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EPCOR Power L.P. reports third quarter results

Edmonton, Alberta – October 31, 2007 (TSX: EP.UN) - EPCOR Power Services Ltd., the general partner of EPCOR Power L.P. ("the Partnership"), today released the Partnership's quarterly results for the period ended September 30, 2007.

"Third quarter results showed a continuation of steady operating performance," said Brian Vaasjo, President, EPCOR Power Services Ltd. "Revenues in the third quarter of $153 million were more than double compared to the same period in the prior year bolstered by strong contributions from the Primary Energy Ventures acquisition. The facilities generated a record quarterly plant output of 1,630 gigawatt hours while maintaining high plant availability of 97 per cent. The net loss of $15.9 million in the third quarter is driven primarily by the $44.4 million accounting recognition of unrealized losses primarily on the change in fair value of natural gas supply contacts and the $13.0 million write down of a management contract asset due to lower-than-expected future incentive payments from Primary Energy Recycling Holdings LLC."

The Partnership reported cash provided by operating activities of $20.8 million or $0.39 per unit for the three months ended September 30, 2007 compared with $29.6 million or $0.60 per unit for the same period in 2006. (1) The decrease reflects a $13.3 million increase in working capital requirements, in part due to the seasonal nature of Primary Energy Ventures LLC ("PEV") operations acquired in the fourth quarter last year, and realized losses of $8.1 million on interest rate contracts which settled in the quarter. These contracts were used to hedge changes in interest rates on the PEV bridge acquisition facilities that were replaced by a US private placement in August. The losses were primarily driven by the declining US treasury rates in the third quarter which created a loss on the interest rate contracts but consistent with the nature of a hedge, allowed for a reduced fixed term rate on the new long-term debt financing. As a result, the net realized losses will be offset by lower financing charges in future periods.

Highlights of EPCOR Power L.P.'s operational and financial performance included:

Operational and Financial Highlights *(unaudited)*	**Three months ended September 30**		**Nine months ended September 30**	
(millions of dollars except per unit and operational amounts)	**2007**	2006	**2007**	2006
Power generated (GWh)	**1,630**	874	**4,080**	2,275
Weighted average plant availability	**97%**	97%	**93%**	95%
Revenue	**153.4**	72.6	**461.6**	244.9
Net income(loss)	**(15.9)**	10.8	**(14.5)**	75.0
Per unit	**$(0.29)**	$0.22	**$(0.28)**	$1.56
Comprehensive loss	**(16.7)**	-	**(17.1)**	-
Cash provided by operating activities	**20.8**	29.6	**89.3**	117.0
Per unit (1)	**$0.39**	$0.60	**$1.73**	$2.43
Cash distributions	**33.9**	31.4	**99.3**	92.7
Per unit	**$0.63**	$0.63	**$1.89**	$1.89
Capital expenditures	**2.6**	2.2	**7.9**	4.2
Weighted average units outstanding (millions)	**53.9**	49.1	**51.7**	48.0

(1) Cash provided by operating activities per unit is a non-GAAP financial measure that is defined in the interim MD&A.

The September 30, 2007 interim report is shown below. The interim management discussion and analysis and interim consolidated financial statements are available on the EPCOR Power L.P. website (www.epcorpowerlp.ca) and will be available on SEDAR (www.sedar.com).

EPCOR Power L.P.

Management's Discussion and Analysis

For the Three and Nine Months Ended September 30, 2007

This management's discussion and analysis ("MD&A"), dated October 31, 2007 should be read in conjunction with the unaudited interim consolidated financial statements of EPCOR Power L.P. ("the Partnership") for the three and nine months ended September 30, 2007 and the audited consolidated financial statements and MD&A of EPCOR Power L.P. for the year ended December 31, 2006. Additional information, relating to EPCOR Power L.P., including the Partnership's 2006 Annual Information Form ("AIF") and continuous disclosure documents are available on SEDAR at www.sedar.com.

EPCOR Power Services Ltd., the General Partner of the Partnership, is an indirect wholly-owned subsidiary of EPCOR Utilities Inc. (collectively with its wholly-owned subsidiaries "EPCOR") and has responsibility for management of the Partnership. The General Partner has engaged certain other EPCOR subsidiaries (collectively, the "Manager") to perform management and administrative services on behalf of the Partnership and to operate and maintain the power plants pursuant to management and operations agreements. The Audit Committee of the Board of Directors of the General Partner is to review and approve the interim MD&A of the Partnership in accordance with the Audit Committee's terms of reference. The Audit Committee has reviewed and approved the contents of this interim MD&A.

Forward-looking statements

Certain information in this MD&A is forward-looking and related to anticipated financial performance, events and strategies. When used in this context, words such as "will", "anticipate", "believe", "plan", "intend", "target" and "expect" or similar words suggest future outcomes. By their nature, such statements are subject to significant risks, assumptions and uncertainties, which could cause the Partnership's actual results and experience to be materially different than the anticipated results. Such risks, assumptions and uncertainties include, but are not limited to, the ability of the Partnership to successfully integrate and realize the financial benefits of its acquisitions, the ability of the Partnership to implement its strategic initiatives and whether such strategic initiatives will yield the expected benefits, the availability and price of energy commodities, plant availability, waste heat availability and water flows, regulatory and government decisions, the renewal and terms of power purchase contracts, competitive factors in the power industry, the current and future economic conditions in North America and the performance of contractors and suppliers.

Readers are cautioned not to place undue reliance on forward-looking statements as actual results could differ materially from the plans, expectations, estimates or intentions expressed in the forward-looking statements. Except as required by law, the Partnership disclaims any intention and assumes no obligation to update any forward-looking statement even if new information becomes available, as a result of future events or for any other reason.

CONSOLIDATED RESULTS OF OPERATIONS

(millions of dollars)(unaudited)	**Three months**	**Nine months**
Cash provided by operating activities for the three and nine months ended September 30, 2006	**29.6**	**117.0**
Contribution of the acquired PEV facilities excluding interest paid and foreign exchange contract losses	17.4	30.8
Increase in generation and revenue at Manchief	1.4	1.7
Contribution of Fredrickson excluding interest paid	1.3	9.1
Mamquam and Queen Charlotte award	-	2.3
Changes in operating working capital	(13.3)	(18.4)
Net realized losses upon the settlement of foreign exchange and interest rate contracts	(8.1)	(17.9)
Decrease in cash flow from Curtis Palmer	(3.8)	(6.9)
Higher financial charges due to acquisitions in 2006	(3.2)	(17.6)
Preferred share dividends	(1.6)	(2.2)
One-time OEFC settlement, net of natural gas contract accruals, in 2006	-	(6.2)
Mamquam maintenance outage	-	(2.4)
Other	1.1	-
Cash provided by operating activities for the three and nine months ended September 30, 2007	**20.8**	**89.3**

The Partnership reported cash provided by operating activities of $20.8 million or $0.39 per unit for the three months ended September 30, 2007 compared with $29.6 million or $0.60 per unit for the same period in 2006. Cash provided by operating activities per unit is defined below under non-GAAP measures. The $8.8 million decrease in cash provided by operating activities compared to the third quarter of 2006 is primarily due to the following:

- A $12.7 million increase in working capital requirements in the third quarter of 2007 compared to a $0.6 million decrease in 2006 in part due to the seasonal nature of the Primary Energy Ventures ("PEV") operations acquired in the fourth quarter of 2006 and the payment of accrued amounts to Devon in respect of a gas contract settlement arrangement;
- Net realized losses of $8.1 million on the interest rate contracts that were entered in anticipation of permanent financing of the PEV bridge acquisition facilities. These contracts settled in the third quarter of 2007 and were used to hedge changes in interest rates on the portion of the credit facilities and bridge facilities that were replaced by long-term fixed rate debt. Declining long-term US treasury rates in the third quarter resulted in a loss on the interest rate contracts but also reduced the fixed term rate that was entered into on the US private placement in August 2007, consistent with the nature of a hedge. As a result, the net realized losses will be offset by lower financing charges in future periods;
- Lower volume at the Curtis Palmer plant resulted in a $3.8 million decrease in operating cash flow;
- Higher interest expense of $3.2 million compared to the prior year's quarter due to increased debt incurred primarily to finance the purchases of PEV and Frederickson Power L.P. ("Frederickson") and the assumption of capital leases on the PEV acquisition, which were repaid during the quarter; and
- Dividends of $1.6 million on preferred shares issued by a subsidiary company in May 2007.

The decreases were partially offset by:

- The contribution resulting from the PEV acquisition on November 1, 2006 of approximately $17.4 million for the quarter, excluding financing costs and realized losses on foreign exchange contracts;
- An increase in generation and revenue at Manchief due to low natural gas prices in Colorado; and
- The contribution of Frederickson acquired on August 1, 2006 of approximately $1.3 million excluding financing costs.

The Partnership reported cash provided by operating activities of $89.3 million or $1.73 per unit for the nine months ended September 30, 2007 compared with $117.0 million or $2.43 per unit for the same period in 2006. Cash provided by operating activities per unit is defined below under non-GAAP measures. The $27.7 million decrease in cash provided by operating activities compared to 2006 is primarily due to the items described above for the current quarter, as well as the following items:

- The one-time OEFC settlement of $9.8 million in the first quarter of 2006 partially offset by accruals for natural gas contracts;
- A maintenance outage at the Mamquam facility in 2007 to effect tunnel repairs resulted in maintenance costs of approximately $2.4 million;
- A $2.3 million arbitration award against the previous owners of the Queen Charlotte and Mamquam facilities in respect of claims in the purchase and sale agreement; and
- Net realized losses of $17.9 million on foreign exchange contracts and interest rate contracts that were entered in anticipation of permanent financing of the PEV bridge acquisition facilities. In addition to the interest rate contracts discussed previously, the loss is primarily driven by the strengthening of the Canadian dollar versus the U.S. dollar. The stronger Canadian dollar allowed for a larger pay down of US dollar bridge acquisition financing from the Canadian dollar equity offering. As a result, the net realized losses will be offset by lower financing charges and debt repayments in future periods.

(millions of dollars)(unaudited)	**Three Months**	**Nine Months**
Net income for the three and nine months ended September 30, 2006	**10.8**	**75.0**
Higher foreign exchange gains compared to 2006, mainly unrealized [1]	24.6	68.0
Contribution from PEV acquired November 1, 2006	15.4	27.2
Increase in generation and revenue at Manchief	1.4	1.7
Contribution from Frederickson acquired August 1, 2006	1.3	9.1
Future income tax recoveries	-	6.7
Mamquam and Queen Charlotte award	-	2.3
Fair value change on natural gas supply, foreign exchange and interest rate contracts	(44.9)	(59.4)
Asset impairment charge	(13.0)	(13.0)
Higher depreciation and amortization mainly due to the PEV and Frederickson acquisitions in 2006	(5.7)	(18.1)
Lower pricing and volume at Curtis Palmer	(3.8)	(13.7)
Higher financial charges due to acquisitions in 2006[1]	(3.2)	(17.6)
Preferred share dividends	(1.6)	(2.2)
Future income tax expenses due to substantive enactment of SIFT tax law	-	(75.5)
One-time OEFC settlement, net of natural gas contract accruals, in 2006	-	(6.2)
Mamquam maintenance outage	-	(2.4)
Other	2.8	3.6
Net loss for the three and nine months ended September 30, 2007	**(15.9)**	**(14.5)**

[1] Excluding changes in the fair value of foreign exchange and interest rate contracts.

Net loss was $15.9 million or $0.29 per unit for the three months ended September 30, 2007 compared to net income of $10.8 million or $0.22 per unit for the same period in 2006. The decrease in net income of $26.7 million was mainly due to:

- In the first quarter of 2007, the Partnership adopted new accounting standards requiring the recording of the natural gas supply contracts at their fair value (see “Changes in accounting policies”). The Partnership recorded a loss of $52.7 million in the third quarter of 2007 on the change in the fair value of the natural gas supply contracts for the Ontario plants. A majority of the changes in the fair value during the quarter and year to date are the result of lower forward natural gas prices and to a lesser extent the result of the receipt of natural gas under the contracts;
- These losses were partly offset by a net gain of $7.6 million on foreign exchange and interest rate contracts (see “Gains (losses) on derivative instruments”). In 2006, the Partnership recorded a fair value loss on foreign exchange contracts of $0.2 million;
- An asset impairment charge of $13.0 million attributed to the management agreement between a subsidiary of the Partnership and Primary Energy Recycling Holdings LLC (“PERH”), Primary Energy Recycling Corporation (“PERC”) and Primary Energy Operations LLC; and
- Lower volume at the Curtis Palmer plant resulted in a $3.8 million reduction in revenue.

These decreases were partially offset by:

- Foreign exchange gains were $24.6 million higher than the same quarter in 2006 excluding fair value changes on foreign exchange contracts (see “Foreign exchange (gains) losses”);

- A $15.4 million positive contribution from PEV, which was acquired on November 1, 2006 excluding depreciation and financial charges; and
- A $1.3 million positive contribution from Frederickson, which was acquired on August 1, 2006 excluding depreciation and financial charges.

The Partnership reported a net loss of $14.5 million or $0.28 per unit for the nine months ended September 30, 2007 compared with net income $75.0 million or $1.56 per unit for the same period in 2006. The $89.5 million decrease in net income compared to 2006 is primarily due to the items described above for the current quarter, as well as the following items:

- In the second quarter, the Federal Government substantively enacted changes to Income Tax Act in respect of Specified Investment Flow Through ("SIFT") entities under which the Partnership's Canadian operations will become taxable in 2011. Accordingly, a future income tax expense of $75.5 was recognized in the second quarter (see "Change in Tax Law");
- Curtis Palmer recognized $6.8 million of previously deferred revenue in the first six months of 2006; and
- Income tax recoveries of $2.8 million in the first quarter of 2007 compared to income tax expense of $3.9 million for the comparable period in 2006, mainly relating to losses in the US operations in the first quarter of 2007.

Operating Margin[1]	**Three months ended September 30**		**Nine months ended September 30**	
(millions of dollars)(unaudited)	**2007**	2006	**2007**	2006
Ontario	**14.2**	14.1	**53.7**	59.8
Williams Lake	**6.9**	6.1	**19.5**	18.8
Mamquam and Queen Charlotte	**3.3**	2.3	**7.4**	9.1
Northwest US Plants[2]	**11.8**	7.7	**30.3**	17.0
California Plants[2]	**13.9**	-	**25.9**	-
Curtis Palmer	**2.9**	6.7	**21.0**	34.7
Northeast US Gas Plants[2]	**2.9**	1.5	**9.0**	5.2
North Carolina Plants[2]	**2.7**	-	**3.0**	-
PERC management fee[2]	**0.2**	-	**1.4**	-
	58.8	38.4	**171.2**	144.6
Fair value changes in natural gas supply contracts	**(52.7)**	-	**(68.2)**	-
Fair value changes in foreign exchange contracts	**14.5**	(0.2)	**37.7**	5.3
	20.6	38.2	**140.7**	149.9

[1] Operating margin is not a defined financial measure according to Canadian GAAP, and does not have a standardized meaning prescribed by GAAP. See Non-GAAP Measures.
[2] From the dates of acquisition: PEV - November 1, 2006; Frederickson - August 1, 2006.

Operating margin excluding fair value changes in foreign exchange and natural gas supply contracts for the three and nine months ended September 30, 2007 increased by $20.4 million and $26.6 million respectively. The increases are primarily due to additional operating margin of $19.8 million and $43.4 million for the three and nine month periods from the Frederickson and PEV operations, acquired in the third and fourth quarters of 2006 respectively. Offsetting these increases are lower generation and pricing at the Curtis Palmer plant resulting in a decline in operating margin of $3.8 million and $13.7 million for the three and nine months ended September 30, 2007 compared to the same periods in the prior year. In addition, an OEFC settlement recovery in the first quarter of 2006 net of related accruals for additional costs on the natural gas supply contracts recorded in the first and second quarters of 2006 resulted in a decrease of $6.2 million in the nine months ended September 30, 2007 compared to the same period in the prior year.

On January 1, 2007 the Partnership implemented new accounting standards which resulted in the Partnership's long-term natural gas supply contracts being recorded at fair value (see "Changes in accounting policies"). The Partnership recorded a decline in the fair value of the natural gas supply contract for the three and nine months ended September 30, 2007. Unrealized fair value changes in derivative instruments recorded for accounting purposes are not representative of their economic value when considering them in conjunction with the economically hedged item such as future natural gas purchases or future power sales.

Non-GAAP Measures

The Partnership uses operating margin as a performance measure and cash provided by operating activities per unit as a cash flow measure. These terms are not defined financial measures according to Canadian generally accepted accounting principles ("GAAP") and do not have standardized meanings prescribed by GAAP. Therefore, these measures may not be comparable to similar measures presented by other enterprises.

The Partnership uses operating margin to measure the financial performance of plants or groups of plants. A reconciliation from operating margin to net income before tax and preferred share dividends is as follows:

	Three months ended September 30		**Nine months ended September 30**	
(millions of dollars)(unaudited)	**2007**	2006	**2007**	2006
Operating Margin	**20.6**	38.2	**140.7**	149.9
Deduct (Add):				
Depreciation and amortization	**23.0**	17.3	**68.8**	50.7
Management and administration	**3.8**	2.5	**9.7**	6.6
Foreign exchange losses (gains)	**(24.1)**	0.5	**(56.3)**	(8.3)
Equity losses in PERH	**1.7**	-	**2.7**	-
Financial charges and other	**16.7**	6.6	**39.7**	18.5
Asset impairment charge	**13.0**	-	**13.0**	-
Net income (loss) before income tax and preferred share dividends	**(13.5)**	11.3	**63.1**	82.4

Cash provided by operating activities per unit is cash provided by operating activities (a GAAP defined measure) divided by the weighted average number of units outstanding in the period. The composition of these measures is consistent with December 31, 2006 reporting.

Changes in pricing at California plants

The California plants receive variable energy payments based on the Short Run Avoided Cost ("SRAC") of their respective PPA counterparties, which substantially passes through the month-to-month natural gas costs related to electricity production. A decision on SRAC was approved by the California Public Utilities Commission in September 2007 to include forward market heat rates in the determination of SRAC and to increase the amount of variable operating cost included in SRAC from US$2.00 to $2.65 per MWh. The decision modifies the application of

Time of Use ("TOU") factors to energy and capacity portions of the SRAC. Historically, TOU factors have been volatile in the regions in which the Oxnard and Naval facilities operate. The changes are expected to be implemented in the first quarter of 2008. The impact on the Partnership is being evaluated.

Long-term debt issued

On August 15, 2007, a subsidiary of the Partnership completed a private placement of senior unsecured notes in the aggregate principal amount of $240.0 million (US$225.0 million). The notes were issued in two tranches consisting of 10 and 12 year maturities. The $160.0 million (US$150.0 million) in 10-year notes have a coupon rate of 5.87% and the $80.0 million (US$75.0 million) in 12-year notes have a coupon rate of 5.97%. The net proceeds of the offering were used primarily to repay existing long term debt, including the amounts initially borrowed as part of the PEV and Frederickson acquisitions and capital lease obligations assumed as part of the PEV acquisition.

Capital lease obligations

On August 24, 2007, the Partnership paid down its capital lease obligations on the North Island, Naval Training Center and Naval Station facilities with proceeds from the U.S. private placement. The extinguishment of the leases provides the Partnership more flexibility in making operational changes at the facilities without the consent of the lessor. It also provides the Partnership the economic benefits of the assets past the lease term. Additionally it replaces lease payments of approximately $10 million per annum to the end of 2010 and an average of $6 million per annum from the start of 2011 to 2020 with interest payments of $4.2 million per annum and principal payments $71.7 million of in 2019.

Asset impairment charge

On the acquisition of PEV, the Partnership allocated $13.6 million of the purchase price to management agreements on the expectation that it would receive incentive payments from PERH based on forecasted PERH cash distributions. In the third quarter, the Partnership made a downward revision to its estimate of future incentives under the management agreement attributed to expectations of lower cash distributions from PERH, resulting in the write-off of this management agreement asset. Accordingly, a $13.0 million asset impairment charge was recorded in the third quarter of 2007.

NAL and Devon claims

A settlement has been reached with Devon Canada Corporation ("Devon") in respect of its claim of frustration of the contract pursuant to which it supplies natural gas to the Partnership's Tunis, Ontario plant. No settlement has yet been reached in respect of a separate but similar claim by NAL Resources Ltd. ("NAL"). The Partnership has accrued for expected additional payments and has incorporated anticipated increases in fuel supply prices into the determination of the fair value of derivative instruments at September 30, 2007.

Kapuskasing plant

On May 12, 2007, during a regular maintenance outage at the Kapuskasing plant, the rotor used by the steam turbine generator sustained damage as a result of a serious transport accident.

The Kapuskasing plant continued to operate but at a reduced capacity of approximately 20 megawatts (approximately 50% capacity) until late August 2007 when a partially refurbished steam turbine generator rotor was installed allowing the plant to return to full capacity. A new steam turbine generator rotor will be installed later in 2007. The financial loss net of insurance claims resulting from this incident is under $1 million.

CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2007, the Partnership adopted new CICA accounting standards: Financial Instruments - Recognition and Measurement, Financial Instruments – Disclosure and Presentation, Hedges, Comprehensive Income and changes to the Equity standard (collectively “the new accounting standards”). The changes and the impact of these changes on the Partnership’s consolidated financial statements are described in Note 2 to the interim consolidated financial statements. In accordance with the requirements of the new accounting standards, the Partnership has not restated any prior period as a result of adopting the accounting changes but has recorded certain transitional amounts that represent the cumulative effect of adjustments relating to prior periods in opening accumulated deficit and in opening accumulated other comprehensive income.

On January 1, 2007, the Partnership made the following adjustments to its balance sheet to adopt the new standards:

Balance Sheet Category **Increase (Decrease)** *(millions of dollars)(unaudited)*	**As at** **January 1, 2007**	**Explanation**
Other Assets	**(4.5)**	To no longer record deferred financing costs as other assets using straight-line amortization
Derivative instruments - asset	**96.0**	To record natural gas supply contracts at fair value
Derivative instruments - net liability	**(8.6)**	To no longer record deferred unrealized gains as derivative instruments
Long-term debt	**(4.6)**	To record deferred financing costs as debenture discounts using effective interest method
Opening accumulated deficit	**(96.1)**	After tax impact to opening retained earnings resulting from adoption of new standards
Opening accumulated other comprehensive income	**8.6**	To record deferred unrealized gains as accumulated other comprehensive income

The financial instrument standard requires that interest income and expense be allocated over the relevant period using the effective interest method (“EIM”). Under the EIM, interest income and expense is calculated and recorded using an effective interest rate, which is the rate that discounts estimated future cash payments or receipts through the expected life of the financial instrument or, when appropriate, a shorter period, to the initial net carrying amount of the financial asset or liability. Transaction costs that are directly attributable to the acquisition or issue of financial instruments classified as other than “held for trading” are either included in the initial carrying value of such instruments and amortized using the EIM or expensed.

The Partnership has chosen as its accounting policy to include transactions costs as part of the initial carrying amount of the debt and as a result deferred financing costs have been reclassified against long-term debt and the method of amortization of deferred financing costs has been changed to the EIM from the straight-line method. Transaction costs on financial instruments classified as “held for trading” are expensed. The Partnership has no transaction costs relating to financial instruments that are classified as held for trading. Upon implementation, the Partnership’s opening accumulated deficit was reduced by $0.1 million.

A new statement entitled “Consolidated Statement of Comprehensive Income” has been added to the set of consolidated financial statements. Each component of the Consolidated Statement of Comprehensive Income has been recorded net of income taxes. The balance of deferred gains on derivatives (cash-flow hedges) that were previously de-designated will be reclassified to the income statement in the period that the corresponding unrealized foreign exchange gain or loss is realized or the corresponding hedged item of the de-designated cash flow hedge affects net income. The cumulative amount of these other comprehensive income components is called “accumulated other comprehensive income” and is included as a new category in partners’ equity. Opening accumulated other comprehensive income was $8.6 million upon implementation of the new accounting standards.

Non-financial derivatives that are designated as contracts for the purpose of receipt of or delivery of a non-financial item in accordance with expected purchase, sale or usage requirements are excluded from the requirements of the new standards. Accordingly, revenues and expenses incurred on these contracts will be recorded in the income statement at the contract settlement date as they have in the past. Non-financial derivatives that are not designated as contracts for the purpose of receipt of or delivery of a non-financial item will be recorded at fair value at each balance sheet date, with any corresponding changes in fair value recognized in net income in the period.

Upon the implementation of the new accounting standards, the Partnership was required to treat its Ontario long-term natural gas supply contracts as non-financial derivatives as they did not meet the criteria for the normal usage exception for executory contracts. The natural gas supplied under contract to its Ontario facilities is at times re-sold in the market and not entirely used to produce electricity. As a result, these contracts did not meet the requirements for the normal usage exception. Previously, the contracts were accounted for by the accrual method and were not recorded at fair value. The fair value of the contracts at January 1, 2007 was $96.0 million and has been recorded as an adjustment to the opening accumulated deficit. Subsequent changes in the fair value of these contracts are reported in the Partnership’s income statement.

The adoption of the new accounting standards will result in increased variability in net income although it will have no impact on cash flows.

In addition, during the first nine months the new accounting standards impacted the financial statements in the following manner:

Financial Statement Category Increase (Decrease) - $ millions	**For the three months ended or as at September 30, 2007**	**For the nine months ended or as at September 30, 2007**	**Explanation**
Accumulated other comprehensive loss	**(0.8)**	**(2.6)**	To reclassify accumulated other comprehensive income related to de-designated cash flow hedges to income.
Cost of fuel	**52.7**	**68.2**	To record change in the fair value of natural gas contracts from January 1, 2007 to September 30, 2007
Derivative instruments - asset	**(52.7)**	**(68.2)**	

Losses of $52.7 million and $68.2 million have been recorded in the three and nine months ended September 30, 2007 to reflect the change in fair value of natural gas supply contracts and were recorded against cost of fuel. Accumulated other comprehensive income was decreased by $0.8 million and $2.6 million for the three and nine month periods ended September 30, 2007 due to the reclassification of gains on de-designated hedges to revenue. Under the Partnership's previous accounting policy, the reclassification to revenue would have been from derivative financial instruments net liability. The impact of the EIM was insignificant in the first nine months of the year.

Revenues and Plant Output (*millions of dollars except GWh*)	**Three months ended September 30**				**Nine months ended September 30**			
	GWh	**2007**	*GWh*	2006	***GWh***	**2007**	*GWh*	2006
Ontario								
- Power	***326***	**29.1**	*323*	25.6	***1,023***	**95.0**	*1,013*	99.4
- Enhancements		**2.0**		2.5		**7.8**		9.1
- Gas diversions		**3.2**		3.5		**8.1**		7.3
		34.3		31.6		**110.9**		115.8
Williams Lake								
- Firm energy	***132***	**9.8**	*127*	9.4	***373***	**28.1**	*368*	27.6
- Excess energy	***9***	**0.4**	*12*	0.7	***33***	**1.4**	*40*	2.2
	141	**10.2**	*139*	10.1	***406***	**29.5**	*408*	29.8
Mamquam/Queen Charlotte	***69***	**4.2**	*44*	3.3	***193***	**13.0**	*187*	12.4
Northwest US Plants (2)	***482***	**16.9**	*237*	11.4	***651***	**46.2**	*276*	24.2
California Plants (2)	***269***	**37.9**	-	-	***769***	**105.7**	-	-
Curtis Palmer	***37***	**4.2**	*76*	8.1	***237***	**25.1**	*302*	38.6
Northeast US Gas Plants (2)	***107***	**14.6**	*55*	8.3	***294***	**47.4**	*89*	18.8
North Carolina Plants(2)	***199***	**15.8**	-	-	***507***	**43.5**	-	-
PERC management fees (2)		**0.8**	-	-		**2.6**	-	-
Fair value changes		**14.5**	-	(0.2)		**37.7**	-	5.3
	1,630	**153.4**	*874*	72.6	***4,080***	**461.6**	*2,275*	244.9

Weighted Average Plant Availability(1)	**Three months ended September 30**		**Nine months ended September 30**	
	2007	2006	**2007**	2006
Ontario Plants	**91%**	95%	**94%**	98%
Williams Lake	**100%**	96%	**95%**	94%
Mamquam/Queen Charlotte	**89%**	95%	**76%**	84%
Northwest US Plants (2)	**98%**	100%	**94%**	92%
California Plants (2)	**95%**	-	**92%**	-
Curtis Palmer (3)	**99%**	90%	**95%**	97%
Northeast US Gas Plants (2)	**97%**	87%	**95%**	94%
North Carolina Plants(2)	**99%**	-	**97%**	-
Weighted Average Total	**97%**	97%	**93%**	95%

(1) Plant availability represents the percentage of time in the period that the plant is available to generate power, whether actually running or not, and is reduced by planned and unplanned outages.
(2) From the dates of acquisition: Frederickson – August 1, 2006; PEV – November 1, 2006.
(3) Prior year availability has been restated to reflect a weighted average of the availability of each unit at Curtis Palmer. Previous reporting was based on a simple average.

Revenues of $153.4 million and $461.6 million for the three and nine months ended September 30, 2007 respectively were $80.8 million and $216.7 million higher than the same periods in 2006. The increase was primarily due to the acquisition of PEV and Frederickson on November 1, 2006 and August 1, 2006 respectively, which contributed an additional $64.3 million and $192.9 million to revenues in the three and nine months ended September 30, 2007 compared to the same periods in the prior year as well as changes in the fair value of foreign exchange contracts. Offsetting the increases were the non-recurrence of the $9.8 million settlement received from the OEFC in the first quarter of 2006 and lower generation and pricing at the Curtis Palmer facility.

Ontario Plants
The Ontario plants reported revenues of $34.3 million and $110.9 million for the three and nine months ended September 30, 2007 and $31.6 million and $115.8 million for the same periods in the prior year. The increase in power revenues for the quarter mainly reflects increased generation as more natural gas was available for power generation due to lower enhancement and diversion sales and higher waste heat availability partly offset by lower generation and revenue at the Kapuskasing plant due to a transport accident. Revenues for the nine month period include the $9.8 million impact of the OEFC settlement recognized in the first quarter of 2006. Enhancement revenues at the Ontario plants are lower in the current quarter due lower market prices for natural gas in 2007.

Williams Lake
Revenues were consistent with the prior year.

Mamquam and Queen Charlotte
Revenues at the Mamquam and Queen Charlotte plants were $4.2 million and $13.0 million for the three and nine months ended September 30, 2007, compared with $3.3 million and $12.4 million for the same periods in 2006. The increase in generation and revenue in the third quarter is the results of above normal water flows. Offsetting this on a year to date basis is tunnel repair work completed in the first and second quarters of 2007 at the Mamquam plant.

Curtis Palmer
Revenue at the Curtis Palmer plant was $4.2 million and $25.1 million for the three and nine months ended September 30, 2007, compared with $8.1 million and $38.6 million for the same periods in 2006. The decrease in revenues was due to the recognition of previously deferred revenue of $6.8 million in the first six months of 2006 in addition to the reduction in the power purchase arrangement ("PPA") pricing that began in late January 2006. In addition, generation was lower resulting from a maintenance outage earlier in the year and lower water flow in the third quarter of 2007.

Northwest US Plants
Revenues were $16.9 million and $46.2 million for the three and nine months ended September 30, 2007 compared to $11.4 million and $24.2 million for 2006. The acquisition of the Frederickson facility in August 2006 and the Greely facility as part of the PEV acquisition in November 2006, added $1.6 million and $2.4 million respectively to revenue in the third quarter and $13.2 million and $7.1 million respectively in the nine month period ended September 30, 2007. The Greeley plant operated above expectations for the quarter and year to date due to lower than expected natural gas prices. Frederickson revenues were in line with expectations, even though the plant experienced a two week outage due to a transmission cable failure in the first quarter.

Revenues from the Manchief facility of $8.4 million and $19.8 million for the three and nine months ended September 30, 2007 were $1.4 million and $1.7 million higher than the same periods in 2006 mainly due to higher generation as the result of low natural gas prices in Colorado.

California Plants
The Naval and the Oxnard facilities were acquired by the Partnership as part of the PEV acquisition on November 1, 2006. Revenues from the Naval and the Oxnard facilities were $28.4 million and $9.4 million for the quarter, respectively and $84.9 million and $20.8 million year to date. Results for the current quarter are in line with expectations. In previous quarters, availability for the Naval facilities was lower than plan due to two unplanned outages at the North Island plant in the first quarter due to auxiliary gear box and turbine compressor failures. The second outage required the engine to be removed from service and replaced temporarily with a lease engine.

Northeast US Gas Plants
Revenues of $8.8 million and $26.6 million for Castleton for the three and nine months ended September 30, 2007 were $0.5 million and $7.8 million higher than the same periods in 2006 mainly due to natural gas sales to utilize excess natural gas transmission capacity. The increase in revenue is mostly offset by higher fuel costs generated from these transactions (see "Cost of fuel").

The Kenilworth plant was acquired on November 1, 2006 as part of the PEV acquisition. Revenues from the Kenilworth plant were $5.8 million and $20.8 million for the three and nine months ended September 30, 2007, slightly below expectations for the nine month period due to weather related forced outages in April.

North Carolina Plants
Revenues from the North Carolina plants were $15.8 million and $43.5 million for three and nine months ended September 30, 2007 which was higher than expected, due to higher than forecast dispatch as a result of supply shortages in the region caused by outages at other non-Partnership plants.

Fair value changes on foreign exchange contracts
The unrealized gains on foreign exchange contracts of $14.5 million and $37.7 million in the three and nine months ended September 30, 2007 were higher than the unrealized loss of $0.2 million and an unrealized gain of $5.3 million reported in same periods in 2006. The change is due to an increase in the value of the Canadian dollar relative to the U.S. dollar in the three months ended September 30, 2007 compared to a decline in the same period in 2006. The increase in the unrealized gain in the nine months ended September 30, 2007 is primarily due to a larger increase in the Canadian dollar relative to the US dollar in 2007. In addition, the Partnership has acquired more foreign exchange contracts as a result of adding the Frederickson and PEV operations. In the second quarter of 2006, the Partnership voluntarily de-designated certain hedge relationships for accounting purposes on foreign exchange contracts.

Cost of fuel	**Three months ended September 30**		**Nine months ended September 30**	
	2007	2006	**2007**	2006
(millions of dollars)(unaudited)				
Ontario Plants				
Natural gas	**15.2**	13.1	**42.7**	42.9
Waste heat	**0.9**	0.1	**1.9**	0.4
Wood waste	**0.4**	0.3	**1.5**	0.8
	16.5	13.5	**46.1**	44.1
Williams Lake - wood waste	**0.8**	1.1	**2.6**	3.2
Northwest US Plants - natural gas (1)	**2.2**	1.1	**7.5**	1.3
California Plants - natural gas (1)	**18.6**	-	**63.6**	-
Northeast US Gas-Fired Plants - natural gas (1)	**10.2**	5.6	**33.0**	10.2
North Carolina Plants - coal, tire derived fuel & wood waste(1)	**9.9**	-	**28.7**	-
Fair value changes on gas contracts	**52.7**	-	**68.2**	-
	110.9	21.3	**249.7**	58.8

(1) From the dates of acquisition: PEV - November 1, 2006; Frederickson - August 1, 2006.

Fuel costs include commodity price, transportation costs and fair value changes on natural gas supply contracts. For the three and nine months ended September 30, 2007, fuel costs were $110.9 million and $249.7 million compared with $21.3 million and $58.8 million for the same periods in 2006. In the three months ended September 30, 2007, fuel cost was higher mainly due to a reduction in the fair value of natural gas supply contracts and fuel costs related to the acquisition of Frederickson on August 1, 2006 ($0.2 million for the quarter and $2.0 million year to date) and the acquisition of PEV on November 1, 2006 ($34.1 million for the quarter and $112.9 million year to date).

Fuel costs at the Ontario plants for the three and nine months ended September 30, 2007 were $16.5 million and $46.1 million compared to $13.5 million and $44.1 million in 2006. The increase was due to higher fuel supply costs at Tunis as a result of the settlement of a supply contract dispute (see “NAL and Devon claims”) and annual price increases in the natural gas supply contracts. These increases were partly offset by retroactive charges for estimated additional fuel charges of $3.6 million in the nine months ended September 30, 2006. The nine months ended September 30, 2007 include a $1.2 million refund of transportation charges related to periods ended before 2007.

Fuel costs at the Northwest US plants increased by $1.1 million and $6.2 million for the three and nine months ended September 30, 2007 due to the acquisition of Frederickson on August 1, 2006 and Greeley on November 1, 2006. Fuel costs for three and nine months ended September 30, 2007 at Frederickson were $1.2 million and $3.0 million and at Greeley were $1.0 million and $4.3 million, generally in line with expectations.

Fuel costs at the California plants were $18.6 million and $63.6 million for the three and nine months ended September 30, 2007. An outage at North Island earlier in the year resulted in lower than expected fuel costs in the nine months end September 30, 2007.

The Northeast US gas plants incurred fuel costs of $10.2 million and $33.0 million for the three and nine months ended September 30, 2007 compared to $5.6 million and $10.2 million in the prior year. Fuel supply costs at the Castleton plant were consistent with the prior year for the quarter and increased by $6.5 million for the year to date as the result of the higher sale of natural gas in the first half of 2007 to utilize excess natural gas transmission capacity. Fuel costs at the Kenilworth plant were $4.6 million for the quarter and $28.7 million year to date, slightly lower than expectations due to lower generation during the year.

Fuel costs at the North Carolina plants were $9.9 million and $28.7 million for the three and nine months ended September 30, 2007. An unfavourable fuel blend (a greater amount of coal burned compared to wood waste and tire derived fuel) and higher dispatch rates led to higher than expected fuel costs.

The Curtis Palmer, Mamquam and Queen Charlotte hydroelectric plants do not have fuel costs. The power buyer under the Manchief PPA provides all the fuel requirements for that plant however the Partnership is obligated to pay for demand charges associated with the transportation of natural gas to the facility.

Operating and maintenance expense	**Three months ended Setpember 30**		**Nine months ended September 30**	
	2007	2006	**2007**	2006
(millions of dollars)(unaudited)				
Ontario	**3.4**	3.4	**10.2**	10.0
Williams Lake	**1.4**	1.4	**4.3**	4.2
Mamquam and Queen Charlotte	**0.3**	0.3	**0.9**	0.9
Northwest US Plants [(1)]	**2.2**	1.7	**6.3**	3.7
California Plants [(1)]	**3.1**	-	**10.3**	-
Curtis Palmer	**0.3**	0.3	**0.9**	0.9
Northeast US Gas Plants [(1)]	**1.2**	0.7	**3.9**	2.2
North Carolina Plants [(1)]	**2.8**	**-**	**8.6**	**-**
PERC management expenses [(1)]	**0.2**	-	**0.7**	-
	14.9	7.8	**46.1**	21.9

[(1)] From the dates of acquisition: PEV - November 1, 2006; Frederickson - August 1, 2006.

Operating and maintenance expenses are based on fixed charges adjusted annually for inflation as well as flow through of costs for plants acquired in 2006, and are payable to the Manager for the operation and routine maintenance of the plants. The acquisitions of PEV and Frederickson in 2006 were the primary cause of the year over year increases.

Other plant operating expenses

Other plant operating expenses, which include insurance, property taxes and major maintenance expenses, were $7.0 million and $25.1 million for the three and nine months ended September 30, 2007 compared to $5.3 million and $14.3 million in 2006. The increase is mainly due to the acquisition of PEV and the Frederickson plant in 2006 and the Mamquam tunnel repair in 2007.

Depreciation and amortization

Depreciation and amortization expense for the three and nine months ended September 30, 2007 was $23.0 million and $68.8 million compared to $17.3 million and $50.7 million in 2006. The higher depreciation charges for the three months and nine months ended September 30, 2007 compared to the prior year periods are mainly due to the acquisition of plants and related contract assets and liabilities in the third and fourth quarters of 2006.

Management and administration

Management and administration costs, which include fees payable to EPCOR and general and administrative costs, were $3.8 million and $9.7 million for the three and nine months ended September 30, 2007 compared to $2.5 million and $6.6 million in 2006. Management and administration costs have increased due to the additional plants acquired in 2006. This increase for the nine months ended September 30, 2007 is offset by a $2.3 million award from the previous owners of the Queen Charlotte and Mamquam facilities in respect of claims in the purchase and sale agreement.

Foreign exchange (gains) losses	**Three months ended September 30**		**Nine months ended September 30**	
	2007	2006	**2007**	2006
(millions of dollars)(unaudited)				
Realized foreign exchange losses	**1.4**	0.8	**1.1**	0.8
Unrealized foreign exchange (gains) on U.S. dollar-denominated debt	**(25.5)**	(0.3)	**(77.4)**	(9.1)
Realized losses on foreign exchange contracts	**-**	-	**15.3**	-
Fair value changes on foreign exchange contracts	**-**	-	**4.7**	-
	(24.1)	0.5	**(56.3)**	(8.3)

The Partnership reported foreign exchange gains of $24.1 million and $56.3 million for the three and nine months ended September 30, 2007 compared to a loss and gain respectively for the same periods in 2006. The foreign exchange gains recorded in the three and nine months ended September 30, 2007 increased from the same periods in 2006 due to a larger increase in the value of the Canadian dollar in 2007 and an increase in US dollar denominated debt as part of the Frederickson and PEV acquisitions. The foreign exchange contracts were entered into in anticipation of the issuance of Canadian equity to replace a portion of the US dollar bridge acquisition facility. During the first two quarters of 2007, the Partnership realized losses on settlement of these contracts of $15.3 million. Although the Partnership realized a loss on the US dollar hedges in the current year, the stronger Canadian dollar allowed for a larger pay down of the US dollar bridge acquisition financing from the Canadian dollar equity offering which translates into lower interest costs and debt repayments in future periods. Realized foreign exchange losses of $1.4 million and $1.1 million for the three and nine months ended September 30, 2007 were higher than the same periods in the prior year due to the Partnership holding a US cash balance for the period between issuance of senior notes and the buy out of capital leases during which time the US dollar weakened.

Equity losses in PERH

Equity losses in PERH are from the Partnership's 17.0% common ownership interest in PERH acquired on November 1, 2006, which is accounted for on an equity basis.

In the three and nine months ended September 30, 2007, the Partnership received dividends on its preferred interest of $0.4 million and $1.2 million and dividends of $0.5 million and $2.8 million from its common interests in PERH. In the second quarter, the monthly cash dividend on the common interest in PERH was reduced by 40%. The results for PERH have been adversely impacted by an outage at PERH's North Lake Energy Facility and unfavourable results at PERH's Harbor Coal joint venture as a result of negative inventory adjustments in each of the first two quarters of 2007. PERH has announced it will defer the monthly distribution for September of 2007. Subject to finalization of certain inventory counts, PERH may also be in violation of certain debt covenants at September 30, 2007 which could cause PERH to suspend its distributions. The Partnership was receiving distributions of $0.4 million per month in common and preferred interest distributions from PERH prior to their deferral announcement.

Financial charges and other

	Three months ended September 30		**Nine months ended September 30**	
	2007	2006	**2007**	2006
(millions of dollars - unaudited)				
Interest on long-term debt	**9.0**	6.1	**27.1**	17.8
Interest on short-term debt	**-**	0.3	**4.9**	0.3
Interest on capital lease obliations	**1.4**	-	**4.5**	-
Dividend income from Class B preferred interests in PERH	**(0.4)**	-	**(1.2)**	-
Realized losses on interest rate contracts	**8.1**	-	**2.6**	-
Fair value changes on interest rate contracts	**(1.2)**	-	**1.0**	-
Other	**(0.2)**	0.2	**0.8**	0.4
	16.7	6.6	**39.7**	18.5

Financial charges and other expenses of $16.7 million and $39.7 million for the three and nine months ended September 30, 2007 were $10.1 million and $21.2 million higher compared with the same periods in 2006. The increase was primarily due to losses realized on interest rate contracts and interest on short-term debt and long-term debt used to finance the PEV acquisition. Contributing to the increase was interest on capital lease obligations assumed as part of the PEV acquisition, which were bought out in the third quarter of 2007, and long-term debt used to finance the Frederickson acquisition. This was partially offset by net gains on fair value changes on interest rate contracts of $1.2 million for the three months ended September 30, 2007 and by dividends earned on the investment in PERH Class B preferred shares.

Income taxes

Income taxes were $0.8 million and $75.4 million for the three and nine months ended September 30, 2007, an increase of $0.3 million and $68.0 million from the same periods in the prior year. The increase is due to a change in tax law in the second quarter of 2007 which will result in the Partnership's Canadian operations becoming taxable in 2011. Accordingly, a future income tax expense of $75.5 million was recognized in the second quarter. Income taxes also relate to the taxes of the Partnership's US subsidiaries and withholding taxes on distributions from the US subsidiaries.

Preferred share dividends of a subsidiary company

In May 2007, a subsidiary of the Partnership issued preferred shares which pay dividends at a rate of 4.85% per annum. The first dividend of $2.1 million was paid to shareholders on September 28, 2007. Dividends of $1.5 million are expected to be paid in future quarters. Part VI.1 tax is paid at a rate of 40% of the dividends and a deduction from Part I tax is available for the payment of the Part VI.1 tax. The subsidiary expects to realize the benefit of the deduction in 2011.

Gains (losses) on derivative instruments

Three months ended	Income Statement	Amounts Recorded In Income Statement		Amount Realized	
September 30	Category	**2007**	2006	**2007**	2006
(millions of dollars)(unaudited)					
Foreign exchange contracts [1]	Revenue	**14.5**	(0.2)	**-**	-
Natural gas contracts	Fuel	**(52.7)**	-	**-**	-
Foreign exchange contracts	Foreign exchange	**-**	-	**-**	-
Interest rate contracts	Financing	**(6.9)**	-	**(8.1)**	-
		(45.1)	(0.2)	**(8.1)**	-

[1] Amounts realized on foreign exchange contracts for operating cash flow are included in plant revenue.

Nine months ended	Income Statement	Amounts Recorded In Income Statement		Amount Realized	
September 30	Category	**2007**	2006	**2007**	2006
(millions of dollars)(unaudited)					
Foreign exchange contracts [1]	Revenue	**37.7**	5.3		-
Natural gas contracts	Fuel	**(68.2)**	-		-
Foreign exchange contracts	Foreign exchange	**(20.0)**	-	**(15.3)**	-
Interest rate contracts	Financing	**(3.6)**	-	**(2.6)**	-
		(54.1)	5.3	**(17.9)**	-

[1] Amounts realized on foreign exchange contracts for operating cash flow are included in plant revenue.

Discussion of changes in fair value amounts is included in the discussion of changes in the respective income statement categories. The amounts realized are included in cash provided by operating activities.

LIQUIDITY AND CAPITAL RESOURCES

Cash distributions

Cash distributions of $0.63 per unit were declared for each of the first, second and third quarters of 2007, consistent with the same periods in 2006. When cash provided by operating activities plus the dividend from PERH exceeds cash distributions and maintenance capital expenditures, the Partnership utilizes the difference to stabilize future quarterly cash distributions, to finance future capital expenditures and to make debt repayments. When cash provided by operating activities plus dividends from PERH are less than cash distributions and maintenance capital expenditures, the Partnership utilizes available cash balances and short term financing to cover the shortfall.

	Three months ended September 30		Nine months ended September 30	
	2007	2006	**2007**	2006
(millions of dollars)(unaudited)				
Cash distributions [(1)]	**33.9**	31.4	**99.3**	91.2
Cash provided by operating activities	**20.8**	29.6	**89.3**	117.0
Net income (loss)	**(15.9)**	10.8	**(14.5)**	75.0
Dividend from PERH	**0.5**	-	**2.8**	-
Additions to property, plant and equipment	**2.6**	2.2	**7.9**	4.2
Excess (shortfall) of cash provided by operating activities over cash distributions	**(13.1)**	(1.8)	**(10.0)**	25.8
Excess (shortfall) of net income (loss) over cash distributions	**(49.8)**	(20.6)	**(113.8)**	(16.2)

[(1)]Cash distributions for the three and nine months ended September 30, 2006 exclude a $1.5 million payment in August 2006 on the Subscription Receipts issued in the acquisition of Frederickson.

Cash distributions exceed cash provided by operating activities by $13.1 million and $10.0 million for the three and nine months ended September 30, 2007 and by $1.8 million for the three months ended September 30, 2006. The shortfall in the three and nine months ended September 30, 2007 are the result of the net realized losses on interest rate and foreign exchange contracts and increases in operating working capital. The net realized losses on interest rate and foreign exchange contracts that were entered into in anticipation of the permanent financing of the PEV acquisition were primarily driven by the strengthening of the Canadian dollar and reduction of long-term interest rates. These events created a loss but consistent with the nature of a hedge, will reduce future interest and debt payments. While the Partnership anticipates seasonal fluctuations in its working capital, it does not expect a significant increase in working capital requirements over the long-term for existing operations. The shortfall between cash distributions and cash provided by operating activities has been funded with a combination of cash on hand and draws on credit facilities, which have been subsequently repaid. The shortfall in the three month period ending September 30, 2006 is the result of the Partnership’s operating cycle prior to the completion of the acquisition of PEV in November 2006. Prior to the acquisition, cash provided by operating activities was lowest in the third quarter due to lower pricing from April to September at the Ontario facilities. This shortfall was funded with cash on hand.

Excluding the realized losses on interest rate and foreign exchange contracts that were entered into in anticipation of the PEV acquisition and increases in operating working capital, cash provided by operating activities exceeded cash distributions for the three and nine months ended September 30, 2007 by $7.7 million and $20.1 million respectively. This surplus is expected to decline in 2008 due to factors outlined under “Outlook”, subject to variable factors including those outlined in our forward-looking statements at the beginning of this MD&A.

Net income is not necessarily comparable to cash distributions as net income includes items like unrealized gains and losses on translation of US dollar denominated debt, changes in the fair value of derivative instruments and future income tax expense related to changes in tax legislation. Absent the unrealized gains and losses on the translation of long-term debt, changes in the fair value of derivative instruments and future income tax expenses, management expects that distributions will continue to exceed net income. Accordingly a portion of the distributions represent a return of capital. To date, and subject to ensuring adequate liquidity, the Partnership has chosen to make distributions that include a return of capital as it believes that major investments of capital to maintain or increase productive capacity are often most effectively made by obtaining new capital in the external markets at the time of the required investment and not necessarily using retained cash.

The third quarter 2007 cash distribution of $0.63 per unit was paid on October 30, 2007 to unitholders of record on September 28, 2007.

Capital expenditures

Capital expenditures for the three and nine months ended September 30, 2007 totalled $2.6 million and $7.9 million compared with $2.2 million and $4.2 million for the same periods in 2006. Capital spending in the remaining quarter of 2007 is expected to be higher than in the first three quarters. Total capital spending for 2007 is expected to be in the $13 to $14 million range, slightly below earlier expectations due to the deferral of certain projects to 2008.

Asset backed commercial paper

At September 30, 2007, the Partnership did not have any investments in asset backed commercial paper.

FOREIGN EXCHANGE RISK MANAGEMENT

The Partnership manages the foreign exchange risk of its future anticipated US dollar-denominated cash flows from its US plants through the use of forward foreign exchange contracts for periods up to seven years. As at September 30, 2007, $312.4 million (US$271.5 million) or approximately 68% of expected future cash flows were economically hedged for 2007 to 2013 at a weighted average exchange rate of $1.15 to US $1.00.

TRANSACTIONS WITH RELATED PARTIES

	Three months ended September 30		Nine months ended September 30	
	2007	2006	**2007**	2006
(millions of dollars)(unaudited)				
Transactions with the Manager				
Cost of fuel - Castleton gas demand charge	**0.5**	0.5	**1.6**	1.6
Acquisition fee - Frederickson	**-**	2.7	**-**	2.7
Operating and maintenance expense	**12.2**	7.1	**38.1**	21.2
Management and administration				
Base fee	**0.3**	0.3	**1.0**	0.9
Incentive fee	**0.6**	0.6	**1.7**	1.6
Enhancement fee	**0.1**	0.2	**0.7**	0.8
Administration fee	**0.2**	0.2	**0.6**	0.5
	1.2	1.3	**4.0**	3.8
Transactions with PERC				
Revenue				
Base management fees	**0.8**	-	**2.6**	-

CONTRACTUAL OBLIGATIONS

In the third quarter, the Partnership closed a US$225 million private placement of senior notes. The proceeds from the transaction were primarily used to repay existing debt, including the bridge acquisition credit facility due in October 2009 incurred to finance the acquisition of PEV. In addition, the Partnership bought out the capital lease obligations for the California facilities located on Navy bases. For further information on the Partnership's obligations, refer to the Partnership's 2006 Annual MD&A and first quarter 2007 MD&A.

SIGNIFICANT ACCOUNTING ESTIMATES

Since a determination of many assets, liabilities, revenues and expenses is dependent upon future events, the preparation of the Partnership's consolidated financial statements requires the use of estimates and assumptions which have been made using careful judgment. The Partnership's critical accounting estimates include the accrued liability on the NAL claim, tax provision calculations as a result of the Partnership becoming taxable in 2011, depreciation and amortization expense, asset retirement obligations and fair value estimates. For further information on the Partnership's critical accounting estimates, refer to the Partnership's 2006 Annual MD&A.

The implementation of the new accounting standards in 2007 requires additional estimates and assumptions associated with the calculation of fair value of the Partnership's natural gas supply contracts. The fair value of non-financial derivatives reflects changes in the commodity market prices, interest rates and foreign exchange rates. Fair value amounts reflect management's best estimates considering various factors including closing exchange or over-the-counter quotations, estimates of futures prices and foreign exchange rates, time value and volatility. It is possible that the assumptions used in establishing fair value amounts will differ from actual prices and the impact of such variations could be material.

INTERNAL CONTROL OVER FINANCIAL REPORTING

There were no changes made to the Partnership's internal control over financial reporting during the interim period ended September 30, 2007 that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

BUSINESS RISKS

The Partnership's business and operational risks remain substantially unchanged since December 31, 2006. For further information on business risks, refer to the Partnership's December 31, 2006 MD&A.

Proposed Emissions Regulations

On April 25, 2007, the Canadian Environment Minister announced a new regulatory framework to reduce greenhouse gas emissions and air pollution in Canada. The Canadian government has set targets of a 20% reduction in greenhouse gases by 2020 and a 50% reduction in air pollution by 2015. The Partnership is an emitter of carbon dioxide (a greenhouse gas), nitrogen oxide and sulphur dioxide which are all targeted for reduction under the proposed new legislation. The Partnership complies, in all material respects, with current federal, provincial, state and local environmental legislation and guidelines. The operational and financial impact to the Partnership of the new regulatory framework cannot be determined until further details are announced but could result in material operating cost increases and / or significant capital investment.

OUTLOOK

Wood supply at the Calstock facility is currently adequate to meet ongoing requirements. The high Canadian dollar and a depressed U.S. housing market have placed economic hardships on Ontario mills which may impact future wood supply at our Calstock facility. In August 2007, the Partnership was successful in negotiating a 2 year agreement with a new wood supplier to provide up to 25% of Calstock's annual requirements. The same economic factors impact supply at the Williams Lake facility, however supply risk is mitigated by additional waste wood resulting from the mountain pine beetle infestation in British Columbia.

Commercially, the Partnership continues to work on re-negotiating the Greeley and Kenilworth PPAs and the review of strategic alternatives for the Castleton facility after its PPA expires in June of 2008. As well, the Partnership is currently reviewing the technical and economic feasibility of enhancing the boilers at the Southport and Roxboro coal plants with a newer technology that would reduce environmental emissions and improve the economic performance of these plants. The Partnership expects to spend up to $5 million on this feasibility study in 2007. Current estimates to enhance the boilers with newer technology are estimated at $60 to $70 million, subject to completion of the study and final engineering estimates. Capital spending on this project, if it occurs, would likely take place at one facility in 2008 and the other facility in 2009.

Excluding the Southport and Roxboro facilities, capital maintenance spending is expected to be higher at the other facilities in 2008 than in recent years. The primary drivers for this expected increase in spending in 2008 include:

- There maybe a carryover of up to $3 million of projects originally scheduled in 2007 to 2008;
- The Manchief facility has been dispatched at higher rates in the third quarter of 2007 due to low natural gas prices. As a result, the scheduled overhaul for one of its gas turbines is likely to be accelerated from 2009 to 2008 with an expected cost of approximately $3 million; and
- The economics of the Castleton facility support performing a major overhaul of the facility in 2008 at a cost estimated to be $4 million to extend the life of the facility beyond its PPA expiry in June 2008.

Cash provided by operating activities, excluding the realized losses on interest rate and foreign exchange contracts that were entered into in anticipation of the PEV acquisition and increases in operating working capital, is expected to exceed cash distributions in 2007. This forecasted surplus is expected to decline in 2008 due to the following factors:

- The Castleton PPA expires in June 2008. This facility currently provides approximately $8 million of operating margin annually. Operating margin after the PPA expires is expected to be positive but at a lower level;
- The Frederickson facility has been dispatched at higher rates in the third quarter of 2007 due to low natural gas prices. As a result, under its long-term service agreement with the turbine manufacturer, a milestone payment of $4 million is expected to be paid in 2008 as opposed to earlier estimates of 2009;
- Curtis Palmer benefited from high water flows in the first and second quarters of 2007. If water flows in 2008 are closer to long-term historical averages, revenues and operating margins would be lower;
- North Bay and Kapuskasing fuel supply pricing is set to increase 18% from 2007 to 2008 under the 20 year agreements. Over the life of the agreements, fuel supply pricing increases an average of 9%. The increase from 2008 to 2009 is set to increase 6%. These fuel supply increases are expected to mostly offset by revenue increases under the PPAs;
- The Mamquam and Queen Charlotte arbitration awards were received in 2007 with no similar amounts forecasted for recovery in 2008;
- Higher preferred share dividends and Part VI.1 tax due to a full year of dividends in 2008; and
- Partially offsetting these items are expected lower financing costs in 2008 due to the equity offerings in 2007, expected lower maintenance at Mamquam and improved operating margins at Kapuskasing based on no forecasted impacts in 2008 from the transport accident incurred in 2007.

Contractual items that should positively impact 2009 cash from operating activities relative to 2008 include the expected increase in Curtis Palmer PPA pricing of 18%, subject to meeting cumulative production thresholds, and the non-recurrence of the long-term service agreement payment on Frederickson.

There are a number of other factors that have a significant impact on cash flow from operating activities including those items listed in our forward-looking statements at the beginning of this MD&A.

Operationally, the portfolio of facilities continues to perform to expectation and the diverse mix of fuel type, geographic location and counterparty credit reduces the exposure to the Partnership from underperformance at any one plant.

SELECTED QUARTERLY CONSOLIDATED FINANCIAL DATA

(unaudited)	**2007**			2006				2005
(millions of dollars except per unit amounts)	**Third**	Second	First	Fourth	Third	Second	First	Fourth
Revenues	**153.4**	165.3	142.9	105.3	72.6	81.0	91.3	81.5
Operating margin[(1)]	**20.6**	16.2	103.9	43.3	38.2	48.3	63.4	53.6
Net income (loss)	**(15.9)**	(68.0)	69.4	(12.9)	10.8	30.3	33.9	21.2
Cash provided by operating activities	**20.8**	9.1	59.4	37.4	29.6	33.1	54.3	45.5
Capital expenditures	**2.6**	4.2	1.1	9.0	2.2	1.2	0.8	9.2
Cash distributions	**33.9**	34.0	31.4	31.4	31.4	29.9	29.9	29.9
Per Unit Statistics								
Net income (loss)	**$ (0.29)**	$ (1.33)	$ 1.39	$ (0.26)	$ 0.22	$ 0.64	$ 0.72	$ 0.45
Cash provided by operating activities[(1)]	**$ 0.39**	$ 0.18	$ 1.19	$ 0.75	$ 0.60	$ 0.70	$ 1.15	$ 0.96
Cash distributions	**$ 0.63**	$ 0.63	$ 0.63	$ 0.63	$ 0.63	$ 0.63	$ 0.63	$ 0.63

[(1)]The selected quarterly consolidated financial data has been prepared in accordance with GAAP except for operating margin and cash provided by operating activities per unit. See "Non-GAAP Measures".

Factors Impacting Quarterly Financial Results

The Partnership's Selected Quarterly Financial Data, which has been prepared in accordance with GAAP, except as noted, is set out above. Quarterly revenues, net income and cash provided by operating activities are affected by seasonal contract pricing, seasonal weather conditions, fluctuations in US dollar exchange rates relative to the Canadian dollar, attainment of firm energy requirements, natural gas prices, waste heat availability and planned and unplanned plant outages, as well as items outside of the normal course of operations. Quarterly net income is also affected by unrealized foreign exchange gains and losses on the Partnership's US dollar-denominated long-term debt and fair value changes in forward foreign exchange contracts and natural gas supply contracts. Under the power sales contracts for the Ontario plants, the Partnership receives higher per megawatt hour ("MWh") prices in the winter months (October to March) and lower prices in the summer months (April to September). The lower summer prices reduce the threshold for economic curtailments thereby increasing the profitability of enhancements, natural gas prices being equal. Contributions from the Williams Lake plant are usually lower in the fourth quarter once the annual firm energy requirements are fulfilled and the plant is only producing lower-priced excess energy. Revenues from the hydroelectric facilities are anticipated to be higher in the spring months due to seasonally higher water flows. Results for the year ended December 31, 2006 were indicative of these trends.

The PEV acquisition has also changed the seasonality of Partnership's cash flow and earnings. The acquisition of the PEV facilities is expected to reduce the quarterly variability in financial performance of the Partnership as the strongest quarters for the PEV facilities (the second and third quarters) complement the historically weaker quarters for the balance of the Partnership's facilities.

Significant items which impacted the last eight quarters' net income were as follows:

In the third quarter of 2007, the Partnership recorded a $13 million asset impairment charge in respect of certain management contracts.

In the second quarter of 2007, a future income tax expense of $75.5 million was recognized due to a change in tax law which will result in the Partnership's Canadian operations becoming taxable in 2011.

In the first quarter of 2007, the Partnership began reporting the natural gas supply contracts for the Ontario plants at their fair value. The Partnership recorded a gain on the change in the fair value of the natural gas supply contracts in the first quarter of 2007 and a loss in the second and third quarters.

Unrealized foreign exchange gains on US dollar-denominated debt were recorded in the second quarter of 2006 and the first three quarters of 2007. Losses were recorded in the fourth quarter of 2005 and the first, third and fourth quarters of 2006. The gains and losses are due to fluctuations in the US dollar relative to the Canadian dollar.

The fourth quarter of 2005, the first, second and fourth quarters of 2006 and the first quarter of 2007 had unseasonably high water flows at the Curtis Palmer facility. Lower pricing for electricity produced at the Curtis Palmer facility started in the first quarter of 2006 when a cumulative MWh threshold was reached. Enhancement and diversion revenues at the Ontario plants increased due to higher natural gas prices in the fourth quarter of 2005 and the first quarter of 2006.

In the first quarter of 2006, the Partnership reached a settlement with the OEFC on a replacement for the Direct Customer Rate index. The retroactive portion of the settlement was recorded in the quarter and increased revenues, net income and cash provided by operating activities.

In the second quarter of 2006, the Partnership de-designated all of the foreign exchange contracts existing at April 1, 2006. Unrealized fair value changes in these contracts and amortization of the deferred gain resulted in a gain in the second quarter of 2006 and in the first three quarters of 2007. Losses were recorded in the third and fourth quarters of 2006. A $2.3 million fuel charge was accrued in the second quarter of 2006 for the potential payments to natural gas suppliers, which impacts net income.

In the third and fourth quarters of 2006, the Partnership acquired Frederickson and PEV, respectively.

QUARTERLY UNIT TRADING INFORMATION

The Partnership units trade on the Toronto Stock Exchange under the symbol EP.UN.

For the three months ended *(unaudited)*	**Sep. 30 2007**	**Jun. 30 2007**	**Mar. 31 2007**	**Dec. 31 2006**	**Sep. 30 2006**
Unit Price					
High	$27.90	$27.29	$29.00	$33.74	$33.60
Low	$22.10	$25.38	$25.27	$22.51	$30.76
Close	$24.64	$26.30	$25.60	$26.75	$32.27
Volume traded (millions)	4.5	5.5	5.1	9.7	5.1

As at September 30, 2007, the Partnership had 53.9 million units outstanding. The weighted average number of units outstanding for the three and nine months ended September 30, 2007 was 53.9 million and 51.7 million which is higher than the same period in 2006 due to the issue of 2,460,000 units related to the Frederickson acquisition and 4,015,297 units related to the PEV acquisition.

EPCOR Power L.P.
CONSOLIDATED STATEMENTS OF INCOME AND LOSS

(unaudited) (In millions of dollars except units and per unit amounts)	Three months ended September 30 2007	2006	Nine months ended September 30 2007	2006
Revenues	**$ 153.4**	$ 72.6	**$ 461.6**	$ 244.9
Cost of fuel	**110.9**	21.3	**249.7**	58.8
Operating and maintenance expense	**14.9**	7.8	**46.1**	21.9
Other plant operating expenses	**7.0**	5.3	**25.1**	14.3
	20.6	38.2	**140.7**	149.9
Other costs (income)				
Depreciation and amortization	**23.0**	17.3	**68.8**	50.7
Management and administration	**3.8**	2.5	**9.7**	6.6
Foreign exchange (gains) losses	**(24.1)**	0.5	**(56.3)**	(8.3)
Equity losses in PERH	**1.7**	-	**2.7**	-
Financial charges and other, net (Note 6)	**16.7**	6.6	**39.7**	18.5
Asset impairment charge (Note 4)	**13.0**	-	**13.0**	-
	34.1	26.9	**77.6**	67.5
Net income (loss) before income tax and preferred share dividends	**(13.5)**	11.3	**63.1**	82.4
Income tax expense (Note 5)	**0.8**	0.5	**75.4**	7.4
Net income (loss) before preferred share dividends	**(14.3)**	10.8	**(12.3)**	75.0
Preferred share dividends of a subsidiary company	**1.6**	-	**2.2**	-
Net income (loss)	**$ (15.9)**	$ 10.8	**$ (14.5)**	$ 75.0
Net income (loss) per unit	**($0.29)**	$0.22	**$ (0.28)**	$1.56
Weighted average units outstanding (millions)	**53.9**	49.1	**51.7**	48.0

See accompanying notes to the consolidated financial statements.

EPCOR Power L.P.

CONSOLIDATED STATEMENTS OF CASH FLOW

(unaudited) *(In millions of dollars)*	**Three months ended September 30** **2007**	2006	**Nine months ended September 30** **2007**	2006
Operating activities				
Net income (loss)	**$ (15.9)**	$ 10.8	**$ (14.5)**	$ 75.0
Items not affecting cash:				
Depreciation and amortization	**23.0**	17.3	**68.8**	50.7
Asset impairment charge (Note 4)	**13.0**	-	**13.0**	-
Future income tax	**(0.7)**	0.8	**70.8**	5.2
Fair value changes on derivative instruments	**37.1**	0.2	**36.3**	(5.3)
Unrealized foreign exchange gains	**(25.5)**	(0.3)	**(77.4)**	(9.1)
Other	**2.5**	0.2	**4.5**	(5.7)
	33.5	29.0	**101.5**	110.8
(Increase) decrease in operating working capital	**(12.7)**	0.6	**(12.2)**	6.2
Cash provided by operating activities	**20.8**	29.6	**89.3**	117.0
Investing activities				
Additions to property, plant and equipment	**(2.6)**	(2.2)	**(7.9)**	(4.2)
Dividends from PERH	**0.5**	-	**2.8**	-
Acquisition of interest in Frederickson Power L.P.	**-**	(137.8)	**-**	(137.8)
Cash used in investing activities	**(2.1)**	(140.0)	**(5.1)**	(142.0)
Financing activities				
Distributions paid	**(33.9)**	(31.4)	**(96.7)**	(91.2)
Net proceeds from preferred share offering (Note 7)	**-**	-	**120.8**	-
Net proceeds from unit offering (Note 9)	**-**	80.0	**101.3**	80.0
Short-term debt repaid	**-**	-	**(200.5)**	-
Issue of short-term debt	**-**	31.2	**-**	31.2
Long-term debt repaid	**(155.6)**	(0.4)	**(185.9)**	(0.9)
Capital lease obligation repaid (Note 8)	**(71.7)**	-	**(74.4)**	-
Proceeds from long-term debt (Note 8)	**239.2**	-	**239.2**	210.0
Issue (repayment) of credit facility	**11.2**	-	**11.2**	(210.0)
Cash (used in) provided by financing activities	**(10.8)**	79.4	**(85.0)**	19.1
Increase (decrease) in cash and cash equivalents	**7.9**	(31.0)	**(0.8)**	(5.9)
Cash and cash equivalents, beginning of period	**23.3**	57.3	**32.0**	32.2
Cash and cash equivalents, end of period	**$ 31.2**	$ 26.3	**$ 31.2**	$ 26.3
Supplementary cash flow information				
Income taxes paid	**$ 0.4**	$ 0.3	**$ 3.5**	$ 2.1
Interest paid	**$ 10.2**	$ 6.8	**$ 38.9**	$ 18.9

See accompanying notes to the consolidated financial statements.

EPCOR Power L.P.

CONSOLIDATED BALANCE SHEETS

(unaudited) *(In millions of dollars)*	**September 30, 2007**	December 31, 2006
ASSETS		
Current assets		
Cash and cash equivalents	**$ 31.2**	$ 32.0
Accounts receivable	**68.2**	66.8
Inventories	**12.4**	15.3
Prepaids and other	**6.4**	5.9
Derivative instruments asset (Note 3)	**30.2**	9.2
	148.4	129.2
Property, plant and equipment	**1,062.6**	1,093.7
Power purchase arrangements	**461.6**	486.8
Long-term investments	**51.5**	56.9
Goodwill	**50.9**	50.1
Derivative instruments asset (Note 3)	**36.3**	6.1
Other assets (Note 4)	**31.1**	57.8
	$ 1,842.4	$ 1,880.6
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities		
Short-term debt	**$ -**	$ 216.3
Accounts payable	**48.8**	53.5
Distributions payable	**34.0**	31.4
Long-term debt due within one year	**12.3**	18.0
Derivative instruments liability (Note 3)	**1.2**	1.0
	96.3	320.2
Asset retirement obligations	**22.8**	21.7
Long-term debt	**620.1**	700.1
Derivative instruments liability (Note 3)	**0.1**	15.1
Contract liabilities	**6.7**	8.3
Future income taxes	**79.1**	9.8
Preferred shares issued by subsidiary company (Note 7)	**122.0**	-
Partners' equity (Note 9)	**895.3**	805.4
Contingencies (Note 11)		
	$ 1,842.4	$ 1,880.6

See accompanying notes to the consolidated financial statements.

EPCOR Power L.P.
CONSOLIDATED STATEMENTS OF PARTNERS' EQUITY

(unaudited) *(In millions of dollars)*	Nine months ended September 30 **2007**	2006
Partnership capital		
Balance at beginning of period	**$ 1,095.5**	$ 1,015.6
Issue of Partnership units (Note 9)	**101.6**	80.0
Balance at end of period	**$ 1,197.1**	$ 1,095.6
Accumulated deficit		
Balance at beginning of period:		
As previously reported	**$ (290.1)**	$ (228.0)
Adjustment for change in accounting policy (Note 2)	**96.1**	-
As restated	**(194.0)**	(228.0)
Net income (loss)	**(14.5)**	75.0
Cash distributions	**(99.3)**	(92.7)
Balance at end of period	**$ (307.8)**	$ (245.7)
Accumulated other comprehensive income		
Balance at beginning of period	**$ -**	$ -
Cumulative effect of adopting new accounting policies (Note 2)	**8.6**	-
Other comprehensive loss	**(2.6)**	-
Balance at end of period	**$ 6.0**	$ -
Partners' equity	**$ 895.3**	$ 849.9

See accompanying notes to the consolidated financial statements.

EPCOR Power L.P.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS

(unaudited) *(In millions of dollars)*	**Three months ended September 30 2007**	Nine months ended September 30 2007
Net loss	**$ (15.9)**	$ (14.5)
Other comprehensive loss, net of income taxes		
Amortization of deferred gains on derivatives de-designated as cash flow hedges to income	**(0.8)**	(2.6)
	(0.8)	(2.6)
Comprehensive loss	**$ (16.7)**	$ (17.1)

See accompanying notes to the consolidated financial statements.

Note 1. Significant accounting policies

The consolidated financial statements of EPCOR Power L.P. ("the Partnership") have been prepared by the management of the General Partner in accordance with Canadian generally accepted accounting principles ("GAAP"). The accounting policies applied are consistent with those outlined in the Partnership's annual financial statements for the year ended December 31, 2006, except for the changes described in Note 2. These consolidated financial statements reflect all normal recurring adjustments that are, in the opinion of management, necessary to present fairly the financial position and results of operations for the respective periods. These consolidated financial statements for the nine months ended September 30, 2007 do not include all disclosures required in the annual financial statements and should be read in conjunction with the annual financial statements included in the Partnership's 2006 Annual Report.

Quarterly revenues, net income and cash provided by operating activities are affected by seasonal contract pricing, seasonal weather conditions, fluctuations in US dollar exchange rates, fulfillment of firm energy requirements, natural gas prices, waste heat availability and planned and unplanned plant outages, as well as items outside of the normal course of operations. Quarterly net income is also affected by unrealized foreign exchange gains and losses on the Partnership's US dollar-denominated monetary assets and liabilities and fair value changes in derivative instruments. Revenues, net income and cash provided by operating activities from the Partnership's Ontario plants are generally higher in the winter months (October to March) and lower in the summer months (April to September) due to seasonal pricing under the power purchase arrangements ("PPAs"). Revenues and net income from the Partnership's hydroelectric plants are generally higher in the spring months due to seasonally higher water flows. The California and North Carolina plants acquired on November 1, 2006 are expected to generate the majority of their operating margin during the summer months.

Since a determination of many assets, liabilities, revenues and expenses is dependent on future events, the preparation of these consolidated financial statements requires the use of estimates and assumptions which have been made with careful judgment. In the opinion of management of the Partnership's General Partner, these consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the Partnership's accounting policies.

Note 2. Change in accounting policy

Commencing January 1, 2007, the Partnership adopted new Canadian accounting standards for Comprehensive Income, Equity and Financial Instruments. The new accounting standards have been applied prospectively and the comparative interim financial statements have not been restated.

Comprehensive income and equity

These new standards establish requirements for the reporting and presentation of comprehensive income which is comprised of net income and other comprehensive income as well as the presentation of equity and changes in equity due to the comprehensive income requirements. The Partnership's other comprehensive income includes amortization of deferred unrealized gains from previously de-designated cash flow hedges. Each component of the statement of comprehensive income is recorded net of income taxes. Accumulated other comprehensive income is a new component of partners' equity.

Financial instruments – recognition and measurement

The new accounting standards require that financial assets be identified and classified as either available-for-sale, held for trading, held-to-maturity or loans and receivables. Financial liabilities are classified as either held for trading or other. Initially, all financial assets and financial liabilities must be recorded on the balance sheet at fair value with subsequent measurement determined by the classification of each financial asset and liability.

Financial assets and financial liabilities held for trading are measured at fair value with the changes in fair value reported in earnings. Financial assets held to maturity, loans and receivables and financial liabilities other than those held for trading are measured at amortized cost. Available-for-sale financial assets are measured at fair value with changes in fair value reported in other comprehensive income until the financial asset is disposed of, or becomes impaired.

Transaction costs related to available-for-sale, held to maturity and loans and receivables are generally capitalized and amortized over the expected life of the instrument using the effective interest method. Transaction costs that are directly attributable to the acquisition or issue of financial instruments classified as "held for trading" are expensed.

All derivative instruments, including embedded derivatives, are recorded at fair value on the balance sheet as derivative assets and derivative liabilities unless exempted from derivative treatment as a normal purchase and sale. All changes in their fair value are recorded in net income unless cash flow hedge accounting is used, in which case changes in fair value are recorded in other comprehensive income. The Partnership has elected to apply normal purchase and sale accounting to all of its host contracts that qualified under the new accounting standards. Because the natural gas supplied under long-term contracts is at times re-sold in the market and not entirely used to produce electricity, these contracts did not meet the requirements for a normal purchase election. Accordingly the natural gas contracts at the Ontario plants have been recorded at fair value at January 1, 2007 as a derivative instrument asset with a corresponding adjustment to opening accumulated deficit. Subsequent changes in the fair value of these contracts are reported in the Partnership's income statement.

Other significant accounting implications arising on the adoption of this accounting standard include the use of the effective interest method of amortizing transaction costs related to loans issued by the Partnership and attributing transaction costs to the related financial liability. Prior to January 1, 2007 the transactions costs were amortized to income on a straight-line basis over the life of the related loan. The new standard requires that the Partnership use the effective interest method to recognize the transaction costs whereby the amount recognized varies over the life of the loan based on the principal outstanding. At January 1, 2007, the Partnership reclassified its deferred transaction costs on its loans from other assets to long-term debt and adjusted the balance to reflect the use of the effective interest method.

The change in accounting policy did not result in a change in the future income tax liability of the Partnership based on the tax laws applicable to the Partnership as at January 1, 2007. The tax status of the Partnership changed on June 12, 2007 when the "Tax Fairness Plan" announced by the Canadian Finance Minister became substantively enacted as discussed in Note 4.

Financial statement impact

Certain physical fuel purchase contracts are not designated as contracts used in accordance with our expected purchase requirements and, therefore, are measured at fair value. An opening adjustment to retained earnings to reflect the fair value of these contracts at January 1, 2007 has been recorded. Subsequent changes in the fair value of these contracts are reported in net income.

Qualifying cash flow hedges of electricity and natural gas sales and purchases have been established and the changes in the fair value of the effective portion of the associated derivative instruments have been reflected as an opening adjustment to accumulated other comprehensive income with subsequent changes to the effective portion included in other comprehensive income. The changes in the fair value of the ineffective portion of these derivatives are included in net income.

Prior to the adoption of these new standards, the unrealized losses on certain financial instruments which did not satisfy all the required conditions for hedge accounting were recorded as a derivative instruments asset in the balance sheet. As required by the new standards, these unrealized losses were reclassified to opening retained earnings.

Also prior to the adoption of these new standards, the unrealized gains associated with discontinued hedges were included in derivative instruments liability in the balance sheet. These gains were recognized in net income on the same basis as the net income recognition of the related hedged item. Consistent with the requirements of the new standards, these unrealized gains were reclassified to accumulated other comprehensive income as a cumulative opening adjustment.

On January 1, 2007, the Partnership made the following adjustments to its balance sheet to adopt the new standards:

Balance Sheet Category Increase (Decrease)		**As at January 1, 2007**	**Explanation**
(In millions of dollars)			
Other assets	$	(4.5)	To no longer record deferred financing costs as other assets using straight-line amortization
Derivative instruments - asset		96.0	To record natural gas supply contracts at fair value
Derivative instruments - net liability		(8.6)	To no longer record deferred unrealized gains as derivative instruments
Long-term debt		(4.6)	To record deferred financing costs as debenture discounts using effective interest method
Opening accumulated deficit		(96.1)	After tax impact to opening retained earnings resulting from adoption of new standards
Opening accumulated other comprehensive income		8.6	To record deferred unrealized gains as accumulated other comprehensive income

During the three and nine months ended September 30, 2007 the new accounting standards impacted the financial statements in the following manner:

Financial Statement Category Increase (Decrease) *(In millions of dollars)*		**For the three months ended or as at September 30, 2007**		**For the nine months ended or as at September 30, 2007**	**Explanation**
Accumulated other comprehensive loss	$	(0.8)	$	(2.6)	To reclassify accumulated other comprehensive income related to de-designated cash flow hedges to income.
Cost of fuel		52.7		68.2	To record change in the fair value of natural gas contracts from January 1, 2007 to September 30, 2007
Derivative instruments - asset		(52.7)		(68.2)	

Losses of $52.7 million and $68.2 million have been recorded in the three and nine months ended September 30, 2007 to reflect the change in fair value of natural gas supply contracts and were recorded against cost of fuel. Accumulated other comprehensive income was decreased by $0.8 million and $2.6 million for the three and nine month periods ended September 30, 2007 due to the reclassification of gains on de-designated hedges to revenue. Under the Partnership’s previous accounting policy the reclassification to revenue would have been from derivative financial instruments - net liability. The impact of the effective interest method was insignificant in the first nine months of the year.

Future accounting standards

On December 1, 2006, the new Canadian accounting standards were issued for Capital Disclosures and Financial Instruments – Disclosures and Presentation. Effective January 1, 2008, the Partnership will adopt these new accounting standards.

As required by the new standards, the Partnership will disclose quantitative and qualitative information that is intended to provide users of the financial statements with additional disclosures on the Partnership's management of capital and on the risks associated with financial instruments. The Partnership is currently reviewing the impact of these new standards on its financial statements.

Effective January 1, 2008, the new Canadian accounting standards will require inventories to be measured at the lower of cost and net realizable value. The Partnership measures inventories held for consumption at the lower of cost and replacement value, which may be the best available measure for net realizable value. The Partnership is assessing the impact, if any, of the new standard.

Note 3. Financial instruments

The classification of fair values and carrying values of the Partnership's other financial instruments at September 30, 2007 are summarized as follows:

	Carrying Value			
(In millions of dollars)	Held-for-trading	Other financial liabilities	Total	Total fair value
Derivative instruments asset – current	$ 30.2	$ -	$ 30.2	$ 30.2
Derivative instruments asset – non-current	36.3	-	36.3	36.3
Derivative instruments liability – current	(1.2)	-	(1.2)	(1.2)
Derivative instruments liability – non-current	(0.1)	-	(0.1)	(0.1)
Long-term debt (including current portion)	-	(632.3)	(632.3)	(658.6)

Fair value amounts reflect management's best estimates considering various factors including closing exchange or over-the-counter quotations, estimates of futures prices and foreign exchange rates, time value and volatility. In illiquid or inactive markets, the Partnership uses appropriate price modeling, such as option pricing models and discounted cash flow analysis, using observable market based inputs to estimate fair value. It is possible that the assumptions used in establishing fair value amounts will differ from actual prices and the impact of such variations could be material.

The fair values of all other financial assets and financial liabilities including cash and cash equivalents, accounts receivable, accounts payable and distributions payable are not materially different from their carrying values due to their short-term nature.

Risk management and hedging activities

The Partnership is exposed to changes in commodity prices, foreign currency exchange rates and interest rates, of which the Partnership uses various risk management techniques including derivative financial instruments to reduce its exposure. Derivative financial instruments may include forward contracts, fixed-for-floating swaps and option contracts. Such instruments may be used to establish a fixed price for physical commodity requirements, interest-bearing obligations, anticipated obligation requirements or obligations denominated in a foreign currency.

The derivative assets and liabilities used for risk management purposes comprise the following:

	September 30, 2007			
(In millions of dollars)	Natural gas Non-hedges	Foreign exchange Non-hedges	Interest rate Non-hedges	Total
Derivative instruments assets:				
Current	$ 18.6	$ 11.6	$ -	$ 30.2
Non-current	9.1	27.2	-	36.3
Derivative instruments liabilities:				
Current	-	(1.2)	-	(1.2)
Non-current	-	(0.1)	-	(0.1)
	$ 27.7	$ 37.5	$ -	$ 65.2

	December 31, 2006			
(In millions of dollars)	Natural gas Non-hedges	Foreign exchange Non-hedges	Interest rate Non-hedges	Total
Derivative instruments assets:				
Current	$ -	$ 8.2	$ 1.0	$ 9.2
Non-current	-	6.1	-	6.1
Derivative instruments liabilities:				
Current	-	(1.0)	-	(1.0)
Non-current	-	(15.1)	-	(15.1)
	$ -	$ (1.8)	$ 1.0	$ (0.8)

Note 4. Asset impairment charge

Changes in outlook for incentives that were expected to be earned under the management agreement between a subsidiary of the Partnership and Primary Energy Recycling Holdings LLC (“PERH”), Primary Energy Operations LLC and Primary Energy Recycling Corporation (“PERC”) based on expected future cash distributions from PERH resulted in the determination that the full book value of this management agreement was unlikely to be recovered from future cash flows. As a result, the Partnership recorded a $13 million pre-tax impairment charge to write off this asset based on its fair value. The asset was previously recorded in other assets.

Note 5. Income taxes

In the second quarter of 2007 tax legislation included in Bill C-52, the Budget Implementation Act, 2007 (the “Bill) was substantively enacted and will result in changes to the manner in which certain publicly traded trusts and partnerships are taxed. Substantive enactment of the Bill resulted in the recognition of future income tax amounts based on estimated net taxable temporary differences of $239 million which are expected to reverse after 2010 and for which no tax has previously been recorded in the Partnership’s financial statements. Accordingly, a future income tax expense and a net future income tax liability of approximately $75.5 million were recognized upon substantial enactment.

Note 6. Financial charges and other, net

(millions of dollars)	Three months ended September 30 **2007**	2006	Nine months ended September 30 **2007**	2006
Interest on long-term debt	**$ 9.0**	$ 6.1	**$ 27.1**	$ 17.8
Interest on short-term debt	**-**	0.3	**4.9**	0.3
Interest on capital lease obligations	**1.4**	-	**4.5**	-
Dividend income from Class B preferred interests in PERH	**(0.4)**	-	**(1.2)**	-
Realized losses on interest rate contracts	**8.1**	-	**2.6**	-
Fair value changes on interest rate contracts	**(1.2)**	-	**1.0**	-
Other	**(0.2)**	0.2	**0.8**	0.4
	$ 16.7	$ 6.6	**$ 39.7**	$ 18.5

Note 7. Preferred shares issued by a subsidiary company

In May 2007, a subsidiary of the Partnership issued 5 million of 4.85% Cumulative Redeemable First Preference Shares, Series 1 priced at $25.00 per share with dividends payable on a quarterly basis at the annual rate of $1.2125 per share. Proceeds of $120.8 million, net of issue costs of $4.2 million were used to repay amounts outstanding under the bridge acquisition credit facility due in October 2007 incurred in conjunction with the Partnership's acquisition of Primary Energy Ventures LLC ("PEV") in November 2006. Future income tax assets of $1.2 million on the share issue costs are recorded in the preferred share balance. On or after June 30, 2012, the shares are redeemable by the subsidiary company at $26.00 per share, declining by $0.25 each year to $25.00 per share after June 30, 2016. The shares are not retractable by the holders.

Note 8. Long-term debt

	Interest Rate	**September 30, 2007**	Interest Rate	December 31, 2006
Senior unsecured medium term notes, due 2036	5.95%	**$ 210.0**	5.95%	$ 210.0
Senior unsecured notes (US$190.0 million), due 2014	5.90%	**189.0**	5.90%	221.4
Senior unsecured notes (US$150.0 million), due 2017	5.87%	**149.2**		-
Senior unsecured notes (US$75.0 million), due 2019	5.97%	**74.6**		-
Revolving credit facilities	4.77%	**11.2**	5.60%	149.4
Secured term loan, due 2010	11.30%	**3.8**	11.30%	4.8
Bridge acquisition credit facility		**-**	5.80%	51.3
Obligations under capital leases		**-**	9.10%	81.2
		637.8		718.1
Less: Current portion of long-term debt		**12.3**		18.0
Deferred debt issue costs		**5.4**		-
		$ 620.1		$ 700.1

The senior unsecured medium term notes due in 2036 have a coupon rate of 5.95% payable semi-annually in June and December and mature on June 23, 2036.

The senior unsecured notes due in 2014 are the obligation of Curtis Palmer Inc., an indirect wholly-owned subsidiary of the Partnership. The notes are fully and unconditionally guaranteed as to payment of principal, premium, if any, and interest on a senior unsecured basis by the Partnership. The notes mature in July 2014. Interest on the notes accrues at 5.9% per annum and is payable semi-annually in January and July.

On August 15, 2007, a subsidiary of the Partnership completed a private placement of senior unsecured notes for aggregate proceeds of $240.0 million (US$225.0 million), less issue costs of $0.8 million (US$0.7 million). The notes were issued in two tranches consisting of 10 and 12 year maturities. The $160.0 million (US$150.0 million) in 10-year notes have a coupon rate of 5.87% and the $80.0 million (US$75.0 million) in 12-year notes have a coupon rate of 5.97%.

The proceeds from the private placement were used to repay the capital lease obligations of $71.7 million (US$68.3 million) and amounts initially borrowed as part of the Frederickson and PEV acquisitions of $155.6 (US$145.3 million).

Under the terms of the revolving credit facilities, the Partnership can obtain advances by way of prime loans, US Base Rate loans, LIBOR loans and Bankers' Acceptances. At September 30, 2007, the revolving credit facilities had an average interest rate of approximately 4.8%. There are three $100.0 million revolving credit facilities with three year terms maturing in September 2009, October 2009 and June 2010, subject to extension. At September 30, 2007, $11.2 million was drawn against these facilities. The Partnership's revolving credit facilities may be used for general partnership purposes including working capital support.

The secured term loan is secured by a first fixed and specific mortgage over the Queen Charlotte plant. The loan bears interest at an annual rate of approximately 11.3% and matures on July 15, 2010.

On August 24, 2007, the Partnership paid off its capital lease obligations for the Naval Station, North Island and Naval Training Centers for $71.7 million (US$68.3 million). The $1.0 million difference between the purchase price and the carrying amount of the lease obligation has been recorded as an increase in the cost of the acquired property plant and equipment.

At January 1, 2007, the Partnership reclassified its deferred debt issue costs on its loans from other assets to long-term debt. Deferred transaction costs are amortized using the effective interest rate method. At September 30, 2007 transaction costs were $7.8 million, net of accumulated amortization of $2.4 million.

Principal repayments

Principal repayments on the long-term debt of the Partnership for the next five years and thereafter are estimated as follows:

	Long-term debt
2007 (3 months)	$ 11.2
2008	1.1
2009	1.3
2010	1.4
2011	-
2012	-
Later Years	622.8
Total Payments	$ 637.8

Note 9. Partners' equity

In May 2007, the Partnership issued 4,015,297 units, priced at $26.15 per unit, to the public and EPCOR for net proceeds of $101.6 million, to repay amounts outstanding under the bridge acquisition credit facility due in October 2007, and a portion of the bridge acquisition credit facility due in October 2009, both incurred in conjunction with the Partnership's acquisition of PEV in November 2006.

	Number of Units
Outstanding at December 31, 2006	49,881,982
Units issued	4,015,297
Outstanding at September 30, 2007	53,897,279

Note 10. US Operations

For the three and nine months ended September 30, 2007, the Partnership's US operations generated approximately $90.2 million and $270.5 million of revenue ($27.6 million and $86.9 million for the three and nine months ended September 30, 2006). At September 30, 2007 the net book value of U.S. plant, property and equipment, PPAs, other intangible assets and goodwill was $969.3 million (December 31, 2006 - $1,025.6 million).

Note 11. Contingencies

A settlement agreement has been reached with Devon Canada Corporation in respect of its claim of frustration of the contract pursuant to which it supplies gas to the Partnership at the Tunis, Ontario plant. No settlement has yet been reached in respect of a separate but similar claim by NAL Resources Ltd. The Partnership has accrued for expected additional payments and has incorporated anticipated increases in fuel supply prices into the determination of the fair value of derivative instruments at September 30, 2007.

For further information on the Partnership visit www.epcorpowerlp.ca or contact:

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