and December 31, 2007, respectively, we could issue an additional $317.5 million and $330 million in principal amount under our commercial paper program. The commercial paper we can issue is limited by the credit available under the terms of our Credit Facility.

We have the ability and intent to refinance all of our commercial paper obligations on a long-term basis under our unsecured long-term Credit Facility. Accordingly, such amounts have been classified as long-term debt in our accompanying Consolidated Statement of Financial Position.

7. PARTNERS' CAPITAL

The following table sets forth the distributions, as approved by the Board of Directors of Enbridge Energy Management, L.L.C. ("Enbridge Management") during the three months ended March 31, 2008:

Distribution Declaration Date	Distribution Payment Date	Record 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
January 28, 2008	February 14, 2008	February 6, 2008	$0.950	$96.7	$12.9	$17.2	$0.6	$66.0

(1) During 2008, in lieu of cash distributions, the Partnership issued 251,302 i-units to Enbridge Management.

(2) During 2008, in lieu of cash distributions, the Partnership issued 341,641 Class C units to our Class C unitholders.

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

Issuance of Class A common units

On March 3, 2008, we issued and sold 4.6 million Class A common units, including 0.6 million units from the over-allotment option that was exercised by the underwriters, at a price to the public of $49.00 per unit, for proceeds of approximately $217.2 million, net of underwriters' discounts, commissions and issuance costs. In addition, our general partner contributed approximately $4.6 million to us to maintain its two percent general partner interest. We used the proceeds from this offering to partially reduce outstanding commercial paper we issued and amounts we previously borrowed under our Credit Facility to finance a portion of our capital expansion projects. We invested a portion of the proceeds for use in future periods to fund additional expenditures under our capital expansion projects.

8. COMMITMENTS, CONTINGENCIES AND ENVIRONMENTAL LIABILITIES

Environmental Liabilities

We are subject to federal and state laws and regulations relating to the protection of the environment. Environmental risk is inherent to liquid hydrocarbon and natural gas pipeline operations and we could, at times, be subject to environmental cleanup and enforcement actions. We manage this environmental risk through appropriate environmental policies and practices to minimize any impact our operations may have on the environment. To the extent that we are unable to recover environmental liabilities associated with the Lakehead system assets through insurance, the 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 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 March 31, 2008 and December 31, 2007, we have recorded $4.1 million and $3.4 million in current liabilities and $2.1 million and $2.8 million, respectively, in long-term liabilities, primarily to address remediation of contaminated sites, asbestos containing materials, management of hazardous waste material disposal, and outstanding air quality measures for certain of our liquids and natural gas assets.

Legal Proceedings

We are a participant in various legal proceedings arising in the ordinary course of business. Some of these proceedings are covered, in whole or in part, by insurance. We believe that the outcome of all these proceedings will not, individually or in the aggregate, have a material adverse effect on our financial condition.

9. FAIR VALUE MEASUREMENTS

We adopted the provisions of Statement of Financial Accounting Statement No. 157, *Fair Value Measurement*, or SFAS No. 157, as of January 1, 2008. SFAS No. 157 provides guidance for determining fair value and requires increased disclosure regarding the inputs to valuation techniques used to measure fair value. SFAS 157 defines fair value as an exit price representing the expected amount we would receive to sell an asset or pay to transfer a liability in an orderly transaction with market participants at the measurement date. We apply the provisions of SFAS No. 157 to fair values we report for our derivative instruments and annual disclosures associated with the fair values of our outstanding indebtedness.

We utilize a mid-market pricing convention for valuation as a practical expedient for assigning fair value to our derivative assets and liabilities. In the case of our liabilities, our nonperformance risk is considered in the valuation, based upon the ratings assigned to our debt obligations by the nationally recognized statistical ratings organizations. We present the fair value of our derivative contracts on a net-by-counterparty basis in our consolidated statements of financial position when we believe a legal right of setoff exists under an enforceable netting agreement. We do not offset the fair value of our derivative contracts with fair value amounts recognized for our right to reclaim cash collateral or our obligation to return cash collateral arising from derivative instruments executed with the same counterparty under master netting arrangements. 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.

SFAS No. 157 establishes a hierarchy which prioritizes the inputs we use to measure fair value into three distinct categories based upon whether such inputs are observable in active markets or unobservable. We classify assets and liabilities in their entirety based on the lowest level of input that is significant to the fair value measurement. Our methodology for categorizing assets and liabilities that are measured at fair value pursuant to this hierarchy gives the highest priority to unadjusted quoted prices in active markets and the lowest level to unobservable inputs as outlined below:

- Level 1—We include in this category the fair value of assets and liabilities that we measure based on unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. We consider active markets as those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis. The fair value of our assets and liabilities included in this category consists primarily of exchange traded derivative instruments.
- Level 2—We categorize the fair value of assets and liabilities that we measure with either directly or indirectly observable inputs as of the measurement date where pricing inputs are other than quoted prices in active markets as Level 2. This category includes those derivative instruments that we value using models or other valuation methodologies derived from observable market data. These models are primarily industry-standard models that consider various inputs including: (a) quoted forward prices for commodities, (b) time value, (c) volatility factors, and (d) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these inputs are observable in the marketplace throughout the full term of the derivative instrument, can be derived from observable data, or supported by observable levels at which transactions are executed in the marketplace.
- Level 3—We include in this category the fair value of assets and liabilities that we measure based on prices or valuation techniques that require inputs which are both significant to the fair value measurement and less observable from objective sources. (i.e., supported by little or no market activity). We may also use these inputs with internally developed methodologies that result in our best estimate of the fair value. Level 3 instruments primarily include derivative instruments for which we do not have sufficient corroborating market evidence, such as binding broker quotes, to support classifying the asset or liability as Level 2. In most instances, the observable data is available for us to validate the inputs used to measure fair value, however the cost of obtaining the information is prohibitive.

Derivative contracts can be exchange traded or over-the counter (“OTC”). We generally value exchange-traded derivatives within portfolios calibrated to market clearing levels on a daily basis. We value OTC derivatives using broker information based on executed market transactions that we have corroborated with other observable market data. For OTC derivatives that trade in liquid markets, such as generic forwards, swaps, and options, inputs can generally be verified and valuation does not involve significant management judgment.

Certain OTC derivatives trade in less liquid markets with limited pricing information, and the determination of fair value for these derivatives is inherently more difficult. Such instruments are classified within Level 3 of the fair value hierarchy. We include the fair value of financial assets and liabilities in Level 3 as a default due to limited market data or in most cases, due to the lack of binding broker quotes to corroborate pricing data as required by current interpretations of SFAS No. 157 Level 2 requirements.

Financial assets and liabilities that are categorized in Level 3 may later be reclassified to the Level 2 category at the point we are able to obtain sufficient binding market data or the interpretation of Level 2 criteria is modified in practice to include non-binding market corroborated data.

The following table sets forth by level within the fair value hierarchy, our financial assets and liabilities that were accounted for at fair value on a recurring basis as of March 31, 2008. 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 the valuation of the financial assets and liabilities and their placement within the fair value hierarchy.

	Fair Value at March 31, 2008			
Recurring fair value measures	**Level 1**	**Level 2**	**Level 3**	**Total**
	(in millions)			
Assets:				
Derivative instruments, net	$ —	$ —	$ 9.1	$ 9.1
Liabilities:				
Derivative instruments, net	(246.5)	—	(121.2)	(367.7)
Total	$(246.5)	$ —	$(112.1)	$(358.6)

The table below provides a summary of changes in the fair value of our Level 3 financial assets and liabilities for the quarter ended March 31, 2008. As reflected in the table, the net unrealized gain on Level 3 financial assets and liabilities was $48.5 million for the quarter ended March 31, 2008.

	Derivative Instruments, net
	(in millions)
Balance at January 1, 2008	$(160.6)
Realized and unrealized net gains	49.4
Purchases and settlements	(0.9)
Transfer in (out) of Level 3	—
Balance at March 31, 2008	$(112.1)
Change in unrealized net gains relating to instruments still held at March 31, 2008	$ 48.5

10. DERIVATIVE FINANCIAL INSTRUMENTS—COMMODITY PRICE RISK

Our net income and cash flows are subject to volatility stemming from changes in commodity prices of natural gas, NGLs, condensate and fractionation margins (the relative price differential between NGL sales and the offsetting natural gas purchases). Our exposure to commodity price risk exists within our Natural Gas and Marketing segments. We use derivative instruments including futures, forwards, swaps, options and other financial instruments with similar characteristics to manage the risks associated with market fluctuations in commodity prices, as well as to reduce the volatility of our cash flows. Our formal hedging program provides a control structure and governance for our hedging activities specific to identified risks and time periods, which are subject to the approval and monitoring by a committee of senior management. Based on our risk management policies, all of our derivative 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.

Accounting Treatment

We record all derivative instruments in our consolidated financial statements at fair value pursuant to the provisions of SFAS No. 133, and the guidance set forth in Statement of Financial Accounting Standards No. 157, *Fair Value Measurement* ("SFAS No. 157") as discussed in Note 9 above. We adjust our consolidated financial statements each period for changes in the fair value of our derivative instruments, which we refer to as "marking to market" or "mark-to-market." 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.

Under the guidance of SFAS No. 133, if a derivative instrument does not qualify as a hedge, or is not designated as a hedge, the derivative instrument is adjusted to its fair value, or marked-to-market, each period with the increases and decreases in fair value recorded in our Consolidated Statements of Income as increases and decreases in Cost of natural gas for our commodity-based derivatives. Our 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 instrument occurs.

If a derivative instrument qualifies and is designated as a cash flow hedge, 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 ("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 value is recognized each period in earnings. Realized gains and losses on derivative instruments that are designated as hedges and qualify for hedge accounting are included in Cost of natural gas in the period 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 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 instruments through earnings. To qualify for cash flow hedge accounting as set forth in SFAS No. 133, very specific requirements must be met in terms of hedge structure, hedge objective and hedge documentation.

Non-Qualified Hedges

Many of our derivative instruments qualify for hedge accounting treatment under the specific requirements of SFAS No. 133. However, we have four primary transaction types associated with our commodity derivative instruments where the hedge structure does not meet the requirements to apply hedge accounting. As a result, these derivative instruments do not qualify for hedge accounting under SFAS No. 133 and are referred to as "non-qualified." Non-qualified derivative instruments are marked-to-market each period with the change in fair value, representing unrealized gains and losses, included in Cost of natural gas 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 when the associated derivative instrument contract settlement is made.

The four primary transaction types that do not qualify for hedge accounting are as follows:

1. **Transportation—**In our Marketing segment, when we transport natural gas from one location to another the pricing index used for natural gas sales is generally different from the pricing index used for natural gas purchases, exposing us to basis price risk relative to changes in those two indices. By entering into a basis swap, we can effectively lock in the margin, or "spread," representing the difference between the sales price and the purchase price, on the combined natural gas purchase and natural gas sale, thereby removing locational price risk on the physical transactions. Although this represents a sound economic hedging strategy, the derivative instruments (i.e., the basis swaps) associated with these transportation contracts do not qualify for hedge accounting under SFAS No. 133, 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 instruments are recorded in earnings.

2. **Storage—**In our Marketing segment, we use derivative instruments (i.e., natural gas swaps) to hedge the "margin," representing 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 instruments is to lock in the margin between storage injections and withdrawals 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 retain the flexibility to make changes in the underlying injection or withdrawal schedule, given 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 instrument is settled in a period that is different from when 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.

3. **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 under SFAS No. 133 and do not qualify for hedge accounting. The changes in fair value of these derivative instruments from the date of de-designation are recorded in 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.

4. **Optional Natural Gas Processing Volumes**—In our Natural Gas segment we use derivative instruments to hedge NGL volumes produced from our natural gas processing facilities. Many of our natural gas contracts provide us with the option of processing natural gas when it is economical, and allow us to cease processing when the "fractionation spread," representing the relative difference between the price received for the NGLs produced less the cost of natural gas used for processing, becomes uneconomic. We have entered into derivative 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 when it is probable the processing will occur. Because our processing forecasts fluctuate due to market conditions, these derivative instruments are deemed "non-qualifying" hedges. For this reason, our operating income will be subject to increased volatility due to fluctuations in both natural gas and NGL prices until the underlying transactions are settled.

In each of the instances 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 utilize for the derivative instruments employed to mitigate the commodity price risk associated with our storage and transportation assets. This difference in accounting treatment between the derivative instrument and the underlying transaction (i.e., the derivative instruments are recorded at fair 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 derivative instruments, which are recorded as an element of cost of natural gas for our commodity-based derivative instruments and interest expense for our interest rate derivative instruments in our Consolidated Statements of Income and disclosed as a reconciling item on our Consolidated Statements of Cash Flows:

Derivative fair value gains (losses)	Three months ended March 31, 2008	2007
	(in millions)	
Natural Gas segment		
Hedge ineffectiveness	$ (1.8)	$ 0.1
Non-qualified hedges	28.6	(3.2)
Marketing		
Non-qualified hedges	(12.9)	(13.2)
Commodity derivative fair value gains (losses)	13.9	(16.3)
Corporate		
Non-qualified interest rate hedges	(0.2)	—
Derivative fair value gains (losses)	$ 13.7	$(16.3)

We record the change in fair value of our cash flow hedges in AOCI until the derivative instruments are settled, at which time they are reclassified from AOCI to earnings. Also included in AOCI at March 31, 2008 are unrecognized losses of approximately $1.9 million associated with cash flow hedges 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 months ended March 31, 2008, we reclassified losses of $31.3 million from AOCI to Cost of natural gas on our Consolidated Statements of Income for the fair value of derivative instruments that were settled.

Derivative Positions

Our derivative financial instruments are included at their fair values in the Consolidated Statements of Financial Position as follows:

	March 31, 2008	December 31, 2007
	(in millions)	
Receivables, trade and other	$ 5.5	$ 6.5
Other assets, net	6.6	6.4
Accounts payable and other	(170.6)	(165.5)
Other long-term liabilities	(200.1)	(192.9)
	$(358.6)	$(345.5)

The increase in our obligation associated with derivative activities is primarily due to an increase in forward natural gas prices from December 31, 2007 to March 31, 2008, partially offset by a decline in NGL prices. The Partnership's portfolio of derivative financial instruments is largely comprised of long-term fixed price natural gas and NGL sales and purchase agreements.

We present the fair value of our derivative contracts on a net-by-counterparty basis in our Consolidated Statements of Financial Position when we believe a legal right of setoff exists under an enforceable netting agreement. 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 counterparty credit quality and exposures, in millions of dollars.

Counterparty Credit Quality*	March 31, 2008	December 31, 2007
	(in millions)	
AAA	$ —	$ —
AA	(294.7)	(298.3)
A	(63.9)	(47.2)
Lower than A	—	—
Total	$(358.6)	$(345.5)

* As determined by nationally recognized statistical ratings organizations.

11. SEGMENT INFORMATION

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

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

- Liquids;
- Natural Gas; and
- Marketing.

The following tables present certain financial information about our business segments:

	As of and for the three months ended March 31, 2008				
	Liquids	Natural Gas	Marketing	Corporate[(1)]	Total
			(in millions)		
Total revenue	$ 157.0	$1,874.1	$1,198.8	$ —	$3,229.9
Less: Intersegment revenue	—	710.1	84.5	—	794.6
Operating revenue	157.0	1,164.0	1,114.3	—	2,435.3
Cost of natural gas	—	987.8	1,111.0	—	2,098.8
Operating and administrative	37.5	74.9	2.3	2.0	116.7
Power	38.3	—	—	—	38.3
Depreciation and amortization	19.6	29.1	0.5	—	49.2
Operating income	61.6	72.2	0.5	(2.0)	132.3
Interest expense	—	—	—	27.6	27.6
Other expense	—	—	—	0.3	0.3
Income before income tax expense	61.6	72.2	0.5	(29.9)	104.4
Income tax expense	—	—	—	1.3	1.3
Net income	$ 61.6	$ 72.2	$ 0.5	$ (31.2)	$ 103.1
Total assets	$3,252.8	$3,439.3	$ 438.5	$184.8	$7,315.4
Capital expenditures (excluding acquisitions)	$ 296.8	$ 73.5	$ —	$ 3.2	$ 373.5

(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 three months ended March 31, 2007				
	Liquids	Natural Gas	Marketing	Corporate[(1)]	Total
			(in millions)		
Total revenue	$ 132.8	$1,324.3	$889.4	$ —	$2,346.5
Less: Intersegment revenue	—	568.8	65.0	—	633.8
Operating revenue	132.8	755.5	824.4	—	1,712.7
Cost of natural gas	—	663.2	821.1	—	1,484.3
Operating and administrative	33.7	61.3	1.6	1.1	97.7
Power	30.1	—	—	—	30.1
Depreciation and amortization	16.4	20.0	0.1	—	36.5
Operating income	52.6	11.0	1.6	(1.1)	64.1
Interest expense	—	—	—	25.3	25.3
Other income	—	—	—	1.4	1.4
Income before income tax expense	52.6	11.0	1.6	(25.0)	40.2
Income tax expense	—	—	—	1.1	1.1
Net income	$ 52.6	$ 11.0	$ 1.6	$ (26.1)	$ 39.1
Total assets	$2,016.7	$2,845.6	$334.5	$162.1	$5,358.9
Capital expenditures (excluding acquisitions)	$ 223.2	$ 166.7	$ 1.2	$ 8.2	$ 399.3

(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.

12. SUBSEQUENT EVENT

Distribution to Partners

On April 28, 2008, the Board of Directors of Enbridge Management declared a distribution payable to our partners on May 15, 2008. The distribution will be paid to unitholders of record as of May 7, 2008, of our available cash of $102.2 million at March 31, 2008, or $0.950 per common unit. Of this distribution, $71.0 million will be paid in cash, $13.1 million will be distributed in i-units to our i-unitholder, $17.5 million will be distributed in Class C units to the holders of our Class C units and $0.6 million will be retained from the General Partner in respect of the i-unit and Class C unit distributions.

Issuance of Debt

In April 2008, we issued and sold in a private offering $400 million in principal amount of our 6.5% Notes due April 15, 2018 and $400 in principal amount of our 7.5% Notes due April 15, 2038, which we collectively refer to as the Notes. We received net proceeds from the offering of approximately $790.4 million after payment of initial purchasers' discounts and offering expenses. We used a portion of the proceeds we received from this offering to repay outstanding issuances of commercial paper and borrowings under our Credit Facility that we had previously used to finance a portion of our capital expansion projects. We temporarily invested the remaining proceeds for use in future periods to fund additional expenditures under our capital expansion programs. The Notes do not contain any covenants restricting our issuance of additional indebtedness and rank equally with all of our other existing and future unsecured and unsubordinated indebtedness. Interest on the Notes is payable on April 15^{th} and October 15^{th} of each year and we may redeem the Notes for cash in whole or in part at any time, at our option. Pursuant to a registration rights agreement we have agreed to file a registration statement with the SEC within 90 days of the offering to offer to exchange the notes for registered notes with similar principal amounts and terms.

13. RECENT ACCOUNTING PRONOUNCEMENTS

Disclosures about Derivative Instruments and Hedging Activities

In March 2008, the Financial Accounting Standard Board, or FASB, issued Statement No. 161, *Disclosures about Derivative Instruments and Hedging Activities, w*hich is effective for fiscal years and interim periods beginning after November 15, 2008. The statement requires qualitative disclosures about the company's strategies and objectives for using derivatives, quantitative disclosures about fair value gains and losses on derivatives, and disclosures of credit-risk-related contingent features in derivative instruments. Although encouraged, we do not anticipate adopting the provisions of this pronouncement early. We do not expect our adoption of this pronouncement to have a material affect on our financial statements other than modifications to our existing derivative disclosures to conform to the requirements set forth in the statement.

Calculation of Earnings Per Unit

In March 2008, the Emerging Issues Task Force, or EITF, reached consensus on EITF Issue No. 07-4, *Application of the Two-Class Method under FASB Statement No. 128 to Master Limited Partnerships*. The pronouncement prescribes the manner in which a master limited partnership, or MLP, should allocate and present earnings per unit using the two-class method set forth in FASB Statement No. 128, *Earning per Share*. Under the two-class method, current period earnings are allocated to the general partner (including any embedded incentive distribution rights) and limited partners according to the distribution formula for available cash set forth in the partnership agreement. To the extent the partnership agreement does not explicitly limit distributions to the general partner, any earnings in excess of distributions are to be allocated to the general partner and limited partners utilizing the distribution formula for available cash specified in the partnership agreement. When current period distributions are in excess of earnings, the excess distributions are to be allocated to the general partner and limited partners based on their respective sharing of losses specified in the partnership agreement for the period. EITF 07-4 is to be applied retrospectively for all financial statements presented and is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. Earlier application is not permitted. We expect to adopt EITF 07-4 for our quarter ending March 31, 2009. We are currently evaluating the affect this pronouncement will have on our present computation of earnings per unit.

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, 2007.

RESULTS OF OPERATIONS—OVERVIEW

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

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

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

The following table reflects our operating income by business segment and corporate charges for the three month periods ended March 31:

	2008	2007
	(in millions)	
Operating Income		
Liquids	$ 61.6	$ 52.6
Natural Gas	72.2	11.0
Marketing	0.5	1.6
Corporate, operating and administrative	(2.0)	(1.1)
Total Operating Income	132.3	64.1
Interest expense	27.6	25.3
Other income (expense)	(0.3)	1.4
Income tax expense	1.3	1.1
Net Income	$103.1	$ 39.1

Several types of 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. We employ derivative financial instruments to reduce our exposure to natural gas and NGL price volatility. Some of these derivative financial instruments do not qualify for hedge accounting under the provisions of statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities* (SFAS No. 133), which can create volatility in our earnings that can be significant. However, these fluctuations in earnings do not affect our cash flow. Cash flow is only affected when we settle the derivative instrument.

Summary Analysis of Operating Results

Liquids

Operating income from our Liquids segment increased by $9.0 million to $61.6 million for the three months ended March 31, 2008 from $52.6 million for the same period in 2007. The increase in operating income of our Liquids segment is primarily due to the following:

- Higher delivery volumes on all three of our Liquids systems; and
- Tariff increases that went into effect during 2007 on each of our liquids systems and in early 2008 on our North Dakota system.

Natural Gas

Operating income from our Natural Gas segment increased by $61.2 million to $72.2 million for the three months ended March 31, 2008, from $11.0 million for the same period in 2007. The increase in contribution from our Natural Gas segment is primarily attributable to the following:

- Greater processing margins, representing the revenue derived from processing natural gas less the costs of natural gas purchased for processing;
- Approximately $30 million more in unrealized, non-cash market-to-market gains from our derivative activities; and
- A 14 percent increase in average daily volumes.

Marketing

Operating income from our Marketing segment decreased by $1.1 million to $0.5 million for the three months ended March 31, 2008 from $1.6 million for the same period in 2007. The operating income of our Marketing segment was affected by increased workforce related costs and depreciation, partially offset by a smaller amount of unrealized, non-cash, mark-to-market losses associated with derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133.

Derivative Transactions and Hedging Activities

We record all derivative instruments in our consolidated financial statements at fair market value pursuant to the requirements of SFAS No. 133, and the guidance set forth in Statement of Financial Accounting Standards No. 157, *Fair Value Measurement* ("SFAS No. 157"). 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 fair values of all our derivative instruments reflect our best estimate of the price we would receive for selling an asset or pay to transfer a liability in an orderly transaction with market participants at the measurement date. SFAS No. 157 defines how we are to determine fair value, establishes criteria for measuring fair value, and requires additional disclosures for assets and liabilities that we report at fair value. We adopted the provisions of SFAS No. 157 prospectively beginning January 1, 2008, which did not affect our results of operations, financial condition or cash flows due to the nature of our derivative instruments and our existing valuation methods.

Our unrealized, non-cash mark-to-market net gains of $13.9 million for the three months ended March 31, 2008 are largely driven by hedging activities around our optional processing of NGLs, partially offset by the increase in forward natural gas prices from December 31, 2007. During the three months ended March 31, 2008, increasing natural gas prices relative to slight decreases in forward NGL prices produced gains in our portfolio of derivatives we use to hedge optional processing activities which do not qualify for hedge accounting under the requirements of SFAS No. 133. We also incurred $0.2 million of unrealized, non-cash mark-to-market losses in connection with our interest rate derivatives that do not qualify for hedge accounting under the requirements of SFAS No. 133. During the three months ended March 31, 2007, increasing forward natural gas and NGL prices produced non-cash mark-to-market net losses of $16.3 million and negatively affected our operating results. Mark-to-market gains or losses create volatility in our operating results although the derivative instruments we have in place do not affect our cash flow until they are settled. We expect these non-cash gains and losses to reverse in future periods as we settle the derivative instruments against the underlying physical transactions. We intend to continue using derivative instruments to hedge our portfolio of natural gas and NGLs because of the economic benefit we derive from minimizing the volatility in our cash flows. Our continued use of derivative instruments is likely to result in additional unrealized, non-cash gains or losses in the future.

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 for our commodity-based derivative instruments and interest expense for our interest rate derivative instruments in our Consolidated Statements of Income and disclosed as a reconciling item on our Consolidated Statements of Cash Flows:

Derivative fair value gains (losses)	Three months ended March 31, 2008	Three months ended March 31, 2007
	(in millions)	
Natural Gas segment		
Hedge ineffectiveness	$ (1.8)	$ 0.1
Non-qualified hedges	28.6	(3.2)
Marketing		
Non-qualified hedges	(12.9)	(13.2)
Commodity derivative fair value gains (losses)	13.9	(16.3)
Corporate		
Non-qualified interest rate hedges	(0.2)	—
Derivative fair value gains (losses)	$ 13.7	$(16.3)

RESULTS OF OPERATIONS—BY SEGMENT

Liquids

The following tables set forth the operating results and statistics of our Liquids segment assets for the periods presented:

	Three months ended March 31,	
	2008	2007
	(in millions)	
Operating Results		
Operating revenues	$157.0	$132.8
Operating and administrative	37.5	33.7
Power	38.3	30.1
Depreciation and amortization	19.6	16.4
Operating expenses	95.4	80.2
Operating Income	$ 61.6	$ 52.6
Operating Statistics		
Lakehead system:		
United States(1)	1,257	1,248
Province of Ontario(1)	380	335
Total Lakehead system deliveries(1)	1,637	1,583
Barrel miles (billions)	109	103
Average haul (miles)	729	722
Mid-Continent system deliveries(1)	251	238
North Dakota system:		
Trunkline(1)	103	87
Gathering(1)	5	6
Total North Dakota system deliveries(1)	108	93
Total Liquids Segment Delivery Volumes(1)	1,996	1,914

(1) Average barrels per day (“Bpd”) in thousands.

Three months ended March 31, 2008 compared with three months ended March 31, 2007

Our Liquids segment accounted for $61.6 million of our operating income for the three months ended March 31, 2008, representing a $9.0 million increase over the same period in 2007. The favorable results reflect solid growth in our transportation volumes coupled with tariff increases that went into effect during 2007, while actively managing our costs. The majority of the increase in delivery volumes is attributable to our Lakehead system; however, our Mid-Continent and North Dakota systems also realized increased delivery volumes.

Operating revenue for the first quarter of 2008 increased by approximately $24.2 million to $157.0 million from $132.8 million for the same period in 2007. The increase in revenue is primarily attributable to the higher delivery volumes on all three of our Liquids systems combined with the increase in average tariffs that went into effect July 1, 2007 for all three of our liquids systems. We increased the transportation rates on our Lakehead system by an average of 4.5 percent and on our Ozark and North

Dakota systems by an average of 4.3 percent. Additionally, new tariffs went into effect April 1, 2007 on our Lakehead system to reflect the annual calculation of the SEP II and other surcharges based on true-ups of prior year amounts and estimates for 2007, as well as an adjustment for the Terrace surcharge due to lower than expected volumes moving on the Lakehead system in 2006. New tariffs also went into effect on our North Dakota system effective January 1, 2008, to implement two new surcharges associated with the Phase V expansion that was completed and placed in service in January 2008. The surcharges on our North Dakota system are applicable for five years and are applied to all transportation routes with a destination of Clearbrook, Minnesota. The looping surcharge is applied to all routes originating at Trenton and Alexander, North Dakota. The increases in average tariffs on all three Liquids systems contributed $10.2 million of additional operating revenue.

Average delivery volumes on our liquids system increased approximately 4 percent, to 1.996 million Bpd during the first quarter of 2008 from 1.914 million Bpd during the same period in 2007, contributing an additional $7.7 million to operating revenue. The increase in average deliveries on our Liquids systems are primarily derived from modest increases of crude oil supplies from upstream production facilities associated with the ongoing development of the Alberta Oil Sands coupled with volume growth associated with completion of the Phase V expansion of our North Dakota system.

Operating and administrative expenses for the Liquids segment increased $3.8 million for the first quarter of 2008, compared with the same period in 2007. The increase is driven primarily by (i) additional workforce related costs associated with the operational, administrative, regulatory, and compliance support necessary for our growing systems, and (ii) further costs we incurred in connection with our pipeline integrity program, partially offset by decreases in oil measurement adjustments.

Power costs increased $8.2 million in the first quarter of 2008, compared with the same period in 2007, predominantly due to the higher delivery volumes coupled with higher utility rates we are charged by our power suppliers. We have experienced a trend of increasing electricity rates from our power suppliers due to higher natural gas and coal costs.

The increase in depreciation expense of $3.2 million is attributable to the additional assets we have placed in service during the last three quarters of 2007 and the first quarter of 2008, predominantly on our North Dakota and Mid-Continent systems.

Future Prospects Update for Liquids

We and Enbridge Inc. (“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 we and Enbridge are constructing 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, 2007.

Partnership Projects

Southern Access

Final construction and commissioning activities are wrapping up on the first stage of our Southern Access expansion project, which includes a 42-inch diameter pipeline from Superior to Delavan, Wisconsin along with pump station enhancements upstream and downstream of this segment and adds approximately 190,000 Bpd of capacity. The toll charges that are associated with this portion of the project became effective April 1, 2008 and we will begin to realize revenues in connection with this increased surcharge as crude oil is delivered from our pipeline, generally the month following the effective date of the tariff.

We continue to progress on the second stage of the expansion project which will provide additional upstream pumping capacity and a new pipeline from Delavan to Flanagan, Illinois. Construction is scheduled to commence on June 1, 2008. We expect to complete this phase of the expansion by the end of the first quarter of 2009. Completion of the total Southern Access expansion project will create a 454-mile pipeline with approximately 400,000 Bpd of incremental capacity on our Lakehead system.

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, 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 and, at the request of our customers, we have revised the scope to also include a delivery connection at Clearbrook, Minnesota and an additional tank at Superior. Alberta Clipper 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 will be obtained by installing additional pump stations. We anticipate that our share of the construction cost for the United States segment of the project will approximate $1.0 billion, in 2007 dollars, excluding capitalized interest. Alberta Clipper will be a common carrier line fully integrated with the Enbridge/Lakehead mainline systems for tolling purposes. We and Enbridge are progressing on schedule with the project, which is expected to be in service in mid-2010.

North Dakota

The U.S. Geological Survey, or USGS, completed an assessment of the undiscovered oil and associated gas resources of the Upper Devonian—Lower Mississippi Bakken Formation in the U.S. portion of the Williston Basin Province and has determined there to be 3.0 to 4.3 billion barrels of technically recoverable oil. Although this assessment provides support for our planned expansion of the North Dakota system, we cannot determine with certainty whether additional crude oil production will be developed in the area or benefit our North Dakota system due to the current nature of the report.

Regional producers in the Williston basin areas of Montana and North Dakota have expressed interest in further expansion of pipeline capacity on our North Dakota system. We have proposed an approximate $0.15 billion additional expansion that will consist of upgrades to existing pump stations, additional tankage, as well as extensive use of drag reducing agents ("DRA") that are injected into the pipeline. This second expansion of our North Dakota system 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 tariff rates. The proposed surcharge is similar to the structure being used on the recently completed expansion project and is subject to approval from the FERC. Regulatory applications have also been filed and are pending approval.

Superior and Griffith Storage

Due to forecasted production increases of synthetic heavy crude oil that we anticipate will be transported on the Enbridge/Lakehead mainline systems from Western Canada to Chicago, we are constructing additional crude oil storage tanks at Superior and Griffith to accommodate the anticipated volumes. We are building two tanks with operational capacity of approximately 205,000 barrels each that are scheduled to be completed during 2008.

<u>Enbridge and Other Projects</u>

Spearhead Pipeline

In another effort to provide shippers access to new markets, Enbridge acquired a pipeline that runs from Cushing, Oklahoma to Chicago, Illinois. The reversed pipeline, renamed Spearhead, began delivering Canadian crude oil to the major oil hub at Cushing in March 2006 and has operated at or near its capacity of 125,000 Bpd. In the first half of 2007, Enbridge successfully concluded a binding open season for expansion of the pipeline to 190,000 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. The Spearhead pipeline is complementary to our Lakehead system as Western Canadian crude oil is carried on our Lakehead system as far as Chicago, and then transferred to the Spearhead pipeline. The Spearhead pipeline expansion is expected to be in service in early 2009.

Southern Access Extension

In July 2006, Enbridge announced that it received support from shippers and CAPP for its 36-inch diameter Southern Access Extension pipeline from Flanagan, Illinois to Patoka, Illinois. The extension will broaden the reach of the Enbridge/Lakehead mainline system to incremental markets accessible from the Patoka hub. This project is being undertaken by Enbridge, however, we will benefit from the incremental volumes moving through our Lakehead system to reach this extension. Enbridge filed a petition for declaratory order with the FERC in October 2007, which is currently pending approval. Subject to regulatory approval, tolls will be fully adjusted for the actual capital cost of the project with an estimated in-service date of 2009.

Southern Lights

Following completion of a successful open season in 2006, Enbridge initiated its Southern Lights project to construct a diluent pipeline from Chicago, Illinois to Edmonton, Alberta, Canada to meet the growing demand for crude oil diluent required to transport the heavy oil and bitumen (a thick, tar-like form of oil) being produced in increasing volumes from the Alberta oil sands. The project involves the exchange of a 156-mile section of pipeline we own for a similar section of a new pipeline to be constructed as part of the project. In addition, this project involves a reconfiguration of our light crude mainline system which will provide an additional 45,000 Bpd of effective capacity at no cost to us. We expect to benefit from increased heavy crude oil shipments, which will be facilitated by the diluent line.

In February 2008, the NEB approved the Canadian portion of the Southern Lights project. Enbridge has filed the majority of necessary applications for the United States portion of the project with United States federal and state regulatory agencies. Enbridge filed a petition for declaratory order with the FERC setting forth the rate structure for establishing tolls and the proposed swap of line 13 discussed above, which the FERC approved in late December 2007. In conjunction with our Southern Access project, the Southern Lights project has been allowed the right to exercise eminent domain for right-of-way in Illinois. Construction and right-of-way acquisition related to this project continues in tandem with the Southern Access project. This project is expected to be placed in service in 2010.

Texas Access Pipeline

Non-binding expressions of interests received in June 2007 demonstrated strong shipper support for the construction of a new heavy crude oil pipeline system to transport crude oil from Patoka, Illinois to the U.S. Gulf Coast. Enbridge (U.S.) Inc. and ExxonMobil Pipeline Company are jointly pursuing development of the Texas Access Pipeline, which, as proposed, will provide approximately 445,000 Bpd of new capacity from Patoka, Illinois to Texas Gulf Coast refineries with a projected in-service date of mid-2011. The proposed project comprises a new 768-mile, 30-inch diameter pipeline that begins in the vicinity of Mobil Pipe Line Company's Patoka, Illinois crude oil terminal southward to Nederland, Texas, coupled with an 88-mile, 24-inch lateral to transport crude oil onward from Nederland to a delivery point in Houston, Texas. The new pipeline will allow for connectivity to existing terminals in both Nederland and Houston, and will be constructed in the same corridor with existing pipelines owned by ExxonMobil Pipeline Company. The initial capacity of the Patoka-to-Nederland segment of the pipeline would be 445,000 Bpd, and the initial capacity of the Nederland-to-Houston segment would be 169,000 Bpd.

In December 2007, an open season was announced to solicit binding 15-year shipper commitments for the proposed Texas Access Pipeline, which concluded on March 14, 2008. Enbridge, along with ExxonMobil Pipeline Company, continues to evaluate the results of the open season and are engaged in shipper discussions regarding feasibility and commercial terms.

Eastern PADD II Access

Enbridge has held discussions with several refiners in the eastern United States to gauge interest in supporting the development of a pipeline to provide incremental pipeline capacity to this market. Development of this project is ongoing and is expected to provide up to approximately 100,000 Bpd of heavy Canadian crude oil to the Eastern PADD II market by late 2010. Additional access initiative discussions have commenced with other area refiners to provide incremental infrastructure in this area for service in the 2013 timeframe. Construction of both of these projects would be complementary to our Lakehead system.

Natural Gas

The following tables set forth the operating results of our Natural Gas segment assets and approximate average daily volumes of our major systems in MMBtu/d for the periods presented:

	Three months ended March 31,	
	2008	**2007**
	(in millions)	
Operating Results		
Operating revenues	$ 1,164.0	$ 755.5
Cost of natural gas	987.8	663.2
Operating and administrative	74.9	61.3
Depreciation and amortization	29.1	20.0
Operating expenses	1,091.8	744.5
Operating Income	$ 72.2	$ 11.0
Operating Statistics (MMBtu/d)		
East Texas	1,396,000	1,135,000
Anadarko	616,000	583,000
North Texas	367,000	320,000
UTOS	196,000	125,000
MidLa	125,000	110,000
AlaTenn	63,000	59,000
Bamagas	102,000	115,000
Other major intrastates	227,000	267,000
Total[(1)]	3,092,000	2,714,000

(1) We have excluded from the table above average daily volumes of 37,000 MMBtu/d for the three months ended March 31, 2007, associated with the KPC system which we sold in November 2007.

Three months ended March 31, 2008 compared with three months ended March 31, 2007

Our Natural Gas segment produced $72.2 million of operating income in the first quarter of 2008, an increase of $61.2 million from the $11.0 million generated in the corresponding period of 2007. The substantial increase in our operating income for the first quarter of 2008 over the results for the same period of 2007 is attributable to three primary factors:

- Greater processing margins, primarily due to increased processing capacity and improved operating performance of our Zybach processing plant;
- Approximately $30 million more in unrealized, non-cash market-to-market gains from our derivative activities; and
- A 14 percent increase in average daily volumes associated with our expansion of the capacity and service capability of our systems.

Operating income derived from our processing facilities has continued to contribute favorably to the results of our Natural Gas business due to a number of factors. NGL prices continue to remain high relative to natural gas prices, providing a favorable environment for the production of NGLs from our processing assets. We added approximately 120 million cubic feet per day, or MMcf/d, of processing capacity on our Anadarko system and 75 MMcf/d on our North Texas system during 2007 providing us with the ability to generate additional processing margin from the natural gas we processed for our customers during the first quarter of 2008. Our Zybach processing plant has continued to operate at expected levels during the first quarter of 2008, which compare favorably with the first quarter of 2007 when we experienced operational issues that reduced processing margins by approximately $8 million.

A variable element of our Natural Gas segment's operating income is derived from the processing of natural gas under keep-whole arrangements that exist within our Anadarko, East Texas and North Texas systems. Operating income derived from our keep-whole processing for the three months ended March 31, 2008 was approximately $31 million, representing an increase of $23 million from the $8 million of operating income derived from keep-whole processing for the same period in 2007. The increase is primarily due to improvement on our Anadarko system resulting from the addition of our Hidetown processing facility in April 2007 and correction of the operational issues we experienced with our Zybach processing plant in the first quarter of 2007. We also added 75 MMcf/d of processing capacity on our North Texas system with the completion and expansion of the Weatherford plant in late 2007. Our processing margins also continue to benefit from a favorable pricing environment. Although the operating income of our Natural Gas business derived from processing natural gas under keep-whole arrangements has increased, we have observed that our customers have become increasingly interested in retaining the price risk associated with NGL production. As a result, we are experiencing a trend of replacing or renegotiating some of our existing keep-whole contracts with percent of liquids, or POL, type contracts. This trend may reduce our exposure to commodity price risk along with a portion of the operating income we derive from processing NGLs under keep-whole arrangements.

A portion of our Natural Gas segment is exposed to commodity price risks associated with the natural gas and NGLs we retain under the various contract structures for the services we provide. We enter into derivative financial instruments to fix the sales price of the natural gas and NGLs we anticipate receiving under the terms of these contracts. The operating income of our Natural Gas segment for the three months ended March 31, 2008 was favorably affected by unrealized non-cash, mark-to-market net gains of $26.8 million from our derivative activities, which are approximately $30 million more than the $3.1 million of losses we recorded for the same period of 2007. We expect the net mark-to-market gains and losses to be offset when the related physical transactions are settled. The following table depicts the affect that unrealized non-cash mark-to-market gains and losses had on the operating results of our Natural Gas business for the three months ended March 31, 2008 and 2007:

Derivative fair value gains (losses)	Three Months Ended March 31, 2008	2007	Change
Hedge ineffectiveness	$(1.8)	$ 0.1	$(1.9)
Non-qualified hedges	28.6	(3.2)	31.8
Unrealized gains (losses)	$26.8	$(3.1)	$29.9

We adopted the provisions of Financial Accounting Standards Board Statement No. 157, *Fair Value Measurements* (SFAS No. 157) effective January 1, 2008, which did not affect the operating results of our Natural Gas business, but did expand the disclosures we provide about how we determine the fair value of our derivative instruments. Refer to the discussions included in Notes 9 and 10 of our consolidated financial statements included in Item 1 of this report and also to the discussions below under "Derivative Activities" and the "Quantitative and Qualitative Disclosures about Market Risk" we include in Item 3 of this report for more information about our derivative activities.

Average daily volumes were up approximately 14 percent in the first quarter of 2008 as compared with the corresponding period in 2007. The increase in our average daily volumes is directly attributable to the robust drilling activity and production growth in the areas served by our systems coupled with the significant investments that we have made to expand the capacity and service capability of our systems. We completed the following projects during 2007 and the first quarter of 2008 which have contributed to the average daily volumes and operating results of our major natural gas system:

- The $635 million expansion and extension of our East Texas natural gas system, referred to as the Clarity project, was substantially completed in February 2008 and includes:
  - ✓ A new 36-inch natural gas pipeline from Bethel, Texas to Southeast Texas near Beaumont, Texas; and
  - ✓ The Marquez treating plant with capacity of approximately 200 MMcf/d and additional pipeline capacity to the existing southeast section of this area was completed and placed in service in March 2007.

  We expect to finish an additional pipeline connection and two compression stations by the third quarter. The total added capacity related to this project will then total approximately 700 MMcf/d. Throughput for the first quarter of 2008 exceeded 300 MMcf/d and is expected to approximate 600 MMcf/d by the end of 2008.

- In the first quarter of 2008 we completed construction of a 25-mile, 20-inch diameter pipeline from a lateral on our East Texas system to gather additional production being developed in East Texas.
- In the latter half of 2007, we completed construction of three hydrocarbon dewpoint control facilities on our East Texas system to add processing capacity to meet the increasingly more stringent pipeline gas quality specifications. These facilities have a cumulative capacity of 550 MMcf/d and obtain a significant portion of their revenues from fees rather than keep-whole processing or percentage-of-liquids revenues.
- Construction and expansion of the Weatherford processing facility within our North Texas system was completed late in 2007 and added approximately 75 MMcf/d of processing capacity.
- Our Hidetown processing facility on our Anadarko system with an approximate capacity of 120 MMcf/d was completed and placed into service in April 2007.

Volume and revenue growth is also the result of additional wellhead supply contracts and continued robust drilling activity in the areas served by our Natural Gas business, primarily the Bossier Trend and Barnett Shale areas. We expect the volumes on our major natural gas systems to continue increasing throughout the year as a result of our investments to expand the capacity of our systems to provide gathering, processing and transportation services to meet the needs of producers in the areas we serve.

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 first quarter 2007, we identified operating conditions on our gathering systems which contributed to an increase in measurement losses. We have since installed separator equipment to identify and eliminate free-water in the natural gas streams, one of the underlying causes for the increase in measurement losses during 2007. As a result of the steps we took in 2007 to address the increase in measurement losses, the measurement losses we have experienced during the three months ended March 31, 2008 are in-line with our expectations.

Operating and administrative costs of our Natural Gas segment were $13.6 million greater for the three months ended March 31, 2008 than the three months ended March 31, 2007, primarily as a result of increased workforce related costs associated with the expansion of our systems, maintenance activities and other costs that are mostly variable with volumes. Our general partner charges us the costs associated with employees and related benefits for personnel that are assigned to us or otherwise provide us with managerial and administrative services. The portion of compensation and related costs we are charged is dependent upon such items as estimated time spent, miles of pipe and headcount. In addition we have experienced an increase in outside contract labor cost, given the high demand and competitive rates within our industry as a result of pipeline expansions across the areas we serve. The operating costs we incurred for the first quarter of 2008 are generally consistent with the operating costs we incurred during the fourth quarter of 2007. The operating costs we incurred during the fourth quarter of 2007 provides a base line for comparison of future operating costs associated with our expanded natural gas systems and the services we provide.

Materials, supplies and other costs along with repair and maintenance costs were higher predominantly related to the increase in volumes and expansion of our natural gas systems. Repair and maintenance costs include compressor maintenance, downtime for routine and unscheduled maintenance, pipeline integrity costs and other similar items that have increased with the expansion of our existing natural gas systems. We expect workforce related costs in addition to materials, supplies and other cost to increase in relation to the increase in volumes of natural gas services we provide.

Depreciation expense for our Natural Gas segment was higher in the first quarter of 2008 as compared to the first quarter of 2007, as a result of the capital projects completed and placed in-service during 2007. We expect deprecation expense will be higher in 2008 as a result of the projects we completed and placed in service throughout 2007 and, excluding the compression to be added in 2008, the completion of the final stage of our Clarity project in the first quarter of 2008.

Future Prospects Update for Natural Gas

We continue to assess various expansion opportunities to pursue our strategy for growth. While we remain committed to making accretive acquisitions in or near areas where we already operate or have a competitive advantage, we will continue to focus our efforts primarily on development of our existing pipeline systems. Although we have successfully completed a majority of the significant expansion projects within our Natural Gas business, we are continually evaluating strategic opportunities to further expand the service capabilities of our existing systems. We may, and have, pursued opportunities to divest any non-strategic natural gas assets as conditions warrant.

Results of our natural gas gathering and processing business depend upon the drilling activities of natural gas producers in the areas we serve. During the first quarter of 2008, increased drilling in the areas where our gathering systems are located has contributed to our volume growth. We expect the growth trend in these areas to continue in the future as evidenced by external production forecast and the strong rig counts and permitting in the areas served by our systems.

Marketing

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

	Three months ended March 31,	
	2008	**2007**
	(in millions)	
Operating revenues	$1,114.3	$824.4
Cost of natural gas	1,111.0	821.1
Operating and administrative	2.3	1.6
Depreciation and amortization	0.5	0.1
Operating Expenses	1,113.8	822.8
Operating Income	$ 0.5	$ 1.6

Three months ended March 31, 2008 compared with three months ended March 31, 2007

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 during 2007, 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.

The operating income of our Marketing segment marginally declined to $0.5 million for the first quarter of 2008 from $1.6 million for the corresponding period in 2007. Included in operating income for the first quarter of 2008 are approximately $12.9 million of unrealized, non-cash, mark-to-market losses associated with derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133, which are $0.3 million less than the $13.2 million of unrealized mark-to-market losses for the comparable period of 2007. The unrealized, mark-to-market losses for the three months ended March 31, 2008 and 2007 result from increases in the forward and daily market prices of natural gas from December 31, 2007 and 2006, respectively. We expect these net mark-to-market losses to be offset when the related physical transactions are settled.

We adopted the provisions of SFAS No. 157 effective January 1, 2008, which did not affect the operating results of our Marketing business, but did expand the disclosures we provide about how we determine the fair value of our derivative instruments. Refer to the discussions included in Notes 9 and 10 of our consolidated financial statements included in Item 1 of this report and also to the discussions below under “Derivative Activities” and the “Quantitative and Qualitative Disclosures about Market Risk” we include in Item 3 of this report for more information about our derivative activities.

The operating and administrative expenses of our Marketing business are slightly more in the current quarter ended March 31, 2008 as compared with the same period of 2007 due to additional workforce related costs associated with the employees and related benefits for personnel that are assigned to us or otherwise provide us with managerial and administrative services.

Depreciation expense was higher in the first quarter of 2008 as compared to the first quarter of 2007, due to the implementation of a software system to provide greater functionality to meet the demands of our Marketing business.

Corporate

Interest expense was $27.6 million for the three months ended March 31, 2008, compared with $25.3 million for the corresponding period in 2007. The increase is primarily the result of a higher weighted average debt balance due to the issuance in August 2007 of our $200 million senior unsecured zero coupon notes and the September 2007 issuance of our $400 million junior subordinated notes. Our weighted average interest rate is 5.5% for the three months ended March 31, 2008 as compared with our weighted average interest rate of 5.9% for the same period in 2007. The increase in interest expense is partially offset by an additional $10.6 million of interest cost we capitalized with respect to our construction projects in the first quarter of 2008 over the amounts capitalized in the same period of 2007. For the three months ended March 31, 2008 and 2007, our interest cost is comprised of the following:

	March 31, 2008	March 31, 2007
	(in millions)	
Interest expense	$27.6	$25.3
Interest capitalized	19.1	8.5
Interest cost incurred	$46.7	$33.8

LIQUIDITY AND CAPITAL RESOURCES

General

We believe that our ability to generate cash flow, in addition to our access to capital, is sufficient to meet the demands of our current and future operating and investment needs. Our primary cash requirements consist of normal operating expenses, capital expenditures for our expansion projects, maintenance capital expenditures, debt service payments, distributions to our partners, acquisitions of new assets and businesses, and payments associated with our derivative transactions. Short-term cash requirements, such as operating expenses, maintenance capital expenditures, and quarterly distributions to our partners, are expected to be funded by our operating cash flows. Margin requirements associated with our derivative transactions are generally supported by letters of credit issued under our Credit Facility. We expect to fund long-term cash requirements for expansion projects and acquisitions from several sources, including cash flows from operating activities, borrowings under our commercial paper program, our Credit Facility, and the issuance of additional equity and debt securities. Our ability to complete future debt and equity offerings and the timing of any such offerings will depend on various factors, including prevailing market conditions, interest rates, our financial condition and credit rating at the time.

Our current business strategy emphasizes developing and expanding our existing Liquids and Natural Gas businesses with less focus on acquisitions. Although the internal growth projects we have planned require significant expenditures of capital over the next several years, since the beginning of 2007 we have raised in excess of $2.2 billion through the issuance of a balanced combination of debt and equity securities to fund these projects. We expect to use the same measured approach to fund the remaining expenditures from additional issuances of partnership capital and long-term debt. Our planned internal growth projects continue to require us to bear the cost of constructing these new assets before we begin to realize a return on them.

Capital Resources

Equity and Debt Securities

Execution of our growth strategy and completion of our planned construction projects contemplate our accessing the public and private equity and credit markets to obtain the capital necessary to fund these projects. In March 2008, we obtained approximately $221.8 million of cash from the public issuance and sale of 4.6 million of our Class A common units at a price to the public of $49.00 per unit, which consists of $217.2 million of net proceeds, after payment of underwriters' discounts, commissions and offering expenses and a contribution of $4.6 million from our general partner to maintain its two percent general partner interest. Additionally, in early April 2008, we completed the private issuance and sale of our $400 million Notes due 2018 and our $400 million Notes due 2038 for net proceeds of approximately $790.4 million, after payment of initial purchasers' discounts and offering expenses. The Notes due 2018 bear interest at the rate of 6.50% and the Notes due 2038 bear interest at the rate of 7.50%. We used a portion of the proceeds from these offerings to repay outstanding issuances of commercial paper and borrowings under our Credit Facility we had previously used to finance a portion of our capital expansion projects. We temporarily invested the remaining proceeds for use in future periods to fund additional expenditures under our capital expansion programs. As a result of the issuances of our equity and debt securities, we have over $1 billion of additional capital to support our capital expansion program.

Available Credit

A significant source of our liquidity is provided by the commercial paper market and our Credit Facility. We have a $600 million commercial paper program that is supported by our long-term Credit Facility, which we access primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions, at rates that are generally more competitive than the rates available under our Credit Facility.

U.S. credit markets in the first quarter of 2008 continue to remain volatile despite actions taken by U.S. and foreign regulators. Investors have continued to seek quality fixed income securities, favoring U.S. government securities over corporate issues. Although the credit ratings assigned to our senior unsecured debt securities by the nationally recognized statistical ratings organizations are considered "investment grade," we may at times experience difficulty accessing the commercial paper and long-term credit markets due to current economic conditions.

Credit Facility

In March 2008, we requested and received approval from the parties named as lenders to our Credit Facility for a one year extension of the maturity date of the Credit Facility from April 4, 2012 to April 4, 2013.

The amounts we can borrow under the terms of our Credit Facility are reduced by the principal amount of our commercial paper issuances and the balance of our letters of credit outstanding. At March 31, 2008, we had $530 million outstanding under our Credit Facility at a weighted average interest rate of 3.27% and letters of credit totaling $177.5 million. At March 31, 2008, we could borrow $317.5 million under the terms of our Credit Facility, determined as follows in millions:

Total credit available under Credit Facility	$1,250.0
Less: Amounts outstanding under Credit Facility	(530.0)
Balance of letters of credit outstanding	(177.5)
Principal amount of commercial paper issuances	(225.0)
Total amount we could borrow at March 31, 2008	$ 317.5

Commercial Paper Program

At March 31, 2008, we had $225.0 million in principal amount of commercial paper outstanding, with unamortized discount of $0.8 million, at a weighted average interest rate of 3.53%, before the effect of our interest rate hedging activities. We had net repayments of approximately $44.7 million during the three months ended March 31, 2008 under our commercial paper program, which include gross issuances of $926.6 million and gross repayments of $971.3 million. At March 31, 2008, we could issue an additional $317.5 million in principal amount under our commercial paper program. The commercial paper we can issue is limited by the credit available under the terms of our Credit Facility.

EUS Credit Agreement

In addition to our Credit Facility and commercial paper program, we have access to an unsecured three year revolving credit agreement with Enbridge (U.S.) Inc., a wholly-owned subsidiary of Enbridge Inc. (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 March 31, 2008 and available for our use.

Cash Requirements for Future Growth

Capital Spending

We expect to make significant expenditures during the next three years for the construction of additional natural gas and crude oil transportation infrastructure. In 2008, we expect to spend approximately $1.4 billion on these and other projects with the expectation of realizing additional cash flows as projects are completed and placed in service. As of March 31, 2008, we have approximately $264.0 million in outstanding purchase commitments for materials and services associated with our capital projects for the construction of assets that we expect to settle during the remainder of 2008. However, we will incur additional commitments as our capital projects continue to progress.

Forecasted Expenditures

We categorize our capital expenditures as either core maintenance or enhancement expenditures. Core maintenance expenditures are those expenditures that are necessary to maintain the service capability of our existing assets and include the replacement of system components and equipment which is worn, obsolete or completing its useful life. Enhancement expenditures improve the service capability of our existing assets, extend asset useful lives, increase capacities from existing levels, reduce costs or enhance revenues, and enable us to respond to governmental regulations and developing industry standards.

We estimate our capital expenditures based upon our strategic operating and growth plans, which are also dependent upon our ability to produce or otherwise obtain the 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, 2008. Although we anticipate making the indicated expenditures, 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, estimates may change as a result of decisions made at a later date to revise the scope of a project. We made capital expenditures of approximately $373.5 million, including $15.6 million for core maintenance activities, during the three months ended March 31, 2008.

For the full year of 2008, we anticipate our capital expenditures to approximate the following amounts in billions:

System enhancements	$0.4
Core maintenance activities	0.1
Southern Access expansion	0.7
Alberta Clipper	0.2
	$1.4

Major Construction Projects

The following table includes our active major construction projects and additional information regarding our projected cost, actual expenditures through March 31, 2008, the incremental capacity that will 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 March 31, 2008	Storage	Oil	Natural Gas	Expected Completion
	(in billions)		(KBbl)	(Kbpd)	(MMcf/d)	
Southern Access expansion (Lakehead)	$2.1	$1.4	—	400	—	2009
Clarity (East Texas)	0.6	0.6	—	—	700	In phases to early 2008
Alberta Clipper	1.2	—	—	450	—	Mid-2010
North Dakota phase 6 expansion	0.2	—	—	50	—	Early 2010
Griffith and Superior storage tanks	0.1	—	1,220	—	—	Mid-2008
Total	$4.2	$2.0	1,220	900	700	

Including major expansion projects and excluding acquisitions, ongoing capital expenditures are expected to be significant over the next three years due to our Southern Access expansion and Alberta Clipper projects. Core maintenance capital is also anticipated to increase over that period of time due to growth of our pipeline systems and aging of infrastructure.

We anticipate funding the system enhancement capital expenditures temporarily through the issuance of commercial paper and borrowing under the terms of our Credit Facility, with permanent debt and equity funding being obtained when appropriate. 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 derivatives instruments (e.g., futures, forwards, swaps, options and other financial instruments with similar characteristics) to mitigate the volatility of our cash flows and manage the purchase and sales prices of our commodities. 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.

The following table provides summarized information about the timing and expected settlement amounts of our outstanding commodity derivative instruments based upon the fair values at March 31, 2008:

	Notional	2008	2009	2010	2011	2012	Total
			($ in millions)				
Swaps							
Natural gas[1]	323,552,841	$ (19.1)	$ (45.4)	$(39.5)	$(33.8)	$ (6.4)	$(144.2)
NGL[2]	9,415,304	(72.4)	(50.5)	(15.8)	(5.2)	—	(143.9)
Crude[2]	7,094,270	(15.3)	(9.5)	(6.7)	(5.3)	(3.6)	(40.4)
Options—calls							
Natural gas[1]	1,370,000	(1.6)	(1.9)	(1.6)	(1.5)	—	(6.6)
Options—puts							
Natural gas[1]	1,248,000	—	—	—	—	—	—
NGL[1]	669,535	—	0.3	—	—	—	0.3
Totals		$(108.4)	$(107.0)	$(63.6)	$(45.8)	$(10.0)	$(334.8)

(1) Notional amounts for natural gas are recorded in MMBtu.
(2) Notional amounts for NGL and Crude are recorded in Bbl.

Operating Activities

Net cash provided by operating activities for the three months ended March 31, 2008 was $276.2 million, an increase of $123.4 million from the $152.8 million generated during the same period in 2007. The increase in operating cash flow is directly attributable to the improved operating performance of our Liquids and Natural Gas systems and other changes in working capital accounts. 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 $107.0 million more in our investing activities during the three months ended March 31, 2008 in relation to the same period in 2007. The increase is attributable to an additional $101.3 million we spent in the first three months of 2008 on our construction projects as compared to the amounts spent during the same period of 2007. The increase in our capital expenditures in the first quarter of 2008 is directly attributable to our previously announced expansion projects.

Financing Activities

Net cash provided by financing activities during the three months ended March 31, 2008 was $241.1 million, compared with $81.8 million for the corresponding period in 2007. The increase in cash provided by financing activities is primarily attributable to the $221.8 million we raised in March 2008 from the issuance of 4.6 million class A common units, which consists of $217.2 million of proceeds, net of underwriters' discounts, commissions and offering expenses, and a contribution of $4.6 million from our general partner to maintain its two percent general partner interest. The increase in cash raised from our unit issuance is partially offset by $54.1 less net Credit Facility borrowings and commercial paper issuances during the first quarter of 2008 as compared with the same period of 2007. Additionally, cash distributions to our partners were approximately $8.4 million more for the first quarter of 2008 compared to the first quarter of 2007 due a greater number of units outstanding and higher incentive distribution payments to our general partner.

OFF-BALANCE SHEET ARRANGEMENTS

We have no significant off-balance sheet arrangements.

SUBSEQUENT EVENTS

Distribution to Partners

On April 28, 2008, the Board of Directors of Enbridge Management declared a distribution payable to our partners on May 15, 2008. The distribution will be paid to unitholders of record as of May 7, 2008, of our available cash of $102.2 million at March 31, 2008, or $0.950 per common unit. Of this distribution, $71.0 million will be paid in cash, $13.1 million will be distributed in i-units to our i-unitholder, $17.5 million will be distributed in Class C units to the holders of our Class C units and $0.6 million will be retained from the General Partner in respect of the i-unit and Class C unit distributions.

Issuance of Debt

In April 2008, we issued and sold in a private offering $400 million in principal amount of our 6.5% Notes due April 15, 2018 and $400 in principal amount of our 7.5% Notes due April 15, 2038, which we collectively refer to as the Notes. We received net proceeds from the offering of approximately $790.4 million after payment of initial purchasers' discounts and offering expenses. We used a portion of the proceeds we received from this offering to repay outstanding issuances of commercial paper and borrowings under our Credit Facility that we had previously used to finance a portion of our capital expansion projects. We temporarily invested the remaining proceeds for use in future periods to fund additional expenditures under our capital expansion programs. The Notes do not contain any covenants restricting our issuance of additional indebtedness and rank equally with all of our other existing and future unsecured and unsubordinated indebtedness. Interest on the Notes is payable on April 15th and October 15th of each year and we may redeem the Notes for cash in whole or in part at any time, at our option. Pursuant to a registration rights agreement we have agreed to file a registration statement with the SEC within 90 days of the offering to offer to exchange the notes for registered notes with similar principal amounts and terms.

REGULATORY MATTERS

FERC Transportation Tariffs-Liquids

Effective April 1, 2008, we filed our annual tariff with the FERC to reflect true-ups for the difference between estimates and actual cost, throughput data for the prior year and our projected costs and throughput for 2008. The projected costs for 2008 include four projects including the Southern Access mainline expansion, two Superior and Griffith terminal tank projects and the Clearbrook Manifold project. This filing increased the average tariff for crude oil movements from the Canadian border to Chicago, Illinois, by approximately $0.34 per barrel, to an average of approximately $1.21 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.

RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

Disclosures about Derivative Instruments and Hedging Activities

In March 2008, the Financial Accounting Standard Board, or FASB, issued Statement No.161, *Disclosures about Derivative Instruments and Hedging Activities*, which is effective for fiscal years and interim periods beginning after November 15, 2008. The statement requires qualitative disclosures about the company's strategies and objectives for using derivatives, quantitative disclosures about fair value gains and losses on derivatives, and disclosures of credit-risk-related contingent features in derivative instruments. Although encouraged, we do not anticipate adopting the provisions of this pronouncement early. We do not expect our adoption of this pronouncement to have a material affect on our financial statements other than modifications to our existing derivative disclosures to conform to the requirements set forth in the statement.

Calculation of Earnings Per Unit

In March 2008, the Emerging Issues Task Force, or EITF reached consensus on EITF Issue No. 07-4, *Application of the Two-Class Method under FASB Statement No. 128 to Master Limited Partnerships*. The pronouncement prescribes the manner in which a master limited partnership, or MLP, should allocate and present earnings per unit using the two-class method set forth in FASB Statement No. 128, *Earning per Share*. Under the two-class method, current period earnings are allocated to the general partner (including any embedded incentive distribution rights) and limited partners according to the distribution formula for available cash set forth in the partnership agreement. To the extent the partnership agreement does not explicitly limit distributions to the general partner, any earnings in excess of distributions are to be allocated to the general partner and limited partners utilizing the distribution formula for available cash specified in the partnership agreement. When current period distributions are in excess of earnings, the excess distributions are to be allocated to the general partner and limited partners based on their respective sharing of losses specified in the partnership agreement for the period. EITF 07-4 is to be applied retrospectively for all financial statements presented and is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. Earlier application is not permitted. We expect to adopt EITF 07-4 for our quarter ending March 31, 2009. We are currently evaluating the affect this pronouncement will have on our present computation of earnings per unit.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

This information updates, and you should read it in conjunction with, our quantitative and qualitative disclosures about market risks reported in our Annual Report on Form 10-K for the year ended December 31, 2007, in addition to information presented in Items 1 and 2 of this Quarterly Report on Form 10-Q.

Our net income and cash flows are subject to volatility stemming from changes in commodity prices of natural gas, NGLs, condensate and fractionation margins (the relative price differential between NGL sales and the offsetting natural gas purchases). Our exposure to commodity price risk exists within our Natural Gas and Marketing segments. We use derivative instruments including futures, forwards, swaps, options and other financial instruments with similar characteristics to manage the risks associated with market fluctuations in commodity prices, as well as to reduce the volatility of our cash flows. Our formal hedging program provides a control structure and governance for our hedging activities specific to identified risks and time periods, which are subject to the approval and monitoring by a committee of senior management. Based on our risk management policies, all of our derivative 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.

The following tables provide information about our derivative financial instruments at March 31, 2008 and December 31, 2007, with respect to our commodity price risk management activities for natural gas and NGLs, including condensate:

	At March 31, 2008						At December 31, 2007	
			Wtd Avg Price(2)		Fair Value(3)		Fair Value(3)	
	Commodity	Notional(1)	Receive	Pay	Asset	Liability	Asset	Liability
Contracts maturing in 2008								
Swaps								
Receive variable/pay fixed	Natural gas	26,250,623	$ 9.65	$ 7.47	$56.9	$ —	$ 7.6	$(14.5)
	NGL	687,679	90.17	90.08	0.1	—	—	—
Receive fixed/pay variable	Natural gas	22,112,354	6.59	10.02	—	(75.1)	10.3	(39.8)
	NGL	4,340,325	42.37	59.26	—	(72.5)	—	(98.9)
	Crude oil	324,970	52.06	99.57	—	(15.3)	—	(17.7)
Receive variable/pay variable	Natural gas	103,802,541	9.83	9.84	3.0	(3.9)	7.0	(3.5)
Options								
Calls (written)	Natural gas	275,000	4.31	10.30	—	(1.6)	—	(1.3)
Puts purchased	Natural gas	153,000	10.52	3.40	—	—	—	—
	NGL	304,535	63.99	44.40	—	—	0.1	—
Contracts maturing in 2009								
Swaps								
Receive variable/pay fixed	Natural gas	13,272,295	$ 9.00	$ 7.66	$17.4	$ —	$ 5.5	$ (1.6)
Receive fixed/pay variable	Natural gas	15,837,265	5.74	9.66	—	(60.4)	1.2	(41.8)
	NGL	3,204,335	44.22	60.46	—	(50.5)	—	(43.6)
	Crude oil	6,062,425	96.16	97.77	—	(9.5)	—	(7.2)
Receive variable/pay variable	Natural gas	76,743,744	9.65	9.68	1.5	(3.9)	2.9	(1.8)
Options								
Calls (written)	Natural gas	365,000	4.31	9.74	—	(1.9)	—	(1.5)
Puts purchased	Natural gas	365,000	3.40	9.74	—	—	—	—
	NGL	365,000	60.63	42.09	0.3	—	0.6	—

	At March 31, 2008						At December 31, 2007	
			Wtd Avg Price(2)		Fair Value(3)		Fair Value(3)	
	Commodity	Notional(1)	Receive	Pay	Asset	Liability	Asset	Liability
Contracts maturing in 2010								
Swaps								
Receive variable/pay fixed	Natural gas	2,419,805	$ 8.61	$ 6.24	$5.4	$ —	$4.4	$ —
Receive fixed/pay variable	Natural gas	9,670,000	4.19	8.94	—	(43.5)	—	(38.0)
	NGL	866,875	35.69	55.03	—	(15.8)	—	(13.8)
	Crude oil	259,150	66.83	94.15	—	(6.7)	—	(4.4)
Receive variable/pay variable	Natural gas	37,735,000	9.12	9.15	0.6	(2.0)	1.5	(0.7)
Options								
Calls (written)	Natural gas	365,000	4.31	9.03	—	(1.6)	—	(1.4)
Puts purchased	Natural gas	365,000	9.03	3.40	—	—	—	—
Contracts maturing in 2011								
Swaps								
Receive variable/pay fixed	Natural gas	817,005	$ 8.67	$ 4.00	$3.5	$ —	$3.2	$ —
Receive fixed/pay variable	Natural gas	7,952,500	3.63	8.76	—	(37.2)	—	(34.1)
	NGL	316,090	36.02	54.05	—	(5.2)	—	(4.3)
	Crude oil	228,125	68.36	93.71	—	(5.3)	—	(3.4)
Receive variable/pay variable	Natural gas	4,185,000	8.17	8.20	—	(0.1)	0.1	—
Options								
Calls (written)	Natural gas	365,000	4.31	8.76	—	(1.5)	—	(1.4)
Puts purchased	Natural gas	365,000	8.76	3.40	—	—	—	—
Contracts maturing in 2012								
Swaps								
Receive variable/pay fixed	Natural gas	209,709	$ 9.18	$ 4.10	$0.9	$ —	$0.9	$ —
Receive fixed/pay variable	Natural gas	1,456,000	3.57	9.31	—	(7.4)	—	(6.8)
	Crude oil	219,600	74.85	93.58	—	(3.6)	—	(1.9)
Receive variable/pay variable	Natural gas	1.089,000	8.31	8.18	0.1	—	—	—

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

(2) Weighted average prices received and paid are in $/MMBtu for Natural gas and in $/Bbl for NGL and Crude.

(3) The fair value is determined based on quoted market prices at March 31, 2008 and December 31, 2007, 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 counterparty credit quality and exposures, in millions of dollars.

Counterparty Credit Quality*	March 31, 2008	December 31, 2007
	(in millions)	
AAA	$ —	$ —
AA	(294.7)	(298.3)
A	(63.9)	(47.2)
Lower than A	—	—
Total	$(358.6)	$(345.5)

* As determined by nationally recognized statistical ratings organizations.

Item 4. Controls and Procedures

We and Enbridge maintain systems of disclosure controls and procedures designed to provide reasonable assurance that we are able to record, process, summarize and report the information required in our annual and quarterly reports under the Securities Exchange Act of 1934. Our management has evaluated the effectiveness of our disclosure controls and procedures as of March 31, 2008. 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 months ended March 31, 2008.

PART II—OTHER INFORMATION

Item 1. Legal Proceedings

Refer to Part I, Item 1. Financial statements, Note 8, which is incorporated herein by reference.

Item 1A. Risk Factors

There have been no material changes to our risk factors as previously disclosed in Part I, Item 1A of our Annual Report on Form 10-K for the fiscal year ended December 31, 2007.

Item 6. Exhibits

Reference is made to the "Index of Exhibits" following the signature page, which we hereby incorporate into this Item.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

ENBRIDGE ENERGY PARTNERS, L.P.
(Registrant)

By: Enbridge Energy Management, L.L.C.
as delegate of
Enbridge Energy Company, Inc.
as General Partner

Date: April 29, 2008

By: /s/ STEPHEN J.J. LETWIN

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

Date: April 29, 2008

By: /s/ MARK A. MAKI

Mark A. Maki
Vice President, Finance
(Principal Financial Officer)

Index of Exhibits

Each exhibit identified below is filed as part of this document. Exhibits not incorporated by reference to a prior filing are designated by an "*"; all exhibits not so designated are incorporated herein by reference to a previous filing as indicated.

3.1	Certificate of Limited Partnership of the Partnership (incorporated by reference to Exhibit 3.1 to the Partnership's Registration Statement 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 dated 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 dated August 16, 2006).
3.4	Amendment No. 1 to the 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 dated January 3, 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 dated October 9, 2001).
4.2	Registration Rights Agreement dated as of April 3, 2008, by and among Enbridge Energy Partners, L.P., Banc of America Securities LLC, Deutsche Bank Securities Inc. and HSBC Securities (USA) Inc. (with respect to the 6.50% Notes due 2018) (incorporated by reference to exhibit 4.4 of our Current Report on Form 8-K dated April 7, 2008).
4.3	Registration Rights Agreement dated as of April 3, 2008, by and among Enbridge Energy Partners, L.P., Banc of America Securities LLC, Deutsche Bank Securities Inc. and HSBC Securities (USA) Inc. (with respect to the 7.50% Notes due 2038) (incorporated by reference to exhibit 4.5 of our Current Report on Form 8-K dated April 7, 2008).
10.1	Seventh Supplemental Indenture dated as of April 3, 2008 between the Partnership and U.S. Bank National Association, successor to SunTrust Bank, as trustee. (incorporated by reference to Exhibit 4.2 of our Current Report on Form 8-K dated April 7, 2008).
10.2	Eighth Supplemental Indenture dated as of April 3, 2008 between the Partnership and U.S. Bank National Association, successor to SunTrust Bank, as trustee. (incorporated by reference to Exhibit 4.3 of our Current Report on Form 8-K dated April 7, 2008).
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.