UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended September 30, 2007

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, or a non-accelerated filer (as defined in Rule 12b-2 of the Exchange Act). Large Accelerated Filer ☒ Accelerated Filer ☐ Non-Accelerated Filer ☐

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 55,238,834 Class A common units outstanding as of October 30, 2007.

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, 2006 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 September 30,		Nine months ended September 30,	
	2007	2006	2007	2006
	(unaudited; in millions, except per unit amounts)			
Operating revenue	$ 1,710.9	$ 1,532.3	$ 5,162.3	$ 4,845.6
Operating expenses				
Cost of natural gas (Notes 4 and 10)	1,430.8	1,265.9	4,390.7	4,099.2
Operating and administrative	103.8	95.1	306.6	256.3
Power	29.7	27.8	87.1	78.3
Depreciation and amortization	45.0	34.8	121.3	101.5
	1,609.3	1,423.6	4,905.7	4,535.3
Operating income	101.6	108.7	256.6	310.3
Interest expense	23.4	28.5	70.2	84.0
Other income	0.4	2.0	2.3	7.4
Income before income tax expense	78.6	82.2	188.7	233.7
Income tax expense (Note 6)	1.3	—	3.7	—
Net income	$ 77.3	$ 82.2	$ 185.0	$ 233.7
Net income allocable to limited partner units (Note 2)	$ 67.9	$ 73.5	$ 158.6	$ 210.6
Net income per limited partner unit (basic and diluted) (Note 2)	$ 0.75	$ 1.03	$ 1.87	$ 3.11
Weighted average limited partner units outstanding	90.0	71.7	84.8	67.8

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 September 30,		Nine months ended September 30,	
	2007	2006	2007	2006
	(unaudited; in millions)			
Net income	$ 77.3	$ 82.2	$ 185.0	$ 233.7
Other comprehensive income (loss) (Note 10)	(1.6)	91.8	(36.6)	95.6
Comprehensive income	$ 75.7	$ 174.0	$ 148.4	$ 329.3

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

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

	Nine months ended September 30,	
	2007	2006
	(unaudited; in millions)	
Cash provided by operating activities		
Net income	$ 185.0	$ 233.7
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	121.3	101.5
Derivative fair value losses (gains) (Note 10)	17.4	(53.1)
Inventory market price adjustments	4.5	16.7
Environmental liabilities (Note 9)	(1.8)	(1.6)
Other	(0.2)	5.1
Changes in operating assets and liabilities, net of acquisitions:		
Receivables, trade and other	42.3	(5.3)
Due from General Partner and affiliates	2.5	9.2
Accrued receivables	116.2	236.8
Inventory (Note 4)	(13.6)	(56.7)
Current and long-term other assets (Note 10)	(5.4)	(3.3)
Due to General Partner and affiliates	39.1	2.0
Accounts payable and other (Notes 3 and 10)	(5.9)	(16.9)
Accrued purchases	(116.8)	(258.5)
Interest payable	28.9	19.0
Current income tax payable (Note 6)	3.5	—
Property and other taxes payable	1.8	1.3
Settlement of interest rate derivatives	(0.9)	—
Net cash provided by operating activities	417.9	229.9
Cash used in investing activities		
Additions to property, plant and equipment	(1,428.4)	(514.3)
Changes in construction payables	56.4	17.4
Asset acquisitions, net of cash acquired	—	(33.3)
Other	(2.0)	0.4
Net cash used in investing activities	(1,374.0)	(529.8)
Cash provided by financing activities		
Net proceeds from unit issuances (Note 8)	628.8	509.6
Distributions to partners (Note 8)	(179.5)	(169.8)
Net proceeds from issuances of long-term debt (Note 7)	592.8	—
Net Credit Facility borrowings (Note 7)	120.0	—
Net commercial paper issuances (repayments) (Note 7)	(241.2)	143.9
Affiliate loan repayment	—	(20.0)
Net cash provided by financing activities	920.9	463.7
Net increase (decrease) in cash and cash equivalents	(35.2)	163.8
Cash and cash equivalents at beginning of year	184.6	89.8
Cash and cash equivalents at end of period	$ 149.4	$ 253.6

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	September 30, 2007	December 31, 2006
	(unaudited; dollars in millions)	
ASSETS		
Current assets		
Cash and cash equivalents (Note 3)	$ 149.4	$ 184.6
Receivables, trade and other, net of allowance for doubtful accounts of $1.8 in 2007 and $2.4 in 2006	104.2	146.7
Due from General Partner and affiliates	28.0	30.5
Accrued receivables	400.3	516.5
Inventory (Note 4)	126.2	117.1
Other current assets (Note 10)	16.3	13.9
	824.4	1,009.3
Property, plant and equipment, net (Note 5)	5,134.7	3,824.9
Other assets, net (Notes 6 and 10)	31.6	26.1
Goodwill	265.7	265.7
Intangibles, net	97.4	97.8
	$ 6,353.8	$ 5,223.8
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Due to General Partner and affiliates	$ 61.7	$ 22.6
Accounts payable and other (Notes 3 and 10)	302.5	211.5
Accrued purchases	413.5	530.3
Interest payable	33.4	11.4
Property and other taxes payable (Note 6)	27.8	18.6
Loans from General Partner and affiliates	143.1	136.2
Current maturities of long-term debt	31.0	31.0
	1,013.0	961.6
Long-term debt (Note 7)	2,541.2	2,066.1
Environmental liabilities (Note 9)	3.0	3.3
Other long-term liabilities (Note 10)	155.5	149.4
	3,712.7	3,180.4
Commitments and contingencies (Note 9)		
Partners' capital (Note 8)		
Class A common units (Units issued—55,238,834 in 2007 and 49,938,834 in 2006)	1,360.7	1,141.7
Class B common units (Units issued—3,912,750 in 2007 and 2006)	74.2	67.6
Class C units (Units issued—17,744,717 in 2007 and 11,070,152 in 2006)	863.5	509.8
i-units (Units issued—13,322,496 in 2007 and 12,674,148 in 2006)	507.4	466.3
General Partner	61.5	47.6
Accumulated other comprehensive loss (Note 10)	(226.2)	(189.6)
	2,641.1	2,043.4
	$ 6,353.8	$ 5,223.8

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

We have prepared the accompanying unaudited interim consolidated financial statements 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 at September 30, 2007 and December 31, 2006; our results of operations and comprehensive income for the three and nine month periods ended September 30, 2007 and 2006; and our cash flows for the nine month periods ended September 30, 2007 and 2006. We derived the Consolidated Statement of Financial Position as of December 31, 2006 from the audited financial statements included in our Annual Report on Form 10-K for the year ended December 31, 2006.

The results of operations for the three and nine month periods ended September 30, 2007 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. Our consolidated statements of cash flows for the nine month period ended September 30, 2006 include reclassifications that were made to present changes in environmental liabilities separately from changes in Accounts payable and other, consistent with our current period presentation. Additionally, we reclassified $6.4 million from "Other assets, net" to "Intangibles, net" in our December 31, 2006 consolidated statement of financial position related to rights we received for contributions we made in aid of construction projects, consistent with our current period presentation. These reclassifications have no effect on previously reported results of operations, comprehensive income or partners' capital. Our interim consolidated financial statements should be read in conjunction with our consolidated financial statements and notes thereto presented in our Annual Report on Form 10-K for the fiscal year ended December 31, 2006.

2. NET INCOME PER LIMITED PARTNER UNIT

Net income per limited partner unit is computed by dividing net income, after deduction of Enbridge Energy Company, Inc.'s (the "General Partner") allocation, 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. We computed net income per limited partner unit as follows:

	Three months ended September 30,		Nine months ended September 30,	
	2007	2006	2007	2006
	(in millions, except per unit amounts)			
Net income	$ 77.3	$ 82.2	$185.0	$233.7
Allocations to the General Partner:				
Net income allocated to the General Partner	(1.5)	(1.7)	(3.7)	(4.7)
Incentive income allocated to the General Partner	(7.9)	(7.0)	(22.6)	(18.3)
Historical cost depreciation adjustments	—	—	(0.1)	(0.1)
	(9.4)	(8.7)	(26.4)	(23.1)
Net income allocable to limited partner units	$ 67.9	$ 73.5	$158.6	$210.6
Weighted average limited partner units outstanding	90.0	71.7	84.8	67.8
Net income per limited partner unit (basic and diluted)	$ 0.75	$ 1.03	$ 1.87	$ 3.11

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 $31.8 million at September 30, 2007 and $46.9 million at December 31, 2006, are included in Accounts payable and other on our Consolidated Statements of Financial Position.

4. INVENTORY

Inventory is comprised of the following:

	September 30, 2007	December 31, 2006
	(in millions)	
Material and supplies	$ 3.9	$ 3.8
Liquids inventory	7.8	9.9
Natural gas and natural gas liquids inventory	114.5	103.4
	$126.2	$117.1

Our inventory at September 30, 2007 is net of charges totaling $4.5 million which we recorded to reduce the cost basis of our natural gas and natural gas liquids, or NGLs, inventory to reflect market value. The lower of cost or market adjustments are recorded in the Cost of natural gas on our Consolidated Statements of Income during the period incurred.

5. PROPERTY, PLANT AND EQUIPMENT

Property, Plant and Equipment is comprised of the following:

	September 30, 2007	December 31, 2006
	(in millions)	
Land	$ 14.8	$ 14.3
Rights-of-way	332.5	298.6
Pipelines	2,744.3	2,320.8
Pumping equipment, buildings and tanks	832.0	747.4
Compressors, meters and other operating equipment	498.1	418.1
Vehicles, office furniture and equipment	122.4	112.4
Processing and treating plants	185.8	86.4
Construction in progress	1,422.1	733.6
Total property, plant and equipment	6,152.0	4,731.6
Accumulated depreciation	(1,017.3)	(906.7)
Net property, plant and equipment	$ 5,134.7	$ 3,824.9

6. INCOME TAXES

We are not a taxable entity for U.S. federal income tax purposes, or for the majority of states that impose income tax. These taxes on our net income are generally borne by our unitholders through the allocation of taxable income. In May 2006, the State of Texas enacted substantial changes to its tax structure to impose a new tax based on modified gross margin, which began in 2007. Under the provisions of Statement of Financial Accounting Standards ("SFAS") No. 109, *Accounting for Income Taxes*, we have determined that this tax is an income tax. Our income tax expense is $1.3 million and $3.7 million for the three and nine month periods ended September 30, 2007, respectively, which we computed by applying a 0.56% state income tax rate to modified gross revenue. Our income tax expense represents an approximate 2% effective rate for the three and nine months ended September 30, 2007, as applied to pretax book income. At September 30, 2007 we have included a current income tax payable of $3.5 million in Property and other taxes payable and a deferred income tax asset of $0.2 million in Other assets, net on our Consolidated Statements of Financial Position.

7. DEBT

Credit Facility

On April 4, 2007 we entered into the Second Amended and Restated Credit Agreement (Credit Facility) which among other things: (i) increased the maximum principal amount of credit available to us at any one time from $1 billion to $1.25 billion; (ii) gave us the right to request increases in the maximum principal amount of credit available at any one time from $1.25 billion to $1.5 billion; (iii) eliminated the sublimit on letters of credit; (iv) provided for a five-year facility that matures April 4, 2012 and grants us the option to request annual extensions of maturity and a one-year term out period upon maturity; (v) modified our leverage ratio to include in the calculations of EBITDA (as defined in the Second Amended and Restated Credit Agreement) pro forma adjustments for material projects and to exclude from the calculation of Consolidated Funded Debt (as defined in the Second Amended and Restated Credit Agreement) certain amounts of preferred securities and subordinated debt that we or our designated subsidiaries may issue in the future; and (vi) eliminated our coverage ratio financial covenant. Our Credit Facility contains restrictive covenants that require us to maintain a maximum leverage ratio of 5.50 to 1.0 for periods ending on or before March 31, 2009; a ratio of 5.25 to 1.0 thereafter, for periods ending on or before March 31, 2010; and a ratio of 5.00 to 1.0 for periods ending June 30, 2010 and following. Our Credit Facility continues to support our commercial paper program.

At September 30, 2007, we had $120.0 million outstanding under our Credit Facility at a weighted average interest rate of 5.81% and letters of credit totaling $89.6 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 September 30, 2007, we could borrow $840.4 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	(120.0)
Balance of letters of credit outstanding	(89.6)
Principal amount of commercial paper issuances	(200.0)
Total amount we could borrow at September 30, 2007	$ 840.4

Commercial Paper Program

Under the terms of our commercial paper program, we can issue up to $600 million of commercial paper. At September 30, 2007, we had outstanding $198.5 million of commercial paper, net of unamortized discount of $1.5 million, bearing interest at a weighted average rate of 5.72%. At December 31, 2006, we had $443.7 million of commercial paper outstanding, net of $1.3 million of unamortized discount, at a weighted average interest rate of 5.45%. At September 30, 2007, we could issue an additional $400.0 million in principal amount of commercial paper under the terms of our commercial paper program.

Junior Subordinated Notes

In September 2007, we issued and sold $400 million in principal amount of our fixed/floating rate, junior subordinated notes due 2067, which we refer to as the Junior Notes. We received proceeds of approximately $393 million, net of underwriting discounts, commissions and estimated offering expenses. We used the net proceeds to temporarily reduce a portion of our outstanding commercial paper and Credit Facility borrowings that we had previously incurred to finance a portion of our capital expansion projects.

The Junior Notes represent our unsecured obligations that are subordinate in right of payment to all of our existing and future senior indebtedness. The Junior Notes bear interest at a fixed annual rate of 8.05%, exclusive of any discounts or interest rate hedging activities, from September 27, 2007 to October 1, 2017, payable semi-annually in arrears on April 1 and October 1 of each year beginning April 1, 2008. After October 1, 2017, the Junior Notes will bear interest at a variable rate equal to the three-month LIBOR for the related interest period increased by 3.7975%, payable quarterly in arrears on January 1, April 1, July 1 and October 1 of each year beginning January 1, 2018. We may elect to defer interest payments on the Junior Notes for up to ten consecutive years on one or more occasions, but not beyond the final repayment date. Until paid, any interest we elect to defer will bear interest at the prevailing interest rate, compounded semi-annually during the period the Junior Notes bear interest at the fixed annual rate and quarterly during the period that the Junior Notes bear interest at a variable annual rate.

The Junior Notes do not restrict our ability to incur additional indebtedness. However, with limited exceptions, during any period we elect to defer interest payments on the Junior Notes, we cannot make distribution payments or liquidate any of our equity securities, nor can we or our subsidiaries make any principal and interest payments for any debt that ranks equally with or junior to the Junior Notes.

The scheduled maturity date for the Junior Notes is initially October 1, 2037, but we may extend the maturity date up to two times, on October 1, 2017 and October 1, 2027, in each case for an additional ten-year period. As a result, the scheduled maturity date may be extended to October 1, 2047 or October 1, 2057. Our obligation to repay the Junior Notes on the scheduled maturity date is limited by an agreement we refer to as the Replacement Capital Covenant, which we entered into in connection with our offering of the Junior Notes, but not as part of the Junior Notes. The Replacement Capital Covenant limits the types of financing sources we can use to repay the Junior Notes. We are required to repay the Junior Notes on the scheduled maturity date only to the extent the principal amount repaid does not exceed proceeds we have received from the issuance and sale of securities, that, among other attributes defined in the Replacement Capital Covenant, have characteristics that are the same or more equity-like than the Junior Notes. We refer to the securities that meet this characterization as qualifying capital securities. If we do not receive sufficient proceeds from the sale of qualifying capital securities to repay the Junior Notes by the scheduled maturity date, we must use our commercially reasonable efforts to raise sufficient proceeds from the sale of qualifying capital securities to permit repayment of the Junior Notes on the following quarterly interest payment date, and on each subsequent quarterly interest payment date until the Junior Notes are paid in full. Regardless of the amount of qualifying capital securities that we have issued and sold, the final repayment date is initially October 1, 2067. We may extend the final repayment date for an additional ten-year period on October 1, 2017, and as a result the final repayment date may be extended to October 1, 2077. We may extend the scheduled maturity date whether or not we also extend the final repayment date, and we may extend the final repayment date whether or not we extend the scheduled maturity date.

We may redeem the Junior Notes in whole at any time, or in part from time, prior to October 1, 2017, for a "make-whole" redemption price, and thereafter at a redemption price equal to the principal amount plus accrued and unpaid interest on the Junior Notes. We may also redeem the Junior Notes prior to October 1, 2017 in whole, but not in part, upon the occurrence of certain tax or rating agency events at specified redemption prices. Our right to optionally redeem the Junior Notes is also limited by the Replacement Capital Covenant, which limits the types of financing sources we can use to redeem the Junior Notes in the same manner as to repay the Junior Notes, as discussed in the above paragraph.

Zero Coupon Senior Notes

In August 2007, we received net proceeds of approximately $200 million from a private placement of our senior, unsecured zero coupon notes due 2022 (the "Zero Coupon Notes"), which at maturity will be payable in the aggregate principal amount of $442 million. We initially recorded the Zero Coupon Notes in long-term debt at the amount of proceeds we received from the private placement, which we refer to as the issue price. The carrying amount at September 30, 2007 includes $0.9 million associated with the accretion of interest we recognized as interest expense during the period. The Zero Coupon Notes are scheduled to mature on August 28, 2022, although they may be called by the note holders prior to the scheduled maturity date on August 28 of any year commencing on August 28, 2009, at a price equal to the then accreted value of the called Zero Coupon Notes. The Zero Coupon Notes have a yield of 5.36% on a semi-annual compound basis and rank equally in right of payment to all of our existing and future senior indebtedness, as set forth in our senior indenture. We used the net proceeds from this private placement to repay a portion of our outstanding commercial paper and Credit Facility borrowings that we had previously incurred to fund a portion of our capital expansion projects.

8. PARTNERS' CAPITAL

The following table sets forth our distributions, as approved by the Board of Directors of Enbridge Energy Management, L.L.C. ("Enbridge Management"), during the nine months ended September 30, 2007:

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
					(in millions, except per unit amounts)			
January 26, 2007	February 14, 2007	February 6, 2007	$ 0.925	$ 80.0	$ 11.7	$ 10.2	$ 0.5	$ 57.6
April 26, 2007	May 15, 2007	May 7, 2007	$ 0.925	$ 86.6	$ 11.9	$ 15.9	$ 0.6	$ 58.2
July 27, 2007	August 14, 2007	August 6, 2007	$ 0.925	$ 92.6	$ 12.1	$ 16.2	$ 0.6	$ 63.7

(1) During 2007, in lieu of cash distributions, the Partnership issued 648,348 i-units to Enbridge Management.

(2) During 2007, in lieu of cash distributions, the Partnership issued 743,773 Class C units to our Class C unitholders.

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

Issuance of Class A Common Units

In May 2007, we issued and sold 5.3 million Class A common units at a price of $58.00 per unit, for proceeds of approximately $301.9 million, net of underwriters' discounts, commissions and expenses. In addition, our general partner contributed approximately $6.1 million to us to maintain its two percent general partner interest. We used the proceeds from this offering partially to reduce outstanding commercial paper we previously issued to finance a portion of our capital expansion projects. We invested the remaining amount in short-term commercial paper for use in future periods to fund additional expenditures under our capital expansion projects.

Private Placement of Class C Units

In April 2007, we issued and sold 4.7 million Class C units at a price of $53.11 per Class C unit to CDP Infrastructure Fund G.P. ("CDP"), 0.9 million Class C units to Tortoise Infrastructure Corporation and 0.3 million Class C units to Tortoise Energy Capital Corporation. We sold the Class C units in a private transaction exempt from registration under Section 4(2) of the Securities Act of 1933, as amended. We received proceeds of approximately $314.4 million, net of expenses associated with the private placement. In addition, our general partner contributed approximately $6.4 million to us to maintain its two percent general partner interest. We used the proceeds from this offering partially to reduce outstanding commercial paper we previously issued to finance a portion of our capital expansion program.

9. 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 the gathering, transportation, storage and processing of liquid hydrocarbon and natural gas products 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.

As of September 30, 2007 and December 31, 2006, we have recorded $2.6 million and $4.1 million, respectively, in current liabilities and $3.0 million and $3.3 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.

In January 2007, we detected a leak on Line 14 of our Lakehead system, near the Owen, Wisconsin pump station. We immediately shut the pipeline down and dispatched emergency response crews to oversee containment, cleanup and repair of the pipeline. We spent approximately $0.9 million to recover the barrels released, complete excavation, clean-up and repairs to return the line to service. We have applied pressure restrictions to the line as we work with federal and state environmental and pipeline safety regulators to investigate the cause of the rupture. Such pressure restrictions have not materially affected throughput on the system. Based upon the results of the inspection reports we have received, we are undertaking a program that will cost approximately $10.5 million, in addition to previous costs incurred, to investigate and remediate any potential conditions that could compromise the integrity of the pipeline.

In February 2007, a contractor undertaking work in Rusk County, Wisconsin on the Enbridge Southern Lights project punctured the adjacent Line 14 pipeline, resulting in a release of crude oil estimated at 3,000 barrels. As the spill was largely contained within the ditch used for construction, environmental impact was minimized. Impact to customers was also minimized as the line was repaired and returned to service in less than two days. We continue investigating this incident and have spent approximately $1.7 million of the $2.6 million we estimated would be required for with the repair and cleanup. We recorded this $2.6 million as a liability and a receivable, since we will recover these costs from the parties responsible for the damage. Any further exposure or impact related to this incident is not believed to be material.

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.

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. To mitigate the volatility of our cash flows, we use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the risks associated with market fluctuations in commodity prices. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on commodity prices.

Accounting Treatment

All derivative financial instruments are recorded in the consolidated financial statements at fair market value and are adjusted each period for changes in the fair market value (“mark-to-market”). The fair market value of these derivative financial instruments reflects the estimated amounts that we would pay or receive, other than in a forced or liquidation sale, to terminate or close the contracts at the reporting date, taking into account the current unrealized losses or gains on open contracts. We use actively traded external market quotes and indices to value substantially all of the derivative financial instruments we utilize.

Under the guidance of SFAS No. 133, if a derivative financial instrument does not qualify as a hedge, or is not designated as a hedge, the derivative is adjusted to its fair market 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. Cash flow is only impacted to the extent the actual derivative contract is settled by making or receiving a payment to or from the counterparty or by making or receiving a payment for entering into a contract that exactly offsets the original derivative contract. Typically, we settle our derivative contracts when the physical transaction that underlies the derivative financial instrument occurs.

If a derivative financial instrument qualifies and is designated as a cash flow hedge, 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 market value is recognized each period in earnings. Realized gains and losses on derivative financial instruments that are designated as hedges and qualify for hedge accounting are included in Cost of natural gas 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 financial instruments to receive hedge accounting treatment whenever possible, to mitigate the non-cash earnings volatility that arises under mark-to-market accounting treatment. 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 financial instruments qualify for hedge accounting treatment under the specific requirements of SFAS No. 133. As discussed in Note 15 to our consolidated financial statements included in our Annual Report on Form 10-K for the year ended December 31, 2006, we have four transaction types where the hedge structure does not meet the requirements to permit application of hedge accounting and are referred to as "non-qualified." Non-qualified derivative financial instruments are marked-to-market each period with the change in fair value, representing unrealized gains and losses, included in Cost of natural gas 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 financial instrument contract settlement is made.

The following table presents the mark-to-market gains and losses associated with changes in the fair value of our commodity price derivative financial instruments, which are recorded as an element of Cost of natural gas in our Consolidated Statements of Income and disclosed as a reconciling item on our Statements of Cash Flows:

Derivative fair value gains (losses)	Three months ended September 30, 2007	Three months ended September 30, 2006	Nine months ended September 30, 2007	Nine months ended September 30, 2006
	(in millions)			
Natural Gas segment				
Ineffectiveness	$ (0.5)	$ (1.4)	$ (0.2)	$ (1.5)
Non-qualified hedges	(7.2)	3.2	(13.2)	1.4
Marketing				
Non-qualified hedges	2.9	21.9	(4.0)	53.2
Derivative fair value gains (losses)	$ (4.8)	$ 23.7	$(17.4)	$ 53.1

We record the change in fair value of our cash flow hedges in AOCI until the derivative financial instruments are settled, at which time they are reclassified from AOCI to earnings. Included in AOCI are unrecognized losses of approximately $2.7 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 and nine month periods ended September 30, 2007, we reclassified losses of $23.8 million and $61.0 million, respectively, from AOCI to Cost of natural gas on our Consolidated Statements of Income for the fair value of derivative financial instruments that were settled. For the three and nine month periods ended September 30, 2006, we reclassified losses of $24.0 million and $63.7 million, respectively, from AOCI to Cost of natural gas on our Consolidated Statements of Income for the fair value of derivative financial 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:

	September 30, 2007	December 31, 2006
	(in millions)	
Other current assets	$ 6.2	$ 7.2
Other assets, net	9.3	11.0
Accounts payable and other	(98.7)	(57.2)
Other long-term liabilities	(147.4)	(136.4)
	$(230.6)	$(175.4)

The increase in our obligation associated with derivative activities is primarily due to the increase in forward natural gas prices from December 31, 2006 to September 30, 2007. Our portfolio of derivative financial instruments is largely comprised of long-term fixed price natural gas sales and purchase agreements.

In connection with our September 2007 issuance and sale of $400 million in principal amount of our Junior Notes, as discussed in Note 7, we paid $0.9 million to settle treasury locks we entered to hedge the first five years of interest payments on a portion of this obligation. The $0.9 million will be amortized from AOCI to interest expense over the five year period for which the derivative instrument was established to hedge of interest payments on the Junior Notes.

We do not require collateral or other security from the counterparties to our derivative financial instruments, all of which were rated "BBB+" or better by the major credit rating agencies.

11. SEGMENT INFORMATION

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

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

- Liquids;
- Natural Gas; and
- Marketing.

The following tables present financial information about our business segments:

	As of and for the three months ended September 30, 2007				
	Liquids	Natural Gas	Marketing	Corporate[1]	Total
			(in millions)		
Total revenue	$ 138.1	$1,376.0	$ 790.3	$ —	$ 2,304.4
Less: Intersegment revenue	—	528.7	64.8	—	593.5
Operating revenue	138.1	847.3	725.5	—	1,710.9
Cost of natural gas	—	711.2	719.6	—	1,430.8
Operating and administrative	33.9	68.1	2.3	(0.5)	103.8
Power	29.7	—	—	—	29.7
Depreciation and amortization	16.9	27.7	0.4	—	45.0
Operating income	57.6	40.3	3.2	0.5	101.6
Interest expense	—	—	—	23.4	23.4
Other income	—	—	—	0.4	0.4
Income before income tax expense	57.6	40.3	3.2	(22.5)	78.6
Income tax expense	—	—	—	1.3	1.3
Net income	$ 57.6	$ 40.3	$ 3.2	$ (23.8)	$ 77.3
Capital expenditures (excluding acquisitions)	$ 354.4	$ 186.8	$ 0.1	$ (4.4)	$ 536.9

(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 September 30, 2006				
	Liquids	Natural Gas	Marketing	Corporate[1]	Total
			(in millions)		
Total revenue	$ 127.2	$ 1,251.9	$ 772.4	$ —	$ 2,151.5
Less: Intersegment revenue	—	565.3	53.9	—	619.2
Operating revenue	127.2	686.6	718.5	—	1,532.3
Cost of natural gas	—	568.0	697.9	—	1,265.9
Operating and administrative	36.0	56.9	1.1	1.1	95.1
Power	27.8	—	—	—	27.8
Depreciation and amortization	16.0	18.7	0.1	—	34.8
Operating income	47.4	43.0	19.4	(1.1)	108.7
Interest expense	—	—	—	28.5	28.5
Other income	—	—	—	2.0	2.0
Net income	$ 47.4	$ 43.0	$ 19.4	$ (27.6)	$ 82.2
Capital expenditures (excluding acquisitions)	$ 50.8	$ 175.6	$ 0.9	$ 1.8	$ 229.1

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

	As of and for the nine months ended September 30, 2007				
	Liquids	Natural Gas	Marketing	Corporate[1]	Total
			(in millions)		
Total revenue	$ 400.3	$4,084.7	$2,634.0	$ —	$ 7,119.0
Less: Intersegment revenue	—	1,767.6	189.1	—	1,956.7
Operating revenue	400.3	2,317.1	2,444.9	—	5,162.3
Cost of natural gas	—	1,966.2	2,424.5	—	4,390.7
Operating and administrative	108.2	190.3	5.8	2.3	306.6
Power	87.1	—	—	—	87.1
Depreciation and amortization	50.0	70.1	1.2	—	121.3
Operating income	155.0	90.5	13.4	(2.3)	256.6
Interest expense	—	—	—	70.2	70.2
Other income	—	—	—	2.3	2.3
Income before income tax expense	155.0	90.5	13.4	(70.2)	188.7
Income tax expense	—	—	—	3.7	3.7
Net income	$ 155.0	$ 90.5	$ 13.4	$ (73.9)	$ 185.0
Total assets	$2,624.1	$3,261.0	$ 261.6	$ 207.1	$ 6,353.8
Capital expenditures (excluding acquisitions)	$ 847.8	$ 572.7	$ 1.6	$ 6.3	$ 1,428.4

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

	As of and for the nine months ended September 30, 2006				
	Liquids	Natural Gas	Marketing	Corporate[(1)]	Total
			(in millions)		
Total revenue	$ 374.7	$4,085.1	$2,406.4	$ —	$6,866.2
Less: Intersegment revenue	—	1,854.0	166.6	—	2,020.6
Operating revenue	374.7	2,231.1	2,239.8	—	4,845.6
Cost of natural gas	—	1,908.4	2,190.8	—	4,099.2
Operating and administrative	99.7	150.6	3.7	2.3	256.3
Power	78.3	—	—	—	78.3
Depreciation and amortization	47.8	53.2	0.3	0.2	101.5
Operating income	148.9	118.9	45.0	(2.5)	310.3
Interest expense	—	—	—	84.0	84.0
Other income	—	—	—	7.4	7.4
Net income	$ 148.9	$ 118.9	$ 45.0	$ (79.1)	$ 233.7
Total assets	$1,752.4	$2,584.1	$ 264.6	$ 237.4	$4,838.5
Capital expenditures (excluding acquisitions)	$ 101.6	$ 404.7	$ 1.8	$ 6.2	$ 514.3

(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 EVENTS

Distribution to Partners

On October 29, 2007, the Board of Directors of Enbridge Management declared a distribution payable to our partners on November 14, 2007. The distribution will be paid to unitholders of record as of November 6, 2007, of our available cash of $96.0 million at September 30, 2007, or $0.950 per common unit. Of this distribution, $65.9 million will be paid in cash, $12.7 million will be distributed in i-units to our i-unitholder, $16.8 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.

Sale of Assets

In October 2007, we entered into an agreement to sell our Kansas Pipeline system, which we refer to as KPC, for $133 million in cash to an unrelated third party. KPC is an interstate natural gas transmission system which serves the Wichita, Kansas and Kansas City, Kansas markets and includes approximately 1,120 miles of pipeline, ranging in diameter from 4 to 12 inches, along with three compressor stations. The final price is subject to an adjustment for working capital items at closing, which is scheduled to occur on November 1, 2007.

13. RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

In February 2007, the Financial Accounting Standards Board (FASB) issued SFAS No. 159, *The Fair Value Option for Financial Assets and Liabilities.* This statement provides companies with an option to report certain financial assets and financial liabilities at fair value. The objective of SFAS No. 159 is to reduce the volatility in earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. SFAS No. 159 also establishes presentation and disclosure requirements designed to facilitate comparisons between companies that choose different measurement attributes for similar types of assets and liabilities. The provisions of SFAS No. 159 are effective at the beginning of our first fiscal year that begins after November 15, 2007 as we have elected not to early adopt its provisions. We do not expect our adoption of SFAS No. 159 to have a material affect on our Consolidated Financial Statements.

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 Quarterly Report on Form 10-Q and with the information included in our Annual Report on Form 10-K for the year ended December 31, 2006.

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
- Providing 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.

We primarily provide fee-based services to our customers to minimize our exposure to commodity price risks. However, in our natural gas and marketing businesses, a portion of our earnings and cash flows are exposed to movements in the prices of natural gas and NGLs. To substantially mitigate this exposure and to provide stability to our cash flow, we enter into derivative financial instrument transactions. Certain of these transactions qualify for hedge accounting under SFAS No. 133, *Accounting for Derivative Transactions and Hedging Activities*; some, however, must be accounted for using the mark-to-market method of accounting which can expose us to significant earnings volatility.

The following table reflects our operating income by business segment and corporate charges for the three and nine month periods ended September 30:

	Three months ended September 30,		Nine months ended September 30,	
	2007	2006	2007	2006
	(in millions)			
Operating Income				
Liquids	$ 57.6	$ 47.4	$ 155.0	$ 148.9
Natural Gas	40.3	43.0	90.5	118.9
Marketing	3.2	19.4	13.4	45.0
Corporate, operating and administrative	0.5	(1.1)	(2.3)	(2.5)
Total Operating Income	101.6	108.7	256.6	310.3
Interest expense	23.4	28.5	70.2	84.0
Other income	0.4	2.0	2.3	7.4
Income tax expense	1.3	—	3.7	—
Net Income	$ 77.3	$ 82.2	$ 185.0	$ 233.7

Summary Analysis of Operating Results

Liquids

Operating income from our Liquids business contributed $57.6 million and $155.0 million to our consolidated operating income for the three and nine month periods ended September 30, 2007, representing increases of $10.2 million and $6.1 million, respectively, over the comparable periods in 2006. The positive results of our Liquids business resulted from increased delivery volumes on all three of our Liquids systems coupled with the annual index rate increases that became effective July 1, 2007, and the annual tariff rate adjustments on April 1, 2007 for historical pipeline expansions known as the SEP II, Terrace and Facilities surcharges. Revenues were also positively affected by the increase in contract storage fees generated by our Cushing terminal associated with the additional storage tanks we completed in late 2006 and during the first half of 2007. Also contributing to the positive results are favorable property tax settlements and oil measurement experience, both of which reduce our operating costs. Partially offsetting these positive factors are higher expenditures associated with our pipeline integrity management program, additional power costs associated with increased volumes and higher utility rates and additional workforce-related and depreciation resulting from the expansion of our existing liquids systems.

Natural Gas

Operating income from our Natural Gas segment slightly decreased by $2.7 million to $40.3 million for the three month period ended September 30, 2007, from $43.0 million for the comparable period in 2006. Operating income for the nine month period ended September 30, 2007 decreased by $28.4 million to $90.5 million, from $118.9 million for the comparable period in 2006.

For the three months ended September 30, 2007, a $9.5 million increase in unrealized, non-cash mark-to-market losses from our derivative activities had a negative affect on operating income in relation to the same period of 2006. The operating income of our Natural Gas segment was also affected during the three month period ended September 30, 2007 by the following additional factors:

- Increased natural gas treating and processing capacity from the completion of new facilities on our East Texas and Anadarko systems.
- Volume growth within our East Texas system due to strong drilling activity in the area, coupled with completion of components of our Clarity project;
- Volume growth within our North Texas systems due to significant production increases and strong drilling activity in the Barnett Shale formation and the addition of the Weatherford II processing plant.
- Increased revenue less cost of natural gas derived from our processing assets due to a favorable pricing environment in the current quarter, consistent with the same period of 2006.
- Additional operating and administrative costs and depreciation associated with the expansion of our natural gas systems.

For the nine months ended September 30, 2007, in addition to the factors discussed above and a $13.3 million increase in unrealized, non-cash mark-to-market losses from our derivative activities, the operating results of our Natural Gas segment were also affected by the following:

- An increase in natural gas measurement losses on two of our major gathering systems.
- Operational inefficiencies at our Zybach plant caused by fouling of the plant with contaminated water in the natural gas stream reduced NGL production and increased operating costs.

Marketing

Operating income from our Marketing segment decreased by $16.2 million to $3.2 million for the three month period ended September 30, 2007, from $19.4 million for the comparable period in 2006. Operating income for the nine month period ended September 30, 2007 decreased by $31.6 million to $13.4 million, from $45.0 million for the comparable period in 2006. The operating results of our Marketing segment are predominantly affected by the following factors:

- Unrealized, non-cash mark-to-market net gains of $2.9 million and net losses of $4.0 million for the three and nine month periods ended September 30, 2007, respectively, compared with unrealized, non-cash mark-to-market net gains of $21.9 million and $53.2 million for the three and nine month periods ended September 30, 2006 that resulted from the changes in market value of our derivative financial instruments that do not qualify for hedge accounting. The unrealized gains we recorded in the three and nine month periods ended September 30, 2006 were the result of an unstable pricing environment that was not present for the same periods of 2007.
- Adjustments to reduce the cost basis of our inventory of natural gas and NGLs to market value in the amount of $3.0 million and $4.5 million for the three and nine months ended September 30, 2007, respectively, compared with adjustments of $6.6 million and $16.3 million for the three and nine months ended September 30, 2006.
- Sales of natural gas inventory for approximately $12 million that we realized for the nine months ended September 30, 2007, including approximately $5 million of gains from the settlement of derivative financial instruments hedging our natural gas inventory.
- Increased access to preferred natural gas markets associated with our natural gas system expansions and other initiatives.

Derivative Transactions and Hedging Activities

We record all derivative financial instruments in the consolidated financial statements at fair market value pursuant to the requirements of SFAS No. 133. For those derivative financial instruments that do not qualify for hedge accounting, all changes in fair market value are recorded through our Consolidated Statements of Income each period. The fair market value of these derivative financial instruments reflects the estimated amounts that we would pay or receive to terminate or close the contracts at the reporting date, although that is not our intent.

Unrealized mark-to-market losses for the three and nine month periods ended September 30, 2007, are the result of increases in the forward and daily market prices of natural gas and NGLs, compared with the three and nine month periods ended September 30, 2006. However, NGL prices, which tend to move in relation to crude oil prices, have continued to trend higher due to price changes in the crude oil market. While the natural gas and NGL pricing environment continues to remain volatile, the mark-to-market gains and losses created by this volatility do not affect our cash flow. We expect these non-cash gains and losses to be offset in future quarters as we settle the derivative financial instruments and the underlying physical transactions.

The following table presents the unrealized, non-cash, mark-to-market gains and losses by segment, associated with our derivative financial instruments:

Derivative fair value gains (losses)	Three months ended September 30, 2007	Three months ended September 30, 2006	Nine months ended September 30, 2007	Nine months ended September 30, 2006
	(unaudited, in millions)			
Natural Gas segment				
Ineffectiveness	$ (0.5)	$ (1.4)	$ (0.2)	$ (1.5)
Non-qualified hedges	(7.2)	3.2	(13.2)	1.4
Marketing				
Non-qualified hedges	2.9	21.9	(4.0)	53.2
Derivative fair value gains (losses)	$ (4.8)	$ 23.7	$ (17.4)	$ 53.1

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 September 30, 2007	Three months ended September 30, 2006	Nine months ended September 30, 2007	Nine months ended September 30, 2006
	(unaudited, in millions)			
Operating Results				
Operating revenues	$138.1	$127.2	$400.3	$374.7
Operating and administrative	33.9	36.0	108.2	99.7
Power	29.7	27.8	87.1	78.3
Depreciation and amortization	16.9	16.0	50.0	47.8
Operating expenses	80.5	79.8	245.3	225.8
Operating Income	$ 57.6	$ 47.4	$155.0	$148.9
Operating Statistics				
Lakehead system deliveries:				
United States[(1)]	1,187	1,175	1,191	1,174
Province of Ontario[(1)]	325	275	333	306
Total Lakehead system deliveries[(1)]	1,512	1,450	1,524	1,480
Barrel miles (billions)	101	97	301	291
Average haul (miles)	723	725	723	721
Mid-Continent system deliveries[(1)]	255	244	248	247
North Dakota system:				
Trunkline	93	82	91	83
Gathering	7	7	6	7
Total North Dakota system deliveries[(1)]	100	89	97	90
Total Liquids Segment Delivery Volumes[(1)]	1,867	1,783	1,869	1,817

(1) Average barrels per day ("Bpd") in thousands.

Three months ended September 30, 2007 compared with three months ended September 30, 2006

Operating income from our Liquids segment accounted for $57.6 million of our consolidated operating income for the three months ended September 30, 2007, an increase of $10.2 million from the $47.4 million produced during the same period in 2006. The favorable results of our Liquids segment are attributable to increased delivery volumes on all three of our Liquids systems along with the annual index rate increases that became effective July 1, 2007 for each of these systems. Also contributing to the positive results are favorable property tax settlements and oil measurement experience, both of which reduce our operating costs. Partially offsetting these positive results are the additional power costs associated with the increased volumes and additional depreciation resulting from the expansion of our existing liquids systems.

Operating revenue for the three months ended September 30, 2007 increased by $10.9 million to $138.1 million from $127.2 million for the same period in 2006. The increase in revenue is attributable to the higher delivery volumes on all three of our Liquids systems combined with the increase in average tariffs associated with the annual index rate increase that went into effect July 1, 2007 for each of these 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. Additional discussion of these tariffs is provided below under the section labeled *Regulatory Matters—FERC Transportation Tariffs-Liquids*. The combined delivery volume and tariff increases for each of our Liquids systems contributed approximately $8 million to our revenues for the three months ended September 30, 2007. Also contributing to the increase in revenues for the three months ended September 30, 2007, was an increase in contract storage fees generated by our Cushing terminal from the additional storage tanks we placed in service during 2007 and in late 2006.

Average delivery volumes on our Liquids systems increased to 1.867 million Bpd for the three months ended September 30, 2007 from 1.783 million Bpd during the same period in 2006. The increase in delivery volumes on our Lakehead system are primarily the result of increased crude oil supplies from upstream production facilities associated with the ongoing development of the Alberta Oil Sands by producers. Our Mid-Continent system continues to operate near capacity, as more light grade crude oil is being transported on the system. Also contributing to the increase is the volume growth on our North Dakota system resulting from a system capacity increase associated with completion of our hydrostatic testing program in the third quarter of 2006, as well as phasing in portions of the system expansion that is scheduled for completion in the fourth quarter of 2007.

Operating and administrative expenses for the Liquids segment decreased $2.1 million for the three months ended September 30, 2007, compared with the same period in 2006. The decrease in these costs is primarily attributable to the following:

i) Favorable settlements of prior year property tax assessments that we realized during the three months ended September 30, 2007;

ii) More favorable oil loss measurement experience than we realized for the same period in 2006; and

iii) We expensed obsolete supplies inventory during the three months ended September 30, 2006 and did not incur a similar expense for the same period of 2007.

Partially offsetting the decrease in Operating and administrative expenses are the following increases:

i) Higher costs we incurred in connection with our pipeline integrity management program;

ii) Additional workforce related costs associated with the operational, administrative and compliance support services necessary for our systems.

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

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

We identified operating conditions in 2005 on a connected third-party facility that contributed to higher levels of physical losses. We have addressed the operating conditions causing these higher levels of physical losses, which have subsequently reduced the physical losses we have experienced on our Lakehead system. We have initiated proceedings to recover damages for the losses we sustained from the owner of the third-party system, but no assurances can be given as to the time to completion or the results of the recovery process.

Power costs increased $1.9 million to $29.7 million in the third quarter of 2007, compared with $27.8 million for the same period in 2006, predominantly due to the higher utility rates we are charged by our power suppliers. The increase in delivery volumes is also a factor contributing to the additional power costs.

The increase in depreciation expense of $0.9 million is attributable to the additional assets we have placed in service during the 2007 and in the fourth quarter of 2006.

Nine months ended September 30, 2007 compared with Nine months ended September 30, 2006

Our Liquids segment accounted for $155.0 million of consolidated operating income for the nine months ended September 30, 2007, representing a $6.1 million increase over the $148.9 million for the same period in 2006. The components of our operating income changed during the nine months ended September 30, 2007 compared with the nine months ended September 30, 2006, for primarily the same reasons as noted above in the three-month analysis.

Future Prospects Update for Liquids

We and Enbridge are actively working with our customers to develop transportation options that will allow Canadian crude oil greater access to markets throughout the United States.

Partnership Projects

Southern Access

In conjunction with Enbridge, we continue to progress mostly on schedule with construction of the 400,000 Bpd Southern Access expansion project. We are undertaking the United States portion of the expansion on our Lakehead system. The first stage of construction is on schedule for completion in the first half of 2008 that will add approximately 44,000 Bpd of capacity in 2007 and up to an additional 146,000 Bpd in the first half of 2008. This stage of the project includes a new pipeline between Superior and Delavan, Wisconsin, along with pump station enhancements upstream and downstream of this segment.

The second stage of the expansion project will provide additional upstream pumping capacity and a new pipeline from Delavan to Flanagan, Illinois, with completion expected in the first half 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.

As a result of the escalation of costs we have experienced with the first stage of the project for labor, materials and rights-of-way, we have revised our estimated cost to complete the project. We anticipate the ultimate cost to complete our portion of this project will approximate $2.1 billion. The impact on the project rate of return resulting from the escalation of costs is largely mitigated by the cost of service tolling arrangement used for this project. Approximately 88 percent of the cost overage will be included in the rate base, which forms the basis for determining our tariff rates for transportation. The remaining 12 percent of the project cost relates to installing larger pipe than required under current agreements which we are financing in anticipation of future expansion opportunities.

Alberta Clipper

Based on forecasts of oil sands production growth developed by Enbridge, as well as forecasts by the Canadian Association of Petroleum Producers, or CAPP, we believe that there will be a need for additional export pipeline capacity out of Western Canada over and above projects currently under construction. As a result of this analysis and support received from shippers, we and Enbridge are developing the Alberta Clipper project. This 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 recently revised the scope to 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 is expected to be in service by mid-2010.

In May 2007, Enbridge filed an application with Canada's National Energy Board, or NEB, for the construction and operation of the Canadian segment of the project. In June 2007 Enbridge filed supplements to this application setting forth the tolling principles for the Canadian portion of the project, which are supported by CAPP. We plan to file a similar set of toll principles with the Federal Energy Regulatory Commission ("FERC"). The project remains subject to regulatory approvals and receipt of various permits in Canada and the United States. Enbridge is progressing with land access, engineering and initial procurement commitments to facilitate commencement of project construction.

North Dakota

Work continues to progress for a fourth quarter 2007 completion of our previously announced North Dakota system expansion, which will increase mainline system capacity to 110,000 Bpd from the 80,000 Bpd currently available and expand the system's feeder segment by approximately 30,000 Bpd at an estimated cost of $0.1 billion.

Regional producers in the Williston basin areas of Montana and North Dakota have expressed interest in further expansion of pipeline capacity on the 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 by year end 2009, from the 110,000 Bpd of capacity we expect will be available by year-end 2007. The commercial structure for this expansion has been modified from an open season requesting contract carriage commitments, to 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 current expansion project. Subject to approval from the FERC, we anticipate completing this expansion at the end of 2009.

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, Illinois we are constructing additional crude oil storage tanks at Superior and Griffith to accommodate the anticipated volumes. We completed construction and placed one 360,000 barrel tank into service at Superior during August 2007 and expect to complete construction of the second 360,000 barrel tank and place it into service at Griffith in December 2007. We are also building two tanks with an approximate capacity of 250,000 barrels each that are scheduled to be completed during 2008.

Mid-Continent Terminal Storage

We continue to experience strong interest from customers in securing access to long-term contract storage capacity at our Cushing, Oklahoma terminal. During 2006, we obtained commitments and initiated construction of an additional 5.0 million barrels of storage tanks, 1.1 million barrels of which were completed in late December 2006. During the first half of 2007, we completed construction of three additional storage tanks with approximately 1.1 million barrels of capacity and expect to complete construction of the remaining 2.8 million barrels of capacity during the remainder of 2007. Once complete our total Mid-Continent terminal capacity will be approximately 16.7 million barrels, which includes 1.4 million barrels of operational storage. This capacity will increase operational tankage available to support our Mid-Continent liquids pipeline systems, and available contract storage.

Enbridge and Other Projects

Spearhead Pipeline

In another effort to provide shippers access to new markets, Enbridge acquired a pipeline that runs from Chicago to Cushing. The 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. 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.

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. The project is scheduled for completion by the end of 2009. The project is being undertaken by Enbridge, however, we will benefit from the incremental volumes moving through our Lakehead system to reach this extension. The planned filing of the tariff application with the FERC in August 2007 was delayed to address administrative matters regarding the detailed tariff terms and related issues. Enbridge filed the petition for declaratory order with the FERC in October 2007, the approval of which will allow the project to proceed on schedule.

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 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. This project is expected to be in service during 2010. We expect to benefit from increased heavy crude oil shipments, which will be facilitated by the diluent line.

United States Gulf Coast Access

In June 2007, Enbridge and ExxonMobil Pipeline Company announced they are jointly assessing the possibility of building a crude oil pipeline from Patoka, Illinois to Beaumont, Texas and through to Houston. This pipeline project is in the initial stages, and Enbridge and ExxonMobil are continuing discussions with potential shippers regarding the scope, timing, and value of the project. Construction of this project would complement our Lakehead system and further support its expansion.

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 approximately 100,000 Bpd of heavy Canadian crude oil to the Eastern PADD II market by late 2010. Construction of this project would be complementary to our Lakehead system.

Other Matters

In September 2007, the Alberta Royalty Review Panel issued its recommendations to the government of the Province of Alberta. A majority of the recommendations of the report were subsequently adopted by the Alberta government. The adopted increases will become effective January 1, 2009. This could create economic hurdles for future oil sands development that may affect the level of future volumes we expect to flow through the Enbridge/Lakehead mainline 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 September 30,		Nine months ended September 30,	
	2007	**2006**	**2007**	**2006**
	(unaudited, in millions)			
Operating Results				
Operating revenues	$ 847.3	$ 686.6	$ 2,317.1	$ 2,231.1
Cost of natural gas	711.2	568.0	1,966.2	1,908.4
Operating and administrative	68.1	56.9	190.3	150.6
Depreciation and amortization	27.7	18.7	70.1	53.2
Operating expenses	807.0	643.6	2,226.6	2,112.2
Operating Income	$ 40.3	$ 43.0	$ 90.5	$ 118.9
Operating Statistics (MMBtu/d)				
East Texas	1,158,000	1,062,000	1,162,000	998,000
Anadarko	594,000	588,000	588,000	573,000
North Texas	360,000	302,000	344,000	288,000
UTOS	212,000	205,000	176,000	197,000
MidLa	110,000	144,000	117,000	119,000
AlaTenn	30,000	32,000	41,000	40,000
KPC	10,000	19,000	24,000	31,000
Bamagas	148,000	162,000	126,000	94,000
Other major intrastates[1]	205,000	225,000	241,000	221,000
Total	2,827,000	2,739,000	2,819,000	2,561,000

(1) We have included in Other major intrastates the volumes of our Gloria system for the three month periods ended September 30, 2007 and 2006, in the amounts of 62,000 MMBtu/d and 67,000 MMBtu/d and for the nine month periods ended September 30, 2007 and 2006 in the amounts of 64,000 MMBtu/d and 65,000 MMBtu/d, respectively.

Three months ended September 30, 2007 compared with three months ended September 30, 2006

Our Natural Gas segment contributed $40.3 million of operating income for the three months ended September 30, 2007, a slight decrease of $2.7 million from the $43.0 million contributed in the corresponding period of 2006. Our revenues increased over the same period last year primarily due to greater volumes gathered and processed in connection with the additional capacity from projects we completed earlier in 2007 and during the three month period ended September 30, 2007. Additionally, increased drilling activity in the areas served by our natural gas assets has also contributed to the volume growth we have experienced during the current quarter. Offsetting the contribution to operating income resulting from the favorable volume growth we have experienced are unrealized, non-cash mark-to-market net losses from our derivative activities totaling $7.7 million which are $9.5 million more than the $1.8 million of net gains we recorded in the same period of 2006. Our operating income was also negatively affected by additional workforce related costs and depreciation expense associated with the expansion of our natural gas systems.

Average daily volumes on our major natural gas systems increased approximately 3.2 percent in the third quarter of 2007, compared with the corresponding period in 2006. The increased volumes for 2007 continue to reflect our ongoing investments to further expand the capacity of our systems and services. We completed the following projects during 2006 and 2007 which have contributed to the increase in the average daily volumes and operating results on our major natural gas systems:

- Various segments of our East Texas Expansion and Extension project (Project Clarity) including the following:
  - ➢ A 24-inch diameter pipeline that runs from the Marquez treating facility to Crockett, Texas and the 36-inch diameter pipeline that runs from Crockett to Goodrich, Texas were both completed and placed into service in late March 2007;
  - ➢ 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 into service in March 2007;
  - ➢ A 20-inch diameter pipeline in close proximity to our Marquez treating facility was completed and placed into service in June 2007; and
  - ➢ A 36-inch diameter pipeline that extends from an interconnect with our existing pipeline at Bethel, Texas to Crockett was completed and placed into service in late July 2007;
- Expansion of our existing 275 MMcf/d Aker treating facility was completed in March 2007;
- Construction of our Hidetown processing facility on our Anadarko system with approximate capacity of 120 MMcf/d was completed and placed into service at the end of April 2007. We also completed construction and placed into service during the second quarter of 2007 the Hobart processing facility with an approximate capacity of 50 MMcf/d. Both plants were operating at expected levels throughout the third quarter of 2007;
- During the second quarter of 2007, we refurbished our Zybach processing plant to address the operational inefficiencies being experienced by the plant. As a result of the service and repairs, processing volumes have been restored to expected levels.
- Construction of our Henderson natural gas processing facility on our East Texas system was completed and operating at the end of the third quarter of 2006 with a capacity of 120 MMcf/d;
- A link between our North Texas and East Texas systems became fully operational during the third quarter of 2006, increasing the utilization of our 500 MMcf/d East Texas intrastate pipeline that we placed in service in June 2005; and
- Construction of our Weatherford II gas processing facility within our North Texas system was completed in September 2007 with a processing capacity of approximately 35 MMcf/d.

In addition to the investments we have made to expand the volumes in areas served by our natural gas assets, the volume and revenue growth is also the result of additional wellhead supply contracts and robust drilling activity in the Bossier Trend and Barnett Shale areas. We expect increasing volumes on our major natural gas systems to result from our continuing investments to expand the capacity of our systems to provide gathering, processing and transportation services to meet the needs of producers in the areas served by our natural gas assets.

Since August 2006, we have added approximately 325 MMcf/d of additional processing capacity to our Natural Gas systems, which has served to increase our processing revenues less the cost of natural gas purchased for processing, or processing margin. During the three months ended September 30, 2007, NGL prices remained high relative to natural gas prices, providing a favorable environment for the production of NGLs from our processing assets, comparable to the pricing environment during the same period of 2006. A variable element of our Natural Gas segment's operating income is derived from the processing of natural gas under keep-whole arrangements. Operating income derived from our keep-whole processing, increased to approximately $32.5 million for the three months ended September 30, 2007 from approximately $16 million for the same period in 2006.

A portion of our Natural Gas segment is exposed to risks from fluctuations in commodity prices associated with the percentage of proceeds, percentage of liquids, and percentage of index contracts that we negotiate with producers. Under the terms of these contracts, we retain a portion of the natural gas and NGLs we process in exchange for providing these producers with our services. In order to protect our unitholders from the volatility in cash flows that can result from fluctuations in commodity prices, 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. We target approximately 70 to 80 percent hedge coverage of our anticipated near-term exposure to commodity prices using derivative financial instruments. As a result of entering into these derivative financial instruments, we have largely fixed the amount of cash that we will pay for natural gas and receive in the future when we sell the processed natural gas and NGLs, although the market price of these commodities will continue to fluctuate during that time. Another significant portion of the revenue we receive is derived from fees charged for gathering and treating of natural gas volumes and other related services which are not directly dependent on commodity prices.

Operating income of our Natural Gas segment for the three months ended September 30, 2007 was negatively affected by unrealized non-cash, mark-to-market net losses of $7.7 million, which are $9.5 million more than the $1.8 million of gains we recorded for the same period of 2006, in connection with our derivative activities. These unrealized non-cash, mark-to-market net losses include $7.2 million of losses derived from our derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133 and $0.5 million of losses resulting from ineffectiveness of our cash flow hedges. The unrealized non-cash, mark-to-market net gains of $1.8 million for the three months ended September 30, 2006, include $3.2 million of gains derived from our derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133 and $1.4 million of losses resulting from ineffectiveness of our cash flow hedges. We expect the net mark-to-market gains and losses to be offset when the related physical transactions are settled (refer also to the discussions included in Note 10 of Item 1. Financial Statements and following under Derivative Activities, and Item 3. Quantitative and Qualitative Disclosures About Market Risk).

Operating and administrative costs of our Natural Gas segment were $11.2 million greater for the three months ended September 30, 2007 than the three months ended September 30, 2006, 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. Workforce related costs have increased due to the additional resources and related benefit costs we are charged for the operational, administrative, regulatory and compliance support necessary for our existing assets and the expansion of our natural gas operations. 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 continuous pipeline expansions across the areas we serve. We expect workforce related costs in addition to materials, supplies and other cost to continue increasing as we expand our systems.

Depreciation expense for our Natural Gas segment was $9.0 million higher in the third quarter of 2007 as compared to the third quarter of 2006, primarily as a result of capital projects completed and placed in-service during 2006 and 2007. We expect depreciation expense to increase during the remainder of 2007 as we complete our construction projects and place the assets into service.

Nine months ended September 30, 2007 compared with nine months ended September 30, 2006

Our Natural Gas segment produced $90.5 million of operating income for the nine months ended September 30, 2007, a decrease of $28.4 million from the $118.9 million of operating income generated in the corresponding period of 2006 due to non-cash mark-to-market losses and operational factors described below. Average daily volumes on our major natural gas systems increased 10 percent, or approximately 258,000 MMBtu/d, for the nine months ended September 30, 2007, compared with the corresponding period of 2006. These increases are largely due to the expansion of our Natural Gas business.

Our operating income benefited from additional processing margins derived from the processing plants we have added since the third quarter of 2006, partially offset by operational inefficiencies at our Zybach plant during the first quarter of 2007 that we corrected during the second quarter of 2007. Operating income derived from processing natural gas under keep-whole arrangements on our major systems increased to approximately $51.5 million for the nine months ended September 30, 2007, compared with approximately $43.4 million for the corresponding period in 2006, primarily due to the additional processing capacity we have added since the third quarter of 2006. Partially offsetting the favorable processing margins generated during the nine month period ended September 30, 2007, were operational issues associated with our Zybach processing plant that occurred during the first quarter of 2007 and reduced processing margins by approximately $10.5 million from the amounts we realized in the comparable period of 2006. We completed the necessary repairs and modifications during April 2007 and the plant has since been operating as expected throughout the third quarter of 2007.

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 taken steps to install 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 the first quarter of 2007. During the first nine months of 2007, we estimate that measurement losses resulted in approximately $15.4 million of additional cost to our natural gas systems relative to the first nine months of 2006.

Operating income of our Natural Gas segment for the nine months ended September 30, 2007 was negatively affected by unrealized non-cash, mark-to-market net losses of $13.4 million, which are $13.3 million greater than the $0.1 million of net losses we recorded for the same period of 2006, in connection with our derivative activities. These unrealized non-cash, mark-to-market net losses include $13.2 million of losses derived from our derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133 and $0.2 million of losses due to hedge ineffectiveness. The unrealized non-cash, mark-to-market net losses of $0.1 million for the nine months ended September 30, 2006, include $1.4 million of gains derived from our derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133 and $1.5 million of losses resulting from ineffectiveness of our cash flow hedges. The non-cash mark-to-market net losses in 2007 are primarily derived from losses from our derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133 partially offset by our gains from our hedge ineffectiveness as discussed above under our three-month analysis (refer also to the discussions included in Note 10 of Item 1. Financial Statements, below under Derivative Activities, and Item 3. Quantitative and Qualitative Disclosures About Market Risk).

Operating and administrative costs associated with our Natural Gas segment were $39.7 million greater for the nine months ended September 30, 2007, than for the corresponding period in 2006 for primarily the same reasons discussed above in our three-month analysis.

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 have a competitive advantage, we will continue to focus our efforts primarily on development of our existing pipeline 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 nine months of 2007, increased drilling in the areas where our gathering systems are located has contributed to the growth of volumes on our systems. We expect the growth trend in these areas to continue in the future as evidenced by external production forecasts and the strong rig counts and permitting in the areas served by our systems.

Producer drilling plans in regional plays, in the areas served by our natural gas assets, are expected to result in continued production growth. To accommodate this further growth, we initiated construction on several projects to increase our gathering, processing, transportation and treating infrastructure and market access capability and have completed a number of these projects as discussed above under our three month analysis. The remaining projects listed below continue to progress and include:

East Texas System Expansion and Extension (Project Clarity):

- The expansion and extension of our East Texas natural gas system, referred to as the Clarity project, includes construction of a 36-inch diameter intrastate pipeline from Bethel, Texas to Orange, Texas with capacity of approximately 700 MMcf/d. The new pipeline, which we expect to be completed during the first quarter of 2008, will provide service to a number of major industrial companies in Southeast Texas with interconnects to interstate pipelines, intrastate pipelines and wholesale customers. We continue to secure additional commitments for capacity on the pipeline. We have continued to experience cost pressures for labor, materials and rights-of-way, in addition to costs associated with construction delays due to inclement weather. Each of these factors has contributed to our expectation that the ultimate cost to complete construction of this project will approximate $635 million.
- We have completed several phases of the construction of our Clarity project as enumerated above. The remainder of our Clarity project is expected to be completed in stages throughout 2007 and early 2008. The remaining phases include construction of a 36-inch diameter intrastate pipeline that extends approximately 42 miles from Goodrich to Kountze, Texas, which was completed in late October 2007 and approximately 41 miles from Kountze to Orange, Texas which we expect to place in service during the first quarter of 2008.

Other East Texas Projects:

- The expansion of our sour gas treating capacity on the East Texas system will increase the total sulfur capacity from 72.5 tons per day (tpd) to 125 tpd by early 2008, in order to handle additional sour gas supply and higher concentration levels of hydrogen sulfide (H_2S).
- We are constructing three hydrocarbon dewpoint control facilities on our East Texas system to add processing capacity to meet the increasingly more stringent pipeline gas quality specification by late 2007. In October 2007, we completed and placed into service two of these facilities, which we refer to as Henderson II and the Grapeland hydrocarbon dewpoint control facilities. Each of these facilities has an approximate processing capacity of 200 MMcf/d. Construction of an additional processing facility will add approximately 200 MMcf/d of additional processing capacity and is progressing on schedule. We expect to place this facility in service by the end of 2007.

- We plan to construct a 25-mile, 20-inch diameter pipeline from a lateral on our East Texas system to gather additional production being developed in East Texas, which we expect will be transported on the Clarity system to markets in Southeast Texas.

North Texas System Projects:

In order to accommodate the active development and anticipated growth occurring in the Barnett Shale play in North Texas we commenced construction of two new gas processing plants totaling approximately 75 MMcf/d of capacity and related upstream facilities. During the third quarter 2007, we placed the 35 MMcf/d Weatherford II processing facility in service and expect to complete construction of the 40 MMcf/d Weatherford III facility in the fourth quarter of 2007.

Anadarko System Projects:

- We continue to increase our field compression in the Anadarko region which we expect will begin contributing to our operating results during the remainder of 2007.

When fully operational, we expect that the new assets we are constructing will provide additional sources of cash flow for us. We continue to evaluate other projects that could further integrate our major Texas-centered natural gas pipeline systems.

Other Matters

A number of new interstate natural gas transportation pipelines are being constructed that may alter the landscape for interstate transportation of natural gas. Although a majority of our Natural Gas segment revenues are derived from the gathering, processing and intrastate transportation of natural gas, these newly constructed pipelines could affect the operating results of our existing market-based interstate and intrastate natural gas pipelines. Conversely, our supply based gathering systems may benefit from enhanced capacity out of our gathering areas.

We recently initiated negotiations with a major customer of our Enbridge Pipelines (Midla), L.L.C., or Midla, mainline transmission system for the renewal of a contract that is set to expire in August 2008. The ultimate outcome of these negotiations is uncertain. The modest amount of operating income we derive from the Midla mainline transmission system could be reduced in the event Midla terminates the contract or renews it at lower rates than they currently charge. Further, such an outcome could reduce Midla's ability to recover the carrying value of its noncurrent assets, which approximate $35 million at September 30, 2007.

In October 2007, we entered into an agreement to sell our Kansas Pipeline system, which we refer to as KPC, for $133 million in cash to an unrelated third party. KPC is an interstate natural gas transmission system which serves the Wichita, Kansas and Kansas City, Kansas markets and includes approximately 1,120 miles of pipeline, ranging in diameter from 4 to 12 inches, along with three compressor stations. The final price is subject to an adjustment for working capital items at closing, which is scheduled to occur on November 1, 2007. The operating income for these assets was $3.6 million for the nine months ended September 30, 2007.

In December 2005, Calpine Corporation ("Calpine") and many of its subsidiaries, including the subsidiary that owns the two utility plants served by our Bamagas system, filed voluntarily petitions to restructure under Chapter 11 of the United States Bankruptcy Code. Calpine has continued to perform under the terms of its agreement with Bamagas. In June 2007, Calpine and certain of its subsidiaries filed a Joint Plan of Reorganization (the "Plan") and Disclosure Statement with the United States Bankruptcy Court. The Plan seeks to provide an equitable return to all stakeholders while providing for the long-term viability of Calpine. During September 2007 the United States Bankruptcy Court approved the Disclosure Statement filed and has authorized Calpine to solicit votes from its creditors and shareholders on its Plan.

Under the Plan as filed, general unsecured creditors are expected to receive from 95 percent to 100 percent of their allowed claims. A Confirmation Hearing date has been set to commence on December 18, 2007. Following the voting process, Calpine will ask the United States Bankruptcy Court to consider approval or "confirmation" of the Plan. Calpine currently looks to have the Plan confirmed prior to the end of January 2008. Calpine has continued to perform under the terms of its agreement with Bamagas. A hearing on Calpine's objections to our claims is scheduled to occur sometime during the remainder of 2007. We continue to monitor the Calpine bankruptcy proceedings and do not anticipate incurring any significant losses as a result of this event.

Marketing

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

	Three months ended September 30,		Nine months ended September 30,	
	2007	2006	2007	2006
	(unaudited; in millions)			
Operating revenues	$ 725.5	$ 718.5	$2,444.9	$2,239.8
Cost of natural gas	719.6	697.9	2,424.5	2,190.8
Operating and administrative	2.3	1.1	5.8	3.7
Depreciation and amortization	0.4	0.1	1.2	0.3
Expenses	722.3	699.1	2,431.5	2,194.8
Operating Income (loss)	$ 3.2	$ 19.4	$ 13.4	$ 45.0

Three months ended September 30, 2007 compared with three months ended September 30, 2006

Our Marketing business has benefited from the increased access to preferred natural gas markets associated with our natural gas system expansions and other initiatives. 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. A portion of the natural gas we purchase is produced in Texas markets where we previously had limited physical access to the primary interstate pipeline delivery points, or hubs such as the Houston Ship Channel. As a result of the completed segments of our natural gas system expansions and other initiatives, our Marketing business now has access to several interstate natural gas pipelines, which it can use to transport natural gas to primary markets where it can be sold. The improvement to the operating income of our Marketing business resulting from the increased access to primary markets for natural gas are obscured by the effects of unrealized, non-cash mark-to-market gains and losses resulting from our derivative activities and charges associated with reducing the cost of our natural gas inventory to market, both of which are discussed below.

In the three months ended September 30, 2007, operating income from our Marketing segment decreased $16.2 million to $3.2 million, from $19.4 million for the corresponding period in 2006, primarily as a result of the $19.0 million decrease in unrealized non-cash, mark-to-market gains from our derivative activities. Included in operating income for the three months ended September 30, 2007 are unrealized, non-cash, mark-to-market gains of approximately $2.9 million compared with unrealized, non-cash, mark-to-market gains of $21.9 million for the comparable period in 2006, resulting from our derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133. The unrealized, non-cash, mark-to-market gains for the three months ended September 30, 2007, are the result of modest declines in the forward and daily market prices of natural gas and NGLs from June 30, 2007. During the three months ended September 30, 2006, we experienced significant declines in the forward and daily market prices of natural gas as a result of an unstable pricing environment, which produced the large non-cash, mark-to-market gains we recorded. The unstable pricing environment that was prevalent during the three months ended September 30, 2006, was not present during the same period of 2007. We expect these net mark-to-market gains to be offset when the related physical transactions are settled (refer also to the discussion included in Note 10 of Item 1. Financial Statements, following under Derivative Activities and Item 3. Quantitative and Qualitative Disclosures About Market Risk).

Operating income for the three months ended September 30, 2007 was also negatively affected by non-cash charges of $3.0 million we recorded to reduce the cost basis of our natural gas inventory to fair market value at September 30, 2007, which is $3.6 million less than the $6.6 million non-cash charge we recorded for the same period of 2006. Natural gas prices as published by Platt's *Gas Daily* for Henry Hub were approximately $6.40 per MMBtu at September 30, 2007, a decline from $6.80 per MMBtu at June 30, 2007. As a result of this decline in the price of natural gas inventory at our storage locations from June 30, 2007 to September 30, 2007, the weighted average cost of our natural gas inventory at September 30, 2007 exceeded the market price of natural gas by approximately $3.0 million. By way of comparison, natural gas prices at September 30, 2006, had declined to $4.18 per MMBtu from $6.09 per MMBtu at June 30, 2006. Due to our hedging structures, we expect that a majority of these charges will be offset by future financial transactions that will settle at the time the natural gas inventory is sold.

Nine months ended September 30, 2007 compared with nine months ended September 30, 2006

Similar to the three month analysis, the improvement to the operating income of our Marketing business for the nine month period ended September 30, 2007 resulting from increased access to the primary markets for natural gas are clouded by the effects of unrealized, non-cash mark-to-market gains and losses resulting from our derivative activities and charges associated with reducing the cost of our natural gas inventory to market, both of which are discussed below.

In the first nine months of 2007, the operating income of our Marketing segment decreased $31.6 million to $13.4 million, from $45.0 million for the corresponding period in 2006, primarily as a result of the $57.2 million change in unrealized, non-cash, mark-to-market net gains and losses associated with our derivative activities. Included in operating income for the nine month period ended September 30, 2007 are unrealized, non-cash, mark-to-market net losses of approximately $4.0 million associated with derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133, as compared with unrealized mark-to-market net gains of $53.2 million for the comparable period in 2006. We expect these net mark-to-market losses to be offset when the related physical transactions are settled (refer also to the discussion included in Note 10 of Item 1. Financial Statements, following under Derivative Activities and Item 3. Quantitative and Qualitative Disclosures About Market Risk).

The operating results of our Marketing business for the first nine months of 2007 also include gains of approximately $12 million that we realized upon the sale of natural gas inventory, including approximately $5 million of gains from the settlement of derivative financial instruments hedging our natural gas inventory. Partially offsetting these gains for the nine months ended September 30, 2007, are non-cash charges of $4.5 million that we recorded to reduce the cost basis of our natural gas inventory to fair market value at September 30, 2007, which is $11.8 million less than the $16.3 million non-cash charge we recorded for the same period of 2006. The market price for natural gas in various storage locations may experience declines during the year from the prices at which the inventory was purchased. Due to our hedging structures, we expect that a majority of these charges will be offset by future financial transactions that will settle at the time the natural gas inventory is sold.

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. A portion of the natural gas we purchase is produced in Texas markets where we have limited physical access to the primary interstate pipeline delivery points, or hubs such as Waha, Texas and the Houston Ship Channel. As a result, our Marketing business must use third-party pipelines to transport the natural gas to these markets where it can be sold to our customers. However, physical pipeline constraints often require our Marketing business to transport natural gas to alternate market points. Under these circumstances, our Marketing segment will sell the purchased gas at a pricing index that is different from the pricing index at which the gas was purchased. This creates a price exposure that arises from the relative difference in natural gas prices between the contracted index at which the natural gas is purchased and the index under which it is sold, otherwise known as the "spread." The spread can vary significantly due to local supply and demand factors. Wherever possible, this pricing exposure is economically hedged using derivative financial instruments. However, the structure of these economic hedges often precludes our use of hedge accounting under the requirements of SFAS No. 133, which can create volatility in the operating results of our Marketing segment.

To ensure that we have access to primary pipeline delivery points, we often enter into firm transportation agreements on interstate and intrastate pipelines. To offset the demand charges associated with these firm transportation contracts, we look for market conditions that allow us to lock in the price differential or spread between the pipeline receipt point and pipeline delivery point. This allows our Marketing business to lock in a fixed sales margin inclusive of pipeline demand charges. We accomplish this by transacting basis swaps between the index where the natural gas is purchased and the index where the natural gas is sold. By transacting a basis swap between those two indices, we can effectively lock in a margin on the combined natural gas purchase and the natural gas sale, mitigating the demand charges on firm transportation agreements and limiting our exposure to cash flow volatility that could arise in markets where the firm transportation becomes uneconomic. However, the structure of these transactions precludes our use of hedge accounting under the requirements of SFAS No. 133, which can create volatility in the operating results of our Marketing segment.

In addition to natural gas basis swaps, we contract for storage to assist with balancing natural gas supply and end use market sales. In order to mitigate the absolute price differential between the cost of injected natural gas and withdrawn natural gas, as well as storage fees, the injection and withdrawal price differential, or "spread," is hedged by buying fixed price swaps for the forecasted injection periods and selling fixed price swaps for the forecasted withdrawal periods. When the injection and withdrawal spread increases or decreases in value as a result of market price movements, we can earn additional profit through the optimization of those hedges in both the forward and daily markets. Although these hedge strategies are sound economic hedging techniques, these types of financial transactions do not qualify for hedge accounting under the SFAS No. 133 guidelines. As such, the non-qualified hedges are accounted for on a mark-to-market basis, and the periodic change in their market value, although non-cash, will impact the income statement.

Corporate

Interest expense was $23.4 million for the three month period ended September 30, 2007, a decrease of $5.1 million from the $28.5 million of interest expense for the same period of 2006. The decrease in interest expense for the three month period ended September 30, 2007 as compared with the same period of 2006 is primarily due to $10.2 million of additional interest capitalized related to our construction projects, partially offset by an increase in the weighted average amount of debt we have outstanding at a higher weighted average rate of interest. Our weighted average interest rate was approximately 5.96% for the three month period ended September 30, 2007 compared with 5.86% for the same period of 2006.

Interest expense was $70.2 million for the nine month period ended September 30, 2007, a decrease of $13.8 million from the $84.0 million of interest expense for the same period of 2006. The decrease in interest expense for the nine month period ended September 30, 2007 as compared with the same period of 2006 is primarily due to $25.6 million of additional interest capitalized during the nine month period ended September 30, 2007, related to our construction projects, partially offset by an increase in the weighted average amount of debt we have outstanding at a higher weighted average rate of interest. Our weighted average rates of interest were approximately 5.93% for the nine month period ended September 30, 2007 compared with 5.86% for the same period of 2006.

We are not a taxable entity for United States federal income tax purposes or for the majority of states that impose an income tax. Our income tax expense of $1.3 million and $3.7 million for the three and nine month periods ended September 30, 2007 results from the enactment, by the State of Texas, of a new state tax computed on our 2007 modified gross margin. No comparable tax existed during 2006. We determined this tax to be an income tax under the provisions of SFAS No. 109, *Accounting for Income Taxes* (SFAS No. 109). We computed our income tax expense for the three and nine month periods ended September 30, 2007 by applying a 0.56% apportioned state income tax rate to taxable margin, as defined in State of Texas statutes. Our income tax expense represents an approximate 2% effective rate as applied to pretax book income for the three and nine month periods ended September 30, 2007.

In July 2007, the State of Michigan enacted substantial changes to its tax structure effective in 2008 by imposing a new tax system on our operations. The new system is comprised of two parts, a modified gross receipts tax at 0.8% and a 4.95% tax on income that will be levied on our Michigan operating activities. We determined that these taxes are income taxes under the provisions of SFAS No. 109. Our initial accounting for the enactment of this income tax did not materially affect our results of operation, financial condition, or cash flows for the three and nine month periods ended September 30, 2007.

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 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, debt service payments 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 our operating activities, borrowings under our commercial paper program or Credit Facility, and the issuance of additional debt and equity securities. Our ability to complete future offerings of our debt and equity securities 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. The internal growth projects we have planned for our Natural Gas business (see Natural Gas segment—Future Prospects), coupled with the Southern Access and Alberta Clipper projects on our Lakehead system (see Liquids segment—Future Prospects), will require significant expenditures of capital over the next several years. We expect to fund these expenditures from a combination of additional issuances of equity, in the form of limited partnership interests, and various forms of long-term debt. Our planned internal growth projects will require us to bear the cost of constructing these assets before we will begin to realize a return on them in the form of additional cash flows. During our construction of these major projects, our ability to increase distributions while funding these construction costs is likely to be limited.

Capital Resources

Equity Capital

Execution of our growth strategy and completion of our planned construction projects contemplate our accessing the public and private equity markets to obtain the capital necessary to fund these projects. During the first nine months of 2007, we generated $628.8 million of cash through equity issuances in both public and private transactions, including contributions of approximately $12.5 million from our general partner to maintain its two percent general partner interest. We used the proceeds from these offerings partially to reduce outstanding commercial paper we previously issued to finance a portion of our capital expansion projects, and invested the remaining amount in short-term commercial paper for use in future periods to fund additional expenditures under our capital expansion programs.

The following table provides additional information about these offerings:

Issuance Date	Class of Limited Partnership Interest	Number of Units Issued	Offering Price per Unit	Net Proceeds to the Partnership	General Partner Contribution	Net Proceeds Including General Partner Contribution
			(in millions, except per unit amounts)			
May 2007	Class A	5.300	$ 58.00	$ 301.9	$ 6.1	$ 308.0
April 2007	Class C	5.931	$ 53.11	314.4	6.4	320.8
Total		11.231		$ 616.3	$ 12.5	$ 628.8

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 lower than the rates available under our Credit Facility.

During the third quarter of 2007, the domestic credit markets were adversely affected by a sharp increase in the perceived credit risk associated with U.S. asset-backed securities. Due to the increase in perceived risks in the credit markets, and the need of large financial institutions to preserve capital, investors turned to investments in U.S. government securities, while selling off more risky credit securities. The magnitude of demand for U.S. government securities and the lack of demand for other domestic credit instruments caused the commercial paper market to freeze, temporarily limiting our ability to issue commercial paper. Our Credit Facility, which supports our commercial paper program, provided us with adequate liquidity to fund our growth projects until access to the commercial paper and other credit markets was restored in late September 2007.

Although the U.S. credit markets remain volatile, we were able to successfully raise approximately $593 million during the third quarter of 2007 with favorable terms from the issuance of $200 million of our senior, unsecured zero coupon notes due 2022 (the "Zero Coupon Notes") and $400 million of our fixed/floating rate, unsecured, long-term junior subordinated notes due 2067, as discussed below and more comprehensively in Note 7 to our Consolidated Financial Statements included in Item 1. Financial Statements to this report on Form 10-Q.

Credit Facility

On April 4, 2007 we entered into the Second Amended and Restated Credit Agreement (Credit Facility) which among other things: (i) increased the maximum principal amount of credit available at any one time to us from $1 billion to $1.25 billion; (ii) gave us the right to request increases in the maximum principal amount of credit available at any one time to us up to $1.5 billion; (iii) eliminated the sublimit on letters of credit; (iv) provided for a five-year facility that matures April 4, 2012 and grants us the option to request annual extensions of maturity and a one-year term out period upon maturity; (v) modified our leverage ratio to include in the calculations of EBITDA (as defined in the Second Amended and Restated Credit Agreement) pro forma adjustments for material projects and to exclude from the calculation of Consolidated Funded Debt (as defined in the Second Amended and Restated Credit Agreement) certain amounts of preferred securities and subordinated debt that we or our designated subsidiaries may issue in the future; and (vi) eliminated our coverage ratio financial covenant. Our Credit Facility continues to support our commercial paper program.

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 September 30, 2007, we had $120.0 million outstanding under our Credit Facility at a weighted average interest rate of 5.81% and letters of credit totaling $89.6 million. At September 30, 2007, we could borrow $840.4 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	(120.0)
Balance of letters of credit outstanding	(89.6)
Principal amount of commercial paper issuances	(200.0)
Total amount we could borrow at September 30, 2007	$ 840.4

Commercial Paper

Under the terms of our commercial paper program, we may issue up to $600 million of commercial paper. At September 30, 2007, we had outstanding $198.5 million of commercial paper, net of unamortized discount of $1.5 million, bearing interest at a weighted average rate of 5.72%. At December 31, 2006, we had $443.7 million of commercial paper outstanding, net of $1.3 million of unamortized discount, at a weighted average interest rate of 5.45%. At September 30, 2007, we could issue an additional $400.0 million in principal amount under our commercial paper program.

Junior Subordinated Notes

On September 27, 2007, we issued and sold $400 million in principal amount of our fixed/floating rate, unsecured, long-term junior subordinated notes due 2067, which we refer to as the Junior Notes. We received net proceeds of approximately $393.0 million, after payment of underwriting discounts, commissions and estimated offering expenses, which we used to temporarily reduce a portion of our outstanding commercial paper and Credit Facility borrowings that we incurred to finance a portion of our capital expansion projects. The Junior Notes are subordinate in right of payment to all of our existing and future senior indebtedness, as defined in the related indenture.

Zero Coupon Senior Notes

In August 2007, we received net proceeds of $200 million from a private placement of our senior, unsecured zero coupon notes due 2022, which at maturity will be payable in the aggregate principal amount of $442 million. We initially recorded the Zero Coupon Notes in long-term debt at the amount of proceeds we received from the private placement, which we refer to as the issue price. The carrying amount at September 30, 2007 includes $0.9 million associated with the accretion of interest we recognized as interest expense during the period. The Zero Coupon Notes are scheduled to mature on August 28, 2022, although they may be called by the note holders prior to the scheduled maturity date on August 28 of any year commencing on August 28, 2009, at a price equal to the then accreted value of the called notes. The Zero Coupon Notes have a yield of 5.36% on a semi-annual compound basis and rank equally in right of payment to all of our existing and future senior indebtedness, as set forth in our senior indenture. We used the net proceeds from this private placement to repay a portion of our outstanding commercial paper and credit facility borrowings that we had previously incurred to fund a portion of our capital expansion programs.

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 2007, we expect to spend approximately $2.2 billion on these and other projects with the expectation of realizing additional cash flows as projects are completed and placed in service. As of September 30, 2007, we have approximately $391 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 2007. 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, 2007. 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 $1,428.4 million, including $40.3 million on core maintenance activities, during the nine months ended September 30, 2007.

For the full year of 2007, we anticipate our capital expenditures to approximate the following in millions:

System enhancements	$ 700
Core maintenance activities	60
Southern Access expansion	1,150
Alberta Clipper	15
East Texas expansion	275
	$2,200

Major Construction Projects

The following table includes our active major construction projects and additional information regarding our estimated construction cost, actual expenditures through September 30, 2007, the incremental capacity that will become available upon completion of the project and the periods during which we expect to complete the construction. From project inception, through the first nine months of

2007, we have incurred approximately $2.0 billion of capital expenditures associated with the projects listed below. The estimated 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 Inception through September 30, 2007	Storage	Oil	Natural Gas	Expected Completion
	(in billions)		(KBbl)	(Kbpd)	(MMcf/d)	
Southern Access expansion (Lakehead)	$ 2.1	$ 0.83	—	400	—	2009
Clarity (East Texas)	0.6	0.56	—	—	700	In phases to early 2008
Alberta Clipper[(1)]	1.0	—	—	450	—	Mid-2010
North Dakota system expansion	0.1	0.05	—	30	—	Late 2007
Cushing terminal storage tanks	0.1	0.07	4,970	—	—	Throughout 2007
Griffith and Superior storage tanks	0.1	0.03	1,220	—	—	Mid-2007 and Mid-2008
Natural gas connects and compression	0.1	0.15	—	—	—	Various
Processing and treating plant expansions	0.3	0.27	—	—	1,130	Various
Total	$ 4.4	$ 1.96	6,190	880	1,830	

(1) Estimated total cost in 2007 dollars, excluding capitalized interest

Including major expansion projects and excluding acquisitions, ongoing capital expenditures are expected to be significant over the next three years due to our East Texas expansion and extension, Southern Access expansion and Alberta Clipper projects. Core maintenance capital is also anticipated to increase over that period of time due to growth in 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 derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to mitigate the volatility of our cash flows and manage the risks associated with market fluctuations in commodity prices. Based on our risk management policies, all of our derivative financial 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 financial instruments at September 30, 2007 for each of the indicated calendar years:

	Notional	2007	2008	2009	2010	2011	2012
			($ in millions)				
Swaps							
Natural gas[1]	254,512,717	$ (6.6)	$ (35.6)	$ (34.4)	$ (28.7)	$ (25.5)	$ (5.0)
NGL[2]	10,406,806	(20.2)	(34.0)	(16.3)	(6.2)	(2.0)	—
Crude[2]	1,092,835	(3.6)	(10.2)	(3.5)	(1.7)	(1.1)	—
Options—calls							
Natural gas[1]	1,553,000	(0.2)	(1.3)	(1.3)	(1.2)	(1.1)	—
Options—puts							
Natural gas[1]	1,798,000	0.2	—	—	—	—	—
NGL[2]	818,108	—	0.6	1.4	—	—	—
Totals		$ (30.4)	$ (80.5)	$ (54.1)	$ (37.8)	$ (29.7)	$ (5.0)

(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 nine months ended September 30, 2007 was $417.9 million, an increase of $188.0 million from the $229.9 million generated during the same period in 2006. The improved operating cash flow is primarily attributable to sales of inventory in the first nine months of 2007 that we did not make in the first nine months of 2006; increases in non-cash adjustments to net income, primarily related to changes in the fair value of our derivative financial instruments and additional depreciation expense; and other changes in working capital accounts related to the general timing differences in the collection on and payment of our current and related party accounts.

Investing Activities

Net cash used in our investing activities during the nine months ended September 30, 2007 was approximately $1.4 billion, an increase of $844.2 million from the $529.8 million used during the same period of 2006. The increase is primarily attributable to the $914.1 million increase in our investments in property, plant and equipment during the nine months ended September 30, 2007, over the amount spent during the same period of 2006. The increase in our capital expenditures during the first nine months of 2007 is directly attributable to our previously described expansion projects.

Financing Activities

Net cash provided by financing activities during the nine months ended September 30, 2007 was $920.9 million, an increase of $457.2 million from the $463.7 million generated during the same period in 2006. We increased the level of our financing activities during 2007 to obtain permanent capital for financing our expansion projects. The permanent financing we completed during the nine months ended September 30, 2007 includes the following:

- We issued and sold in September 2007, $400.0 million of our Junior Notes for net proceeds of $393.0 million, which we used to partially reduce issuances of commercial paper and borrowings under our Credit Facility;

- We issued and sold in August 2007, $200.0 million in principal amount of our Zero Coupon Notes for net proceeds of $199.8 million, which we used to partially reduce issuances of commercial paper and borrowings under our credit facility.
- In May 2007, we issued and sold 5.3 million of our Class A common units for net proceeds of $308.0 million including a $6.1 million contribution from our general partner to maintain its 2 percent general partner interest.
- In April 2007, we issued and sold approximately 5.9 million of our Class C units in a private placement for net proceeds of approximately $320.8 million, including a $6.4 million contribution from our general partner to maintain its 2 percent general partner interest.

Also contributing to the increase in our financing activities for the nine months ended September 30, 2007 are net Credit facility borrowings of $120.0 million, which include gross borrowings of $340.0 million and gross repayments of $220.0 million. We also had net repayments of commercial paper of $241.2 million, which include gross issuances of $3,611.5 million and gross repayments of $3,852.7 million.

During the nine months ended September 30, 2007, cash distributions to our partners increased to $179.5 million from $169.8 million in the same period of 2006 due to:

- An increase in the number of units outstanding; and
- An increase in the general partner incentive distributions, as a result of the increased distributions to our limited partners.

OFF-BALANCE SHEET ARRANGEMENTS

We have no significant off-balance sheet arrangements.

SUBSEQUENT EVENTS

Distribution to Partners

On October 29, 2007, the Board of Directors of Enbridge Management declared a distribution payable to our partners on November 14, 2007. The distribution will be paid to unitholders of record as of November 6, 2007, of our available cash of $96.0 million at September 30, 2007, or $0.950 per common unit. Of this distribution, $65.9 million will be paid in cash, $12.7 million will be distributed in i-units to our i-unitholder, $16.8 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.

Sale of Assets

In October 2007, we entered into an agreement to sell our interstate natural gas transmission system, which we refer to as KPC (the Kansas Pipeline System), for $133 million in cash to an unrelated third party. The KPC natural gas system serves the Wichita, Kansas and Kansas City, Kansas markets and includes approximately 1,120 miles of pipeline, ranging in diameter from 4 to 12 inches, along with 3 compressor stations. The final price is subject to an adjustment for working capital items at closing, which is scheduled to occur on November 1, 2007.

REGULATORY MATTERS

FERC Transportation Tariffs-Liquids

Effective July 1, 2007, we increased our rates for transportation on our Lakehead, North Dakota and Ozark systems in compliance with the indexed rate ceilings allowed by the FERC. In March 2006, The FERC determined that the Producer Price Index For Finished Goods plus 1.3 percent (PPI + 1.3 percent) should be the oil pricing index for a five year period ending July 2011. The index is used to establish rate ceiling levels for oil pipeline rate changes. For our Lakehead system, indexing only applies to the base rates, not the SEP II, Terrace and Facilities surcharges. Effective July 2007, we increased the transportation rates on our Lakehead system by an average of 4.5 percent. Our Lakehead system base tariff rates are slightly below the indexed ceiling level allowed under the FERC's indexing methodology. On our Lakehead system, the new rate for heavy crude movements from the International Border near Neche, North Dakota to Chicago, Illinois is $0.958 per barrel, which reflects a $0.032 per barrel increase over the rates filed effective April 1, 2007. In addition to the rates on our Lakehead system, we increased the transportation rates on our North Dakota and Ozark systems by an average of 4.3 percent. The tariff rates for our North Dakota and Ozark systems are at the ceiling levels allowed under the FERC methodology.

Effective April 1, 2007, we filed our annual tariff with the FERC for 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. These surcharges compensate Lakehead for expansions of the system completed in prior years. This filing increased the tariff for heavy crude oil movements from the Canadian border to Chicago by approximately $0.007 per barrel, to approximately $0.926 per barrel.

RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Liabilities.* This statement provides companies with an option to report certain financial assets and financial liabilities at fair value. The objective of SFAS No. 159 is to reduce the volatility in earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. SFAS No. 159 also establishes presentation and disclosure requirements designed to facilitate comparisons between companies that choose different measurement attributes for similar types of assets and liabilities. The provisions of SFAS No. 159 are effective at the beginning of our first fiscal year that begins after November 15, 2007, as we have elected not to early adopt the provisions of SFAS No. 159. We do not expect our adoption of SFAS No. 159 to have a material effect on our Consolidated Financial Statements.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

The following should be read in conjunction with the information presented in our Annual Report on Form 10-K for the year ended December 31, 2006, in addition to information presented in Items 1 and 2 of this Quarterly Report on Form 10-Q. There have been no material changes to that information other than as presented below.

Our net income and cash flows are subject to volatility stemming from changes in 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. To mitigate the volatility of our cash flows, we use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the risks associated with market fluctuations in commodity prices. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability or forecasted transaction and are not entered into with the objective of speculating on commodity prices.

The following tables provide information about our derivative financial instruments at September 30, 2007 and December 31, 2006, with respect to our commodity price risk management activities for natural gas and NGLs, including condensate:

	At September 30, 2007						At December 31, 2006	
			Wtd Avg Price[(2)]		Fair Value[(3)]		Fair Value[(3)]	
	Commodity	Notional[(1)]	Receive	Pay	Asset	Liability	Asset	Liability
Contracts maturing in 2007								
Swaps								
Receive variable/pay fixed	Natural gas	13,795,370	$ 6.38	$ 7.30	$ 1.3	$ (13.9)	$ 8.1	$ (86.7)
	NGL	25,116	54.39	43.22	0.3	—	—	(0.5)
Receive fixed/pay variable	Natural gas	15,519,380	6.97	6.65	13.0	(8.2)	79.8	(33.0)
	NGL	1,096,732	37.78	56.51	—	(20.5)	14.4	(23.2)
	Crude oil	94,944	41.29	79.46	—	(3.6)	—	(8.6)
Receive variable/pay variable	Natural gas	31,997,981	6.36	6.32	2.6	(1.4)	3.1	(3.7)
Options								
Calls (written)	Natural gas	92,000	4.31	6.99	—	(0.2)	—	(1.0)
Puts	Natural gas	337,000	6.15	6.75	0.2	—	1.0	—
Contracts maturing in 2008								
Swaps								
Receive variable/pay fixed	Natural gas	36,624,424	7.11	7.15	9.2	(10.7)	9.5	(5.1)
Receive fixed/pay variable	Natural gas	32,560,720	6.37	7.49	6.1	(42.7)	3.6	(44.1)
	NGL	5,776,578	40.74	46.61	—	(34.0)	2.5	(7.7)
	Crude oil	337,241	43.45	73.57	—	(10.2)	—	(7.0)
Receive variable/pay variable	Natural gas	42,094,761	7.40	7.35	3.4	(0.9)	2.5	(0.4)
Options								
Calls (written)	Natural gas	366,000	4.31	7.95	—	(1.3)	—	(1.3)
Puts	Natural gas	366,000	3.40	7.95	—	—	—	—
Puts	NGL	453,108	44.50	52.80	0.6	—	—	—
Contracts maturing in 2009								
Swaps								
Receive variable/pay fixed	Natural gas	8,861,709	7.08	6.94	3.7	(2.4)	2.9	(2.1)
Receive fixed/pay variable	Natural gas	14,966,095	5.12	7.55	1.5	(37.9)	0.7	(31.5)
	NGL	2,475,065	38.67	45.27	—	(16.3)	1.4	(1.4)
	Crude oil	264,625	54.35	67.65	—	(3.5)	—	(1.9)
Receive variable/pay variable	Natural gas	25,966,532	7.64	7.62	1.6	(0.9)	1.4	(0.6)
Options								
Calls (written)	Natural gas	365,000	4.31	8.27	—	(1.3)	—	(1.2)
Puts	Natural gas	365,000	3.40	8.27	—	—	—	—
Puts	NGL	365,000	42.09	48.20	1.4	—	—	—

			At September 30, 2007				At December 31, 2006	
			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	2,235,245	6.81	5.38	3.2	—	2.5	(0.3)
Receive fixed/pay variable	Natural gas	9,670,000	3.69	7.06	—	(32.6)	0.2	(26.1)
	NGL	784,750	29.78	37.67	—	(6.2)	—	(1.5)
	Crude oil	213,525	55.29	63.28	—	(1.7)	—	(0.6)
Receive variable/pay variable	Natural gas	9,900,000	7.73	7.66	0.9	(0.2)	0.8	(0.1)
Options								
Calls (written)	Natural gas	365,000	4.31	8.09	—	(1.2)	—	(1.0)
Puts	Natural gas	365,000	3.40	8.09	—	—	—	—
Contracts maturing in 2011								
Swaps								
Receive variable/pay fixed	Natural gas	730,000	6.58	3.57	2.6	—	2.0	—
Receive fixed/pay variable	Natural gas	7,952,500	3.63	6.58	—	(28.1)	—	(21.5)
	NGL	248,565	26.81	34.74	—	(2.0)	—	(0.6)
	Crude oil	182,500	53.66	59.61	—	(1.1)	—	(0.2)
Options								
Calls (written)	Natural gas	365,000	4.31	7.84	—	(1.1)	—	(0.9)
Puts	Natural gas	365,000	3.40	7.84	—	—	—	—
Contracts maturing after 2011								
Swaps								
Receive variable/pay fixed	Natural gas	182,000	6.78	3.57	0.7	—	0.6	—
Receive fixed/pay variable	Natural gas	1,456,000	3.57	6.78	—	(5.7)	—	(4.5)

(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 September 30, 2007 and December 31, 2006, 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.

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 September 30, 2007. 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 September 30, 2007.

PART II—OTHER INFORMATION

Item 1. Legal Proceedings

Refer to Part I, Item 1. Financial statements, Note 9, which is incorporated herein by reference.

Item 1A. Risk Factors

The risk factors presented below update and should be considered in addition to the risk factors previously disclosed in our Annual Report on Form 10-K for the fiscal year ended December 31, 2006.

RISKS RELATED TO OUR BUSINESS

Our financial performance could be adversely affected if our pipeline systems are used less.

Our financial performance depends to a large extent on the volumes transported on our pipeline systems. Decreases in the volumes transported by our systems, whether caused by supply or demand factors in the markets these systems serve, competition or otherwise, can directly and adversely affect our revenues and results of operations.

The volume of shipments on our Lakehead system depends heavily on the supplies of western Canadian crude oil. Insufficient supplies of western Canadian crude oil will adversely affect our business by limiting shipments on our Lakehead system. Decreases in conventional crude oil exploration and production activities in western Canada and other factors including supply disruption and competition can reduce the utilization of our Lakehead system. For example, in January 2005, deliveries on our Lakehead system were impacted by a fire at a Suncor facility. The volume of crude oil that we transport on the Lakehead system also depends on the demand for crude oil in the Great Lakes and Midwest regions of the United States and the delivery by others of crude oil and refined products into these regions and the Province of Ontario. Pipeline capacity for the delivery of crude oil to the Great Lakes and Midwest regions of the United States currently exceeds refining capacity.

In addition, our ability to increase deliveries to expand the Lakehead system in the future depends on increased supplies of western Canadian crude oil. We expect that growth in future supplies of western Canadian crude oil will come from oil sands projects in Alberta, Canada. Furthermore, full utilization of additional capacity as a result of our current and future expansions of the Lakehead system, including the Terrace expansion program, will largely depend on these anticipated increases in crude oil production from oil sands projects. The government of the Province of Alberta has adopted measures to increase its share of revenues from oil sands development. These measures could cause oil sands producers to cancel or delay plans to expand their facilities, which, in turn, would reduce the volume growth we have anticipated in executing our construction projects to increase the capacity of our crude oil pipelines.

RISKS RELATED TO OUR DEBT AND OUR ABILITY TO DISTRIBUTE CASH

Agreements relating to our debt restrict our ability to make distributions, which could adversely affect the value of our Class A common units, and our ability to incur additional debt and otherwise maintain financial and operating flexibility.

Our primary operating subsidiary is prohibited by its First Mortgage Notes from making distributions to us, and we are prohibited from making distributions to our unitholders, if (1) a default exists under the respective governing agreements of our Credit Facility, or (2) during a period in which we have elected to defer interest payments on the Junior Notes, subject to limited exceptions as set forth in the related indenture, as supplemented. In addition, the agreements governing our Credit Facility and our subsidiary's First Mortgage Notes may prevent us from engaging in transactions or capitalizing on business opportunities that we believe could be beneficial to us by requiring us to comply with various covenants, including the maintenance of certain financial ratios and restrictions on:

- incurring additional debt;
- entering into mergers or consolidations or sales of assets; and
- granting liens.

Although the indentures governing our senior notes do not limit our ability to incur additional debt, they impose restrictions on our ability to enter into mergers or consolidations and sales of assets and to incur liens to secure debt. A breach of any restriction under our Credit Facility or our indentures or our subsidiary's First Mortgage Notes could permit the holders of the related debt to declare all amounts outstanding under those agreements immediately due and payable and, in the case of the Credit Facility, terminate all commitments to extend further credit. Any subsequent refinancing of our current debt or any new indebtedness incurred by us or our subsidiaries could have similar or greater restrictions.

Item 6. Exhibits

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

SIGNATURES

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

ENBRIDGE ENERGY PARTNERS, L.P.
(Registrant)

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

Date: October 30, 2007

By: /s/ STEPHEN J.J. LETWIN

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

Date: October 30, 2007

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).
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 August 15, 2006, between Enbridge Energy Partners, L.P. and CDP Infrastructures Fund G.P. (incorporated by reference to Exhibit 4.1 of the Partnership's Current Report on Form 8-K dated August 16, 2006).
4.3	Indenture dated September 15, 1998, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank (incorporated by reference to Exhibit 4.1 of the Lakehead Pipe Line Company, Limited Partnership's Current Report on Form 8-K dated October 20, 1998).
4.4	First Supplemental Indenture dated September 15, 1998, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank (incorporated by reference to Exhibit 4.2 of the Lakehead Pipe Line Company, Limited Partnership's Current Report on Form 8-K dated October 20, 1998).
4.5	Second Supplemental Indenture dated September 15, 1998, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank (incorporated by reference to Exhibit 4.3 of the Lakehead Pipe Line Company, Limited Partnership's Current Report on Form 8-K dated October 20, 1998).
4.6	Third Supplemental Indenture dated November 21, 2000, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank (incorporated by reference to Exhibit 4.2 of the Lakehead Pipe Line Company, Limited Partnership's Current Report on Form 8-K dated November 16, 2000).
4.7	Indenture dated September 15, 1998, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank (incorporated by reference to Exhibit 4.4 of the Lakehead Pipe Line Company, Limited Partnership's Current Report on Form 8-K dated October 20, 1998).
4.8	Indenture dated May 27, 2003, between the Partnership, as Issuer, and SunTrust Bank, as Trustee (incorporated by reference to Exhibit 4.5 of the Partnership's Registration Statement on Form S-4 filed on June 30, 2003).
4.9	First Supplemental Indenture dated May 27, 2003 between the Partnership and SunTrust Bank (incorporated by reference to Exhibit 4.5 of the Partnership's Registration Statement on Form S-4 filed on June 30, 2003).
4.10	Second Supplemental Indenture dated May 27, 2003 between the Partnership and SunTrust Bank (incorporated by reference to Exhibit 4.5 of the Partnership's Registration Statement on Form S-4 filed on June 30, 2003).

4.11	Third Supplemental Indenture dated January 9, 2004 between the Partnership and SunTrust Bank (incorporated by reference to Exhibit 99.3 of the Partnership's Current Report on Form 8-K filed on January 9, 2004).
4.12	Fourth Supplemental Indenture dated December 3, 2004 between the Partnership and SunTrust Bank (incorporated by reference to Exhibit 4.2 of the Partnership's Current Report on Form 8-K filed on December 3, 2004).
4.13	Fifth Supplemental Indenture dated December 3, 2004 between the Partnership and SunTrust Bank (incorporated by reference to Exhibit 4.3 of the Partnership's Current Report on Form 8-K filed on December 3, 2004).
4.14	Sixth Supplemental Indenture dated December 21, 2006 between the Partnership and U.S. Bank National Association, successor to SunTrust Bank, as trustee (incorporated by reference to Exhibit 4.2 of the Partnership's Current Report on Form 8-K filed on December 21, 2006).
4.15	Registration Rights Agreement, dated April 2, 2007 by and among Enbridge Energy Partners, L.P. Tortoise Energy Infrastructure Corporation, Tortoise Energy Capital Corporation and CDP Infrastructures Fund G.P. (incorporated by reference to Exhibit 4.1 of the Partnership's Current Report on Form 8-K dated April 2, 2007).
4.16	Indenture for Subordinated Debt Securities dated September 27, 2007 between Enbridge Energy Partners, L.P. and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.1of the Partnership's Current Report on Form 8-K dated September 28, 2007).
4.17	First Supplemental Indenture to the Indenture dated as of September 27, 2007 between Enbridge Energy Partners, L.P. and U.S. Bank National Association, as Trustee (including form of Note) (incorporated by reference to Exhibit 4.2 of the Partnership's Current Report on Form 8-K dated September 28, 2007).
10.1	Replacement Capital Covenant dated as of September 27, 2007 by Enbridge Energy Partners, L.P. in favor of the debtholders designated therein (incorporated by reference to Exhibit 10.1 of the Partnership's Current Report on Form 8-K dated September 28, 2007).
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.