

EPCOR Power L.P.

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EPCOR Power L.P. reports third quarter results

Edmonton, Alberta – October 26, 2009 (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, 2009.

Third quarter revenue was \$155.5 million, up 16.5 per cent from the year earlier level. Gross margin from the Partnership's plants, before adjustments for fair value changes, totaled \$53.4 million, a 5.8 per cent reduction from the 2008 period. Cash provided by operating activities from continuing operations excluding working capital changes was \$37.3 million in the quarter, consistent with expectations, compared with \$41.4 million for the same period last year. This resulted in a third quarter, 2009 payout ratio of 71 per cent, which reflected maintenance capital expenditures of \$3.9 million. The 71 per cent payout ratio is in-line with the Partnership's long-term payout ratio target of 75 per cent and represents a more conservative payout level when compared to the 89 per cent level in the corresponding period in 2008.

"Performance at our facilities was mixed in the third quarter of 2009," said Stuart Lee, President of the General Partner of EPCOR Power L.P. "We benefited from the additional contribution from the Morris facility acquired in October 2008 and higher contributions from our Northwest U.S. plants and the Curtis Palmer facility compared to the third quarter of 2008. However, these increases were more than offset by lower power demand in our Ontario and North Carolina regions that negatively impacted the financial performance of our plants operating in those areas."

"The Partnership remains committed to the diversification of our portfolio, both in terms of geography and fuel type, as one of the cornerstones of our strategy," added Mr. Lee. "As seen in this quarter, the diversity leads to mixed facility performance but stable consolidated results, supporting a consistent distribution policy."

On October 13, 2009, the Partnership announced the launch of a Premium DistributionTM and Distribution Reinvestment Plans and a change in the cash distribution frequency to monthly from quarterly payments, effective October 2009.

Also on October 13, 2009, the Partnership announced that a subsidiary will issue \$100 million of 7.0% cumulative rate reset preferred shares. The equity raised from this offering will be used to reduce debt and provide a portion of the permanent financing of recent growth initiatives.

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

Operational and Financial Highlights <i>(unaudited)</i>	Three months ended September 30		Nine months ended September 30	
	2009	2008	2009	2008
<i>(millions of dollars except per unit and operational amounts)</i>				
Power generated (GWh)	1,228	1,247	2,331	2,319
Weighted average plant availability	93%	95%	92%	92%
Revenue	155.5	133.5	292.8	262.0
Cash provided by operating activities of continuing operations	33.8	20.0	100.6	101.0
Per unit ⁽¹⁾	\$0.63	\$0.37	\$1.87	\$1.87
Cash distributions	23.7	34.0	81.4	101.9
Per unit	\$0.44	\$0.63	\$1.51	\$1.89
Payout ratio ⁽²⁾	71%	89%	89%	107%
Capital expenditures	33.0	5.1	75.9	18.5
Weighted average units outstanding (millions)	53.9	53.9	53.9	53.9

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

⁽²⁾ Payout ratio is cash distributions divided by cash provided by operating activities of continuing operations excluding working capital changes less maintenance capital expenditures.

The September 30, 2009 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.epcorpowlp.ca) and will be available on SEDAR (www.sedar.com).

EPCOR Power L.P.

Management's Discussion and Analysis

For the Nine Months Ended September 30, 2009

This management's discussion and analysis (MD&A) is dated October 26, 2009 and should be read in conjunction with the unaudited interim consolidated financial statements of EPCOR Power L.P. (collectively with its subsidiaries, the Partnership, unless otherwise specifically stated) for the nine months ended September 30, 2009 and the audited consolidated financial statements and MD&A of the Partnership for the year ended December 31, 2008. Additional information relating to the Partnership, including the 2008 Annual Information Form and continuous disclosure documents are available on SEDAR at www.sedar.com. This discussion contains certain forward-looking information and readers are advised to read this discussion in conjunction with the cautionary statement regarding forward-looking information and statements on page 27 of this report.

On July 9, 2009, as part of the transfer by EPCOR Utilities Inc. (EPCOR) of a 27.8% interest in its power generation business to Capital Power Corporation (collectively with its subsidiaries, CPC, unless otherwise indicated), (i) EPLP Investments Inc. (EPLP Investments) acquired 16,513,504 limited partnership units in the capital of the Partnership, representing 30.6% of the total outstanding units of the Partnership, and all of the common shares of EPCOR Power Services Ltd., the General Partner of the Partnership, and (ii) CPC acquired 100% ownership of the companies that provide management and operations services to the Partnership and its subsidiaries pursuant to management and operations agreements. EPCOR owns all of the 51 voting, non-participating shares of EPLP Investments and CPC owns all of the 49 voting, participating shares of EPLP Investments.

The General Partner is responsible for management of the Partnership. The Board of Directors (the Board) of the General Partner declares the cash distributions to the Partnership's unitholders. The General Partner has engaged CP Regional Power Services Limited Partnership and Capital Power Operations (USA) Inc., both subsidiaries controlled by CPC (collectively herein, the Manager), to perform management and administrative services for the Partnership and to operate and maintain the power plants pursuant to management and operations agreements. The Audit Committee of the Board 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.

SIGNIFICANT EVENTS

Change to monthly distributions and launch of distribution reinvestment plan

On October 13, 2009, the Partnership announced a change in the frequency of its distributions to monthly from quarterly. Cash distributions of the Partnership for periods commencing after September 30, 2009 will be made in respect of each calendar month instead of the quarters ending March, June, September and December of each year. The annual distributions are expected to remain at \$1.76, in keeping with the Partnership's target of a long-term payout ratio

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of approximately 75% of cash provided by operating activities less maintenance capital. The Partnership also announced the launch of a Premium Distribution[™] and Distribution Reinvestment Plan (the Plan) that provides eligible unitholders with two alternatives to receiving the monthly cash distributions, including the option to accumulate additional units in the Partnership by reinvesting cash distributions in additional units issued at a 5% discount to the Average Market Price of such units (as defined in the Plan) on the applicable distribution payment date. Under the Premium Distribution[™] component of the Plan, eligible unitholders may elect to exchange these additional units for a cash payment equal to 102% of the regular cash distribution on the applicable distribution payment date.

Preferred share offering

On October 13, 2009, a subsidiary of the Partnership entered into a bought deal for the issuance of 4,000,000 7.0% Cumulative Rate Reset Preferred Shares, Series 2 (the Series 2 Shares) at a price of \$25.00 per share, for aggregate gross proceeds of \$100 million (the Offering). The Series 2 Shares will pay fixed cumulative dividends of \$1.75 per share per annum, as and when declared, for the initial five-year period ending December 14, 2014. The dividend rate will reset on December 31, 2014 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 4.18%. The Series 2 Shares are redeemable at \$25.00 per share by the Corporation on December 31, 2014 and every five years thereafter. The holders of the Series 2 Shares will have the right to convert their shares into Cumulative Floating Rate Preferred Shares, Series 3 (the Series 3 Shares) of the Corporation, subject to certain conditions, on December 31, 2014 and every five years thereafter. The holders of Series 3 Shares will be entitled to receive quarterly floating rate cumulative dividends, as and when declared by the board of directors of the Corporation, at a rate equal to the sum of the then 90-day Government of Canada treasury bill rate and 4.18%. The offering is expected to close on or about November 2, 2009, subject to certain conditions. The net proceeds will be used to repay outstanding bank indebtedness.

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CONSOLIDATED RESULTS OF OPERATIONS

<i>(millions of dollars)(unaudited)</i>	Three months	Nine months
Cash provided by operating activities of continuing operations for the three and nine months ended September 30, 2008	20.0	101.0
Changes in operating working capital	17.9	1.8
Contribution of Morris acquired October 31, 2008, excluding interest paid	5.6	11.3
Higher operating margin at the Northwest US plants	4.2	5.4
Lower management and administration costs	1.0	2.3
Higher operating margin at Curtis Palmer	0.8	4.5
Lower operating margin at the Ontario plants	(10.3)	(14.5)
Lower operating margin at the North Carolina plants	(2.4)	(8.9)
Higher interest expenses	(1.0)	(4.2)
Other	(2.0)	1.9
Cash provided by operating activities of continuing operations for the three and nine months ended September 30, 2009	33.8	100.6

The Partnership reported cash provided by operating activities of continuing operations of \$33.8 million or \$0.63 per unit for the quarter ended September 30, 2009 compared to \$20.0 million or \$0.37 per unit for the same period in 2008. Cash provided by operating activities of continuing operations per unit is defined below under Non-GAAP Measures. The \$13.8 million increase in cash provided by operating activities of continuing operations for the third quarter of 2009 compared to the third quarter of 2008 was primarily due to the following:

- An increase in working capital of \$3.5 million in the three months ended September 30, 2009 compared to \$21.4 million during the same period in the prior year. Working capital increased in 2009 primarily due to the timing of payments and receipts;
- The Morris facility, which was acquired on October 31, 2008, provided \$5.6 million of operating margin;
- Operating margin was \$4.2 million higher at the Northwest US plants due to the payment of a non-recurring milestone payment by Frederickson under its long-term service agreement with the turbine manufacturer in the third quarter of 2008;
- Administrative costs were \$1.0 million lower primarily due to lower incentive fees as a result of changes in the method of determining the incentive fees; and
- Operating margin was \$0.8 million higher at Curtis Palmer due to a step-up in pricing under the power purchase arrangement (PPA) of 18% in December 2008 and higher generation due to higher water flows.

Increases were partially offset by the following:

- Operating margin was \$10.3 million lower at the Ontario plants primarily due to lower natural gas prices, a \$3.4 million reduction of natural gas costs recorded in 2008 as the Partnership updated its estimate of the cost for natural gas supplied under contract, an unplanned outage at Calstock, lower power demand in Ontario and lower revenues from waste heat;
- Operating margin was \$2.4 million lower at the North Carolina plants due to higher maintenance costs and lower generation due to lower natural gas prices resulting in increased competition from natural gas plants in the region; and
- Higher interest expenses of \$1.0 million were incurred due to interest on draws under the Partnership’s revolving credit facilities to finance the acquisition of the Morris facility.

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The Partnership reported cash provided by operating activities of continuing operations of \$100.6 million or \$1.87 per unit for the nine months ended September 30, 2009 compared with \$101.0 million or \$1.87 per unit for the same period in 2008. Cash provided by operating activities of continuing operations per unit is defined below under Non-GAAP Measures. The \$0.4 million decrease in cash provided by operating activities of continuing operations for the nine months ended September 30, 2009 compared to the same period in 2008 is primarily due to the items described above for the current quarter, as well as the following.

- Higher interest expenses of \$4.2 million were incurred due to the impact of a stronger US dollar relative to the Canadian dollar on US dollar interest expenses and interest on draws under the Partnership’s revolving credit facilities to finance the acquisition of the Morris facility.

<i>(millions of dollars)(unaudited)</i>	Three months	Nine months
Cash provided by operating activities for the three and nine months ended September 30, 2008	21.5	104.8
Increase (decrease) in cash provided by operating activities of continuing operations – see previous table	13.8	(0.4)
Decrease in cash provided by operating activities of discontinued operations	(1.5)	(6.6)
Cash provided by operating activities for the three and nine months ended September 30, 2009	33.8	97.8

The Partnership reported cash provided by operating activities of \$33.8 million and \$97.8 million for the three and nine months ended September 30, 2009 compared to \$21.5 million and \$104.8 million for the same periods in 2008. The decrease in cash provided by operating activities of discontinued operations in the three and nine months ended September 30, 2009 compared to the same periods in 2008 was due to lower cash provided by Castleton after the expiry of its PPA in June 2008, which resulted in positive cash flow in the third quarter of 2008 as PPA related receivables were collected, and its subsequent sale in May 2009.

<i>(millions of dollars)(unaudited)</i>	Three months	Nine months
Net (loss) income from continuing operations for the three and nine months ended September 30, 2008	(152.2)	6.2
Fair value changes on natural gas supply and foreign exchange contracts	187.6	11.5
Foreign exchange losses in 2008	15.9	26.4
Contribution of Morris acquired October 31, 2008, excluding interest paid	5.6	11.3
Higher operating margin at the Northwest US plants	4.2	5.4
Lower management and administration costs	1.0	2.3
Higher operating margin at Curtis Palmer	0.8	4.5
Increase (decrease) in income tax recovery	(17.9)	3.9
Lower operating margin at the Ontario plants	(10.3)	(14.5)
Lower operating margin at the North Carolina plants	(2.4)	(8.9)
Higher interest expenses	(1.0)	(4.2)
Higher depreciation and amortization mainly due to the Morris acquisition in 2008	(0.1)	(3.4)
Other	(0.5)	(0.1)
Net income from continuing operations for the three and nine months ended September 30, 2009	30.7	40.4

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Net income from continuing operations was \$30.7 million or \$0.57 per unit for the quarter ended September 30, 2009 compared to a net loss of \$152.2 million or \$2.82 per unit for the same period in 2008. In addition to the items described above for the change in cash provided by operating activities, the increase in net income of \$182.9 million was the result of the following:

- Net gains of \$12.5 million were recorded in the third quarter of 2009 on changes in the fair value of the natural gas supply and foreign exchange contracts compared to a net losses of \$175.1 million in the third quarter of 2008. The majority of the changes in fair value are the result of a strengthening of future prices for the Canadian dollar relative to the US dollar in the third quarter of 2009 compared to decreases in the future prices for natural gas in the third quarter of 2008; and
- In the fourth quarter of 2008, the Partnership re-evaluated the functional currency of its US subsidiaries and determined it to be US dollars. Accordingly, gains and losses on foreign currency translation are accumulated as a component of partners’ equity commencing in the fourth quarter of 2008. The Partnership reported net foreign exchange losses of \$15.8 million for the three months ended September 30, 2008.

Increases were partially offset by the following:

- An income tax recovery of \$4.2 million was recorded in the third quarter of 2009 compared to \$22.1 million in 2008. The change was mainly due to future income taxes on changes in temporary differences primarily related to changes in the fair value of natural gas and foreign exchange contracts.

Net income from continuing operations was \$40.4 million or \$0.75 per unit for the nine months ended September 30, 2009 compared with \$6.2 million or \$0.12 per unit for the same period in 2008. The \$34.2 million increase in net income from continuing operations for the nine months ended September 30, 2009 compared to the same period in 2008 is primarily due to the items described above for the current quarter, as well as the following:

- Net losses of \$2.5 million were recorded in the nine months ended September 30, 2009 on the change in the fair value of the natural gas supply and foreign exchange contracts compared to \$14.1 million in the same period in 2008. The majority of the changes in fair value are the result of decreases in future prices for natural gas partially offset by a strengthening of future prices for the Canadian dollar relative to the US dollar in the nine months ended September 30, 2009 compared to a weakening of future prices for the Canadian dollar relative to the US dollar in the same period in 2008.

<i>(millions of dollars)(unaudited)</i>	Three months	Nine months
Net (loss) income for the three and nine months ended September 30, 2008	(153.0)	5.3
Increases in the net income from continuing operations – see previous table	182.9	34.2
Increase in net income from discontinued operations	0.8	0.7
Net income for the three and nine months ended September 30, 2009	30.7	40.2

NON-GAAP MEASURES

The Partnership uses operating margin as a performance measure and cash provided by operating activities of continuing operations per unit as a cash flow measure. These terms are not defined financial measures according to Canadian generally accepted accounting principles

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(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 and groups of plants. A reconciliation from operating margin to net income from continuing operations before tax and preferred share dividends is as follows:

<i>(millions of dollars)(unaudited)</i>	Three months		Nine months	
	ended September 30	2008	ended September 30	2008
Operating margin	65.9	(118.4)	152.8	143.5
Deduct:				
Depreciation and amortization	22.9	22.8	70.0	66.6
Management and administration	3.7	4.7	10.9	13.2
Foreign exchange losses	0.1	15.9	0.7	26.4
Equity losses in PERH	0.8	1.7	3.1	3.8
Financial charges and other, net	10.2	9.2	31.6	27.4
Net income (loss) from continuing operations before tax and preferred share dividends	28.2	(172.7)	36.5	6.1

Cash provided by operating activities of continuing operations per unit is cash provided by operating activities of continuing operations (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, 2008 reporting.

CHANGES IN ACCOUNTING POLICIES

Commencing January 1, 2009, the Partnership adopted new accounting guidelines and standards as issued by the Canadian Institute of Chartered Accountants (CICA) for credit risk and the fair value of financial assets and financial liabilities as well as goodwill and intangible assets.

Credit risk and the fair value of financial assets and financial liabilities

On January 20, 2009 the Emerging Issues Committee of the CICA issued EIC-173, Credit Risk and the Fair Value of Financial Assets and Financial Liabilities, which clarifies that an entity's own credit risk and the credit risk of the counterparty should be taken into account in determining the fair value of financial assets and liabilities, including derivative instruments. Effective January 1, 2009, the Partnership adopted the recommendations of EIC-173 and applied the recommendations retrospectively without restatement of prior periods. On January 1, 2009, the Partnership made the following adjustments to the balance sheet to adopt the recommendations of EIC-173:

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Balance sheet item	Increase (decrease)	Explanation
Derivative instruments assets	(1.5)	Impact to fair value of foreign exchange and natural gas contracts from incorporating credit risk of counterparties of the Partnership.
Derivative instruments liabilities	(6.3)	
Future income taxes liabilities - non-current	0.9	Tax impact from adoption of new standard.
Opening deficit	(3.9)	After tax impact to opening deficit resulting from adoption of new standard.

Goodwill and intangible assets

In February 2008, the CICA issued Handbook Section 3064 – Goodwill and Intangible Assets and consequential amendments to Section 1000 – Financial Statement Concepts. The new section establishes standards for the recognition, measurement and disclosure of goodwill and intangible assets. The provisions relating to the definition and initial recognition of intangible assets, including internally generated intangible assets, are equivalent to the corresponding provisions in International Financial Reporting Standards (IFRS). The Partnership adopted these amendments January 1, 2009 which did not result in a material transition adjustment to the financial statements. The new accounting standard has been applied prospectively and the comparative financial statements have not been restated.

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REVENUE, OPERATING MARGIN⁽¹⁾ AND PLANT OUTPUT

<i>(millions of dollars except GWh) (unaudited)</i>	Three months ended September 30					
	2009			2008		
	GWh	Revenue	Operating Margin ⁽¹⁾	GWh	Revenue	Operating Margin ⁽¹⁾
Ontario plants	294	\$ 29.0	\$ 7.2	266	\$ 37.7	\$ 17.5
Williams Lake	47	10.8	8.4	132	10.7	7.7
Mamquam and Queen Charlotte	43	2.9	1.6	68	4.1	3.1
Northwest US plants	360	15.6	9.0	305	16.1	4.8
California plants	248	29.4	15.8	205	45.6	16.5
Curtis Palmer	59	6.9	5.4	50	5.6	4.6
Northeast US natural gas plants ⁽²⁾	171	21.0	6.3	45	6.6	0.4
North Carolina plants	6	6.2	(0.9)	176	20.8	1.5
PERC management fees		1.0	0.6		0.9	0.6
	1,228	122.8	53.4	1,247	148.1	56.7
Fair value changes						
Foreign exchange contracts		32.7	32.7		(14.6)	(14.6)
Natural gas supply contracts		-	(20.2)		-	(160.5)
	1,228	\$ 155.5	\$ 65.9	1,247	\$ 133.5	\$ (118.4)

<i>(millions of dollars except GWh) (unaudited)</i>	Nine months ended September 30					
	2009			2008		
	GWh	Revenue	Operating Margin ⁽¹⁾	GWh	Revenue	Operating Margin ⁽¹⁾
Ontario plants	979	\$ 105.2	\$ 36.7	888	\$ 119.6	\$ 51.2
Williams Lake	216	31.9	21.0	355	28.8	18.8
Mamquam and Queen Charlotte	162	10.9	7.5	182	12.2	8.8
Northwest US plants	697	47.7	27.3	611	45.1	21.9
California plants	697	75.9	26.9	674	116.7	29.2
Curtis Palmer	248	30.1	25.7	242	24.7	21.2
Northeast US natural gas plants ⁽²⁾	499	69.8	14.6	128	21.0	2.1
North Carolina plants	62	23.4	(6.3)	492	48.7	2.6
PERC management fees		2.9	1.9		2.6	1.8
	3,560	397.8	155.3	3,572	419.4	157.6
Fair value changes						
Foreign exchange contracts		50.5	50.5		(23.9)	(23.9)
Natural gas supply contracts			(53.0)			9.8
	3,560	\$ 448.3	\$ 152.8	3,572	\$ 395.5	\$ 143.5

⁽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⁾ Includes the results of Morris from the date of acquisition of October 31, 2008. Restated to reflect the operations of Castleton as discontinued operations.

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Weighted average plant availability ⁽¹⁾	Three months ended September 30		Nine months ended September 30	
	2009	2008	2009	2008
Ontario plants	84%	97%	92%	96%
Williams Lake	100%	98%	97%	87%
Mamquam and Queen Charlotte	77%	85%	85%	84%
Northwest US plants	100%	99%	97%	93%
California plants	94%	94%	91%	92%
Curtis Palmer	92%	57%	90%	85%
Northeast US natural gas plants ⁽²⁾	100%	98%	99%	96%
North Carolina plants	77%	100%	73%	98%
Weighted average total	93%	95%	92%	93%

⁽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⁾ Includes the results of Morris from the date of acquisition of October 31, 2008. Restated to reflect the operations of Castleton as discontinued operations.

Operating margin excluding fair value changes in foreign exchange and natural gas supply contracts for the three and nine months ended September 30, 2009 decreased by \$3.3 million and \$2.3 million respectively compared to the same periods in 2008. The decreases were primarily the result of lower enhancement profits at the Ontario facilities, a \$3.4 million reduction of natural gas costs recorded in 2008 as the Partnership updated its estimate of the cost for natural gas supplied under contract and lower dispatch of the North Carolina plants. These decreases were partially offset by the acquisition of Morris on October 31, 2008, the payment of a non-recurring milestone payment by Frederickson in the third quarter of 2008 under its long-term service agreement and a step-up in pricing under the Curtis Palmer PPA of 18% in December 2008.

Revenue excluding fair value changes in foreign exchange contracts for the three and nine months ended September 30, 2009 decreased by \$25.3 million and \$21.6 million respectively compared to the same period in 2008 due to decreased electricity prices at the California plants driven by lower natural gas prices and lower dispatch of the North Carolina plants partially offset by the acquisition of Morris on October 31, 2008.

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, future power sales or future US dollar cash flows.

Ontario Plants

The Ontario plants reported operating margin of \$7.2 million and \$36.7 million for the three and nine months ended September 30, 2009 compared to \$17.5 million and \$51.2 million for the same periods in 2008. The decreases were primarily due to lower natural gas prices, a \$3.4 million reduction of natural gas costs recorded in 2008 as the Partnership updated its estimate of the cost for natural gas supplied under contract, an unplanned outage at Calstock, lower power demand in Ontario and lower revenues from waste heat. The lower natural gas prices have resulted in lower enhancement profits but have reduced waste heat optimization costs, natural gas transportation costs and the cost of spot natural gas purchases. Lower electrical demand has resulted in curtailment of operations at Kapuskasing and North Bay during off peak periods by the PPA counterparty. On July 23, 2009, Calstock experienced a turbine failure. The turbine was partially repaired and returned to services on September 9, 2009. The financial loss,

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net of insurance claims, resulting from this incident was \$0.7 million. A complete repair of the turbine is expected to be completed as part of regularly scheduled maintenance in 2011 subject to the output and reliability of the plant between now and 2011.

Revenue from Ontario plants <i>(millions of dollars)(unaudited)</i>	Three months ended September 30		Nine months ended September 30	
	2009	2008	2009	2008
Power	27.3	26.2	99.0	92.4
Enhancements	0.7	7.0	1.3	17.6
Gas diversions	1.0	4.5	4.9	9.6
	29.0	37.7	105.2	119.6

Revenues from the Ontario plants were lower for the three and nine months ended September 30, 2009 compared to the same periods in 2008 due to lower waste heat availability, lower enhancement activity and lower prices for diverted natural gas, partially offset by increased power sales. Revenues from waste heat declined 47% and 20% for the three and nine months ended September 30, 2009 compared to the same periods in 2008 respectively as a result of lower throughput on TransCanada Corporation’s Canadian Mainline, the natural gas transmission line to Northern Ontario and the outage at Calstock.

Williams Lake

Operating margin from Williams Lake was \$8.4 million and \$21.0 million for the three and nine months ended September 30, 2009 compared to \$7.7 million and \$18.8 million for the same periods in 2008. The increases in operating margin and revenue were primarily due to a planned outage to complete a major overhaul in the second quarter of 2008, partially offset by higher pricing in 2008 to offset the lower generation caused by the outage.

Generation during the three and nine months ended September 30, 2009 was lower than in the same periods in 2008 due to a temporary outage starting on April 23, 2009 initiated by the Partnership and the PPA counterparty due to reduced production from the plant’s major wood waste suppliers. The Partnership has identified other sources of supply, but these sources are more expensive. Considering the economics of the power produced at high fuel prices relative to the value of the electricity produced during a low electricity demand period in the region, the Partnership and the PPA counterparty agreed to the temporary outage. The plant returned to service on August 31, 2009 at the request of the PPA counterparty. The Partnership will continue to work with the PPA counterparty to determine the optimal dispatch strategy for the plant based on available wood waste supplies and the economics of the power produced by the plant. Under the terms of the Williams Lake PPA, the Partnership continued to receive energy payments while the plant was offline.

Williams Lake expanded its wood waste storage capacity in July 2009, to provide flexibility in managing available wood waste supplies. At September 30, 2009, the plant had sufficient wood waste inventory for the plant to produce its maximum output of 66 megawatts (MW) for 120 days. Based on the anticipated impact of the increase in storage capacity, the operating margin provided by Williams Lake in 2009 is expected to be similar to 2008 levels.

Mamquam and Queen Charlotte

Operating margin at Mamquam and Queen Charlotte was \$1.6 million and \$7.5 million for the three and nine months ended September 30, 2009 compared to \$3.1 million and \$8.8 million for the same periods in 2008. The decreases were due to lower water volumes at the plants.

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Northwest US Plants

Operating margin from Frederickson was \$3.2 million and \$9.6 million for the three and nine months ended September 30, 2009 compared to an operating margin loss of \$1.5 million and operating margin of \$5.5 million for the same periods in 2008. The increases are due to the payment of a non-recurring milestone payment by Frederickson under its long-term service agreement with the turbine manufacturer in the third quarter of 2008.

Operating margin from Manchief was \$5.6 million for the three months ended September 30, 2009 down from \$6.0 million for the same period in 2008. Operating margin increased by \$1.0 million for the nine months ended September 30, 2009 to \$17.0 million compared to the same period in 2008 as the result of higher dispatch of the plant due to outages at other plants in the region.

Operating margin from Greeley was \$0.2 million and \$0.7 million for the three and nine months ended September 30, 2009 consistent with \$0.3 million and \$0.4 million for the same periods in 2008.

California Plants

Operating margin from the Naval facilities was \$10.4 million and \$18.5 million for the three and nine months ended September 30, 2009 compared to \$10.6 million and \$20.1 million for the same periods in 2008. The decreases were due to the impact of lower natural gas prices on the pricing mechanisms in the PPAs and steam purchase agreements for the facilities and lower dispatch of Naval Station due to planned outages for inspections in February 2009 and an unplanned outage at Naval Station in April 2009 partially offset by lower maintenance costs at North Island in 2009.

Operating margin from Oxnard was \$5.4 million and \$8.4 million for the three and nine months ended September 30, 2009 compared to \$5.9 million and \$9.1 million for the same periods in 2008. During the second quarter of 2009, Oxnard repaired damage to the natural gas turbine identified in 2008. The total cost of the repair was \$3.1 million, including lease engine costs. Insurance covered approximately 75% of the costs.

Curtis Palmer

Operating margin from Curtis Palmer was \$5.4 million and \$25.7 million for the three and nine months ended September 30, 2009 compared to \$4.6 million and \$21.2 million for the same periods in 2008. The increases were due to a step-up in pricing under the PPA of 18% in December 2008 and higher generation due to higher water flows partially offset by a planned outage to complete an overhaul in June 2009.

Northeast US Natural Gas Plants

Operating margin from Morris, which was acquired on October 31, 2008, was \$5.6 million and \$11.3 million for the three and nine months ended September 30, 2009, in line with expectations.

Operating margin from Kenilworth was \$0.7 million for the three months ended September 30, 2009, a small increase from \$0.4 million for the same period in 2008. Operating margin increased by \$1.2 million for the nine months ended September 30, 2009 to \$3.3 million compared to the same period in 2008 as due to reduced exposure to natural gas prices in a revised PPA effective July 1, 2008.

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North Carolina Plants

The North Carolina plants reported operating margin losses of \$0.9 million and \$6.3 million for the three and nine months ended September 30, 2009 compared to operating margin of \$1.5 million and \$2.6 million for the same periods in 2008. The decreases in operating margin, revenue and generation were due to lower dispatch due to lower natural gas prices. These facilities are fuelled by coal, wood waste and tire-derived fuel. Low natural gas prices result in lower operating costs for natural gas-fired power generation relative to other types of thermal generation, including those used at the North Carolina facilities.

The decrease in operating margin was also the result of higher maintenance costs for planned repairs as well as for a generator failure at Roxboro. The Roxboro unit returned to service in September 2009 and the negative impact of the outage on operating margin in the third quarter of 2009 was \$1.1 million including anticipated insurance coverage. These outages, as well as scheduled outages associated with the enhancement projects at the plants, resulted in lower availability in 2009.

Fair value changes

Unrealized gains on foreign exchange contracts were \$32.7 million and \$50.5 million for the three and nine months ended September 30, 2009 compared to unrealized losses of \$14.6 million and \$23.9 million reported for the same periods in 2008. The changes in fair value were primarily due to changes in the forward prices for US dollars relative to Canadian dollars which decreased \$0.082 and \$0.120 for the three and nine months ended September 30, 2009 compared to an increase of \$0.041 and an increase of \$0.061 for the same periods in 2008.

The Partnership recorded fair value losses on natural gas supply contracts of \$20.2 million and \$53.0 million for the three and nine months ended September 30, 2009 compared to fair value losses \$160.5 million and fair value gains of \$9.8 million for the same periods in 2008. The changes in the fair value of the natural gas contracts were primarily due to changes in natural gas forward prices. Alberta forward natural gas prices decreased \$0.43 per gigajoule (GJ) and \$0.96 per GJ for the three and nine months ended September 30, 2009 compared to \$2.69 per GJ and an increase of \$0.26 per GJ for the same periods in 2008. On July 31, 2009, the Partnership designated certain of its natural gas supply contracts as hedges. Net gains of \$4.2 million relating to these contracts were recorded in other comprehensive income in the third quarter of 2009.

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COST OF FUEL <i>(millions of dollars)(unaudited)</i>	Three months ended		Nine months ended	
	September 30		September 30	
	2009	2008	2009	2008
Ontario plants				
Natural gas	16.9	14.6	51.6	48.7
Waste heat	0.5	1.3	3.0	6.3
Wood waste	0.1	0.6	2.0	2.1
	<u>17.5</u>	<u>16.5</u>	<u>56.6</u>	<u>57.1</u>
Williams Lake - wood waste	0.5	0.8	3.8	2.0
Northwest US plants - natural gas	2.9	2.8	8.9	8.8
California plants - natural gas	9.5	23.6	33.8	70.7
Northeast US natural gas plants ⁽¹⁾	12.2	5.4	46.6	16.8
North Carolina plants - coal, tire-derived fuel & wood waste	2.7	15.3	12.8	34.4
	<u>45.3</u>	<u>64.4</u>	<u>162.5</u>	<u>189.8</u>
Fair value changes on natural gas contracts	20.2	160.5	53.0	(9.8)
	<u>65.5</u>	<u>224.9</u>	<u>215.5</u>	<u>180.0</u>

⁽¹⁾ Includes the results of Morris from the date of acquisition of October 31, 2008. Restated to reflect the operations of Castleton as discontinued operations.

Fuel costs, which are the Partnership’s most significant cost of operations, include commodity costs, transportation costs and fair value changes on natural gas supply contracts.

For the three and nine months ended September 30, 2009, fuel costs, excluding fair value changes on natural gas contracts, were \$45.3 million and \$162.5 million compared to \$64.4 million and \$189.8 million for the same periods in 2008.

Fuel costs at the Ontario plants for the three months ended September 30, 2009 were \$17.5 million compared to \$16.5 million for the same period in 2008. The increase was primarily due to a \$3.4 million reduction of natural gas costs recorded in 2008 as the Partnership updated its estimate of the cost for natural gas supplied under contract partially offset by lower natural gas prices which have resulted in lower waste heat optimization costs, natural gas transportation costs and the cost of spot natural gas purchases. Fuel costs for the nine months ended September 30, 2009 were \$56.6 million compared to \$57.1 million for the same period in 2008. The decrease was primarily due lower natural gas prices partially offset by a \$3.4 million reduction of natural gas costs recorded in 2008 as the Partnership updated its estimate of the cost for natural gas supplied under contract.

Williams Lake incurred fuel costs of \$0.5 million for the three months ended September 30, 2009 down from \$0.8 million for the same period in 2008. Fuel costs increased by \$1.8 million for the nine months ended September 30, 2009 compared to the same period in 2008 primarily as the result of the use of higher priced wood waste due to reduced production from the plant’s major wood waste suppliers.

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The Northwest US plants incurred fuel costs of \$2.9 million and \$8.9 million for the three and nine months ended September 30, 2009, consistent with \$2.8 million and \$8.8 million for the same periods in 2008.

Fuel costs at the California facilities were \$9.5 million and \$33.8 million for the three and nine months ended September 30, 2009 compared to \$23.6 million and \$70.7 million for the same periods in 2008. The decreases were due to lower natural gas prices and outages at Naval Station.

The Northeast US natural gas plants incurred fuel costs of \$12.2 million and \$46.6 million for the three and nine months ended September 30, 2009, compared to \$5.4 million and \$16.8 million for the same periods in 2008. The increases were primarily due to the acquisition of Morris on October 31, 2008, which had fuel costs of \$6.3 million and \$26.1 million in the three and nine months ended September 30, 2009.

The North Carolina plants incurred fuel costs of \$2.7 million and \$12.8 million for the three and nine months ended September 30, 2009 compared to \$15.3 million and \$34.4 million for the same periods in 2008. The decrease was the result of lower generation.

The Curtis Palmer, Mamquam and Queen Charlotte hydroelectric plants do not have fuel costs.

OPERATING AND MAINTENANCE EXPENSE

<i>(millions of dollars)(unaudited)</i>	Three months ended		Nine months ended	
	September 30		September 30	
	2009	2008	2009	2008
Ontario plants	4.3	3.7	11.9	11.3
Williams Lake	1.9	2.2	7.1	8.0
Mamquam and Queen Charlotte	1.3	1.0	3.4	3.4
Northwest US plants	3.7	8.5	11.5	14.4
California plants	4.1	5.5	15.2	16.8
Curtis Palmer	1.5	1.0	4.4	3.5
Northeast US natural gas plants ⁽¹⁾	2.5	0.8	8.6	2.1
North Carolina plants	4.4	4.0	16.9	11.7
PERC management expenses	0.4	0.3	1.0	0.8
	24.1	27.0	80.0	72.0

⁽¹⁾ Includes the results of Morris from the date of acquisition of October 31, 2008. Restated to reflect the operations of Castleton as discontinued operations.

Operating and maintenance expenses include payments to the Manager and third parties for the operation and routine maintenance of the plants. Fees paid to the Manager are based on fixed charges adjusted annually for inflation for the Canadian plants, Curtis Palmer and Manchief, and a flow through of costs for the remaining US plants. Operating and maintenance expenses were \$24.1 million and \$80.0 million for the three and nine months ended September 30, 2009 compared to \$27.0 million and \$72.0 million for the same periods in 2008. The decrease during the three months ended September 30, 2009 was due to the payment of a non-recurring milestone payment by Frederickson in 2008 under its long-term service agreement and lower maintenance costs at North Island, partially offset by repairs to the generator at Roxboro and

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the acquisition of Morris on October 31, 2008. Morris had operating and maintenance costs of \$1.9 million and \$6.4 million in the three and nine months ended September 30, 2009. The increase in operating and maintenance costs during the nine months ended September 30, 2009 was due to the acquisition of Morris, higher maintenance costs at the North Carolina plants and a turbine repair at Frederickson in the second quarter of 2009 partially offset by the Frederickson long-term service agreement payment in 2008 and lower maintenance costs at North Island.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization expense for the three and nine months ended September 30, 2009 was \$22.9 million and \$70.0 million compared to \$22.8 million and \$66.6 million for the same periods in 2008. The increase was primarily due to the acquisition of Morris on October 31, 2008.

MANAGEMENT AND ADMINISTRATION

Management and administration costs, which include fees payable to CPC (and prior to June 30, 2009, EPCOR) and general and administrative costs, were \$3.7 million and \$10.9 million for the three and nine months ended September 30, 2009 compared to \$4.7 million and \$13.2 million for the same periods in 2008. The decreases were primarily due to lower incentive fees as a result of the distribution reduction on the incentive fee calculation for the six months ended June 30, 2009 and changes in the method of determining the incentive fees thereafter. The Partnership also paid lower enhancement fees as a result of lower enhancement profits.

FOREIGN EXCHANGE LOSSES

The Partnership reported net foreign exchange losses of \$0.1 million and \$0.7 million for the three and nine months ended September 30, 2009 compared to \$15.9 million and \$26.4 million for the same periods in 2008. In the fourth quarter of 2008 the Partnership re-evaluated the functional currency of its US subsidiaries and determined it to be US dollars. Accordingly, gains and losses on translating the Partnership’s US operations into Canadian dollars are accumulated as a component of partners’ equity commencing in the fourth quarter of 2008. The foreign exchange losses recorded in the three and nine months ended September 30, 2008 were primarily the result of a weakening of the Canadian dollar of \$0.045 and \$0.073 relative to the US dollar on the translation of US dollar-denominated debt.

EQUITY LOSSES IN PERH

Equity losses in Primary Energy Recycling Holdings LLC (PERH) were from the Partnership’s common ownership interest in PERH, which was accounted for on the equity basis up to August 24, 2009 and on a cost basis thereafter as a result of a recapitalization of PERH and changes to the management agreement between the Partnership, PERH, Primary Energy Recycling Corporation (PERC) and Primary Energy Operations LLC. The Partnership has converted all of its common and preferred interests in PERH to a 14.3% common equity interest in PERH in connection with a recapitalization of PERH pursuant to which all previously outstanding common and preferred interests in PERH, including those held by the Partnership and PERC, were converted to new common equity interests. No gain or loss was recorded on the conversion.

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For the three and nine months ended September 30, 2009, the Partnership received dividends of \$0.4 million and \$1.1 million (\$0.5 million and \$1.4 million for the same periods in 2008) on its 14.2% preferred ownership interest and dividends of nil and \$1.3 million (\$0.8 million and \$2.4 million for the same periods in 2008) from its common interest in PERH. The Partnership holds 14.3% of the common interest in PERH after the recapitalization. PERH has suspended dividends on its common equity interests.

Concurrently with the PERH recapitalization, certain changes were made to the long-term management agreement pursuant to which a wholly-owned subsidiary of the Partnership provides management and administrative services to PERH, certain subsidiaries of PERH and to PERC. The changes include: (i) PERH has assumed responsibility for certain management functions, (ii) the parties agreed that PERH can terminate the management agreement for a specified price, declining over time, if the Partnership agrees to sell its interest in PERH, and (iii) the allocation agreement among the Partnership, PERC and certain other parties, together with the rights of first offer in respect of certain projects of the Partnership granted to PERC and to PERH under the management agreement and the allocation agreement, has been terminated. PERC has announced that the US\$131 million term loan facility in a PERH subsidiary has been amended to extend the maturity date of the loan from August 24, 2009 to February 24, 2010. PERH and PERC are working on alternatives to replace a US\$131 million term loan to a subsidiary of PERH that matures on February 24, 2010, however, there is no assurance that these initiatives will be successful.

PERC has filed a prospectus qualifying the issuance of rights to acquire subscription receipts which will be converted into common shares of PERC upon PERC obtaining sufficient funds to refinance the credit facility. PERC has advised that upon such occurrence, PERC immediately intends to use the net proceeds of the rights offering to subscribe for new common membership interests in PERH. The Partnership has a pre-emptive right to maintain its current pro-rata interest (14.3%) in PERH. The Partnership has determined that it will exercise its pre-emptive right, subject to changes in circumstances prior to the close of the rights offering that may cause the Partnership to reconsider this decision. If the Partnership exercises its pre-emptive right, the Partnership will be required to subscribe for new common membership interests at an aggregate subscription price of US\$8.3 million concurrently with PERC’s subscription. The Partnership will finance the subscription with cash on hand or by drawing on its revolving credit facilities.

FINANCIAL CHARGES AND OTHER, NET

<i>(millions of dollars)(unaudited)</i>	Three months ended		Nine months ended	
	September 30		September 30	
	2009	2008	2009	2008
Interest on long-term debt	10.4	9.8	32.1	28.5
Interest on short-term debt	-	0.2	0.6	0.5
Capitalized interest	(0.2)	-	(0.2)	-
Dividend income from Class B preferred share interests in PERH	(0.4)	(0.5)	(1.1)	(1.4)
Other	0.4	(0.3)	0.2	(0.2)
	10.2	9.2	31.6	27.4

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Financial charges and other expenses were \$10.2 million and \$31.6 million for the three and nine months ended September 30, 2009 compared to \$9.2 million and \$27.4 million for same periods in 2008. The increases were primarily due to the impact of a stronger US dollar relative to the Canadian dollar on US dollar interest expenses and interest on draws under the Partnership’s revolving credit facilities used to finance the acquisition of Morris.

INCOME TAX RECOVERY

Income tax recoveries were \$4.2 million and \$8.9 million for the three and nine months ended September 30, 2009 compared to \$22.1 million and \$5.0 million for the same periods in 2008.

During the quarter ended September 30, 2009, the Partnership recorded an out-of-period adjustment of \$9.5 million relating to 2007, 2008 and 2009 to recognize net future income tax assets associated with the Partnership’s interest in PERH. PERH is treated as a partnership for US tax purposes and the adjustments are attributable to the allocation of tax deductions between the Partnership and PERH’s other partner, PERC, that were incorrectly calculated by PERH’s external tax advisors for the relevant periods. Of the \$9.5 million, \$2.8 million is attributable to 2007, \$5.8 million is attributable to 2008 and \$0.9 million is attributable to the six months ended June 30, 2009.

The remaining changes were mainly due to future income taxes on changes in temporary differences primarily related to changes in the fair value of natural gas supply and foreign exchange contracts which are expected to reverse after 2010. Currently, the taxable income of the Partnership is expected to be taxed in the hands of unitholders. After 2010, the Partnership expects taxes will be applied at the Partnership level as changes to Canadian tax legislation become effective.

Withholding taxes on payments between US and Canadian subsidiaries, excluding dividends, are expected to be eliminated by 2010 from the current 4% rate on payments made in 2009.

PREFERRED SHARE DIVIDENDS OF A SUBSIDIARY COMPANY

A subsidiary of the Partnership issued Series 1 preferred shares, which pay dividends at a rate of 4.85% per annum. For the three and nine months ended September 30, 2009, dividends of \$1.5 million and \$4.5 million were paid to shareholders and net income tax expenses of \$0.2 million and \$0.5 million were recorded. Part VI.1 tax is paid at a rate of 40% of the dividends and a deduction from Part I tax is available for payment of Part VI.1 tax. The subsidiary expects to realize the benefit of the deduction beginning in 2011.

LIQUIDITY AND CAPITAL RESOURCES

Cash distributions

In the second quarter of 2009, the Partnership reduced its distribution from \$0.63 per quarter to \$0.44 per quarter which targets a long-term payout ratio of approximately 75% of cash provided by operating activities less maintenance capital. The payout ratio was 71% in the third quarter of 2009 excluding changes in working capital. The Partnership has announced a change in the frequency of its distributions to monthly from quarterly and the launch of a Premium Distribution and Distribution Reinvestment Plans (See Significant Events).

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When cash provided by operating activities exceeds cash distributions and maintenance capital expenditures, the Partnership utilizes the difference to stabilize future quarterly cash distributions, to finance growth capital expenditures and to make debt repayments. When cash provided by operating activities is less than cash distributions and maintenance capital expenditures, the Partnership utilizes available cash balances and short-term financing to cover the shortfall. The ability of the Partnership to sustain current cash flow is subject to the Partnership finding cash accretive investments to replace expected future declines in cash flow as contracts expire.

<i>(millions of dollars)(unaudited)</i>	Three months ended		Nine months ended	
	September 30		September 30	
	2009	2008	2009	2008
Cash distributions	23.7	34.0	81.4	101.9
Cash provided by operating activities of continuing operations	33.8	20.0	100.6	101.0
Net income (loss) from continuing operations	30.7	(152.2)	40.2	6.2
Payout ratio ⁽¹⁾	71%	89%	89%	107%
Dividends from PERH	-	0.8	1.3	2.4
Additions to property, plant and equipment	33.0	5.1	75.9	18.5
Excess (shortfall) of cash provided by operating activities of continuing operations over cash distributions	10.1	(14.0)	19.2	(0.9)
Excess (shortfall) of net income (loss) from continuing operations over cash distributions	7.0	(186.2)	(41.2)	(95.7)

⁽¹⁾ Payout ratio is cash distributions divided by cash provided by operating activities of continuing operations excluding changes in working capital less maintenance capital expenditures.

Cash provided by operating activities of continuing operations exceeded cash distributions by \$10.1 million and \$19.2 million for the three and nine months ended September 30, 2009. The Partnership also incurred capital expenditures of \$33.0 million and \$75.9 million during the three and nine months ended September 30, 2009, which the Partnership financed with cash on hand and draws under its revolving credit facilities. The Partnership also received proceeds on the sale of Castleton of \$11.8 million during the nine months ended September 30, 2009.

Net income is not necessarily comparable to cash distributions as net income includes items such as changes in the fair value of derivative instruments. Aside from these items, management expects that distributions will 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.

To the extent there is a shortfall between the Partnership's cash provided by operating activities and cash distributions and capital expenditures, the Partnership has available to it two revolving credit facilities, each of \$100.0 million expiring in September 2011 and October 2011 and a third revolving credit facility of \$125.0 million expiring in June 2011. The Partnership also has two demand facilities, of \$20.0 million and US\$20.0 million. Alternatively, in the case of major investments of capital, the Partnership may obtain new capital from external markets at the time of the required investment, utilizing its \$1 billion shelf prospectus which expires in August 2010.

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The third quarter 2009 cash distribution of \$0.44 per unit will be paid on October 30, 2009 to unitholders of record on September 30, 2009. The Partnership has announced a change in the frequency of its distributions to monthly from quarterly and the launch of a Premium Distribution and Distribution Reinvestment Plans (See Significant Events).

Capital expenditures

Capital expenditures for the three and nine months ended September 30, 2009 totalled \$33.0 million and \$75.9 million compared to \$5.1 million and \$18.5 million for the same periods in 2008. Capital spending included spending for the enhancement of the Southport and Roxboro coal plants and the upgrade of the LM5000 natural gas turbines at North Island and Oxnard with LM6000 units.

<i>(millions of dollars)(unaudited)</i>	Three months ended September 30		Nine months ended September 30	
	2009	2008	2009	2008
Maintenance capital expenditures	3.9	3.2	16.0	14.9
North Carolina enhancement project	23.7	1.9	41.6	3.6
North Island turbine replacement project	1.1	-	14.0	-
Oxnard turbine replacement project	4.3	-	4.3	-
	33.0	5.1	75.9	18.5

The North Carolina enhancement project is nearing completion of the installation phase and the project in service date remains December 31, 2009. The Partnership plans to invest an additional \$33 million (US\$31 million) in the remaining three months of 2009 for the enhancement of Southport and Roxboro to reduce environmental emission levels and improve their economic performance by increasing the use of tire-derived fuel and wood waste in the fuel mix. The total expected cost for the projects is US\$80 million. Several challenges in retrofitting the existing facilities have been encountered and are putting pressure on the costs of the project. Management is currently evaluating options to address these challenges.

During the second quarter of 2009 the Partnership completed the repowering of the natural gas turbine at North Island to improve plant efficiency and financial performance. Project costs incurred to date were \$18.6 million (US\$15.3 million) with an additional \$2.9 million (US\$2.7 million) investment expected in the remaining three months of 2009 for capital spares and costs associated with final inspections.

The Partnership has initiated a similar repowering project at Oxnard to be completed in 2010. Total cost of the project is expected to be approximately \$21 million (US\$20 million).

In March 2009, the Partnership filed a proposal with the Public Service Company of Colorado to construct additional facilities at Manchief in the range of US\$250 million to US\$350 million depending on configuration with an in service timeline of 2014. The Partnership has chosen not to pursue at this time a development opportunity at the Queen Charlotte Islands as indicated in its second quarter MD&A due to a lack of a definitive timeline from BC Hydro regarding a request for proposal process.

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Financing

The following table summarizes the long-term debt of the Partnership.

<i>(millions of dollars)(unaudited)</i>	September 30 2009	December 31 2008
Senior unsecured notes, due 2036	210.0	210.0
Senior unsecured notes (US\$415.0) due 2014 to 2019	444.4	505.5
Secured term loan, due 2010	1.4	2.6
Revolving credit facilities	141.6	86.7
	797.4	804.8

The Partnership’s debt to total capitalization ratio as at September 30, 2009 increased to 54% from 51% at December 31, 2008 primarily due to drawings on its revolving credit facilities partially offset by the impact of a weakening US dollar on US dollar-denominated borrowings. If the planned \$100 million preferred share offering (see Significant Events – Preferred Share Offering) had been completed at September 30, 2009, the debt to capitalization ratio would have been 48% on a pro-forma basis, assuming the proceeds from the offering were used to repay long-term debt. The debt to total capitalization ratio is calculated as follows:

$$\text{Debt to total capitalization ratio} = \frac{\text{Debt (short-term debt + long-term debt)}}{\text{Debt + preferred shares + partners' equity}}$$

Under the terms of its debt agreements, the Partnership must maintain a debt to capitalization ratio of not more than 65% at the end of each fiscal quarter. During the nine months ended September 30, 2009, the Partnership drew \$63.9 million on its revolving credit facilities to fund the North Carolina, North Island and Oxnard capital projects. In addition, under the revolving credit facilities, in the event the Partnership is assigned a rating of less than BBB+ by Standard and Poors (S&P) and BBB(high) by DBRS Limited (DBRS), the Partnership also would be required to maintain a ratio of EBITDA (earnings before interest, income taxes, depreciation and amortization as defined in the credit facilities) to interest expense of not less than 2.5 to 1, measured quarterly. Although the Partnership is not required to meet the EBITDA to interest ratio, the ratio was 4.3 at as at September 30, 2009.

In the second quarter of 2009, DBRS lowered its outlook for the Partnership from stable trend to negative trend and reduced its stability rating from STA-2(high) to STA-2(low) as a result of increasing debt levels. At the same time, DBRS confirmed its BBB(high) with a negative trend credit rating. In April 2009, S&P lowered its outlook for the Partnership from stable to negative as a result of increasing debt levels. At the same time, S&P confirmed its BBB+ with a negative outlook credit rating and SR-2 stability rating for the Partnership. The negative outlook/trend by S&P and DBRS highlights the potential that the long-term ratings may be lowered.

The BBB+ debt rating by S&P is the fourth highest rating out of 10 rating categories. The plus sign shows the relative standing within the major rating categories. DBRS’ BBB(high) rating designates the Partnership’s debt as being of satisfactory credit quality with the protection of interest and principal still substantial. The “BBB” rating is DBRS’ fourth highest of 10 categories. The high classification shows the relative standing within the major rating categories.

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Having an investment grade credit rating improves the Partnership’s ability to re-finance existing debt as it matures and to access cost competitive capital for future growth.

The stability ratings of SR-2 by S&P is the second highest rating of seven categories and indicates that the Partnership has a high level of distributable cash generation stability relative to other rated Canadian income funds. The STA-2 (low) stability rating by DBRS is the second highest of seven categories in their rating system for income fund stability. DBRS further subcategorizes each rating by the designation of “high”, “middle” and “low” to indicate where an entity falls within the rating category.

Financial market liquidity

The exposure of the Partnership to the ongoing volatility in the Canadian and US financial markets is substantially unchanged from December 31, 2008. For further information on our outlook, refer to the Partnership’s December 31, 2008 MD&A. In line with expectations, the Partnership has increased the amount drawn on its revolving credit facilities to finance the enhancement capital spending at North Island and the North Carolina plants. The Partnership has a sufficient liquidity position with revolving credit facilities of \$325 million and a demand credit facility of \$20.0 million with Canadian tier 1 banks. The Partnership also has a demand credit facility of US\$20.0 million with a US tier 1 bank. Principal repayments on the Partnership’s long-term debt facilities are as follows:

Long-term debt principal repayment

(unaudited) (millions of dollars)

2010	1.4
2011	141.6
2014	203.5
2017	160.6
2019	80.3
2036	210.0

The Partnership expects to borrow an additional US\$30 million to US\$35 million on its credit facilities to fund the completion of the North Carolina capital project in 2009 and expects to repay a portion of the revolving credit facilities that mature in 2011 with the proceeds of the \$100 million preferred share offering (see Significant Events – Preferred Share Offering).

Further, the Partnership has established a Premium Distribution Reinvestment Program to foster its capacity for growth (see Significant Events - Launch of Distribution Reinvestment Plan).

Uncertainty in global financial markets and, in particular, the Canadian and US financial markets may adversely affect the Partnership’s ability to arrange permanent long-term financing for large acquisitions or development opportunities.

FOREIGN EXCHANGE RISK MANAGEMENT

The Partnership manages the foreign exchange risk of its 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, 2009, \$507.1 million (US\$453.3 million) or approximately 94% of expected future US cash flows were economically hedged for 2009 to 2015 at a weighted average exchange rate of \$1.12 to US \$1.00.

TRANSACTIONS WITH RELATED PARTIES

<i>(millions of dollars)(unaudited)</i>	Three months ended September 30		Nine months ended September 30	
	2009	2008	2009	2008
Transactions with CPC ⁽¹⁾				
Revenue - Frederickson duct firing capacity fees	-	-	0.1	-
Cost of fuel - Greeley natural gas contract	0.7	-	2.2	-
Operating and maintenance expense	11.9	10.7	38.4	32.6
Management and administration				
Base fee	0.2	0.3	0.8	1.0
Incentive fee	-	0.5	-	1.7
Enhancement fee	0.1	0.9	0.2	2.3
General and administrative costs	2.1	1.4	5.9	4.2
	2.4	3.1	6.9	9.2
Transactions of discontinued operations				
Cost of fuel - Castleton natural gas demand charge	0.1	0.6	1.1	1.6
Operating and maintenance expense - Castleton	-	0.7	1.4	2.1
	0.1	1.3	2.5	3.7
Acquisition and divestiture fees	-	-	0.2	-
Transactions with PERH				
Revenue				
Base management fees	0.6	0.9	2.5	2.6

⁽¹⁾ Prior to June 30, 2009, EPCOR.

In operating the Partnership’s 20 power plants, the Partnership and CPC (and prior to June 30, 2009, EPCOR) engage in a number of related party transactions which are in the normal course of business. These transactions are based on contracts and many of the fees are escalated by inflation. The table above summarizes the amounts included in the calculation of net income for the three and nine months ended September 30, 2009 and 2008. Operating and maintenance expenses were \$11.9 million and \$38.4 million for the three and nine months ended September 30, 2009, an increase of \$1.2 million and \$5.8 million respectively from the same periods in 2008 due to the acquisition of Morris and the impact of a stronger US dollar on US operating and maintenance costs.

During the nine months ended September 30, 2009, the Partnership made quarterly cash distributions to EPLP Investments (and prior to June 30, 2009, EPCOR) in the amount proportionate to its ownership interest. At September 30, 2009, EPLP Investments owned 30.6% of the Partnership’s units (at September 30, 2008 EPCOR owned 30.6% of the Partnership’s units). EPCOR owns all of the 51 voting, non-participating shares of EPLP Investments and CPC owns all of the 49 voting, participating shares of EPLP Investments.

CONTRACTUAL OBLIGATIONS, COMMITMENTS AND CONTINGENCIES

The Partnership has committed up to US\$20 million for the replacement of the turbine at Oxnard, to be spent over 2009 and 2010. There were no other material changes to the Partnership’s purchase obligations, commitments or contingencies during the third quarter, including payments for the next five years and thereafter. For further information on these obligations, refer to the Partnership’s December 31, 2008 MD&A.

CRITICAL 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 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 December 31, 2008 MD&A.

INTERNAL CONTROL OVER FINANCIAL REPORTING

During the period, the ownership and legal names of the Manager changed however there were no significant changes to the staff provided to the Partnership. Accordingly, there were no changes made to the Partnership’s internal controls over financial reporting during the interim period ended September 30, 2009 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, 2008 as provided in the Partnership’s December 31, 2008 MD&A. Recent developments on risk are described below. For further information on business risks, refer to the Partnership’s December 31, 2008 MD&A.

Proposed emissions regulation

On May 15, 2009, Rep. Waxman and Rep. Markey introduced the American Clean Energy and Security Act in the Energy and Commerce Committee of the US House of Representatives (the Waxman-Markey Bill). The Waxman-Markey Bill would establish an economy wide cap and trade program, create incentives and standards for clean energy and energy efficiency, and establish green house gas emissions (GHG) standards for vehicles, stationary sources, and fuels. The provisions of the bill remain subject to extensive debate and it is unclear whether it will be passed, and if so, what revisions will be made in advance of passage.

On May 27, 2009, the Ontario Government proposed amendments to the Environmental Protection Act that will enable the government to establish a provincial GHG cap and trade system. The government has stated that it aims to harmonize its cap and trade program with Canadian federal, North American and international approaches and will continue to work with its partners in the Western Climate Initiative, which is playing an important role in the development of a US federal and broader North American cap and trade system. However, the timing and specifics of such a GHG cap and trade system are not known at this time, although

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public consultation will occur into the fall of 2009 and final regulations may not be implemented until 2012.

The proposed Canadian federal regulatory framework known as “Turning the Corner”, to reduce GHG emissions and air pollution, recommended an 18% reduction in GHG emissions intensity starting in 2010 and increasing by 2% per year thereafter resulting in a 20% absolute reduction in GHG emissions from 2006 levels by 2020, and a 50% reduction in air pollution by 2015. Subsequently released government information indicates that some or all of these proposed compliance dates will be extended, starting in 2012 as opposed to 2010.

The Partnership is assessing the potential impact of these initiatives, but at this time there is insufficient information to assess the full financial and operational implications on the Partnership's facilities. To the extent that additional regulation is passed, the Partnership could incur increased costs.

FUTURE ACCOUNTING STANDARDS

International financial reporting standards

In February 2008, the CICA confirmed that Canadian reporting issuers will be required to report under IFRS effective January 1, 2011, including comparative figures for the prior year.

The Partnership's plan for conversion to and implementation of these international standards has not changed substantially since December 31, 2008. For further information on our plan for conversion and implementation, refer to the Partnership's December 31, 2008 MD&A.

Fair value measurement disclosure

In June 2009, the CICA amended Handbook Section 3862 Financial Instruments – Disclosures, to adopt the amendments recently made by the International Accounting Standards Board to IFRS 7 Financial Instruments: Disclosures. The amendments require enhanced disclosures about fair value measurements, including the relative reliability of the inputs used in those measurements, and about the liquidity risk of financial instruments. Although the amendments apply to financial statements relating to fiscal years ending after September 30, 2009, comparative information is not required in the first year of application. The impacts of these amendments will be assessed and the necessary additional disclosures will be implemented commencing with the annual financial statements for 2009.

Consolidated financial statements and non-controlling interests

In January 2009, the CICA issued Handbook Section 1601 – Consolidated Financial Statements and Section – 1602 Non-controlling Interests, which replace Section 1600 – Consolidated Financial Statements. Section 1601 establishes the standards for the preparation of consolidated financial statements while Section 1602 establishes the standards for accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. Section 1602 is equivalent to the corresponding provisions of International Auditing Standard 27 – Consolidated and Separate Financial Statements.

Sections 1601 and 1602 will apply to the Partnership's interim and annual consolidated financial statements relating to periods commencing on or after January 1, 2011. Earlier adoption is permitted as of the beginning of a fiscal year, provided Section 1582 – Business Combinations

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is also adopted at the same time. The impact of the new standards and the option to adopt them early will be assessed as part of our IFRS project.

Business combinations

In January 2009, the CICA issued Handbook Section 1582 – Business Combinations, which replaces Section 1581 – Business Combinations and provides the Canadian equivalent to IFRS 3 – Business Combinations. The section will apply on a prospective basis to the Partnership’s future business combinations for which the acquisition date is on or after January 1, 2011. Earlier adoption is permitted as of the beginning of a fiscal year provided Sections 1601 – Consolidated Financial Statements and 1602 – Non-controlling Interests are also adopted at the same time. The impact of the new standard and the option to adopt it early will be assessed as part of the Partnership’s IFRS project.

OUTLOOK

In a news release dated October 7, 2009, the Partnership announced that the Partnership’s financial expectations for 2009 is expected to be approximately 5 per cent lower than its previous 2009 financial guidance provided in the Partnership’s December 31, 2008 MD&A issued in March 2009. The 2009 financial guidance provided in the December 31, 2008 MD&A was based on the expectation that cash provided by operating activities before working capital changes plus dividends from PERH would be approximately \$147 million. The Partnership’s October 7, 2009 news release is available on SEDAR at www.sedar.com.

The revised expectations primarily reflect lower expected operating margins at the North Carolina generation facilities (Southport and Roxboro). As disclosed in the Partnership’s second quarter MD&A in July 2009, the North Carolina facilities are experiencing dispatch at minimal levels, which is a direct result of low natural gas prices. These facilities are fuelled by coal, wood waste and tire-derived fuel. Low natural gas prices result in lower operating costs for natural gas-fired power generation relative to other types of thermal generation, including those used at the North Carolina facilities. With natural gas prices expected to remain low at least through 2009, the North Carolina facilities are expected to be dispatched at minimal levels for the remainder of the year.

The current PPAs for the North Carolina facilities expire on December 31, 2009. The Partnership and Progress Energy Carolinas, Inc. (Progress) have been in negotiations but, to date, have been unable to finalize new PPAs that are acceptable to both parties. By regulation, Progress is required to offer contracts to any certified Qualifying Facility (QF) at Progress’ avoided cost. The Southport facility is currently certified as a QF and the Partnership has filed a self-certification to recertify the Roxboro facility as a QF which will become effective when the Roxboro facility begins utilizing the modified fuel mix following completion of the improvements at the end of 2009.

The Partnership noted that in August 2009, Progress applied to the North Carolina Utilities Commission (NCUC) to replace 397 megawatts of coal-fired generation with 950 megawatts of new gas-fired generation (New Build), a net add of over 550 megawatts, with an expected in service date of early 2013. On October 22, 2009 the NCUC issued an order (the Order) approving Progress’ New Build subject to several conditions, including that within 60 days Progress submit for NCUC approval, following opportunities for comments by parties, plans to retire additional coal generation reasonably proportionate to the incremental 550 megawatts. The NCUC’s Order acknowledged the Partnership’s concerns about the potential impacts of

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additional capacity on its negotiations with Progress and urged the parties to continue negotiations. The Partnership believes that the retirement of additional generation creates a gap in Progress' resource plan which the cost competitive generation offered by the Partnership's North Carolina facilities can help fill.

In its new build application, Progress indicated that its full cost of generation from this repowered facility would approximate \$147 per megawatt-hour. By comparison, the PPA pricing terms under discussion between the Partnership and Progress are considerably less costly than those proposed for Progress' re-powered facility.

The Partnership had finalized a petition for arbitration when the NCUC issued its Order. Following the NCUC's issuance of the Order, the Partnership has sent Progress a proposal setting forth an accelerated timeframe for restarting and finalizing negotiations. If negotiations are unsuccessful, the Partnership will file for arbitration. The Partnership remains optimistic that either a NCUC arbitration ruling or further negotiations with Progress will result in new PPAs for the Roxboro and Southport facilities. It is not certain at this time whether the final contract terms will immediately result in positive cash provided by operating activities for the facilities or achieve previous expectations of accretion from the North Carolina enhancement project. The Partnership's long-term outlook for the North Carolina plants remains positive as current modifications to the facilities are nearing completion that will significantly reduce coal use and replace it with more wood waste that will substantially reduce greenhouse gas emissions and increase the production of renewable energy to meet North Carolina's renewable energy requirements.

SELECTED QUARTERLY CONSOLIDATED FINANCIAL DATA

<i>(unaudited)</i>	2009				2008			2007	
<i>(millions of dollars except per unit amounts)</i>	Third	Second	First	Fourth	Third	Second	First	Fourth	
Revenues	155.5	165.2	127.6	103.8	133.5	143.9	118.1	114.1	
Operating margin ⁽¹⁾	65.9	87.7	(0.8)	(32.1)	(118.4)	155.1	106.8	81.5	
Net income (loss) from continuing operations	30.7	42.3	(32.6)	(73.3)	(152.2)	105.1	53.3	45.3	
Net income (loss)	30.7	42.8	(33.3)	(73.1)	(153.0)	104.9	53.4	45.3	
Cash provided by operating activities of continuing operations	33.8	33.1	33.7	56.5	20.0	39.4	41.6	35.7	
Capital expenditures	33.0	25.9	17.0	21.5	5.1	10.0	3.4	4.1	
Cash distributions	23.7	23.7	34.0	33.9	34.0	33.9	34.0	34.0	
Per unit statistics									
Net income (loss) from continuing operations	\$ 0.57	\$ 0.78	\$ (0.60)	\$ (1.36)	\$ (2.82)	\$ 1.95	\$ 0.99	\$ 0.84	
Cash provided by operating activities of continuing operations ⁽¹⁾	\$ 0.63	\$ 0.61	\$ 0.63	\$ 1.05	\$ 0.37	\$ 0.73	\$ 0.77	\$ 0.66	
Cash distributions	\$ 0.44	\$ 0.44	\$ 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 of continuing operations 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 primarily on the

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Partnership’s US dollar-denominated long-term debt prior to the fourth quarter of 2008 and fair value changes in foreign exchange contracts and natural gas supply contracts.

The Partnership’s cash flow tends to be relatively stable over the year with seasonal fluctuations at the individual facilities. The Naval facilities earn approximately 75% of their capacity revenue during the summer peak demand months and all the California plants can earn performance bonuses during these months. Under the power sales contracts for the Ontario plants, the Partnership receives higher per megawatt hour 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 Williams Lake 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 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:

In the fourth quarter of 2008, the Partnership acquired Morris.

In the fourth quarter of 2008, the Partnership recorded a \$24.1 million asset impairment charge on its investment in the common shares of PERH. In the third quarter of 2007, the Partnership recorded a \$13.0 million asset impairment charge in respect of certain management contracts.

In the third quarter of 2008 the Partnership recorded a \$3.4 million reduction in natural gas costs as the Partnership updated its estimate of the cost for natural gas supplied under contract.

Unrealized foreign exchange gains on US dollar-denominated debt were recorded in the fourth quarter of 2007 and the second quarter of 2008. Losses were recorded in the first and third quarters of 2008. The gains and losses are due to fluctuations in the US dollar relative to the Canadian dollar.

The Partnership recorded gains on the change in the fair value of the natural gas supply contracts in the fourth quarter of 2007 and the first and second quarters of 2008 and the second quarter of 2009 and losses in the third and fourth quarters of 2008 and the first and third quarters of 2009.

Unrealized fair value changes on foreign exchange contracts resulted in gains in the second quarter of 2008 and the second and third quarters of 2009. Losses were recorded in the fourth quarter of 2007, in the first, third and fourth quarters of 2008 and in the first quarter of 2009.

The first quarter of 2008 had unseasonably high water flows at Curtis Palmer, while the fourth quarter of 2007 had unseasonably low water flows.

FORWARD-LOOKING INFORMATION

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. In particular, forward-looking information and statements

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include (i) the sustainability of distributions, including relative to a long-term payout ratio target of 75% of cash provided by operating activities less maintenance capital; (ii) planned capital upgrades at Southport and Roxboro of US\$80 million, (iii) planned capital upgrades at Oxnard of US\$20 million, (iv) expectations regarding the in service timeline for additional facilities at Manchief, (v) expectations regarding the Partnership's cash provided by operating activities, dividends received from PERH, capital expenditures generally and working capital in 2009, (vi) expectations regarding the cash to be retained by the Partnership as a result of the distribution reduction and the expected uses of that cash, (vii) anticipated closed date of the preferred share offering, (viii) expectations regarding the financing of the Partnership's capital expenditures (ix) expectations with regard to the operating margin and dispatch levels for the North Carolina facilities, (x) managements expectations in respect of new PPA's for the Southport and Roxboro facilities, (xi) with respect to the Partnership's long-term outlook for the North Carolina plants, (xii) anticipated completion of the Roxboro and Southport facility modifications and the impact thereof on the operation of the facilities, (xiii) the expectation that the Roxboro facility will be re-certified as a QF by the end of 2009, and (xiv) that the Partnership will apply to the NCUC to arbitrate if an agreement for a new PPA with Progress is not reached.

These statements are based on certain assumptions and analyses made by the Partnership in light of its experience and perception of historical trends, current conditions and expected future developments and other factors it believes are appropriate. The material factors and assumptions used to develop these forward-looking statements include: (i) the Partnership's operations, financial position and available credit facilities, (ii) the Partnership's assessment of commodity, currency and power markets, (iii) the markets and regulatory environment in which the Partnership's facilities operate, (iv) the state of capital markets, (v) management's analysis of applicable tax legislation, (vi) the assumption that the currently applicable and proposed tax laws will not change and will be implemented, (vii) the assumption that counterparties to fuel supply and power purchase agreements will continue to perform their obligations under the agreements taking account of the matters described herein, (viii) the level of plant availability and dispatch, (ix) the performance of contractors and suppliers, (x) the renewal or replacement of PPAs and terms of PPAs (xi) the ability of the Partnership to successfully integrate and realize the benefits of its acquisitions, (xii) the ability of the Partnership to implement its strategic initiatives and whether such initiatives will yield the expected benefits, (xiii) expected water flows, and (xiv) the ability of the Partnership to adequately source alternative sources of supply of wood waste.

Whether actual results, performance or achievements will conform to the Partnership's expectations and predictions is subject to a number of known and unknown risks and uncertainties which could cause actual results to differ materially from the Partnership's expectations. Such risks and uncertainties include, but are not limited to risks relating to (i) the operation of the Partnership's facilities, (ii) plant availability and performance, (iii) the availability and price of energy commodities including natural gas and wood waste, (iv) the performance of counterparties in meeting their obligations under PPAs, (v) competitive factors in the power industry, (vi) economic conditions, including in the markets served by the Partnership's facilities, (vii) ongoing compliance by the Partnership with its current debt covenants, (viii) developments within the North American capital markets, (ix) the availability and cost of permanent long-term financing in respect of acquisitions and investments, (x) unanticipated maintenance and other expenditures, (xi) the Partnership's ability to successfully realize the benefits of acquisitions and investments, (xii) changes in regulatory and government decisions including changes to emission regulations, (xiii) waste heat availability and water flows, (xiv) changes in existing and proposed tax and other legislation in Canada and the US and including changes in the Canada-US tax treaty, (xv) the tax attributes of and implications of any acquisitions, (xvi) the availability

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and cost of equipment, (xvii) changing demand for natural gas in northern Ontario and areas further to the east and levels of natural gas supply in western Canada available for shipping on the TransCanada Canadian Mainline, (xix) the ability of the Partnership to adequately source alternative sources of supply of wood waste, (xx) the regulatory process by which the Roxboro facility gets re-certified as a QF may not result in such re-certification, and (xxi) the NCUC arbitration or negotiations with Progress may not result in PPAs with satisfactory financial terms.

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. Forward-looking statements are provided for the purpose of presenting information about management’s current expectations and plans relating to the future and readers are cautioned that such statements may not be appropriate for other purposes. Except as required by law, the Partnership disclaims any intention and assumes no obligation to update any forward-looking statement.

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 2009	Jun. 30 2009	Mar. 31 2008	Dec. 31 2008	Sep. 30 2008
Unit price					
High	\$16.30	\$16.21	\$18.98	\$20.65	\$23.50
Low	\$13.62	\$11.65	\$12.90	\$15.50	\$19.83
Close	\$15.26	\$15.25	\$13.80	\$17.72	\$20.32
Volume traded (millions)	4.3	9.2	3.3	5.1	3.6

As at October 26, 2009, the Partnership had 53.9 million units outstanding. The weighted average number of units outstanding for the three and nine months ended September 30, 2009 was 53.9 million.

ADDITIONAL INFORMATION

Additional information relating to EPCOR Power L.P. including the Partnership’s Annual Information Form and continuous disclosure documents are available on SEDAR at www.sedar.com.

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

<i>(unaudited)</i>	Three months ended September 30		Nine months ended September 30	
	2009	2008	2009	2008
(In millions of dollars except units and per unit amounts)				
Revenues	\$ 155.5	\$ 133.5	\$ 448.3	\$ 395.5
Cost of fuel	65.5	224.9	215.5	180.0
Operating and maintenance expense	24.1	27.0	80.0	72.0
	65.9	(118.4)	152.8	143.5
Other costs				
Depreciation and amortization	22.9	22.8	70.0	66.6
Management and administration	3.7	4.7	10.9	13.2
Foreign exchange losses	0.1	15.9	0.7	26.4
Equity losses in PERH	0.8	1.7	3.1	3.8
Financial charges and other, net (Note 4)	10.2	9.2	31.6	27.4
	37.7	54.3	116.3	137.4
Net income (loss) from continuing operations before income tax and preferred share dividends	28.2	(172.7)	36.5	6.1
Income tax recovery (Note 5)	(4.2)	(22.1)	(8.9)	(5.0)
Net income (loss) from continuing operations before preferred share dividends	32.4	(150.6)	45.4	11.1
Preferred share dividends of a subsidiary company	1.7	1.6	5.0	4.9
Net income (loss) from continuing operations	30.7	(152.2)	40.4	6.2
Loss from discontinued operations, net of income tax (Note 3)	-	(0.8)	(0.2)	(0.9)
Net income (loss)	\$ 30.7	\$ (153.0)	\$ 40.2	\$ 5.3
Net income (loss) per unit from continuing operations	\$ 0.57	\$ (2.82)	\$ 0.75	\$ 0.12
Net loss per unit from discontinued operations	\$ -	\$ (0.01)	\$ 0.00	\$ (0.02)
Net income (loss) per unit	\$ 0.57	\$ (2.84)	\$ 0.75	\$ 0.10
Weighted average units outstanding (millions)	53.9	53.9	53.9	53.9

See accompanying notes to the consolidated financial statements.

EPCOR Power L.P.
CONSOLIDATED STATEMENTS OF CASH FLOW

<i>(unaudited)</i>	Three months ended September 30		Nine months ended September 30	
	2009	2008	2009	2008
(In millions of dollars)				
Operating activities				
Net income (loss) from continuing operations	\$ 30.7	\$ (152.2)	\$ 40.4	\$ 6.2
Items not affecting cash:				
Depreciation and amortization	22.9	22.8	70.0	66.6
Future income tax recovery	(6.1)	(23.1)	(11.4)	(8.6)
Fair value changes on derivative instruments	(12.5)	175.1	2.6	14.1
Unrealized foreign exchange losses	0.2	16.0	0.5	26.3
Other	2.1	2.8	5.4	5.1
	37.3	41.4	107.5	109.7
Change in non-cash operating working capital	(3.5)	(21.4)	(6.9)	(8.7)
Cash provided by operating activities of continuing operations	33.8	20.0	100.6	101.0
Cash provided by (used in) operating activities of discontinued operations	-	1.5	(2.8)	3.8
Cash provided by operating activities	33.8	21.5	97.8	104.8
Investing activities				
Additions to property, plant and equipment	(33.0)	(5.1)	(75.9)	(18.5)
Change in non-cash working capital	0.3	(3.5)	(1.9)	0.1
Dividends from PERH	-	0.8	1.3	2.4
Cash used in investing activities of continuing operations	(32.7)	(7.8)	(76.5)	(16.0)
Cash (used in) provided by investing activities of discontinued operations	-	(3.4)	11.6	(3.4)
Cash used in investing activities	(32.7)	(11.2)	(64.9)	(19.4)
Financing activities				
Distributions paid	(23.7)	(33.9)	(91.6)	(101.8)
Net borrowings under credit facilities	26.3	17.0	63.9	17.0
Long-term debt repaid	(0.7)	(0.6)	(1.3)	(1.1)
Cash provided by (used in) financing activities	1.9	(17.5)	(29.0)	(85.9)
Foreign exchange (losses) gains on cash held in a foreign currency	(0.6)	0.1	(1.4)	0.8
Increase (decrease) in cash and cash equivalents	2.4	(7.1)	2.5	0.3
Cash and cash equivalents, beginning of period	3.1	27.5	3.0	20.1
Cash and cash equivalents, end of period	\$ 5.5	\$ 20.4	\$ 5.5	\$ 20.4
Supplementary cash flow information				
Net income taxes paid (recovered)	\$ (1.0)	\$ 2.5	\$ 0.4	\$ 7.0
Interest paid net of interest received	\$ 14.4	\$ 12.6	\$ 36.8	\$ 31.2

See accompanying notes to the consolidated financial statements.

EPCOR Power L.P.
CONSOLIDATED BALANCE SHEETS

<i>(unaudited)</i>	September 30, 2009	December 31, 2008
(In millions of dollars)		
ASSETS		
Current assets		
Cash and cash equivalents	\$ 5.5	\$ 3.0
Accounts receivable	46.1	60.6
Inventories	22.7	23.2
Prepays and other	7.2	5.0
Derivative instruments assets (Note 6)	6.0	22.8
Future income taxes	2.3	2.3
Current assets of discontinued operations	-	2.3
	89.8	119.2
Property, plant and equipment	1,065.6	1,106.0
Power purchase arrangements	342.5	408.6
Long-term investments	12.9	19.2
Goodwill	48.4	55.1
Derivative instruments assets (Note 6)	28.4	27.1
Future income taxes	27.0	16.8
Other assets	39.0	45.2
Long-term assets of discontinued operations	-	12.0
	\$ 1,653.6	\$ 1,809.2
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities		
Accounts payable	\$ 49.8	\$ 70.3
Distributions payable	23.7	33.9
Long-term debt due within one year	1.4	1.3
Derivative instruments liabilities (Note 6)	2.6	13.0
Current liabilities of discontinued operations	-	1.2
	77.5	119.7
Asset retirement obligations	28.6	28.6
Long-term debt	791.1	798.5
Derivative instruments liabilities (Note 6)	26.9	38.5
Contract liabilities	2.3	4.7
Future income taxes	63.1	60.7
Long-term liabilities of discontinued operations	-	4.2
Preferred shares issued by a subsidiary company	122.0	122.0
Partners' equity	542.1	632.3
Commitments (Note 8)		
Subsequent events (Note 9)		
	\$ 1,653.6	\$ 1,809.2

See accompanying notes to the consolidated financial statements.

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

<i>(unaudited)</i>	Nine months ended September 30	
(In millions of dollars)	2009	2008
Partnership capital		
Balance, beginning of period	\$ 1,197.1	\$ 1,197.1
Issue of partnership units	-	-
Balance, end of period	\$ 1,197.1	\$ 1,197.1
Deficit		
Balance, beginning of period:		
As previously reported	\$ (500.1)	\$ (296.5)
Adjustment for changes in accounting policies (Note 2)	3.9	-
As restated	(496.2)	(296.5)
Net income	40.2	5.3
Cash distributions	(81.4)	(101.9)
Balance, end of period	\$ (537.4)	\$ (393.1)
Accumulated other comprehensive (loss) income		
Balance, beginning of period	\$ (64.7)	\$ 5.1
Other comprehensive loss	(52.9)	(2.9)
Balance, end of period	\$ (117.6)	\$ 2.2
Total of deficit and accumulated other comprehensive (loss) income	\$ (655.0)	\$ (390.9)
Partners' equity	\$ 542.1	\$ 806.2

See accompanying notes to the consolidated financial statements.

EPCOR Power L.P.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME AND LOSS

<i>(unaudited)</i>	Three months ended September 30		Nine months ended September 30	
	2009	2008	2009	2008
(In millions of dollars)				
Net income (loss)	\$ 30.7	\$ (153.0)	\$ 40.2	\$ 5.3
Other comprehensive loss, net of income tax				
Losses on translating net assets of self-sustaining foreign operations ⁽¹⁾	(32.8)	-	(56.7)	-
Amortization of deferred gains on derivatives de-designated as cash flow hedges to income ⁽¹⁾	-	(1.0)	(0.4)	(2.9)
Unrealized gains on derivative instruments designated as cash flow hedges ⁽²⁾	4.2	-	4.2	-
	(28.6)	(1.0)	(52.9)	(2.9)
Comprehensive income (loss)	\$ 2.1	\$ (154.0)	\$ (12.7)	\$ 2.4

⁽¹⁾ Net of income tax of nil.

⁽²⁾ Net of income tax of \$0.1 for the three and nine months ended September 30, 2009.

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, 2008, 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 three and nine months ended September 30, 2009 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 2008 Annual Report.

Quarterly revenues, net income and cash provided by operating activities are affected by seasonal contract pricing, seasonal weather conditions, fluctuations in United States (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 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 plants normally generate the majority of their operating margin during the summer months when the plants can earn performance bonuses. Additionally, the plants located on Naval bases earn approximately 75% of their capacity revenue during these 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. Changes in accounting policies

Credit risk and the fair value of financial assets and financial liabilities

On January 20, 2009 the Emerging Issues Committee of the Canadian Institute of Chartered Accountants (CICA) issued EIC-173, Credit Risk and the Fair Value of Financial Assets and Financial Liabilities, which clarifies that an entity's own credit risk and the credit risk of the counterparty should be taken into account in determining the fair value of financial assets and liabilities, including derivative instruments. Effective January 1, 2009, the Partnership adopted the recommendations of EIC-173 and applied the recommendations retrospectively without restatement of prior periods. On January 1, 2009, the Partnership made the following adjustments to the balance sheet to adopt the recommendations of EIC-173:

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Balance sheet item (<i>millions of dollars</i>)	Increase (decrease)	Explanation
Derivative instruments assets	(1.5)	Impact to fair value of foreign exchange and natural gas contracts from incorporating credit risk of counterparties of the Partnership.
Derivative instruments liabilities	(6.3)	
Future income taxes liabilities - non-current	0.9	Tax impact from adoption of new standard.
Opening deficit	(3.9)	After tax impact to opening deficit resulting from adoption of new standard.

Goodwill and intangible assets

In February 2008, the CICA issued Handbook Section 3064 – Goodwill and Intangible Assets and consequential amendments to Section 1000 – Financial Statement Concepts. The new section establishes standards for the recognition, measurement and disclosure of goodwill and intangible assets. The provisions relating to the definition and initial recognition of intangible assets, including internally generated intangible assets, are equivalent to the corresponding provisions of International Financial Reporting Standards (IFRS). The Partnership adopted these amendments January 1, 2009 which did not result in a material transition adjustment to the financial statements. The new accounting standard has been applied prospectively and the comparative financial statements have not been restated.

Future accounting changes

International financial reporting standards

In 2005, the CICA announced plans to converge Canadian GAAP with IFRS over a transition period from 2006 to 2011. The CICA indicated that Canadian entities will be required to begin reporting under IFRS effective the first quarter of 2011 including comparative figures. A high level IFRS implementation plan has been developed and an assessment of the financial statement impact of the accounting standard differences is currently in progress. Based on the analysis to date, the most significant differences for the Partnership are anticipated to be related to property, plant and equipment, leases, joint arrangements, financial instruments and hedges, income taxes, impairments, business combinations, emission credits, asset retirement obligations and financial statement disclosure. The Partnership also expects to make changes to certain processes and systems before 2010, in time to ensure transactions are recorded in accordance with IFRS for comparative reporting purposes at the required implementation date.

Consolidated financial statements and non-controlling interests

In January 2009, the CICA issued Handbook Section 1601 – Consolidated Financial Statements and Section – 1602 Non-controlling Interests, which replace Section 1600 – Consolidated Financial Statements. Section 1601 establishes the standards for the preparation of consolidated financial statements while Section 1602 establishes the standards for accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. Section 1602 is equivalent to the corresponding provisions of IFRS IAS 27 – Consolidated and Separate Financial Statements.

Sections 1601 and 1602 will apply to the Partnership's interim and annual consolidated financial statements relating to periods commencing on or after January 1, 2011. Earlier adoption is permitted as of the beginning of a fiscal year, provided Section 1582 – Business Combinations

is also adopted at the same time. The impact of the new standards and the option to adopt them early will be assessed as part of the Partnership's IFRS project.

Business combinations

In January 2009, the CICA issued Handbook Section 1582 – Business Combinations, which replaces Section 1581 – Business Combinations and provides the Canadian equivalent to IFRS 3 – Business Combinations. The section will apply on a prospective basis to the Partnership's future business combinations for which the acquisition date is on or after January 1, 2011. Earlier adoption is permitted as of the beginning of a fiscal year provided Sections 1601 – Consolidated Financial Statements and 1602 – Non-controlling Interests are also adopted at the same time. The impact of the new standard and the option to adopt it early will be assessed as part of the Partnership's IFRS project.

Fair value measurement disclosure

In June 2009, the CICA amended Handbook Section 3862 Financial Instruments – Disclosures, to adopt the amendments recently made by the International Accounting Standards Board to IFRS 7 Financial Instruments: Disclosures. The amendments require enhanced disclosures about fair value measurements, including the relative reliability of the inputs used in those measurements and about the liquidity risk of financial instruments. Although the amendments apply to financial statements relating to fiscal years ending after September 30, 2009, comparative information is not required in the first year of application. The impacts of these amendments will be assessed and the necessary additional disclosures will be implemented commencing with the annual financial statements for 2009.

Derivative instruments and hedging activities

To reduce its exposure to movements in energy commodity prices, interest rate changes and foreign currency exchange rates, the Partnership uses various risk management techniques including the use of derivative instruments. Derivative instruments may include forward contracts, fixed-for-floating swaps, and option contracts. Such instruments may be used to establish a fixed price for an energy commodity, a cash flow denominated in a foreign currency or an interest-bearing obligation. All derivative instruments, including embedded derivatives, are recorded at fair value on the balance sheet as derivative instruments assets or derivative instruments liabilities except for embedded derivatives instruments that are clearly and closely linked to their host contract and the combined instrument is not measured at fair value. Any contract to buy or sell a non-financial item is not treated as a non-financial derivative if that contract was entered into and continues to be held for the purpose of the receipt or delivery of a non-financial item in accordance with the Partnership's expected purchase, sale or usage requirements. All changes in the fair value of derivatives are recorded in net income unless cash flow hedge accounting is used, in which case changes in fair value of the effective portion of the derivatives are recorded in other comprehensive income.

The Partnership uses non-financial forward delivery derivatives to manage the Partnership's exposure to fluctuations in natural gas prices related to obligations arising from its natural gas fired generation facilities. Under these instruments, the Partnership agrees to purchase natural gas at a fixed price for delivery of a pre-determined quantity under a specified timeframe.

Foreign exchange forward contracts are used by the Partnership to manage foreign exchange exposures, consisting mainly of US dollar exposures, resulting from anticipated transactions denominated in foreign currencies.

The Partnership may use forward interest rate or swap agreements and option agreements to manage the impact of fluctuating interest rates on existing debt.

The Partnership may use hedge accounting when there is a high degree of correlation between the risk in the item designated as being hedged (the hedged item) and the derivative instrument designated as a hedge (the hedging instrument). The Partnership documents all relationships between hedging instruments and hedged items at the hedge's inception, including its risk management objectives and its assessment of the effectiveness of the hedging relationship on a retrospective and prospective basis. The Partnership uses cash flow hedges for certain of its anticipated transactions to reduce exposure to fluctuations in changes in natural gas prices. In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is recognized in other comprehensive income, while the ineffective portion is recognized in net income. The amounts recognized in accumulated other comprehensive income are reclassified into net income in the same period or periods in which the hedged item occurs and is recorded in net income or when the hedged item becomes probable of not occurring. The hedging relationship for the natural gas contracts was established after the inception of the contracts, which are derivative instruments. The fair value of these contracts at the date of hedge designation will be recognized in net income as the natural gas is delivered under the contracts based on the anticipated fair value of the deliveries at the inception of the hedging relationship.

The Partnership has not designated any fair value hedges at the balance sheet date.

A hedging relationship is discontinued if the hedge relationship ceases to be effective, if the hedged item is an anticipated transaction and it is probable that the transaction will not occur by the end of the originally specified time period, if the Partnership terminates its designation of the hedging relationship, or if either the hedged or hedging instrument ceases to exist as a result of its maturity, expiry, sale, termination or cancellation and is not replaced as part of the Partnership's hedging strategy.

If a cash flow hedging relationship is discontinued or ceases to be effective, any cumulative gains or losses arising prior to such time are deferred in accumulated other comprehensive income and recognized in net income in the same period as the hedged item, and subsequent changes in the fair value of the derivative instrument are reflected in net income. If the hedged or hedging item matures, expires, or is sold, extinguished or terminated and the hedging item is not replaced, any gains or losses associated with the hedging item that were previously recognized in other comprehensive income are recognized in net income in the same period as the corresponding gains or losses on the hedged item. When it is no longer probable that an anticipated transaction will occur within the originally determined period and the associated cash flow hedge has been discontinued, any gains or losses associated with the hedging item that were previously recognized in other comprehensive income are recognized in net income in the period.

When the conditions for hedge accounting cannot be applied, the changes in fair value of the derivative instruments are recognized as described above. The fair value of derivative financial instruments reflects changes in the commodity market prices and foreign exchange rates. Fair

value is determined based on exchange or over-the-counter price quotations by reference to bid or asking price as appropriate, in active markets. In illiquid or inactive markets, the Partnership uses appropriate valuation and price modeling techniques commonly used by market participants to estimate fair value. Fair values determined using valuation models require the use of assumptions concerning the amounts and timing of future cash flows. Fair value amounts reflect management's best estimates using external readily observable market data such as future prices, interest rate yield curves, foreign exchange rates, discount rates for time value, and volatility where available. It is possible that the assumptions used in establishing fair value amounts will differ from future outcomes and the impact of such variations could be material.

Investment in PERH

The Partnership's common ownership interest in PERH was accounted for on the equity basis up to August 24, 2009 and on a cost basis thereafter as a result of a recapitalization of PERH and changes to the management agreement between the Partnership, PERH, Primary Energy Recycling Corporation (PERC) and Primary Energy Operations LLC. The Partnership has converted all of its common and preferred interests in PERH to a 14.3% common equity interest in PERH in connection with a recapitalization of PERH pursuant to which all previously outstanding common and preferred interests in PERH, including those held by the Partnership and PERC, were converted to new common equity interests. No gain or loss was recorded on the conversion.

Note 3. Discontinued operations

The Partnership completed the sale of its Castleton facility (Castleton) on May 26, 2009. The disposition of Castleton resulted in proceeds of \$12.0 million (US\$10.7 million) less transaction costs of \$0.2 million (US\$0.2 million) and a pre-tax accounting gain of \$2.4 million. A summary of revenues and expenses of Castleton were as follows:

<i>(millions of dollars)</i>	Three months ended		Nine months ended	
	September 30		September 30	
	2009	2008	2009	2008
Revenues	\$ -	\$ 4.4	\$ 2.1	\$ 11.2
Expenses				
Cost of fuel	-	3.9	2.1	5.0
Operating and maintenance expense	-	1.1	2.1	3.1
Depreciation and amortization	-	0.3	-	3.4
Foreign exchange gains	-	(0.3)	-	(0.2)
Loss from operations	-	(0.6)	(2.1)	(0.1)
Gain on sale of Castleton	-	-	2.4	-
(Loss) income before income tax	-	(0.6)	0.3	(0.1)
Income tax expense	-	0.2	0.5	0.8
Loss from discontinued operations	\$ -	\$ (0.8)	\$ (0.2)	\$ (0.9)

Note 4. Financial charges and other, net

<i>(millions of dollars)</i>	Three months ended		Nine months ended	
	September 30		September 30	
	2009	2008	2009	2008
Interest on long-term debt	\$ 10.4	\$ 9.8	\$ 32.1	\$ 28.5
Interest on short-term debt	-	0.2	0.6	0.5
Capitalized interest	(0.2)	-	(0.2)	-
Dividend income from Class B preferred share interests in PERH	(0.4)	(0.5)	(1.1)	(1.4)
Other	0.4	(0.3)	0.2	(0.2)
	\$ 10.2	\$ 9.2	\$ 31.6	\$ 27.4

Note 5. Income taxes

During the quarter ended September 30, 2009, the Partnership recorded an out-of-period adjustment of \$9.5 million relating to 2007, 2008 and 2009 to recognize net future income tax assets associated with the Partnership's interest in PERH. PERH is treated as a partnership for US tax purposes and the adjustments are attributable to the allocation of tax deductions between the Partnership and PERH's other partner, PERC that were incorrectly calculated by PERH's external tax advisors for the relevant periods. Of the \$9.5 million, \$2.8 million is attributable to 2007, \$5.8 million is attributable to 2008 and \$0.9 million is attributable to the six months end June 30, 2009. Management determined that the impact of the adjustment was not material, either individually or in aggregate, to any of the prior periods' financial statements or to the expected results for the year ending December 31, 2009 and accordingly, that a restatement of previously issued financial statements was not necessary. As such, the adjustment was recorded during the quarter ended September 30, 2009.

Note 6. Financial instruments

Derivative instruments

Derivative instruments are held to manage financial risk related to energy procurement and treasury management. All derivative instruments, including embedded derivatives, are classified as held for trading and are recorded at fair value on the balance sheet as derivative instruments assets and derivative instruments liabilities unless exempted from derivative treatment as a normal purchase, sale or usage. All changes in their fair value are recorded in net income.

The derivative instruments assets and liabilities used for risk management purposes consist of the following:

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September 30, 2009					
	Natural gas		Foreign exchange		Total
	Hedges	Non-hedges	Non-hedges		
Derivative instruments assets:					
Current	\$ 0.8	\$ 1.7	\$ 3.5	\$	6.0
Non-current	0.4	7.8	20.2		28.4
Derivative instruments liabilities:					
Current	(1.6)	(0.1)	(0.9)		(2.6)
Non-current	(21.7)	-	(5.2)		(26.9)
	\$ (22.1)	\$ 9.4	\$ 17.6	\$	4.9
Net notional amounts:					
Gigajoules (GJs)(millions)	47	12			
US foreign exchange (US dollars in millions)			453.3		
Contract terms (years)	1.3 to 7.3	0.3 to 3.3	0.2 to 6.2		

December 31, 2008					
	Natural gas		Foreign exchange		Total
	Hedges	Non-hedges	Non-hedges		
Derivative instruments assets:					
Current	\$ -	\$ 15.5	\$ 7.3	\$	22.8
Non-current	-	23.5	3.6		27.1
Derivative instruments liabilities:					
Current	-	(1.5)	(11.5)		(13.0)
Non-current	-	(0.6)	(37.9)		(38.5)
	\$ -	\$ 36.9	\$ (38.5)	\$	(1.6)
Net notional amounts:					
Gigajoules (GJs)(millions)	-	69			
US foreign exchange (US dollars in millions)			456.9		
Contract terms (years)	-	0.1 to 8.0	0.2 to 6.0		

The fair value of derivative instruments are determined, where possible, using exchange or over-the-counter price quotations by reference to quoted bid, ask, or closing market prices, as appropriate in active markets. Where there are limited observable prices due to illiquid or inactive markets, the Partnership uses appropriate valuation and price modeling commonly used by market participants to estimate fair value. Fair value determined using valuation models requires the use of assumptions concerning the amount and timing of future cash flows. In general, fair value amounts reflect management's best estimates using external readily observable market data such as future prices, interest rate yield curves, foreign exchange rates, discount rates for time value, and volatility for all of the Partnership's financial instruments. It is possible that the assumptions used in establishing fair value amounts will differ from future outcomes and the impact of such variations could be material. With respect to natural gas the Partnership has determined the market is active to the end of the contract terms, a change from its previous assessment that the market was active within five years. In changing its

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assessment the Partnership considered market activity and the short period of time that the contracts extend beyond five years.

Unrealized and realized pre-tax gains and (losses) on derivative instruments recognized in net income and other comprehensive income were:

<i>(millions of dollars)</i>	Income statement category	Three months ended September 30		Nine months ended September 30	
		2009	2008	2009	2008
Foreign exchange non-hedges	Revenue	\$ 32.6	\$ (11.1)	\$ 50.8	\$ (13.3)
Natural gas non-hedges	Cost of fuel	(20.2)	(160.5)	(53.0)	9.8
Foreign exchange non-hedges	Foreign exchange losses (gains)	0.1	0.1	(0.4)	(0.1)
Natural gas hedges	Other comprehensive income	4.3	-	4.3	-

If hedge accounting requirements are not met, unrealized and realized gains and losses on natural gas derivatives are recorded in cost of fuel. If hedge accounting requirements are met, realized gains and losses on natural gas derivatives are recorded in cost of fuel while unrealized gains and losses are recorded in other comprehensive income.

The Partnership has elected to apply hedge accounting effective July 31, 2009, on certain derivative instruments it uses to manage commodity price risk relating to natural gas prices. For the three and nine months ended September 30, 2009, the change in the fair value of the ineffective portion of hedging derivatives required to be recognized in the income statement was nil. Of the \$4.2 million of after tax gains related to derivative instruments designated as cash-flow hedges included in accumulated other comprehensive income at September 30, 2009, gains of \$3.6 million, net of income taxes of \$nil are expected to settle and be reclassified to net income over the next twelve months. The Partnership's cash flow hedges extend up to 2016.

Note 7. Segment disclosures

The Partnership operates in one reportable business segment involved in the operation of electrical generation plants within British Columbia, Ontario, and in the US in California, Colorado, Illinois, New Jersey, New York, North Carolina and Washington.

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Geographic information

<i>(millions of dollars)</i>	Three months ended September 30 2009			Three months ended September 30 2008		
	Canada	US	Total	Canada	US	Total
Revenue	\$ 75.2	\$ 80.3	\$ 155.5	\$ 41.5	\$ 92.0	\$ 133.5

<i>(millions of dollars)</i>	Nine months ended September 30 2009			Nine months ended September 30 2008		
	Canada	US	Total	Canada	US	Total
Revenue	\$ 198.7	\$ 249.6	\$ 448.3	\$ 147.3	\$ 248.2	\$ 395.5

<i>(millions of dollars)</i>	As at September 30, 2009			As at December 31, 2008		
	Canada	US	Total	Canada	US	Total
Assets						
PP&E	\$ 540.9	\$ 524.7	\$ 1,065.6	\$ 559.3	\$ 546.7	\$ 1,106.0
PPAs	37.4	305.1	342.5	39.7	368.9	408.6
Other assets	-	39.0	39.0	-	45.2	45.2
Goodwill	-	48.4	48.4	-	55.1	55.1
Total assets	\$ 578.3	\$ 917.2	\$ 1,495.5	\$ 599.0	\$ 1,015.9	\$ 1,614.9

Note 8. Commitments

The Partnership has committed to spend an additional \$33 million (US\$31 million) in the remaining three months of 2009 at the Southport and Roxboro facilities to increase the plants' ability to use tire derived fuel and wood waste in their fuel mix, with a total expected cost for the projects of US\$80 million.

The Partnership has committed up to \$17 million (US\$16 million) for the replacement of the LM5000 natural gas turbine with an LM6000 unit at the Oxnard facility, with \$1 million expected to be spent in the remaining three months of 2009 and the remainder in 2010, with a total expected cost for the project of US\$20 million.

Note 9. Subsequent events

On October 13, 2009, the Partnership announced a change in the frequency of its distributions to monthly from quarterly. Cash distributions of the Partnership for periods commencing after September 30, 2009 will be made in respect of each calendar month instead of the quarters ending March, June, September and December of each year. The Partnership also announced the launch of a Premium Distribution™ and Distribution Reinvestment Plan (the Plan) that provides eligible unitholders with two alternatives to receiving the monthly cash distributions, including the option to accumulate additional units in the Partnership by reinvesting cash distributions in additional units issued at a 5% discount to the Average Market Price of such units (as defined in the Plan) on the applicable distribution payment date. Under the Premium Distribution™ component of the Plan, eligible unitholders may elect to exchange these

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additional units for a cash payment equal to 102% of the regular cash distribution on the applicable distribution payment date.

On October 13, 2009, a subsidiary of the Partnership entered into a bought deal for the issuance of 4,000,000 7.0% Cumulative Rate Reset Preferred Shares, Series 2 (the Series 2 Shares) at a price of \$25.00 per share, for aggregate gross proceeds of \$100 million (the Offering). The Series 2 Shares will pay fixed cumulative dividends of \$1.75 per share per annum, as and when declared, for the initial five-year period ending December 14, 2014. The dividend rate will reset on December 31, 2014 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 4.18%. The Series 2 Shares are redeemable at \$25.00 per share by the Corporation on December 31, 2014 and every five years thereafter. The holders of the Series 2 Shares will have the right to convert their shares into Cumulative Floating Rate Preferred Shares, Series 3 (the Series 3 Shares) of the Corporation, subject to certain conditions, on December 31, 2014 and every five years thereafter. The holders of Series 3 Shares will be entitled to receive quarterly floating rate cumulative dividends, as and when declared by the board of directors of the Corporation, at a rate equal to the sum of the then 90-day Government of Canada treasury bill rate and 4.18%. The offering is expected to close on or about November 2, 2009, subject to certain conditions.

PERC has filed a prospectus qualifying the issuance of rights to acquire subscription receipts which will be converted into common shares of PERC upon PERC obtaining sufficient funds to refinance its credit facility. PERC has advised that upon such occurrence, PERC immediately intends to use the net proceeds of the rights offering to subscribe for new common membership interests in PERH. The Partnership has a pre-emptive right to maintain its current pro-rata interest (14.3%) in PERH. The Partnership has determined that it will exercise its pre-emptive right, subject to changes in circumstances prior to the close of the rights offering that may cause the Partnership to reconsider this decision. If the Partnership exercises its pre-emptive right, the Partnership will be required to subscribe for new common membership interests at an aggregate subscription price of US\$8.3 million concurrently with PERC's subscription. The Partnership will finance the subscription with cash on hand or by drawing on its revolving credit facilities.

Note 10. Comparative figures

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

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

Media Inquiries:	Mike Long	(780) 392-5207
Unitholder & Analyst Inquiries:	Randy Mah	(780) 392-5305
	Toll Free	(866) 896-4636