



EPCOR  
Power L.P.

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## EPCOR Power L.P. Announces 2006 Third Quarter Results

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**Edmonton, Alberta** – October 30, 2006 (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, 2006.

"With Primary Energy Ventures acquisition on track for completion in the current quarter, the Partnership is continuing its emergence as one of Canada's significant energy funds," said Brian Vaasjo, President of EPCOR Power Services Ltd. "This acquisition strengthens the Partnership's position in the U.S. market and provides a platform for further growth. The acquisition will contribute approximately six cents to the Partnership's cash available for distribution on a per unit basis, based on current markets and operating conditions. Once the acquisition is completed, the number of facilities owned by the Partnership will increase to 20 facilities while increasing the generation capacity by 52 per cent to 1,323 megawatts. The Partnership has also reached an agreement with Xcel Energy to extend the term of the Manchief plant's power purchase arrangement for an additional 10 years. Both of these initiatives align with the Partnership's goal of providing unitholders with stable distributions over the long-term."

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

Funds generated from operations were \$29.0 million or \$0.59 per unit and \$110.8 million or \$2.31 per unit for the three and nine months ended September 30, 2006 compared with \$35.7 million or \$0.75 per unit and \$114.4 million or \$2.41 per unit for the same periods in 2005. <sup>(1)</sup> The third quarter decrease in funds generated from operations is primarily due to lower enhancement and diversion revenue at the Ontario plants due to the lower market price of natural gas. The year to date decrease in funds generated from operations in total and on a per unit basis was primarily due to lower revenue from enhancement and diversion revenue due to the lower market price for natural gas, the lower Curtis Palmer pricing and higher fuel supply costs at the Ontario plants. This is partially offset by higher water flows at Curtis Palmer and an agreement with the Ontario Electricity Financial Corporation ("OEFC") on a replacement for the Direct Customer Rate ("DCR") index that was discontinued in 2002. The OEFC settlement adjusts the amount owed to the Partnership under the power purchase agreements ("PPAs") for the Ontario plants for the period from 2002 through to the end of the respective PPAs. The retroactive portion of the settlement was received in the first quarter and positively impacted funds generated from operations and net income by \$8.5 million.

Net income was \$10.8 million or \$0.22 per unit and \$75.0 million or \$1.56 per unit for the three and nine months ended September 30, 2006 compared to \$28.0 million or \$0.59 per unit and \$65.3 million or \$1.38 per unit for the same periods in 2005. The decrease in net income for the three months ended September 30, 2006 compared to the same prior year period was due to lower enhancement and diversion revenue, increased major maintenance and a significant

<sup>(1)</sup> Funds generated from operations is a non-GAAP financial measure that is defined in the interim report.

unrealized foreign exchange gain on the translation of the Partnership's U.S. dollar denominated debt in 2005.

Cash distributions of \$31.4 million or \$0.63 per unit were declared for the third quarter of 2006, compared to \$29.9 million and \$0.63 per unit for the same period in 2005. The increase in cash distributions reflects the addition of 2,460,000 Limited Partnership Units which were issued in respect of the Frederickson Power L.P. acquisition. The Partnership utilizes funds generated from operations in excess of cash distributions to stabilize future quarterly cash distributions, to finance capital expenditures and to make discretionary debt repayments.

<b>Operational and Financial Highlights</b> <i>(unaudited)</i>	<b>Three months ended</b> <b>September 30</b>		<b>Nine months ended</b> <b>September 30</b>	
	<b>2006</b>	2005	<b>2006</b>	2005
<i>(millions of dollars except per unit and operational amounts)</i>				
Power Generated (GWh)	<b>874</b>	623	<b>2,275</b>	2,043
Weighted Average Plant Availability	<b>97%</b>	97%	<b>95%</b>	94%
Funds Generated from Operations <sup>(a)</sup>	<b>29.0</b>	35.7	<b>110.8</b>	114.4
Per unit	<b>\$0.59</b>	\$0.75	<b>\$2.31</b>	\$2.41
Net Income	<b>10.8</b>	28.0	<b>75.0</b>	65.3
Per unit	<b>\$0.22</b>	\$0.59	<b>\$1.56</b>	\$1.38
Cash Available for Distributions <sup>(a)</sup>	<b>26.4</b>	33.2	<b>105.7</b>	108.4
Per unit	<b>\$0.54</b>	\$0.70	<b>\$2.20</b>	\$2.29
Cash Distributions	<b>31.4</b>	29.9	<b>92.7</b>	89.6
Per unit	<b>\$0.63</b>	\$0.63	<b>\$1.89</b>	\$1.89
Capital Expenditures	<b>2.2</b>	2.1	<b>4.2</b>	5.2
Weighted Average Units Outstanding (millions)	<b>49.1</b>	47.4	<b>48.0</b>	47.4

a) Funds Generated from Operations, Funds Generated from Operations per unit, Cash Available for Distributions and Cash Available for Distributions per unit are non-GAAP financial measures that are defined in the interim report.

The September 30, 2006 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.epcorpwrp.ca](http://www.epcorpwrp.ca)) and will be available at SEDAR ([www.sedar.com](http://www.sedar.com)).

# **EPCOR Power L.P.**

## **Interim Report**

### **September 30, 2006**

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#### **Management's discussion and analysis**

This management's discussion and analysis (MD&A), dated October 30, 2006 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, 2006 and the audited consolidated financial statements and MD&A of EPCOR Power L.P. for the year ended December 31, 2005.

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 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 and uncertainties, which could cause the Partnership's actual results and experience to be materially different than the anticipated results. Such risks and uncertainties include, but are not limited to, the ability of the Partnership to successfully 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, 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.

#### **RESULTS OF OPERATIONS**

The Partnership reported funds generated from operations of \$29.0 million or \$0.59 per unit and \$110.8 million or \$2.31 per unit for the three and nine months ended September 30, 2006 compared with \$35.7 million or \$0.75 per unit and \$114.4 million or \$2.41 per unit for the same periods in 2005. Funds generated from operations is defined below under Non-GAAP measures. The third quarter decrease in funds generated from operations compared to the prior year period is primarily due lower enhancement and diversion revenue at the Ontario plants resulting from lower natural gas prices. The year to date decrease in funds generated from operations in total and on a per unit basis was primarily due to lower revenue from enhancement and diversion revenue due to a lower market price for natural gas, the lower Curtis Palmer pricing and higher fuel supply costs at the Ontario plants. This is partially offset by higher water flows at Curtis Palmer and an agreement with the Ontario Electricity Financial Corporation ("OEF") on a replacement for the Direct Customer Rate ("DCR") index that was discontinued in 2002. The OEF settlement adjusts the amount owed to the Partnership under the power purchase agreements ("PPAs") for

the Ontario plants for the period from 2002 through to the end of the respective PPAs. The retroactive portion of the settlement was received in the first quarter and positively impacted funds generated from operations and net income by \$8.5 million. The expected full year impact of the settlement relating to the current year, excluding any retroactive amounts, is approximately a \$3 million increase in net income and funds from operations.

Net income was negatively impacted in the third quarter by lower enhancement and diversion revenue due to lower market prices for natural gas, foreign exchange losses primarily related to the Partnership's U.S. dollar-denominated debt and increased major maintenance at the Williams Lake facility. Enhancement and diversion revenues at the Ontario plants decreased \$5.5 million from the same period last year as a result of lower market prices for natural gas.

### Operating Margin

<i>(millions of dollars)(unaudited)</i>	Three months ended September 30		Nine months ended September 30	
	2006	2005	2006	2005
Ontario	14.1	19.8	59.8	58.0
Williams Lake	6.1	7.5	18.8	19.4
Mamquam and Queen Charlotte	2.3	1.2	9.1	9.0
Curtis Palmer	6.6	6.5	37.5	31.2
ManChief	5.2	5.6	16.2	15.2
Castleton	1.5	2.0	6.1	6.0
Frederickson	2.4	-	2.4	-
	<b>38.2</b>	<b>42.6</b>	<b>149.9</b>	<b>138.8</b>

Operating margin of \$38.2 million and \$149.9 million for the three and nine months ended September 30, 2006 was \$4.4 million lower and \$11.1 million higher respectively than the same periods of 2005. Operating margin is defined below under Non-GAAP measures. The decrease in operating margin for the three months ended September 30, 2006 compared to September 30, 2005 is due to lower enhancement and diversion sales at the Ontario plants as a result of the lower natural gas prices which has been partly offset by the addition of the Frederickson plant. The year to date increase in operating margin compared to the same period in the prior year was primarily due to the DCR settlement with the OEFC, an increase in revenues at the Curtis Palmer plant due to higher water flows and the addition of the Frederickson plant.

### Non-GAAP measures

The Partnership uses operating margin, funds generated from operations, funds generated from operations per unit, cash available for distributions and cash available for distributions per unit as performance measures with respect to the plants and the Partnership. These terms are not defined financial measures according to Canadian generally accepted accounting principles ("GAAP"), and they do not have standardized meanings prescribed by GAAP. Therefore, these measures may not be comparable to similar measures presented by other enterprises. There have been no changes in the composition of these measures as used by the Partnership in 2006 or 2005.

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 income tax is as follows:

<i>(millions of dollars)(unaudited)</i>	Three months ended September 30		Nine months ended September 30	
	2006	2005	2006	2005
Operating Margin	38.2	42.6	149.9	138.8
Deduct:				
Depreciation and amortization	17.3	16.5	50.7	49.5
Management and administration	2.5	2.4	6.6	6.4
Foreign exchange (gain)/loss	0.5	(11.3)	(8.3)	(7.2)
Financial charges and other	6.6	6.2	18.5	18.9
Net Income Before Income Tax	11.3	28.8	82.4	71.2

The Partnership uses funds generated from operations as a performance measure of the Partnership's ability, over the long term, to fund unitholder distributions, capital expenditures and debt repayment. A reconciliation of cash flow provided by operating activities to funds generated from operations is as follows:

<i>(millions of dollars)(unaudited)</i>	Three months ended September 30		Nine months ended September 30	
	2006	2005	2006	2005
Cash provided by operating activities	29.6	25.5	117.0	101.2
Increase/(decrease) in operating working capital	(0.6)	10.2	(6.2)	13.2
Funds generated from operations	29.0	35.7	110.8	114.4

Funds generated from operations per unit are equal to funds generated from operations divided by the weighted average number of units outstanding for the respective periods.

The Partnership uses cash available for distributions as a performance measure of the Partnership's ability over the long term to fund unitholder distributions. Cash available for distributions in excess of cash distributions is utilized by the Partnership to stabilize future quarterly cash distributions, to finance future capital expenditures and to make discretionary debt repayments. A reconciliation from cash provided by operating activities to cash available for distributions is as follows:

<i>(millions of dollars)(unaudited)</i>	Three months ended September 30		Nine months ended September 30	
	2006	2005	2006	2005
Cash provided by operating activities	29.6	25.5	117.0	101.2
Increase/(decrease) in operating working capital	(0.6)	10.2	(6.2)	13.2
Additions to property, plant and equipment	(2.2)	(2.1)	(4.2)	(5.2)
Long-term debt repayments	(0.4)	(0.4)	(0.9)	(0.8)
Cash available for distributions	26.4	33.2	105.7	108.4

Cash available for distributions per unit is equal to cash available for distributions divided by the weighted average number of units outstanding for the respective periods.

## Primary Energy Ventures LLC

On August 14, 2006 the Partnership and Primary Energy Ventures LLC ("PEV") announced the Partnership had signed a definitive agreement to acquire a 100 per cent interest in PEV. PEV owns eight combined heat and power facilities in the United States with an aggregate generation capacity of approximately 454 megawatts and 3.1 million lbs./hr of thermal energy, and owns a 15.4 per cent equity interest in Primary Energy Recycling Holdings LLC ("PERH"). PERH owns 4 energy facilities in the United States with an aggregate generation capacity of 284 megawatts and 1.9 million lbs./hr of thermal energy, and a 50 per cent interest in a pulverized coal facility. The acquisition price is U.S. \$380 million, consisting of U.S. \$310 million cash and assumption of U.S. \$70 million of lease obligations, subject to closing adjustments.

Based on current markets and operating conditions, the transaction is expected to be accretive to the Partnership's cash otherwise available for distribution by approximately CDN \$0.06 per unit per annum (see "Non-GAAP Measures").

The transaction is anticipated to close in the fourth quarter of 2006. The purchase price of the acquisition will be temporarily financed with a bank bridge facility with permanent financing to be arranged after the close of the transaction. The permanent financing is expected to consist of an offering of units by the Partnership representing approximately 70 per cent of the purchase price with the remaining 30 per cent financed with debt and the assumption of leases.

## **Frederickson Acquisition**

On August 1, 2006 the Partnership acquired from EPCOR a 100 per cent interest in Frederickson Power L.P. ("FPLP") for an aggregate purchase price of US \$117.8 million. FPLP owns a 50.15 per cent interest in the Frederickson power facility, a 249 megawatt ("MW") (nominal) single unit, natural gas-fired combined cycle generating facility located in Pierce County, Washington State, U.S.A. In addition, at the closing of the acquisition, EPCOR granted to the Partnership an option to acquire a 49 per cent interest in the development rights for a second generating unit adjacent to the Frederickson facility site for US \$4 million.

The acquisition was financed out of cash on hand, available committed lines of credit and the issuance of Subscription Receipts. The Partnership issued 2,460,000 Subscription Receipts at a price of \$33.35 per Subscription Receipt, representing net proceeds of \$80.0 million. The Subscription Receipts were converted into limited partnership units on a one for one basis upon closing of the acquisition. The holders of these units received a payment of \$0.63 per unit on August 4, 2006 in respect of the second quarter distribution.

## **Manchief Power Purchase Agreement**

On October 24, 2006 the Partnership announced that it has reached a 10-year extension on its PPAs with Public Service Company of Colorado ("PSCo"), conducting business in Colorado as Xcel Energy, for the output of the Partnership's Manchief power plant.

Electricity generated from the Manchief power plant is currently sold to Xcel Energy under two PPAs', both of which will expire on April 30, 2012. The 10-year extension with substantially similar terms and arrangements to the existing PPAs', applies to the entire output of the plant under a tolling arrangement. Under the new terms of the PPA extension, the capacity payments starting in May 2012 will be approximately 15 per cent lower than the existing PPAs'.

The Partnership and PSCo have also signed an Option Agreement whereby PSCo has the right, during the latter part of the PPA extension term, to acquire the Manchief power plant. If PSCo exercises the purchase option, the Partnership would receive a fixed purchase price, as specified in the Option Agreement, which the Partnership believes will maintain the economic value of the ten year PPA extension and compensate the Partnership for the power plant's expected residual value.

## **NAL and Devon Claims**

In July, 2004 NAL Resources Limited ("NAL") and Devon Canada Corporation ("Devon"), (collectively the "Plaintiffs") commenced actions against the Partnership claiming that the gas supply contracts under which the Plaintiffs sell gas to the Partnership for its Tunis, Ontario power plant have been frustrated as of January 1, 2003. The frustration claims are premised on an alleged inability to determine escalations in the commodity charge for gas under the agreements due to the Ontario government's decision to restructure the Ontario electricity market and the consequent interruption of the former Ontario Hydro's practice of annually determining a "Direct Customer Rate" (DCR). The Plaintiffs' additionally seek monetary damages based on referenced spot prices for natural gas deliveries. Discussions toward settlement of the claims have taken place and are expected to continue. Management believes there was no frustration of the contracts and that any amounts claimed above the aforementioned accrued amounts are without merit.

In March 2006, the Partnership determined that price escalations respecting power sales from the Tunis plant would appropriately be premised upon a calculation termed DCR(new) as put forth by one of Ontario Hydro's successors, the OEFC and as posted on the OEFC website, with potential for adjustments and reconciliations as the DCR(new) is updated. One feature of the DCR(new) is "three year averaging" which

has the effect of lengthening the time over which volatility in the electricity market impacts current prices. In the second quarter of 2006, the Partnership accrued for potential additional payments to gas suppliers, including NAL and Devon, based on the aforementioned ongoing and publicly available OEFC price escalation information but without the added feature of 3 year averaging, with a view to eliminating any ongoing basis for differences of opinion over the interpretation of the price escalation provisions in the gas supply agreements. As of the end of the third quarter, the Partnership has accrued a total of \$5.7 million in the current year for potential additional payments of which \$4.1 million relates to periods prior to 2006.

### **Credit Facility Increase**

On September 22, 2006, the Partnership replaced its existing \$50.0 million credit facility with a new \$100 million credit facility. The new credit facility is revolving with a three year extendible term committed to September, 2009 on substantially the same terms as the prior credit facility. At September 30, 2006 \$30.7 million was drawn against this facility.

On October 2, 2006, the Partnership arranged an additional \$100.0 million credit facility with another Canadian chartered bank. This credit facility has a revolving three-year extendible term committed to October 2009 on substantially the same terms as the other \$100 million credit facility.

The Partnership's bank credit facilities may be used for general partnership purposes including working capital support.

**Revenues and Plant Output**  
(millions of dollars except GWh)  
(unaudited)

**Three months ended  
September 30**

**Nine months ended  
September 30**

	<b>GWh</b>	<b>2006</b>	<b>GWh</b>	<b>2005</b>	<b>GWh</b>	<b>2006</b>	<b>GWh</b>	<b>2005</b>
Ontario								
- Power <sup>(1)</sup>	<b>323</b>	<b>\$ 25.6</b>	314	\$ 24.5	<b>1,013</b>	<b>\$ 99.4</b>	993	\$ 84.6
- Enhancements		<b>2.5</b>		5.4		<b>9.1</b>		12.0
- Gas diversions		<b>3.5</b>		6.1		<b>7.3</b>		10.5
		<b>31.6</b>		36.0		<b>115.8</b>		107.1
Williams Lake								
- Firm energy	<b>127</b>	<b>9.4</b>	131	9.3	<b>368</b>	<b>27.6</b>	372	26.7
- Excess energy	<b>12</b>	<b>0.7</b>	15	0.6	<b>40</b>	<b>2.2</b>	38	1.5
	<b>139</b>	<b>10.1</b>	146	9.9	<b>408</b>	<b>29.8</b>	410	28.2
Mamquam/Queen Charlotte	<b>44</b>	<b>3.3</b>	24	2.6	<b>187</b>	<b>12.4</b>	183	11.5
Curtis Palmer <sup>(2)</sup>	<b>76</b>	<b>8.0</b>	52	8.1	<b>302</b>	<b>41.8</b>	230	36.2
Manchief	<b>58</b>	<b>6.9</b>	49	7.3	<b>97</b>	<b>21.1</b>	62	20.0
Castleton	<b>55</b>	<b>8.3</b>	38	3.5	<b>89</b>	<b>19.6</b>	165	11.2
Frederickson <sup>(3)</sup>	<b>179</b>	<b>4.4</b>	-	-	<b>179</b>	<b>4.4</b>	-	-
	<b>874</b>	<b>\$ 72.6</b>	623	\$ 67.4	<b>2,275</b>	<b>\$244.9</b>	2,043	\$214.2

**Weighted Average Plant  
Availability<sup>(4)</sup>**

(unaudited)

**Three months ended  
September 30**

**Nine months ended  
September 30**

	<b>2006</b>	<b>2005</b>	<b>2006</b>	<b>2005</b>
Ontario Plants	<b>95%</b>	96%	<b>98%</b>	97%
Williams Lake	<b>96%</b>	100%	<b>94%</b>	96%
Mamquam/Queen Charlotte <sup>(5)</sup>	<b>95%</b>	75%	<b>84%</b>	84%
Curtis Palmer <sup>(2)</sup>	<b>93%</b>	98%	<b>97%</b>	98%
Manchief	<b>100%</b>	100%	<b>91%</b>	91%
Castleton <sup>(6)</sup>	<b>87%</b>	100%	<b>94%</b>	95%
Frederickson <sup>(3)</sup>	<b>100%</b>	-	<b>100%</b>	-
Weighted Average Total	<b>97%</b>	97%	<b>95%</b>	94%

(1) Power revenues for the Ontario plants are higher due to the settlement on the DCR replacement index in 2006 and increased generation due to reduced curtailment opportunities due to the price of natural gas.

(2) Revenues for Curtis Palmer for the nine months ended September 30, 2006 were higher than the same period last year due to higher water flows and the recognition of previously deferred revenue which offsets the impact of the lower pricing block that took effect in the current year. Lower availability this quarter is due to planned maintenance.

(3) Reflects results from the date of acquisition on August 1, 2006.

(4) 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. The weighted average total is based on plant capacity.

(5) The 50 MW Mamquam facility was unavailable for part of the third quarter last year due to planned and unplanned maintenance outages and Queen Charlotte was unavailable for part of the third quarter this year.

(6) Revenues for Castleton for the three and nine months ended September 30, 2006 were higher due to increased gas diversion revenue compared to the prior year. The plant was unavailable during the latter part of August due to an unplanned outage.

Revenues of \$72.6 million and \$244.9 million for the three and nine months ended September 30, 2006 were \$5.2 million and \$30.7 million higher than the same periods in 2005. The increase for the three month period was primarily due to the addition of the Frederickson plant. The increase for the nine month period includes the settlement with the OEFC on the replacement index for the DCR, increased natural gas optimization at the Castleton facility and higher water flows at the Curtis Palmer facility early in the year.

Revenues at the Ontario plants of \$31.6 million and \$115.8 million for the three and nine months ended September 30, 2006 were \$4.4 million lower and \$8.7 million higher than the same periods in 2005. Power revenue in the three month period was higher due to increased generation as result of lower curtailment activity. Enhancement revenues reflect decisions by the Manager to voluntarily curtail power production in favour of selling the unused natural gas at prevailing market prices. This is normally done in off-peak hours when contracted power prices are lower. Gas diversions occur when the Partnership sells gas in excess of daily plant requirements in situations, other than voluntary curtailment, such as during planned and unplanned outages. Enhancement and diversion revenues for the three months and nine months ended September 30, 2006 were lower than the comparable period in 2005 due to lower market prices for natural gas. The increase in power revenues for the nine month period also reflects the OEFC settlement recognized in the first quarter of 2006.

Revenues at the Williams Lake plant consist of firm energy sales, cost recovery components and excess energy sales under the PPAs with British Columbia Hydro and Power Authority ("BC Hydro"). Firm energy revenues of \$9.4 million and \$27.6 million for the three and nine months ended September 30, 2006 were \$0.1 million and \$0.9 million higher than the same periods in 2005 due partially to an increase in cost recoveries for higher fuel costs. Excess energy sales were \$0.7 million higher for the first three quarters of 2006 compared to the same prior year period due to an increase in generation and a higher market-based excess energy price in 2006 of \$54 per MWh compared with \$40 per MWh in 2005.

The Mamquam and Queen Charlotte plants reported revenues of \$3.3 million and \$12.4 million for the three and nine months ended September 30, 2006 compared with revenues of \$2.6 million and \$11.5 million for the same periods in the prior year. The higher revenue for the three months and nine months ended September 30, 2006 compared to the prior year periods was due to higher availability and increased production.

Revenue at the Curtis Palmer plant was \$8.0 million and \$41.8 million for the three and nine months ended September 30, 2006, compared with \$8.1 million and \$36.2 million for the same periods in 2005. The increase in revenues for the nine months ending September 30, 2006 compared to the same prior year period is due primarily to higher water flows early in the year. The increased generation of 24GWh and 72GWh for the three and nine month periods was offset by the step-down in pricing block that took affect January 2006. During the first five months of the year, the decreased revenue from the price block change was offset by recognition of previously deferred revenue of \$6.8 million.

Revenues at the Manchief plant were \$6.9 million and \$21.1 million for the three and nine months ended September 30, 2006 compared with \$7.3 million and \$20.0 million for the same periods in 2005. The decrease of \$0.4 million for the three months ended September 30, 2006 compared to the same period in 2005 is due primarily to the weakening of the \$US. The increase of \$1.1 million for the nine months ended September 30, 2006 compared to the same period in 2005 was due to changes in dispatch at the plant.

Revenues at the Castleton plant were \$8.3 million and \$19.6 million for the three and nine months ended September 30, 2006, compared to \$3.5 million and \$11.2 million for the same periods in 2005. The increase is due to the sale of excess gas transmission capacity which generated revenues of \$5.1 million and \$8.4 million for the three and nine months ended September 30, 2006. The increase in revenue is partly offset by higher fuel costs generated from these transactions, as discussed below.

The Partnership acquired the Frederickson plant on August 1, 2006 and the results of operations from this facility have been included in income from the date of acquisition.

Revenues at the U.S. plants including Curtis Palmer, Castleton, Manchief and Frederickson were also lower by \$0.3 million and higher by \$4.7 million for the three months and nine months ended September 30, 2006 due to unrealized changes in the fair value of foreign currency contracts. In the second quarter of 2006 the Partnership voluntarily de-designated certain hedge relationships for accounting purposes on foreign exchange contracts.

### **Cost of fuel**

Fuel costs include commodity price and transportation costs. For the three and nine months ended September 30, 2006 fuel costs were \$21.3 million and \$58.8 million compared with \$13.6 million and \$42.1 million for the same periods in 2005. Fuel costs at the Castleton plant for the three and nine months ended September 30, 2006 increased compared to the same periods in 2005 due to the gas transmission capacity sales, as discussed above. The increase in fuel costs also resulted from the \$5.7 million impact of the DCR index used in some of the Ontario gas supply contracts for the period from 2002 to the end of 2005 and accruals on certain gas supply contract claims. Contractual increases in other gas supply contracts for the Ontario plants also contributed to the increase.

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**

Operating and maintenance expense is based on fixed fees, adjusted annually for inflation, payable to EPCOR for the operation and routine maintenance of the plants. Operating and maintenance expense was \$7.8 million and \$21.9 million for the three and nine months ended September 30, 2006 compared to \$7.0 million and \$21.0 million for the same periods in 2005.

### **Other plant operating expenses**

Other plant operating expenses, which include insurance, property taxes and major maintenance expenses, of \$5.3 million and \$14.3 million for the three and nine months ended September 30, 2006 compared to \$4.2 million and \$12.3 million for the same periods in 2005. The quarter over quarter increase is due to higher major maintenance of \$1.0 million at the Williams Lake facility due to timing of work and \$0.2 million of other operating expenses at the Frederickson plant. The year to date increase also reflects additional maintenance work completed at Mamquam and Queen Charlotte compared to the respective prior year period.

### **Depreciation and amortization**

Depreciation and amortization expense for the three and nine months ended September 30, 2006 were \$17.3 million and \$50.7 million compared to \$16.5 million and \$49.5 million for the same periods in 2005. The higher depreciation charges for the 2006 periods are due to the addition of the Frederickson facility.

### **Management and administration**

Management and administration costs, which include fees payable to EPCOR and general and administrative costs, were at levels consistent with prior year periods.

### **Foreign exchange gain/loss**

The Partnership reported a foreign exchange loss of \$0.5 million for the three months ended September 30, 2006, compared to an \$11.3 million gain for the same period in 2005. A foreign exchange gain of \$8.3 million was reported for the nine months ended September 30, 2006 compared to a gain of \$7.2 million reported for the same period in 2005. The foreign exchange gains and losses reported in 2006 and 2005 were primarily unrealized and related to the translation of the Partnership's U.S. dollar-denominated debt.

## **Financial charges and other**

Financial charges and other expenses of \$6.6 million and \$18.5 million for the three and nine months ended September 30, 2006 were \$0.4 million higher and \$0.4 million lower compared with the same periods in 2005. The increase for the three months ended September 30, 2006 compared to the prior year period was due to short-term debt used to partially finance the Frederickson acquisition and slightly higher interest rates on the \$210 million medium-term notes that replaced the previous \$210 million credit facility. On a year to date basis, this is partially offset by higher interest income earned on higher average cash balances in 2006 compared to 2005.

## **Income taxes**

Income taxes relate to the taxes of the Partnership's U.S. subsidiaries and withholding taxes on distributions from the U.S. subsidiaries. The increase of \$1.5 million in income tax expense for the nine months ended September 30, 2006 compared to the same period in 2005 was due primarily to increased income from the Partnership's Curtis Palmer facility and the addition of the Frederickson plant.

## **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 2006, consistent with the same periods in 2005. The Partnership utilizes cash available for distributions in excess of cash distributions to stabilize future quarterly cash distributions, to finance capital expenditures and to make discretionary debt repayments.

The third quarter 2006 cash distribution of \$0.63 per unit will be paid on October 30, 2006 to unitholders of record on September 29, 2006.

### **Capital expenditures**

Capital expenditures for the nine months ended September 30, 2006 totaled \$4.2 million compared with \$5.2 million for the same period in 2005 and consisted of plant improvements. Capital spending in the fourth quarter of 2006 is expected to be higher than the previous three quarters with the expected result that full year 2006 expenditures will be slightly lower than full year 2005 or 2004.

## **FOREIGN EXCHANGE RISK MANAGEMENT**

The Partnership manages the foreign exchange risk of its future anticipated U.S. dollar-denominated cash flows from its U.S. plants through the use of forward foreign exchange contracts for periods up to six years. As at September 30, 2006, \$198.1 million or approximately 88 per cent of expected future cash flows were hedged for 2006 to 2012 at a weighted average exchange rate of \$1.169 to US \$1.00. The Partnership expects to hedge additional U.S. denominated cash flows upon successful completion of the PEV acquisition.

## TRANSACTIONS WITH RELATED PARTIES

<i>(unaudited)</i> <i>(millions of dollars)</i>	Three months ended September 30		Nine months ended September 30	
	2006	2005	2006	2005
<b>Revenues <sup>(1)</sup></b>				
Castleton - capacity payments	-	2.4	-	9.8
Ontario - enhancement revenues	-	5.4	-	12.0
Ontario - gas diversion sales	-	6.1	-	10.5
Ontario - Calstock guarantee fee	-	0.4	-	2.1
	<b>-</b>	<b>14.3</b>	<b>-</b>	<b>34.4</b>
<b>Cost of Fuel</b>				
Ontario - gas fuel supply <sup>(1)</sup>	-	3.1	-	14.9
Ontario - gas transportation <sup>(1)</sup>	-	1.9	-	7.5
Ontario - waste heat <sup>(1)</sup>	-	0.1	-	0.4
Castleton - gas demand charge	<b>0.5</b>	<b>0.3</b>	<b>1.6</b>	<b>1.5</b>
	<b>0.5</b>	<b>5.4</b>	<b>1.6</b>	<b>24.3</b>
<b>Acquisition Fee - Frederickson</b>	<b>2.7</b>	-	<b>2.7</b>	-
<b>Operating and Maintenance Expense</b>	<b>7.1</b>	<b>7.0</b>	<b>21.2</b>	<b>21.0</b>
<b>Management and Administration</b>				
Base fee	<b>0.3</b>	0.3	<b>0.9</b>	0.9
Incentive fee	<b>0.6</b>	0.5	<b>1.6</b>	1.5
Enhancement fee	<b>0.2</b>	0.9	<b>0.8</b>	1.7
	<b>1.1</b>	<b>1.7</b>	<b>3.3</b>	<b>4.1</b>

(1) These transactions were related party transactions only until September 1, 2005 at which time TransCanada sold its interest in the Partnership to EPCOR.

## CONTRACTUAL OBLIGATIONS

There have been no material changes to the Partnership's purchase obligations, including payments for the next five years and thereafter, since December 31, 2005 other than the proposed PEV acquisition. For further information on these obligations, refer to the MD&A in the Partnership's 2005 Annual Report.

## 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/Devon claims, depreciation expense and asset retirement obligations. For further information on the Partnership's critical accounting estimates, refer to the MD&A in the Partnership's 2005 Annual Report.

## BUSINESS RISKS

The Partnership's business and operational risks remain substantially unchanged since December 31, 2005 with the exception of the Calstock fuel supply described below. For further information on business risks, refer to the MD&A in the Partnership's 2005 Annual Report.

## **Calstock Fuel Supply**

The Partnership procures its wood waste fuel from a number of suppliers for the Calstock plant. In June, a fire at the mill of one supplier resulted in this mill temporarily shutting down to effect repairs. The mill is expected back in production in March 2007. Another supplier closed its mills on October 6, 2006. Combined these two suppliers represent approximately 40 per cent of the current Calstock fuel supply. The Partnership is actively pursuing long-term replacements for the displaced supply. To manage wood inventory until replacement supply is in place, the plant will curtail some power generation in off-peak periods. The financial impact from this curtailment is not expected to be significant in 2006 but could reduce operating margin for the plant by up to \$1.5 million in 2007 if the Partnership is unable to secure new sources of supply.

## **OUTLOOK**

The short-term outlook for the Partnership's business remains substantially unchanged since December 31, 2005. Funds generated from operations per unit in 2006 are expected to decline relative to 2005 due to the October 2005 expiry of the Calstock guarantee fee of approximately \$2.5 million annually, and a temporary step-down in pricing of approximately 33 per cent under the Curtis Palmer PPA which began in the first quarter of 2006. This impact is estimated to reduce funds generated from operations by approximately \$14 million in 2006 compared to 2005. The price changes at Curtis Palmer over the remainder of the contract are step increases with the first one at eighteen per cent currently estimated to take effect in 2009. In the third and fourth quarters of 2005, the Partnership also benefited from high natural gas prices which have declined to date in the second half of 2006. A portion of these impacts have been offset by the retroactive settlement with the OEFC on the replacement DCR index. The acquisition of the Frederickson facility and the proposed acquisition of PEV are forecast to be modestly accretive to funds generated from operations on a per unit basis. Results for the Partnership will vary based on a number of factors, including the operational performance of the plants, natural gas prices, the level of waste heat fuel at the Ontario plants provided by TransCanada's adjacent compressor stations and water flows at the hydro electric facilities. Maintenance capital spending is expected to be slightly lower in 2006 than it has averaged in 2004 and 2005.

Based on the Partnership's 2006 operating and capital plan and taking into consideration the above noted factors, management estimates that 2006 cash available for distributions will exceed recent annual cash distributions of \$2.52 per unit.

The long-term outlook for the Partnership continues to improve as a result of many recent initiatives. These initiatives include the expected acquisition of PEV, the completed acquisition of the Frederickson power facility, the extension of the Manchief PPA, and the public offering in Canada of senior unsecured medium term notes in the aggregate principal amount of \$210 million, which provides a fixed interest rate of 5.95 per cent for a term of 30 years. These initiatives align with the Partnership's goal of providing unitholders with long term stability and sustainable cash distributions.

## SELECTED QUARTERLY CONSOLIDATED FINANCIAL DATA

<i>(unaudited)</i> <i>(millions of dollars except per unit amounts)</i>	2006				2005			2004	
	Third	Second	First	Fourth	Third	Second	First	Fourth	
Revenues	<b>72.6</b>	81.0	91.3	81.5	67.4	72.3	74.5	69.1	
Net Income	<b>10.8</b>	30.3	33.9	21.2	28.0	15.5	21.8	30.2	
Funds Generated from Operations	<b>29.0</b>	31.0	50.6	42.9	35.7	37.1	41.6	36.9	
Capital Expenditures	<b>2.2</b>	1.2	0.8	9.2	2.1	2.6	0.5	3.8	
Cash Available for Distributions	<b>26.4</b>	29.8	49.3	33.7	33.2	34.5	40.7	33.1	
Cash Distributions	<b>31.4</b>	29.9	29.9	29.9	29.9	29.9	29.9	29.9	
<b>Per Unit Statistics</b>									
Net Income	<b>\$0.22</b>	\$0.64	\$0.72	\$0.45	\$0.59	\$0.33	\$0.46	\$0.64	
Funds Generated from Operations	<b>\$0.59</b>	\$0.65	\$1.07	\$0.91	\$0.75	\$0.78	\$0.88	\$0.78	
Cash Available for Distributions	<b>\$0.54</b>	\$0.63	\$1.04	\$0.71	\$0.70	\$0.73	\$0.86	\$0.70	
Cash Distributions	<b>\$0.63</b>	\$0.63	\$0.63	\$0.63	\$0.63	\$0.63	\$0.63	\$0.63	

### Factors Impacting Quarterly Financial Results

Quarterly revenues, net income and funds generated from operations are affected by seasonal contract pricing, seasonal weather conditions, fluctuations in U.S. 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 U.S. dollar-denominated long-term debt and fair value changes in forward foreign exchange contracts that are included in revenue. Revenues, net income and funds generated from operations 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 PPAs. Contributions from the Williams Lake plant are usually lower in the fourth quarter once the annual firm energy requirements are met and the plant is only producing lower-priced excess energy. Revenues and net income from the Partnership's hydroelectric plants are generally higher in the spring months due to seasonally higher water flows.

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

The Partnership issued U.S. dollar-denominated debt in 2004. This resulted in unrealized foreign exchange gains in quarters three and four of 2004, quarter three of 2005 and quarter two of 2006. Losses were recorded in the first, second and fourth quarters of 2005 and the first and third quarters of 2006. The gains and losses are due to fluctuations in the U.S. dollar relative to the Canadian dollar.

The fourth quarter of 2005 and the first and second quarters of 2006 had unseasonably high water flows at the Curtis Palmer hydroelectric facility. Enhancement and diversion revenues at the Ontario plants increased due to higher natural gas prices in the third and fourth quarters of 2005 and the first quarter of 2006.

The first quarter of 2006 the Partnership reached a settlement with the OEFC on a replacement for the DCR index. The retroactive portion of the settlement was recorded in the quarter and increased revenues, net income, funds generated from operations and cash available for distributions.

In the second quarter of 2006, the Partnership de-designated all of the forward foreign exchange cash flow hedges existing at April 1, 2006. Unrealized fair value changes in these contracts and amortization of the deferred gain totaling \$5.2 million was recognized in revenue and net income in the quarter. A \$3.0 million fuel charge was accrued in the quarter for the potential payments to gas suppliers which impacts net income, funds generated from operations and cash available for distributions.

In the third quarter of 2006, the Partnership acquired the Frederickson power facility resulting in increased revenue, net income and funds generated from operations.

## QUARTERLY UNIT TRADING INFORMATION

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

For the three months ended ( <i>unaudited</i> )	Sep. 30 2006	Jun. 30 2006	Mar. 31 2006	Dec. 31 2005	Sep. 30 2005	Jun. 30 2005
<b>Unit Price</b>						
High	<b>\$33.60</b>	\$33.90	\$36.00	\$37.00	\$37.47	\$37.06
Low	<b>\$30.76</b>	\$30.30	\$33.05	\$29.41	\$34.75	\$33.15
Close	<b>\$32.27</b>	\$33.00	\$33.75	\$35.25	\$35.99	\$36.60
<b>Volume traded (millions)</b>	<b>5.1</b>	4.6	4.9	5.4	3.7	3.7

As at September 30, 2006, the Partnership had 49,881,982 units outstanding. The weighted average number of units outstanding for the three months ended September 30, 2006 was 49.1 million which is 1.7 million higher than the same period in 2005 due to the issue of 2,460,000 units related to the Frederickson acquisition.

## ADDITIONAL INFORMATION

Additional information relating to EPCOR Power L.P. including the Partnership's 2005 Annual Information Form (AIF) and continuous disclosure documents are available on SEDAR at [www.sedar.com](http://www.sedar.com).

**EPCOR Power L.P.**  
**CONSOLIDATED STATEMENTS OF INCOME**

<i>(unaudited)</i> <i>(millions of dollars except per unit amounts)</i>	Three months ended		Nine months ended	
	2006	September 30 2005	2006	September 30 2005
<b>Revenues</b>	<b>72.6</b>	67.4	<b>244.9</b>	214.2
<b>Cost of Fuel</b>	<b>21.3</b>	13.6	<b>58.8</b>	42.1
<b>Operating and Maintenance Expense</b>	<b>7.8</b>	7.0	<b>21.9</b>	21.0
<b>Other Plant Operating Expenses</b>	<b>5.3</b>	4.2	<b>14.3</b>	12.3
	<b>38.2</b>	42.6	<b>149.9</b>	138.8
<b>Other Costs</b>				
Depreciation and amortization	<b>17.3</b>	16.5	<b>50.7</b>	49.5
Management and administration	<b>2.5</b>	2.4	<b>6.6</b>	6.4
Foreign exchange (gain)/loss	<b>0.5</b>	(11.3)	<b>(8.3)</b>	(7.2)
Financial charges and other	<b>6.6</b>	6.2	<b>18.5</b>	18.9
	<b>26.9</b>	13.8	<b>67.5</b>	67.6
<b>Net Income Before Income Tax</b>	<b>11.3</b>	28.8	<b>82.4</b>	71.2
<b>Income Tax Expense</b>	<b>0.5</b>	0.8	<b>7.4</b>	5.9
<b>Net Income</b>	<b>10.8</b>	28.0	<b>75.0</b>	65.3
<b>Net Income Per Unit</b>	<b>\$0.22</b>	\$0.59	<b>\$1.56</b>	\$1.38
<b>Weighted Average Units Outstanding (millions)</b>	<b>49.1</b>	47.4	<b>48.0</b>	47.4

See accompanying notes to the Consolidated Financial Statements.

**EPCOR Power L.P.**  
**CONSOLIDATED STATEMENTS OF CASH FLOW**

<i>(unaudited)</i>	<b>Three months ended</b>		<b>Nine months ended</b>	
<i>(millions of dollars except per unit amounts)</i>	<b>September 30</b>		<b>September 30</b>	
	<b>2006</b>	2005	<b>2006</b>	2005
<b>Cash Generated from Operations</b>				
Net income	10.8	28.0	75.0	65.3
Depreciation and amortization	17.3	16.5	50.7	49.5
Future income tax	0.8	2.8	5.2	4.2
Unrealized (gain)/loss de-designation of hedges	0.3	-	(4.7)	-
Unrealized foreign exchange (gain)/loss	(0.3)	(11.3)	(9.1)	(7.2)
Other	0.1	(0.3)	(6.3)	2.6
Funds generated from operations	29.0	35.7	110.8	114.4
Increase/(decrease) in operating working capital	0.6	(10.2)	6.2	(13.2)
Net cash provided by operating activities	29.6	25.5	117.0	101.2
<b>Investing Activities</b>				
Capital expenditures	(2.2)	(2.1)	(4.2)	(5.2)
Acquisition of interest in Frederickson Power L.P. (Note 2)	(137.8)	-	(137.8)	-
Net cash used in investing activities	(140.0)	(2.1)	(142.0)	(5.2)
<b>Financing Activities</b>				
Distributions paid	(31.4)	(29.8)	(91.2)	(89.6)
Proceeds from medium term notes	-	-	210.0	-
Repayment of credit facility	-	-	(210.0)	-
Issue of short-term debt	31.2	-	31.2	-
Issue of Limited Partnership Units, net	80.0	-	80.0	-
Long Term Debt repayments	(0.4)	(0.4)	(0.9)	(0.8)
Net cash provided by (used in) financing activities	79.4	(30.2)	19.1	(90.4)
<b>Increase (decrease) in Cash and Cash Equivalents</b>	<b>(31.0)</b>	<b>(6.8)</b>	<b>(5.9)</b>	<b>5.6</b>
<b>Cash and Cash Equivalents, Beginning of Period</b>	<b>57.3</b>	<b>32.6</b>	<b>32.2</b>	<b>20.2</b>
<b>Cash and Cash Equivalents, End of Period</b>	<b>26.3</b>	<b>25.8</b>	<b>26.3</b>	<b>25.8</b>
<b>Supplementary Cash Flow Information</b>				
Income taxes paid	0.3	0.4	2.1	1.7
Interest paid	6.8	8.9	18.9	20.7

See accompanying notes to the Consolidated Financial Statements.

**EPCOR Power L.P.**  
**CONSOLIDATED BALANCE SHEET**

<i>(unaudited)</i> <i>(millions of dollars)</i>	September 30, 2006	December 31, 2005
<b>ASSETS</b>		
<b>Current Assets</b>		
Cash and cash equivalents	26.3	32.2
Accounts receivable	37.7	46.4
Inventories	7.3	7.2
Prepays and other	6.0	4.3
Derivative finance instruments asset (Note 4)	3.8	-
	<u>81.1</u>	<u>90.1</u>
<b>Plant, Property and Equipment</b>	<b>955.4</b>	<b>873.7</b>
<b>Power Purchase Arrangements</b>	<b>355.7</b>	<b>347.9</b>
<b>Derivative Financial Instruments Asset</b> (Note 4)	<b>12.1</b>	<b>-</b>
<b>Goodwill</b> (Note 2)	<b>12.6</b>	<b>-</b>
<b>Other Assets</b>	<b>6.2</b>	<b>4.6</b>
	<u>1,423.1</u>	<u>1,316.3</u>
<b>LIABILITIES AND PARTNERS' EQUITY</b>		
Short-term debt (Note 5)	30.7	-
Accounts payable	36.7	42.2
Distributions payable	31.4	29.9
Current portion of long-term debt (Note 6)	1.0	0.9
Derivative financial instruments liability (Note 4)	0.2	0.3
	<u>100.0</u>	<u>73.3</u>
<b>Asset Retirement Obligations</b>	<b>18.3</b>	<b>17.1</b>
<b>Long-Term Debt</b> (Note 6)	<b>426.1</b>	<b>435.8</b>
<b>Derivative Financial Instruments Liability</b> (Note 4)	<b>11.1</b>	<b>-</b>
<b>Future Income Taxes</b>	<b>17.7</b>	<b>2.5</b>
<b>Partners' Equity</b>	<b>849.9</b>	<b>787.6</b>
<b>Contingencies</b> (Note 10)	<b>-</b>	<b>-</b>
	<u>1,423.1</u>	<u>1,316.3</u>

**CONSOLIDATED PARTNERS' EQUITY**

*Nine months ended September 30 (unaudited)*

<i>(millions of dollars)</i>	2006	2005
<b>Partnership Capital, beginning of period</b>	<b>1,015.6</b>	<b>1,015.6</b>
Issue of Partnership units (Note 3)	80.0	-
<b>Partnership Capital, end of period</b>	<u><b>1,095.6</b></u>	<u><b>1,015.6</b></u>
<b>Accumulated Deficit, beginning of period</b>	<b>(228.0)</b>	<b>(195.0)</b>
Net Income	75.0	65.3
Cash Distributions	(92.7)	(89.7)
<b>Accumulated Deficit, end of period</b>	<u><b>(245.7)</b></u>	<u><b>(219.4)</b></u>
<b>Partners' Equity</b>	<u><b>849.9</b></u>	<u><b>796.2</b></u>

See accompanying notes to the Consolidated Financial Statements.

## **EPCOR Power L.P.**

### **Notes to Consolidated Financial Statements (Unaudited)**

#### **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. The accounting policies applied are consistent with those outlined in the Partnership's annual financial statements for the year ended December 31, 2005. 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 three and nine months ended September 30, 2006 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 2005 Annual Report.

Quarterly revenues, net income and funds generated from operations are affected by seasonal contract pricing, seasonal weather conditions, fluctuations in U.S. dollar exchange rates, 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 U.S. dollar-denominated long-term debt and fair value changes in derivative financial instruments. Revenues, net income and funds generated from operations 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 agreements (“PPAs”). Revenues and net income from the Partnership's hydroelectric plants are generally higher in the spring months due to seasonally higher water flows.

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.

#### **2. Acquisition of Interest in Frederickson Power L.P.**

On August 1, 2006, the Partnership acquired from EPCOR Utilities Inc. (collectively with its wholly-owned subsidiaries “EPCOR”) a 100 per cent interest in Frederickson Power L.P. (“FPLP”). FPLP owns a 50.15 per cent interest in the Frederickson power facility located in Pierce County, Washington State, U.S.A. In addition, at the closing of the acquisition, EPCOR granted to the Partnership an option to acquire a 49 per cent interest in the development rights for a second generating unit adjacent to the Frederickson facility site for US \$4 million.

The total consideration paid was US\$117.8 million in cash plus acquisition costs of approximately US\$3.2 million including a \$2.7 million acquisition fee paid to EPCOR. The acquisition was financed out of cash on hand, available committed lines of credit and issued Subscription Receipts.

The acquisitions US\$121.0 million (CAD\$137.8 million) purchase price was allocated to the assets acquired and liabilities assumed on a preliminary basis based on their estimated fair values as follows:

Accounts receivable	\$ 2.3
Prepays and other	0.2
Property, plant and equipment	109.8
Power purchase arrangements	25.0
Goodwill	12.6
Accounts payable	(1.4)
Asset retirement obligations	(0.4)
Future income tax liability, non-current	(10.3)
<u>Fair value of net assets acquired</u>	<u>\$ 137.8</u>

The fair value estimates of certain assets and liabilities will be finalized during the fourth quarter based on completion of review by management. Such review could result in a material adjustment to the fair value purchase price allocation in subsequent periods.

Goodwill is the residual amount that results from the purchase price exceeding the sum of amounts allocated to the net assets acquired based on their fair values. Goodwill is not amortized, but rather is tested for impairment at least annually or more frequently if events and circumstances indicate that a possible impairment may arise earlier. The amount allocated to goodwill is not expected to be deductible for income tax purposes.

### 3. Partners' Equity

In April of 2006, the Partnership issued 2,460,000 Subscription Receipts, priced at \$33.35 per Subscription Receipt, to the public and EPCOR for net proceeds of \$80.0 million to finance part of the Frederickson acquisition. Upon closing of the acquisition, each Subscription Receipt was exchanged for one Limited Partnership Unit.

	<u>Number of Units</u>
Outstanding at December 31, 2005	47,421,982
<u>Units issued through Subscription Receipt offering</u>	<u>2,460,000</u>
<u>Outstanding at September 30, 2006</u>	<u>49,881,982</u>

### 4. Derivative Financial Instruments

The Partnership has a hedging program to manage its exposure to changes in foreign currency exchange rates that result from future anticipated U.S. dollar-denominated cash flows from its U.S. power plants. Up to April 1, 2006 the Partnership elected to apply hedge accounting to these foreign exchange contracts where accounting hedge criterion were met. On April 1, 2006 the Partnership voluntarily de-designated these hedging relationships for accounting purposes on all outstanding foreign exchange contracts. As a result a net derivative financial instrument asset of \$12.0 million was recognized which will be recorded into income in the same periods that the related previously hedged U.S. revenue occurs. As the hedged item is still considered highly probable to occur, the previously deferred unrealized gains on the hedging of U.S. dollar-denominated cash flows are deferred and carried forward for subsequent recognition in earnings as or when the hedged item occurs. Changes in the fair value of these foreign exchange contracts from April 1, 2006 forward are recorded in the revenue of the U.S. plants.

## **5. Short-term Debt**

On September 22, 2006, the Partnership replaced its existing \$50.0 million credit facility with a new \$100 million credit facility. The new credit facility is revolving with a three year extendible term committed to September, 2009 on substantially the same terms as the prior credit facility. At September 30, 2006 \$30.7 million was drawn against this facility.

On October 2, 2006, the Partnership arranged an additional \$100.0 million credit facility with another Canadian chartered bank. This credit facility has a revolving three-year extendible term committed to October 2009 on substantially the same terms as the other \$100 million credit facility.

The Partnership's bank credit facilities may be used for general partnership purposes including working capital support.

## **6. Long-Term Debt**

On June 23, 2006, the Partnership completed its first public offering in Canada of senior unsecured medium term notes in the aggregate principal amount of \$210 million. The notes have a coupon rate of 5.95 per cent payable semi annually in June and December and mature on June 23, 2036. The net proceeds of the offering were used to repay the Partnership's previous \$210 million credit facility.

## **7. Operating Leases**

As at September 30, 2006, the carrying value of the Manchief, Mamquam and Queen Charlotte plant, property and equipment was \$234.7 million (September 30, 2005 – \$232.7 million) less accumulated depreciation of \$15.8 million (September 30, 2005 – \$8.9 million). The Partnership's revenues for the three and nine months ended September 30, 2006 included \$10.2 million and \$33.5 million with respect to the Manchief, Mamquam and Queen Charlotte PPAs (\$9.9 million and \$31.5 million for the three and nine months ended September 30, 2005).

## **8. United States Operations**

For the three and nine months ended September 30, 2006, the Partnership's U.S. operations generated approximately \$27.6 million and \$86.9 million of revenue (\$18.9 million and \$67.4 million for the three and nine months ended September 30, 2005). As at September 30, 2006, the net book value of plant, property and equipment and PPAs related to assets held in the U.S. was \$661.4 million (September 30, 2005 - \$562.0 million).

## **9. Sale of Interest in the Partnership**

On September 1, 2005, EPCOR completed its acquisition of TransCanada Corporation's ("TransCanada") interest in TransCanada Power, L.P. (the Partnership). In connection with the close of the transaction, the Partnership was renamed EPCOR Power L.P. EPCOR's acquisition included: approximately 14.5 million units of the Partnership, representing approximately 30.6 per cent of the outstanding units; 100 per cent ownership of the General Partner of the Partnership; and management and operations agreements governing the ongoing operation of the Partnership's power generation assets.

## **10. Contingencies**

In July, 2004 NAL Resources Limited ("NAL") and Devon Canada Corporation ("Devon"), (collectively the "Plaintiffs") commenced actions against the Partnership claiming that the gas supply contracts under which the Plaintiffs' sell gas to the Partnership for its Tunis, Ontario power plant have been frustrated as of January 1, 2003. The frustration claims are premised on an alleged inability to determine escalations in the

commodity charge for gas under the agreements due to the Ontario government's decision to restructure the Ontario electricity market and the consequent interruption of the former Ontario Hydro's practice of annually determining a "Direct Customer Rate" (DCR). The Plaintiffs' additionally seek monetary damages based on referenced spot prices for natural gas deliveries. Discussions toward settlement of the claims have taken place and are expected to continue. Management believes there was no frustration of the contracts and that any amounts claimed above the aforementioned accrued amounts are without merit.

In March 2006, the Partnership determined that price escalations respecting power sales from the Tunis plant would appropriately be premised upon a calculation termed DCR(new) as put forth by one of Ontario Hydro's successors, the Ontario Electricity Financial Corporation ("OEFC") and as posted on the OEFC website, with potential for adjustments and reconciliations as the DCR(new) is updated. One feature of the DCR(new) is "three year averaging" which has the effect of lengthening the time over which volatility in the electricity market impacts current prices. In the second quarter of 2006, the Partnership accrued for potential additional payments to gas suppliers, including NAL and Devon, based on the aforementioned ongoing and publicly available OEFC price escalation information but without the added feature of three year averaging, with a view to eliminating any ongoing basis for differences of opinion over the interpretation of the price escalation provisions in the gas supply agreements. As of the end of the third quarter, the Partnership has accrued a total of \$5.7 million in the current year for potential additional payments of which \$4.1 million relates to periods prior to 2006.

## 11. Proposed Acquisition

On August 14, 2006 the Partnership and Primary Energy Ventures LLC ("PEV") announced the Partnership had signed a definitive agreement to acquire a 100 per cent interest in PEV. PEV owns eight combined heat and power facilities in the United States with an aggregate generation capacity of approximately 454 megawatts and 3.1 million lbs./hr of thermal energy, and owns a 15.4 per cent equity interest in Primary Energy Recycling Holdings LLC ("PERH"). PERH owns 4 energy facilities in the United States with an aggregate generation capacity of 284 megawatts and 1.9 million lbs./hr of thermal energy, and a 50 per cent interest in a pulverized coal facility. The acquisition price is U.S. \$380 million, consisting of U.S. \$310 million cash and assumption of U.S. \$70 million of lease obligations, subject to closing adjustments.

The transaction is anticipated to close in the fourth quarter of 2006. The acquisition will be temporarily financed with a bank bridge facility with permanent financing to be arranged after the close of the transaction. The permanent financing is expected to consist of an offering of units by the Partnership representing approximately 70 per cent of the purchase price with the remaining 30 per cent financed with debt and the assumption of leases.

## 12. Comparative Figures

Certain of the comparative figures have been reclassified to conform to the current year's presentation.

For further information on the Partnership visit [www.epcorp.powerlp.ca](http://www.epcorp.powerlp.ca) or contact:

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