CAPITAL POWER INCOME L.P.

MD&A

For the Year Ended December 31, 2009

MANAGEMENT'S DISCUSSION AND ANALYSIS

This management's discussion and analysis (MD&A) is dated March 4, 2010 and should be read in conjunction with the accompanying audited consolidated financial statements of Capital Power Income L.P. (collectively with its subsidiaries the Partnership, unless otherwise specifically stated) for the years ended December 31, 2009 and 2008.

As part of the sale by EPCOR Utilities Inc. (collectively with its subsidiaries, EPCOR) of a 27.8% interest in its power generation business to Capital Power Corporation (collectively with its subsidiaries, CPC, unless otherwise indicated: (i) in June 2009, CPI Investments Inc. (Investments) acquired 16,511,104 limited partnership units in the capital of the Partnership and all of the common shares of CPI Income Services Ltd., the General Partner of the Partnership (herein the General Partner), which directly owns 2,400 limited partnership units in the capital of the Partnership, representing 30.6% of the then total outstanding units of the Partnership, and (ii) in July 2009, 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 51 voting, non-participating shares of Investments and CPC indirectly owns 49 voting, participating shares of Investments.

In accordance with its terms of reference, the Audit Committee of the Board of Directors (the Board) of the General Partner, reviews the contents of the MD&A and recommends its approval by the Board. The Board has approved this MD&A.

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 at the end of this MD&A.

OPERATION OF THE PARTNERSHIP

The General Partner is responsible for management of the Partnership. 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 of 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 Partnership's power plants use natural gas, fuel oil, waste heat, wood waste, coal, tire-derived fuel, water flows or a combination of these energy sources to produce electricity and steam.

STRATEGY

The Partnership's strategic plan continues to be focused on providing stable and sustainable distributions to unitholders over the long term by generating a reliable stream of cash flows. Where opportunities arise, the Partnership will also seek to grow its cash flows by expanding capacity and implementing enhancements at existing plants and by pursuing acquisition or development opportunities that meet the Partnership's investment criteria and are accretive to cash flow. These criteria include generation assets that have relatively stable and predictable cash flows, risk profiles similar to the assets already owned by the Partnership with predictable capital expenditures and long operating lives.

SIGNIFICANT EVENTS

Distribution reduction

In the second quarter of 2009, the Partnership reduced its distribution to $0.44 per quarter from $0.63 per quarter. The reduction in distributions was made to position the Partnership for long term distribution sustainability that addresses current financing requirements and positions it for future growth. The Partnership believes the new distribution level is sustainable until at least the end of 2014 based on existing cash flows regardless of whether it remains a partnership or converts to a corporation. The retained cash has been and will be applied toward the permanent financing of the Southport and Roxboro enhancement projects, the North Island and Oxnard repowering projects (see Liquidity and Capital Recourses – Capital Expenditures) and the Morris acquisition and will be available to fund internal and external development opportunities as well as acquisitions.

Completion of plant upgrades

The Partnership completed the replacement of the existing GE LM5000 natural gas turbine with a more efficient and reliable GE LM6000 at North Island at a cost of approximately US$17.0 million, lower than the original estimated cost of US$19.0 million. The repowering project was completed on May 1, 2009, in time for the summer peak demand season in Southern California. The Partnership has initiated a similar repowering project at Oxnard.

The enhancements at Roxboro and for one of the two units at Southport to reduce environmental emissions and improve the economic performance of the plants were completed in December 2009. The Partnership expects the enhancements to the second unit at Southport will be completed by April 1, 2010 and that the material handling improvements at Southport will be completed by June 30, 2010. The Partnership has invested $78.2 million (US$70.7 million) to December 31, 2009 and plans to invest an additional $17 million (US$16 million) in 2010.

Change to relationship with CPC

In connection with the transfer by EPCOR to CPC of a 27.8% interest in its power generation business, the Partnership, CPC and EUI entered into a Memorandum of Agreement (Memorandum of Agreement) dated June 7, 2009, pursuant to which the parties agreed on certain matters, including: (i) an approach by which CPC and the Partnership will work together early in the process to review CPC development opportunities in which the Partnership might have an interest in participating and acquisitions under the Partnership's right of first look applicable to operating power generation acquisitions (including brownfield development opportunities tied to such assets) on which CPC plans to bid; (ii) the Partnership will have a right of first look on the sale of CPC generation assets so it may become the acquiring vehicle at not less than the fair market value for such assets; (iii) amendments to the incentive fee pursuant to which the Manager is compensated by the Partnership, and (iv) a basis on which the Partnership would in the future provide some relief to CPC with respect to maintaining up to a 30% interest in the Partnership.

As contemplated in the Memorandum of Agreement, the Partnership and the Manager agreed to a revised incentive fee of 10% of any Annual Distributable Cash Flow (as defined below) greater than $2.40 per unit to better align the incentives of the Manager to increase the amount of cash available for distribution to unitholders. For the purposes of the incentive fee, Annual

Distributable Cash Flow is defined as cash flow from operating activities before changes in non-cash working capital plus dividends from Primary Energy Recycling Holdings LLC (PERH), less scheduled debt repayments and maintenance capital.

The Partnership and each of EPCOR and CPC have agreed to a standstill whereby CPC and EPCOR are not able to increase their ownership in the Partnership without the consent of the independent directors of the General Partner until July 1, 2010, subject to certain exceptions relating to maintaining up to a 30% interest in the Partnership.

Tunis PPA amendment

To address a contract expiry mismatch between long-term fuel supply contracts for Tunis, one of which expired in January 2010 and the other that expires in December 2010, and the Tunis power purchase agreement (PPA), the Partnership reached an agreement with the Ontario Electricity Financial Corporation (OEFC) to amend the Tunis PPA effective January 16, 2010 to allow the Partnership to flow-through any deviation of natural gas and transportation costs from benchmark amounts to OEFC and extends OEFC the right to curtail the plant during summer off-peak periods through the remaining term of the PPA in 2014.

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. The Partnership also announced the launch of a Premium Distribution (Premium Distribution is a trademark of Canaccord Capital Corporation) 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. Alternatively, 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 November 2, 2009, CPI Preferred Equity Ltd. (CPEL), a subsidiary of the Partnership, issued 4,000,000 7.0% Cumulative Rate Reset Preferred Shares, Series 2 (the Series 2 Shares) at a price of $25.00 per share. Net proceeds of $96.9 million were used to repay outstanding bank indebtedness incurred to fund the acquisition of Morris and the capital expenditures at the North Carolina and North Island facilities. 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 31, 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 subsidiary 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 subsidiary, 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 CPEL, at a rate equal to the sum of the then 90-day Government of Canada treasury bill rate for the relevant quarter and 4.18%.

Partnership name change

On November 5, 2009 the Partnership announced it had changed its name to Capital Power Income L.P. from EPCOR Power L.P. as a result of CPC's acquisition of EPCOR's power generation assets and operations.

POWER AND STEAM GENERATION CAPACITY	Energy Source	POWER (MW)	STEAM (MLBS/HR)
Ontario Plants			
Nipigon (1)	Natural gas/waste heat	**40**	**-**
North Bay (1)	Natural gas/waste heat	**40**	**-**
Kapuskasing (1)	Natural gas/waste heat	**40**	**-**
Tunis (1)	Natural gas/waste heat	**43**	**-**
Calstock (1), (2)	Wood waste/waste heat	**35**	**-**
Williams Lake (2)	Wood waste	**66**	**-**
BC Hydro Plants (3)			**-**
Mamquam	Water flows	**50**	
Moresby Lake (4)	Water flows	**6**	
Northwest US Plants			
Manchief (5)	Natural gas	**300**	**-**
Greeley (6)	Natural gas	**72**	**170**
Frederickson (7)	Natural gas	**125**	**-**
California Plants			
Naval Station (8)	Natural gas/fuel oil	**47**	**479**
North Island (6)	Natural gas	**40**	**390**
Naval Training Center (8)	Natural gas/fuel oil	**25**	**220**
Oxnard (6)	Natural gas	**49**	**120**
Curtis Palmer (3)	Water flows	**60**	**-**
Northeast US Gas Plants			
Kenilworth (6)	Natural gas	**30**	**78**
Morris (6), (9)	Natural gas	**177**	**1,080**
North Carolina Plants			
Southport (10)	Wood waste/ tire-derived fuel/coal	**103**	**1,080**
Roxboro (10)	Wood waste/ tire-derived fuel/coal	**52**	**540**

(1) The Ontario natural gas plants use a process called enhanced combined cycle generation that uses both natural gas and waste heat as energy sources. These plants and the Calstock plant are located adjacent to TransCanada's Canadian Mainline gas compressor stations.
(2) Williams Lake and Calstock use wood waste from local mills as their primary source of energy.
(3) The Curtis Palmer, Mamquam and Moresby Lake hydroelectric facilities rely on water flows to produce electricity.
(4) Moresby Lake was previously named Queen Charlotte.
(5) Manchief is a simple-cycle natural gas facility.
(6) Greeley, North Island, Oxnard, Kenilworth and Morris are natural gas combined heat and power facilities.
(7) Frederickson is a combined cycle natural gas plant. Capacity for Frederickson is the Partnership's 50.15% interest.
(8) Naval Station and Naval Training Center are dual fuel (natural gas and No. 2 distillate fuel oil) fired combined heat and power facilities.
(9) Morris was acquired on October 31, 2008.
(10) The Southport and Roxboro combined heat and power facilities are fueled by wood waste, tire-derived fuel and coal.

Of the Partnership's fleet of 20 power plants, 18 have PPAs in place that expire between April, 2011 and 2027. The PPAs for the two North Carolina facilities expired on December 31, 2009. The electric output from the facilities is sold to Carolina Power & Light Company, which is a regulated utility servicing North Carolina and South Carolina, and is a subsidiary of Progress Energy Inc. (Progress). The North Carolina Utilities Commission (NCUC) has ordered that Progress continue to pay for the output of the North Carolina facilities pursuant to the terms of the PPAs that expired December 31, 2009 until an arbitration before the NCUC is resolved (see Outlook). Eight of these power plants also have steam purchase agreements (SPAs) with expiry dates ranging from 2012 to 2023. The existence of long-term sales contracts combined with long-term energy supply and operating contracts reduces the financial risk to unitholders, minimizes commodity price risk and increases the stability and security of long-term cash flows.

Consolidated Results-at-a-Glance [1]

Years ended December 31	**2009**	2008	2007
(millions of dollars except unit and per unit amounts)			
Revenues			
Ontario Plants	**145.4**	161.9	152.3
Williams Lake	**42.9**	38.2	38.1
BC Hydro Plants	**15.7**	16.7	18.0
Northwest US Plants	**63.1**	62.1	61.3
California Plants	**97.0**	145.3	130.6
Curtis Palmer	**42.1**	34.5	32.1
Northeast US Gas Plants [2]	**90.6**	45.4	27.3
North Carolina Plants	**27.3**	59.8	52.3
PERC management and incentive fees	**3.6**	3.5	3.4
	527.7	567.4	515.4
Fair value changes on foreign exchange contracts	**58.8**	(68.1)	34.4
	586.5	499.3	549.8
Operating margin [1]			
Ontario Plants	**52.7**	69.5	74.4
Williams Lake	**27.8**	25.2	24.9
BC Hydro Plants	**11.1**	12.0	11.2
Northwest US Plants	**36.7**	32.0	40.3
California Plants	**29.8**	32.2	29.0
Curtis Palmer	**36.3**	29.3	26.9
Northeast US Gas Plants [2]	**18.4**	6.0	3.2
North Carolina Plants	**(10.0)**	1.2	2.5
PERC management and incentive fees	**2.5**	2.5	1.8
	205.3	209.9	214.2
Fair value changes on foreign exchange and natural gas contracts	**6.4**	(98.5)	2.0
	211.7	111.4	216.2
Net income (loss)	**57.6**	(67.8)	30.8
Per unit	**$1.07**	($1.26)	$0.59
Cash provided by operating activities of continuing operations	**139.7**	157.5	123.4
Per unit [1]	**$2.59**	$2.92	$2.36
Capital expenditures	**105.9**	40.0	12.0
Long-term debt	**720.8**	799.8	619.7
Distributions	**105.2**	135.8	133.3
Per unit	**$1.95**	$2.52	$2.52
Payout ratio [1] [3]	**86%**	111%	112%
Total assets	**1,668.1**	1,809.2	1,853.0
Weighted average units outstanding (millions)	**53.9**	53.9	52.2

(1) The selected three-year annual financial data has been prepared in accordance with Canadian generally accepted accounting principles except for operating margin, cash provided by operating activities of continuing operations per unit and payout ratio. See Non-GAAP Measures.

(2) Northeast US Gas Plants include Morris from the dates of acquisition of October 31, 2008 and have been restated to reflect the operations of Castleton as discontinued operations. Castleton was sold in May 2009.

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

Revenues excluding fair value changes in foreign exchange contracts were $527.7 million for the year ended December 31, 2009 compared to $567.4 million in 2008. The decrease was primarily 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.

Operating margin excluding fair value changes in foreign exchange and natural gas supply contracts for the year ended December 31, 2009 decreased by $4.6 million. The decrease in operating margin was 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. See Non-GAAP Measures.

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.

CONSOLIDATED RESULTS OF OPERATIONS

(millions of dollars)	
Cash provided by operating activities of continuing operations for the year ended December 31, 2008	**157.5**
Impact of full year cash flow from Morris, excluding interest paid	17.5
Higher operating margin at Curtis Palmer	7.0
Higher operating margin at the Northwest US plants	4.7
Lower management and administration costs	2.6
Lower operating margin at the Ontario plants	(16.8)
Changes in operating working capital	(16.4)
Lower operating margin at the North Carolina plants	(11.2)
Higher interest expenses	(4.1)
Other	(1.1)
Cash provided by operating activities of continuing operations for the year ended December 31, 2009	**139.7**

The Partnership reported cash provided by operating activities of continuing operations of $139.7 million or $2.59 per unit for the year ended December 31, 2009 compared to $157.5 million or $2.92 per unit in 2008. Cash provided by operating activities of continuing operations per unit is defined below under Non-GAAP Measures. The $17.8 million decrease in cash provided by operating activities of continuing operations for 2009 compared to 2008 is primarily due to the following:

- Operating margin was $16.8 million lower at the Ontario plants primarily due to lower enhancement and diversion revenues as a result of lower natural gas prices, lower revenues from waste heat and 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 waste heat optimization costs;

- An increase in working capital of $3.1 million in the year ended December 31, 2009 compared to a decrease of $13.3 million in the prior year. Working capital increased in 2009 primarily due to the timing of payments and receipts;
- Operating margin was $11.2 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 $4.1 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.

Decreases were partially offset by the following:

- An increase of $17.5 million in the cash flow from Morris, which was acquired on October 31, 2008. The contribution of Morris in 2008 includes a provision of $2.4 million against amounts receivable from Equistar LLC (Equistar) (see Business Risks – Counterparty Credit Risk);
- Operating margin was $7.0 million higher at Curtis Palmer due to a step-up in pricing under the PPA of 18% in December 2008 and higher generation due to higher water flows;
- Operating margin was $4.7 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 2008; and
- Administrative costs were $2.6 million lower primarily due to lower incentive fees as a result of changes in the method of determining the incentive fees (see Significant Events – Change to Relationship with CPC).

(millions of dollars)	
Cash provided by operating activities of continuing operations for the year ended December 31, 2007	**123.4**
Net realized losses on foreign exchange and interest rate contracts in 2007	17.9
Changes in operating working capital	20.2
Lower interest expenses	6.6
Higher operating margin at the California plants	3.2
Higher revenues at Curtis Palmer	2.4
Contribution of Morris acquired October 31, 2008, excluding interest paid	0.5
Lower operating margin at Northwest US plants	(8.3)
Lower operating margin at the Ontario plants	(4.9)
Preferred share dividends	(2.6)
Mamquam and Moresby Lake arbitration award	(1.8)
Other	0.9
Cash provided by operating activities of continuing operations for the year ended December 31, 2008	**157.5**

The Partnership reported cash provided by operating activities of continuing operations of $157.5 million or $2.92 per unit for the year ended December 31, 2008 compared to $123.4 million or $2.36 per unit in 2007. Cash provided by operating activities of continuing operations per unit is defined below under Non-GAAP Measures. The $34.1 million increase in cash provided by operating activities of continuing operations for 2008 compared to 2007 is primarily due to the following:

- In 2007, net losses of $17.9 million were realized on foreign exchange and interest rate contracts that were entered into in anticipation of permanent financing of acquisitions completed in 2006;
- A $13.3 million decrease in working capital in 2008 compared to a $6.9 million increase in 2007. Working capital decreased in 2008 primarily due to lower accounts receivable at the Ontario facilities due to the timing of collections;
- Lower interest expenses of $6.6 million primarily due to the pay down of debt with the proceeds from the issue of Partnership units and preferred shares in the second quarter of 2007 partially offset by interest on borrowing used to finance the acquisition of Morris;
- Operating margin at the California plants was $3.2 million higher due to increased electricity prices driven by higher natural gas prices, partially offset by higher fuel costs and higher maintenance costs due to turbine repairs at North Island;
- Revenues at Curtis Palmer were $2.4 million higher compared to 2007 due to higher water flow, partially offset by a planned maintenance outage at one of the units; and
- The Morris facility, acquired on October 31, 2008, contributed approximately $0.5 million to operating margin. The contribution from Morris includes a provision of $2.4 million against the pre-petition amounts receivable from Equistar.

Increases were partially offset by the following:

- A decrease in operating margin of $8.3 million at the Northwest US plants due to a milestone payment at Frederickson under its long-term service agreement with the turbine manufacturer, lower revenue and generation at Manchief due to higher natural gas prices in Colorado and higher fuel costs at Greeley to meet minimum generation requirements in its PPA;
- Operating margin at the Ontario plants was $4.9 million lower due to: (i) lower generation and revenue at Calstock due to high moisture levels in the wood waste inventory and lower inventory levels which caused Calstock to scale back production in 2008 to optimize available wood waste, (ii) lower waste heat availability and higher waste heat optimization costs due to lower throughput on TransCanada Corporation's (TransCanada) Canadian Mainline, (iii) a 19% increase in the natural gas prices in 2008 at Kapuskasing and North Bay under the 20 year supply agreements and (iv) the settlement of natural gas supply contract disputes at Tunis in July 2007 and January 2008. These decreases were partially offset by a $3.4 million reduction in natural gas costs as the Partnership updated its estimate of the cost for natural gas supplied under contract;
- Dividends on preferred shares issued in May 2007 by a subsidiary company of the Partnership were $6.6 million for the year ended December 31, 2008 compared to $4.0 million in 2007; and
- Arbitration awards against the previous owners of Mamquam and Moresby Lake in respect of claims by the Partnership in the purchase and sale agreement were $2.3 million in the second quarter of 2007 compared with $0.5 million awarded in the first quarter of 2008.

(millions of dollars)	
Cash provided by operating activities for the year ended December 31, 2007	**133.0**
Increases in cash provided by operating activities of continuing operations – see previous table	34.1
Decrease in cash provided by operating activities of Castleton	(6.9)
Cash provided by operating activities for the year ended December 31, 2008	**160.2**
Decreases in cash provided by operating activities of continuing operations – see previous table	(17.8)
Decrease in cash provided by operating activities of Castleton	(5.5)
Cash provided by operating activities for the year ended December 31, 2009	**136.9**

The Partnership reported cash provided by operating activities of $136.9 million for the year ended December 31, 2009 compared to $160.2 million in 2008 and $133.0 million in 2007. The decrease in cash provided by operating activities of Castleton in 2009 is due to lower cash provided by operating activities after the expiry of its PPA in June 2008 and the sale of the facility on May 26, 2009.

(millions of dollars)	
Net loss from continuing operations for the year ended December 31, 2008	**(67.1)**
Fair value changes on natural gas supply and foreign exchange contracts	104.9
Foreign exchange losses in 2008	26.2
Asset impairment charge in 2008	24.1
Contribution of Morris acquired October 31, 2008, excluding interest paid	13.3
Higher operating margin at Curtis Palmer	7.0
Higher operating margin at the Northwest US plants	4.7
Lower management and administration costs	2.6
Decrease in income tax recovery	(22.5)
Lower operating margin at the Ontario plants	(16.8)
Lower operating margin at the North Carolina plants	(11.2)
Higher depreciation and amortization mainly due to the Morris acquisition in 2008	(5.0)
Higher interest expenses	(4.1)
Other	1.7
Net income from continuing operations for the year ended December 31, 2009	**57.8**

Net income from continuing operations was $57.8 million or $1.07 per unit for the year ended December 31, 2009 compared to a net loss from continuing operations of $67.1 million or $1.24 per unit in 2008. In addition to the items described above for the change in cash provided by operating activities of continuing operations, the increase in net income of $124.9 million was the result of the following:

- Net gains of $6.4 million were recorded in 2009 on changes in the fair value of the natural gas supply and foreign exchange contracts compared to net losses of $98.5 million in 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 2009 compared to a weakening in 2008 partially offset by larger decreases in the future prices for natural gas in 2009 compared to 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 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 $26.2 million in 2008;
- The Partnership recorded an impairment of its investment in the common shares of PERH in 2008 of $24.1 million; and
- The increase in the contribution from Morris, which was acquired on October 31, 2008, is due to a full year of earnings in 2009 partially offset by an increase in revenue deferrals of $4.2 million, which will be recognized in future periods. The contribution of Morris in 2008 includes a provision of $2.4 million against amounts receivable from Equistar.

Increases were partially offset by the following:
- An income tax recovery of $8.9 million was recorded in 2009 compared to $31.4 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.

(millions of dollars)	
Net income from continuing operations for the year ended December 31, 2007	**31.0**
Decrease in income tax expense	105.5
Lower interest expenses[1]	6.6
Higher operating margin at the California plants	3.2
Higher revenues at Curtis Palmer	2.4
Contribution of Morris acquired October 31, 2008, excluding interest paid	0.5
Foreign exchange losses in 2008 compared to gains in 2007 [1]	(103.2)
Fair value changes on derivative contracts	(76.9)
Asset impairment charges	(11.1)
Lower operating margin at Northwest US plants	(8.3)
Lower operating margin at the Ontario plants	(4.9)
Preferred share dividends	(2.6)
Mamquam and Moresby Lake arbitration award	(1.8)
Other	(7.5)
Net loss from continuing operations for the year ended December 31, 2008	**(67.1)**

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

Net loss from continuing operations was $67.1 million or $1.24 per unit for the year ended December 31, 2008 compared to net income from continuing operations of $31.0 million or $0.59 per unit in 2007. In addition to the items described above for the change in cash provided by operating activities of continuing operations, the decrease in net income of $98.1 million was the result of the following:
- Foreign exchange losses of $26.2 million in 2008 compared to gains of $77.0 million for the same period in 2007. The foreign exchange losses recorded in 2008 were the result of a weakening of the Canadian dollar of $0.2267 relative to the US dollar during the year on the translation of US dollar-denominated debt, compared to a strengthening of $0.1741 in 2007;
- A net loss of $98.5 million was recorded in 2008 on the change in the fair value of the natural gas supply and foreign exchange contracts compared to a net loss of $21.6 million on natural gas supply, foreign exchange and interest rate contracts in 2007. The majority of the changes in fair value are the result of the impact of a weakening of the Canadian dollar in 2008 compared to a strengthening of the Canadian dollar in 2007 on the fair value of foreign exchange contracts; and
- The Partnership recorded an impairment of its investment in the common shares of PERH in 2008 of $24.1 million. In 2007, the Partnership recorded an asset impairment charge of

$13.0 million attributed to the management agreement between a subsidiary of the Partnership and PERH, PERC and Primary Energy Operations LLC.

The items that increased the net loss were partially offset by the following:

- A change in tax law in 2007, which will result in the Partnership's Canadian operations becoming taxable in 2011, resulted in the recording of a future income tax expense of $74.1 million. An income tax recovery of $31.4 million was recorded 2008 primarily related to the future income taxes that resulted from an increase in accumulated tax losses.

(millions of dollars)	
Net income for the year ended December 31, 2007	**30.8**
Decreases in net income from continuing operations – see previous table	(98.1)
Increase in net loss from Castleton	(0.5)
Net loss for the year ended December 31, 2008	**(67.8)**
Increase in net income from continuing operations – see previous table	124.9
Decrease in net loss from Castleton	0.5
Net income for the year ended December 31, 2009	**57.6**

NON-GAAP MEASURES

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

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

Years ended December 31 *(millions of dollars)*	**2009**	2008	2007
Operating margin	**211.7**	111.4	216.2
Deduct (Add):			
Depreciation, amortization and accretion	**93.3**	88.3	85.5
Management and administration	**15.2**	20.2	13.2
Financial charges and other, net	**42.3**	38.2	48.4
Foreign exchange losses (gains)	**1.0**	26.2	(57.0)
Equity losses from the PERH investment	**3.1**	6.3	4.0
Asset impairment charge	**-**	24.1	13.0
Net income (loss) from continuing operations before tax and preferred share dividends	**56.8**	(91.9)	109.1

Cash provided by operating activities of continuing operations per unit is cash provided by operating activities of continuing operations divided by the weighted average number of units outstanding in the period.

Payout ratio is defined as distributions divided by cash provided by operating activities of continuing operations excluding working capital changes less maintenance capital expenditures. Working capital changes have been excluded from this measure as short-term changes in working capital are expected to be largely reversed in future periods or represent reversals from prior periods. Non-maintenance capital spending has been excluded from this measure as capital expenditures related to an expansion of the productive capacity of the business represent a long-term investment beyond the maintenance capital requirements of the existing business.

The composition of the operating margin and cash provided by operating activities of continuing operations per unit used in this MD&A is consistent with December 31, 2008 reporting. The Partnership did not disclose the payout ratio in its December 31, 2008 reporting.

OPERATING MARGIN(1) AND PLANT OUTPUT

Years ended December 31	2009		2008	
	GWh	*(millions of dollars)*	*GWh*	*(millions of dollars)*
Ontario Plants	**1,330**	**52.7**	1,263	69.5
Williams Lake	**362**	**27.8**	499	25.2
BC Hydro Plants	**232**	**11.1**	245	12.0
Northwest US Plants	**990**	**36.7**	872	32.0
California Plants	**971**	**29.8**	941	32.2
Curtis Palmer	**356**	**36.3**	328	29.3
Northeast US Gas Plants (2)	**657**	**18.4**	253	6.0
North Carolina Plants	**65**	**(10.0)**	554	1.2
PERC management fees	**-**	**2.5**	-	2.5
Fair value changes on derivative contracts	**-**	**6.4**	-	(98.5)
	4,963	**211.7**	4,955	111.4
Weighted average plant availability (3)				
Ontario Plants		**93%**		97%
Williams Lake		**98%**		90%
BC Hydro Plants		**86%**		87%
Northwest US Plants		**97%**		95%
California Plants		**93%**		91%
Curtis Palmer		**94%**		86%
Northeast US Gas Plants (2)		**99%**		98%
North Carolina Plants		**69%**		92%
Total weighted average availability		**92%**		93%
Average price per MWh				
Ontario Plants		$104		$105
Williams Lake		$119		$77
BC Hydro Plants		$68		$68
California Plants		$100		$154
Curtis Palmer		$118		$105
North Carolina Plants		$420		$108

(1) Operating margin is a non-GAAP financial measure. 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. Castleton was sold in May 2009.

(3) Plant availability represents the percentage of time in the year that the plant is available to generate power, whether actually running or not, and is reduced by planned and unplanned outages.

Ontario Plants

All the power output from the Ontario plants is sold to OEFC under long-term PPAs with expiry dates ranging from 2012 to 2020. The Ontario plants reported operating margin of $52.7 million for the year ended December 31, 2009 compared to $69.5 million in 2008. The decrease was 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 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. On July 23, 2009, Calstock experienced a turbine failure. The turbine was partially repaired and returned to service on September 10, 2009. The financial loss, 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

Years ended December 31	**2009**	2008
(millions of dollars)		
Power	**138.3**	132.2
Enhancements	**1.1**	18.5
Gas diversions	**6.0**	11.2
	145.4	161.9

Revenues from the Ontario plants were lower for the year ended December 31, 2009 compared to 2008 due to lower enhancement activity, lower prices for diverted natural gas and lower waste heat availability, partially offset by increased power sales. Revenues from waste heat declined 29% for the year ended December 31, 2009 compared to 2008 as a result of lower throughput on the TransCanada Canadian Mainline, the natural gas transmission line to Northern Ontario, and the outage at Calstock. Future throughput on the TransCanada Canadian Mainline will continue to be subject to supply and demand variances, however the Partnership expects throughput to be depressed over the next two to three years with potential recovery thereafter. Lower throughput on this natural gas transmission line also has an impact on natural gas transportation costs to the Partnership's Ontario natural gas facilities (see Cost of Fuel).

Power output from the Ontario plants for the year ended December 31, 2009 was 67 gigawatt hours (GWh) higher year-over-year as more natural gas was available for power generation due to lower enhancement and diversion sales in 2009 partially offset by lower power generated by waste heat and lower generation at Calstock as a result of the turbine failure. Weighted average plant availability for the Ontario plants was lower in 2009 due to the turbine failure at Calstock.

Williams Lake

Revenues at Williams Lake consist of firm energy sales including cost recovery components and excess energy sales under the power sales contract with British Columbia Hydro and Power Authority (BC Hydro) expiring in 2018. The amount of firm energy sold to BC Hydro on an annual basis is fixed at 445 GWh, except in years when major overhauls are performed (approximately every five years). A major overhaul was performed in 2008. Revenues remain constant in major overhaul years due to higher firm energy pricing and the firm energy commitment to BC Hydro is reduced to 401 GWh. Cost recovery components are escalated annually for inflation.

Operating margin from Williams Lake was $27.8 million for the year ended December 31, 2009 compared to $25.2 million 2008. The increases in operating margin was primarily due to a higher price for excess energy.

Included in revenue are excess energy sales for the year ended December 31, 2009 of $6.4 million compared with $4.8 million in 2008. Excess energy sales result when a surplus of energy is generated above the annual firm commitment amount. The increase in excess energy sales reflected an increase in the market-based price (2009 - $58 per megawatt hour (MWh); 2008 - $49 per MWh). The market based price for 2010 is set at $30 per MWh.

Generation during the year ended December 31, 2009 was lower than 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 identified other sources of supply, but these sources were 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 December 31, 2009, the plant had sufficient wood waste inventory for the plant to produce its maximum output of 66 megawatts (MW) for 95 days.

Availability during the year ended December 31, 2009 was higher than in 2008 due to a major overhaul completed in 2008.

BC Hydro Plants
Mamquam and Moresby Lake have long-term PPAs with BC Hydro that expire in 2027 and 2022, respectively. The PPAs consist of a fixed energy component per MWh up to certain output thresholds, an operations and maintenance component adjusted annually for inflation and a reimbursable cost component. All electricity generated at Mamquam and substantially all electricity generated at Moresby Lake is sold to BC Hydro. A small amount of electricity from Moresby Lake is sold to two local customers.

Operating margin at the BC Hydro plants was $11.1 million for the year ended December 31, 2009 compared to $12.0 million in 2008. The decrease in operating margin, as well as the decrease in revenue and generation, was due to lower water volumes at the plants.

Northwest US Plants
Manchief has two separate tolling agreements covering the sale of capacity and incremental energy to Public Service Company of Colorado (PSCo) that expire in 2022. PSCo controls the dispatch of electricity from Manchief, including start-ups, shut-downs and generation loading levels. Capacity payments are generally unaffected by output levels but vary depending upon changes in plant availability. Capacity payments will decline by approximately 15% starting in May 2012. PSCo pays for incremental energy generated at the plant based upon a fixed price per MWh, escalated annually for inflation. PSCo also pays for turbine start-up fees, heat rate adjustments and gas transportation charges. Operating margin increased by $0.6 million for the

year ended December 31, 2009 to $22.4 million compared to 2008 as the result of higher dispatch of the plant due to outages at other plants in the region.

The Partnership's portion of the capacity of Frederickson has been sold under tolling arrangements expiring in 2022 to three Washington State public utility districts (the PUDs). The remaining interest in Frederickson is held by Puget Sound Energy, Inc. which works cooperatively with the PUDs to economically dispatch Frederickson. The PUDs pay capacity and fixed operating and maintenance charges as well as all fuel related costs and commercial start-up costs. Operating margin from Frederickson was $13.2 million for year ended December 31, 2009 compared to $9.4 million in 2008. The increase was due to the payment of a non-recurring milestone payment by Frederickson under its long-term service agreement with the turbine manufacturer in 2008.

Greeley provides all of its electrical output to PSCo under a PPA which expires in 2013. PSCo pays a monthly capacity payment and an energy payment pursuant to the PPA. Greeley sells hot water to the University of Northern Colorado (UNC) pursuant to a Thermal Supply Agreement which expires in August 2013. Under the agreement, Greeley is obligated to deliver for sale to UNC only such heat energy as is generated during the production of electrical capacity and energy for sale to PSCo. Operating margin from Greeley was $1.1 million for the year ended December 31, 2009 consistent with $0.8 million in 2008.

Availability for the Northwest US plants for the year ended December 31, 2009 was consistent with 2008. Generation was higher due to higher dispatch of Manchief due to outages at other plants in the region.

California Plants

The three US Naval facilities (the Naval facilities) sell power to San Diego Gas and Electric Company (SDG&E) under long-term PPAs which expire in 2019, except for a 4 MW steam turbine at North Island which sells power to the United States Navy (the Navy) under its SPA which expires in 2018. The price paid under the PPAs includes a capacity payment and an energy payment based on SDG&E's full Short Run Avoided Cost (SRAC). Each of the Naval facilities sells steam to the Navy pursuant to long-term SPAs, each of which expires in February 2018. The SPAs also give the Navy a right to purchase electrical energy from the Naval facilities at prices comparable to those under the PPAs. The Navy has an obligation to consume enough thermal energy for the Naval facilities to maintain their Qualifying Facility (QF) status. The Navy pays a combination of steam commodity charges, fixed charges and water cost pass through provisions. Steam pricing is linked to the cost of natural gas and SDG&E's SRAC by an energy sharing formula. Operating margin from the Naval facilities was $21.5 million for the year ended December 31, 2009 compared to $22.7 million in 2008. The decrease was 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.

All power output from Oxnard is sold to Southern California Edison Company (SCE) under a PPA which expires in 2020. The price paid under the PPA includes a capacity payment and an energy payment based on SCE's SRAC. Steam from Oxnard is used to provide refrigeration services to Boskovich Farms, a food processing and cold storage facility, thereby maintaining Oxnard's QF status. Operating margin from Oxnard was $8.3 million for the year ended December 31, 2009 compared to $9.5 million 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.

Availability and generation for the California plants for the year ended December 31, 2009 was consistent with 2008.

Revenues and operating margins for the California facilities are seasonal. Approximately 75% of capacity revenue at the Naval facilities is earned during the summer peak demand months. For all the California plants, performance bonuses can be earned during these months if forced outage rates are below 15%.

Curtis Palmer
Output from Curtis Palmer is sold to Niagara Mohawk Power Corporation (Niagara Mohawk) under a PPA which expires the earlier of 2027 and the delivery to Niagara Mohawk of a cumulative 10,000 GWh of electricity. The PPA sets out eleven pricing blocks over the contract term for electricity sold to Niagara Mohawk and the price is dependent on the cumulative GWh of electricity delivered. A cumulative GWh threshold was reached in December 2008 when a cumulative total of 4,344 GWh was delivered, at which point the price for electricity increased by approximately 18%. Over the remaining term of the PPA, the price increases by US$10/MWh with each additional 1,000 GWh of electricity delivered.

Operating margin from Curtis Palmer was $36.3 million for the year ended December 31, 2009 compared to $29.3 million in 2008. The increase was due to the step-up in pricing under the PPA 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 Gas Plants
Morris sells a combination of steam and power to Equistar under an energy services agreement (ESA) that expires in October 2023. Pursuant to the Morris ESA, Equistar pays tiered energy payments based on electricity and steam delivered to a maximum of 77 MW and 720 million pounds of steam per hour and adjusted for monthly natural gas prices. Based on the energy payment formula, there is a small portion of energy costs that are not recovered through the energy payments and this non-recoverable amount fluctuates with the price of natural gas. Equistar also pays capacity fees, comprised of both a non-escalating fixed fee that expires in October 2013 and a variable fee that escalates with materials and labour indices and expires in 2023. The non-escalating capacity payment is fixed at $8.7 million (US$8.3 million) per year. Morris has a PPA with Exelon Generation Company, LLC (Exelon) covering 100 MW of electrical capacity. Exelon pays a capacity charge that varies based on the time of year together with an energy charge based on amount of energy dispatched. The annual capacity revenue earned under the PPA with Exelon has averaged just over US$6 million per year, including bonus payments for peak availability that exceeds 98 per cent. The Exelon PPA expires in April 2011.

Operating margin from Morris, which was acquired on October 31, 2008, was $13.8 million for the year ended December 31, 2009 compared to $2.9 million for the two month period from the date of acquisition to December 31, 2008. Operating margin from Morris in 2009 was in line with the Partnership's expectations.

Kenilworth sells electrical energy and steam to Schering-Plough Corporation (Schering) under an ESA that expires in July 2012. Pursuant to the ESA, Schering pays an energy rate that escalates annually. Any power produced in excess of Schering's requirements is sold to Public

Service Enterprise Group Incorporated at current market prices. Revenues from steam are calculated as a function of the delivered cost of fuel. The ESA allows natural gas costs to be passed on to Schering when natural gas prices exceed a set price. Operating margin from Kenilworth was $4.6 million for the year ended December 31, 2009 compared to $3.1 million in 2008. The increase was due to higher natural gas prices in the first half of 2008, which were not fully passed on to Schering under the terms of the ESA which was replaced effective July 1, 2008.

North Carolina Plants

The North Carolina plants provide all of their electrical output to Progress. The PPA with Progress expired in December 2009. The Partnership has filed a Complaint and Petition for Arbitration with the NCUC. The NCUC has required that Progress continue to purchase electrical output from The North Carolina plant pursuant to the terms of the expired PPAs until the arbitration is completed. During this interim period, the price paid includes capacity payments and energy payments that reflect the price paid for coal and cycling charges. If this pricing does not result in a dispatch order for the facility, the Partnership has the right, but not the obligation, to bid an alternate price based upon its own pricing strategies to obtain a dispatch order. Southport sells steam pursuant to a SPA which expires in December 2014. Roxboro does not currently have a SPA. Both the facilities are QF certified.

The North Carolina plants reported operating margin losses of $10.0 million for the year ended December 31, 2009 compared to operating margin of $1.2 million in 2008. The decrease in operating margin, revenue and generation were due to lower dispatch due to lower natural gas prices. These facilities are fuelled by wood waste, tire-derived fuel and coal. 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 in the third quarter of 2009. The Roxboro unit returned to service in September 2009. The negative impact of the outage on operating margin in 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 $58.8 million for the year ended December 31, 2009 compared to unrealized losses of $68.1 million 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 $0.105 for the year ended December 31, 2009 compared to an increase of $0.192 in 2008.

The Partnership recorded fair value losses on natural gas supply contracts of $52.4 million for the year ended December 31, 2009 compared to $30.4 million 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 $1.02 per gigajoule (GJ) for the year ended December 31, 2009 compared to $0.10 per GJ in 2008. On July 31, 2009, the Partnership designated certain of its natural gas supply contracts as hedges. Net losses of $9.2 million relating to these contracts were recorded in other comprehensive income in 2009.

COST OF FUEL

Years ended December 31	**2009**	2008
(millions of dollars except average cost per MWh)		
Ontario Plants		
Natural gas	**69.7**	66.3
Waste heat	**3.4**	8.3
Wood waste	**3.0**	2.7
	76.1	77.3
Williams Lake - wood waste	**5.7**	2.4
Northwest US Plants - natural gas	**11.7**	12.1
California Plants - natural gas	**47.5**	90.0
Northeast US Gas Plants - natural gas (1)	**61.1**	35.5
North Carolina Plants - wood waste, tire-derived fuel & coal	**16.9**	41.1
Fair value changes on natural gas contracts	**52.4**	30.4
	271.4	288.8

(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. Castleton was sold in May 2009.

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 year ended December 31, 2009, fuel costs, excluding fair value changes on natural gas contracts, were $219.0 million compared to $258.4 million in 2008.

Fuel costs at the Ontario plants for the year ended December 31, 2009 were $76.1 million compared to $77.3 million for in 2008. The decrease was primarily due to lower natural gas prices which have resulted in lower waste heat optimization costs, lower natural gas transportation costs and lower prices for spot natural gas purchases 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 $5.7 million for the year ended December 31 2009 compared to $2.4 million in 2008. The increase was primarily the result of the use of higher priced wood waste due to reduced production from the plant's major wood waste suppliers.

The Northwest US plants incurred fuel costs of $11.7 million for the year ended December 31, 2009, consistent with $12.1 million in 2008.

Fuel costs at the California facilities were $47.5 million for the year ended December 31, 2009 compared to $90.0 million in 2008. The decrease was due to lower natural gas prices and outages at Naval Station.

The Northeast US natural gas plants incurred fuel costs of $61.1 for the year ended December 31, 2009, compared to $35.5 million in 2008. The increase was primarily due to the acquisition of Morris on October 31, 2008, which had fuel costs of $34.7 million in the year ended

December 31, 2009 compared to $11.5 for the two month period from the date of acquisition to December 31, 2008.

The North Carolina plants incurred fuel costs of $16.9 million for the year ended December 31, 2009 compared to $41.1 million in 2008. The decrease was the result of lower generation.

The Curtis Palmer, Mamquam and Moresby Lake hydroelectric plants do not have fuel costs.

OPERATING AND MAINTENANCE EXPENSE

Years ended December 31 *(millions of dollars)*	**2009**	2008
Ontario Plants	**16.6**	15.1
Williams Lake	**9.4**	10.6
BC Hydro Plants	**4.6**	4.7
Northwest US Plants	**14.7**	18.0
California Plants	**19.7**	23.1
Curtis Palmer	**5.8**	5.1
Northeast US Gas Plants [(1)]	**11.1**	3.9
North Carolina Plants	**20.4**	17.6
PERC management expenses	**1.1**	1.0
	103.4	99.1

(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. Castleton was sold in May 2009.

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 $103.4 million for the year ended December 31, 2009 compared to $99.1 million in 2008. The increase was due to the acquisition of Morris on October 31, 2008 and higher maintenance costs at the North Carolina plants partially offset by 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. Operating and maintenance costs for Morris were $8.2 million for the year ended December 31, 2009 compared to $0.9 million for the two month period from the date of acquisition to December 31, 2008.

DEPRECIATION, AMORTIZATION AND ACCRETION

Years ended December 31 *(millions of dollars)*	**2009**	2008
Depreciation of property, plant and equipment	**65.0**	55.9
Accretion of asset retirement obligations	**1.9**	1.6
Amortization of PPAs	**27.8**	31.4
Amortization of other assets	**1.3**	2.1
Amortization of contract liabilities	**(2.7)**	(2.7)
	93.3	88.3

Depreciation, amortization and accretion expense for the year ended December 31, 2009 was $93.3 million compared to $88.3 million in 2008. The increase in depreciation charges for the year was mainly due to the acquisition of Morris on October 31, 2008.

MANAGEMENT AND ADMINISTRATION

Years ended December 31 *(millions of dollars)*	**2009**	2008
Base fee	**1.1**	1.4
Incentive fee	**-**	2.3
Enhancement fee	**0.2**	2.4
General and administrative costs	**13.9**	14.1
	15.2	20.2

Management and administration costs, which include fees payable to CPC (and prior to June 30, 2009 EPCOR) and general and administrative costs, were $15.2 million for the year ended December 31, 2009 compared to $20.2 million in 2008. The decrease was 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 (see Significant Events – Change to Relationship with CPC). The Partnership also paid lower enhancement fees as a result of lower enhancement profits and in 2008 recorded a $2.4 million allowance for potential default by Equistar on pre-Chapter 11 petition amounts owed to the Partnership (see Business Risks – Counterparty Credit Risk).

FINANCIAL CHARGES AND OTHER, NET

Years ended December 31 *(millions of dollars)*	**2009**	2008
Interest on long-term debt	**42.6**	40.3
Dividend income from Class B preferred share interests in PERH	**(1.1)**	(1.9)
Other	**0.8**	(0.2)
	42.3	38.2

Financial charges and other expenses were $42.3 million for the year ended December 31, 2009 compared to $38.2 million in 2008. The increase was 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.

FOREIGN EXCHANGE LOSSES

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 $1.0 million for the year ended December 31, 2009 compared to $26.2 million in 2008. The foreign exchange losses recorded in 2008 were the result of a weakening of the Canadian dollar over the first nine months of $0.045 relative to the US dollar on the translation of US dollar-denominated debt.

EQUITY LOSSES FROM THE PERH INVESTMENT

Equity losses from the PERH investment 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.

During the year ended December 31, 2009, the Partnership received dividends of $1.1 million ($1.9 million in 2008) on its 14.2% preferred ownership interest and dividends of $1.3 million ($3.2 million in 2008) from its common interest in PERH. The Partnership holds 14.3% of the common interest in PERH after the recapitalization. PERH suspended dividends on its common equity interests in June 2009.

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 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.

In November 2009, PERC issued subscription receipts which were subsequently converted into common shares of PERC. The proceeds were used to subscribe for new common membership interests in PERH. The Partnership exercised its pre-emptive right to maintain its pro-rata interest (14.3%) in PERH whereby the Partnership subscribed for new common membership interests at an aggregate subscription price of $8.8 million (US$8.3 million) concurrently with PERC's subscription. PERH used the net proceeds combined with funds from a new term loan of US$105 million that matures in October 2014 to repay its existing US$131 million term loan facility.

INCOME TAX RECOVERY

Income tax recovery was $8.9 million for the year ended December 31, 2009 compared to $31.4 million in 2008. During the year ended December 31, 2009, the Partnership recorded an out-of-period adjustment of $9.7 million relating to 2007 and 2008 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 $9.7 million, $2.9 million is attributable to 2007 and $6.8 million is attributable to 2008.

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 (see Outlook).

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

PREFERRED SHARE DIVIDENDS OF A SUBSIDIARY COMPANY

A subsidiary of the Partnership issued $125.0 million of Series 1 preferred shares in the second quarter of 2007, which pay dividends at a rate of 4.85% per annum, and on November 2, 2009 issued $100.0 million Series 2 preferred shares, which pay dividends at a rate of 7.0% until their reset date on December 31, 2014. For the year ended December 31, 2009, dividends of $7.2 million were paid to shareholders and net income tax expenses of $0.7 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, which results in a tax benefit approximately equal to the Part VI.1 tax paid. The subsidiary expects to realize the benefit of the deduction starting in 2011.

LIQUIDITY AND CAPITAL RESOURCES

Distributions

The Partnership makes monthly cash distributions to its Unitholders in accordance with the Partnership Agreement and subject to Board approval. Cash distributions are made in respect of each month in each year to unitholders of record on the last day of such month. Payments are made in the month following each record date. Distributions are prohibited by certain loan agreement covenants if an uncured default exists. Additionally, distributions are prohibited if declaration or payment of dividends on the preferred shares is in arrears. A portion of cash distributions are taxable to unitholders in the year received.

In the second quarter of 2009, the Partnership reduced its distribution from $0.63 per quarter to $0.44 per quarter. If the distribution reduction was in effect for all of 2009, the payout ratio would have been 77% for the twelve months ended December 31, 2009 excluding changes in working capital (see Non-GAAP measures), in line with the Partnership's target of a long-term payout ratio of 75%. The retained cash has been and will be applied toward the permanent financing of the Southport and Roxboro enhancement projects, the North Island and Oxnard repowering projects and the Morris acquisition and will be available to fund internal and external development opportunities as well as acquisitions. 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).

When cash provided by operating activities exceeds distributions and maintenance capital expenditures, the Partnership utilizes the difference to stabilize future distributions, to finance growth capital expenditures and to make debt repayments. When cash provided by operating activities is less than 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 from contracts that expire and may not be replaced with contracts under similar terms.

Years ended December 31 *(millions of dollars except payout ratio)*	**2009**	2008
Distributions	**105.2**	135.8
Cash provided by operating activities of continuing operations	**139.7**	157.5
Net income (loss) from continuing operations	**57.8**	(67.1)
Payout ratio [1]	**86%** [2]	111%
Dividends from PERH	**1.3**	3.2
Additions to property, plant and equipment	**105.9**	40.0
Excess of cash provided by operating activities of continuing operations over distributions	**34.5**	21.7
Shortfall of net income (loss) from continuing operating over distributions	**(47.4)**	(202.9)

(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. See Non-GAAP Measures.

(2) Payout ratio would have been 77% for the year ended December 31, 2009 had the current distribution of $1.76 per unit been in effect for the full year.

Cash provided by operating activities of continuing operations exceeded distributions by $34.5 million for the year ended December 31, 2009. The Partnership also incurred capital expenditures of $105.9 million during the year ended December 31, 2009. The cash shortfall between distributions plus capital expenditures and cash provided by operating activities of continuing operations has been funded with a combination of cash on hand, draws on credit facilities and the issuance of preferred shares. The financing needs of the Partnership will be influenced by, among other factors, its capital spending in 2010 and potential acquisitions.

The Partnership expects cash provided by operating activities (excluding changes in working capital requirements) to be lower in 2010 compared to 2009 as further outlined under Outlook, subject to variable factors including those discussed in our forward looking statements at the end of this MD&A. In addition, the Partnership expects capital expenditures in 2010, excluding the investments in the North Carolina and Oxnard projects, to be approximately $2 million to $4 million higher than maintenance capital expenditures in 2009 as outlined under Capital Expenditures. However, the Partnership expects total capital expenditures to be lower in 2010 as the Partnership completed the North Island turbine replacement and completed a majority of the North Carolina enhancements in 2009.

While the Partnership anticipates seasonal fluctuations in its working capital, it does not expect a significant increase in working capital requirements over the long term for existing operations. Year end 2010 working capital requirements are expected to remain at levels consistent with December 31, 2009 balances, with higher balances in the second and third quarters of 2010 and lower balances in the first and fourth quarters of 2010.

Net income is not necessarily comparable to 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 in 2010. 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 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 respectively. 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.

Beginning in 2006, the Partnership deferred utilizing elective deductions, including capital cost allowance, for Canadian income tax purposes in response to the Partnership's Canadian operations becoming taxable in 2011. As a result, the 2009 taxable amount of cash distributions per unit increased from $0.74, had the Partnership claimed full elective deductions in the year, to the actual amount of $1.20 per unit. The use of elective deductions for Canadian income tax purposes would not benefit a tax deferred investor whereas the deferral of these elective deductions is expected to benefit all investors beginning in 2011.

The following table summarizes the tax pools the Partnership has available to deduct against future taxable income. Tax pools are comprised primarily of undepreciated capital costs and accumulated tax losses.

As at December 31 *(millions of dollars)*	**2009**	2008
Canadian tax pools	**376.7**	335.7
US tax pools (US$)	**867.0**	811.4

Capital expenditures

Capital expenditures are primarily comprised of maintenance capital and additions to, or replacements of, equipment required to maintain or increase current output capacity. Major overhauls are performed periodically at each of the plants based on the number of operating hours and type of equipment. Major overhauls at the Ontario, Kenilworth, Morris and Naval plants are performed approximately every 25,000 operating hours or roughly every three years for hot section refurbishments on the gas turbines to approximately 50,000 operating hours or every six years for turbine overhauls. As a result of SRAC changes implemented in 2009, the Partnership may choose to dispatch the Naval facilities only during peak periods, thus increasing the interval between major overhauls. Hot section refurbishments and turbine overhauls are performed at Frederickson, Manchief and Oxnard at the same number of operating hours, however these plants are normally dispatched only during periods of peak power demand reducing operating hours each year and consequently increasing the interval between major overhauls. Similarly, major overhauls are performed at Greeley depending on plant usage. It is expected that the heat recovery steam generators will require re-tubing approximately once in 20 years.

Major overhauls are completed at the Williams Lake, Calstock and North Carolina plants approximately every five to eight years and are condition based.

Maintenance capital expenditures for the hydroelectric facilities are expected to be at longer intervals and are condition based.

Capital expenditures for the year ended December 31, 2009 totalled $105.9 million, compared with $40.0 million in 2008. Capital spending for the year ended December 31, 2009 included spending for the enhancement of the Southport and Roxboro plants and the upgrade of the LM5000 natural gas turbines at North Island and Oxnard with LM6000 units.

Years ended December 31 *(millions of dollars)*	**2009**	2008
Maintenance capital expenditures	**20.0**	22.0
North Carolina enhancement project	**65.0**	13.3
North Island turbine replacement project	**15.7**	4.7
Oxnard turbine replacement project	**5.2**	-
	105.9	40.0

The Partnership has invested $78.2 million (US$70.7 million) to December 31, 2009 and plans to invest an additional $17 million (US$16 million) in 2010 for the enhancement of the Southport and Roxboro plants to reduce environmental emissions and improve the economic performance. Several challenges in retrofitting the existing facilities were encountered in 2009 causing the Partnership to delay the completion of the project while evaluating alternatives. As a result, the expected project cost increased to US$87 million from the previous estimate of US$80 million. The enhancements at Roxboro and for one of the two units at Southport were completed in December 2009. The Partnership expects the enhancements to the second unit at Southport will be completed by April 1, 2010 and that the material handling improvements at Southport will be completed by June 30, 2010.

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. The cost of the project was $20.4 million (US$17.0 million).

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

A proposal the Partnership filed with PSCo to construct additional facilities at Manchief in the range of US$250 million to US$350 million was not selected. The Partnership will consider resubmitting its proposal in future requests from PSCo.

The spending on the North Carolina and Oxnard projects will be financed using cash on hand and available credit facilities.

The Partnership expects that over its five year planning cycle maintenance capital expenditures will average $20 million to $22 million annually for its existing facilities. Aside from the installation of new technology at the North Carolina and Oxnard facilities, the Partnership expects maintenance capital spending to be approximately $22 million to $24 million in 2010, higher than previous estimates of $20 million to $22 million as a turbine overhaul at North Bay had to be brought forward to 2010.

Financing

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

As at December 31 *(millions of dollars)*	**2009**	**2008**
Senior unsecured notes, due 2036	**210.0**	210.0
Senior unsecured notes (US$415.0) due 2014 to 2019	**436.1**	505.5
Secured term loan, due 2010	**1.4**	2.6
Revolving credit facilities	**78.3**	86.7
	725.8	804.8

The Partnership's debt to total capitalization ratio as at December 31, 2009 decreased to 49% from 51% at December 31, 2008 primarily due to the $100 million preferred share offering (see Significant Events – Preferred Share Offering) and the impact of a weakening US dollar on US dollar-denominated borrowings. 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 year ended December 31, 2009, the Partnership had net drawings of $1.8 million on its revolving credit facilities after repaying a portion of the drawings during the year with the proceeds of the $100.0 million preferred share offering. Draws on the credit facilities were used 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 December 31, 2009. The Partnership was compliant with all of its debt covenants under its debt agreements for the years ended December 31, 2009 and 2008.

If an event of default occurs and continues under the Partnership's credit facilities, the Partnership may not declare, make or pay distributions (subject to certain limited exceptions).

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.

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

Ongoing volatility in the Canadian and US financial markets may adversely impact the Partnership's access to capital. 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:

Year	**Principal repayment** *(millions of dollars)*
2010	1.4
2011	78.3
2014	199.7
2017	157.6
2019	78.8
2036	210.0

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 acquisitions, for significant capital expenditures, such as enhancement expenditures at the Oxnard and North Carolina facilities, and potentially to refinance indebtedness under the credit facilities outstanding at their maturity dates. This may also affect the Partnership's credit ratings.

The Partnership continues to monitor changes in counterparty credit quality. Counterparties to the Partnership's PPAs are primarily investment grade, with 79% of operating margin from counterparties with a credit rating of A- or higher by S&P and include government agencies and utilities. The balance of the PPAs, other than with Equistar, are with enterprises with investment grade credit ratings of at least BBB- by S&P. The A credit rating is the third highest rating and the BBB credit rating is the fourth highest rating out of 10 rating categories. The minus sign shows the relative standing within the major rating categories. Equistar has a non-investment grade credit rating and is currently undergoing a reorganization under Chapter 11 of the US Bankruptcy Code. As well, a significant counterparty risk exists with wood waste suppliers given current market conditions, both in terms of slowing demand in the housing industry and its impact on the forestry industry in Canada as well as potential constraints wood waste suppliers may face in raising new capital. The Partnership has been actively seeking new sources of wood waste supply.

TRANSACTIONS WITH RELATED PARTIES

Years ended December 31 *(millions of dollars)*	**2009**	2008
Transactions with CPC [1]		
Revenue - Frederickson duct firing capacity fees	**0.1**	0.1
Cost of fuel - Greeley natural gas contract	**2.6**	0.3
Operating and maintenance expense	**50.5**	45.1
Management and administration		
Base fee	**1.1**	1.4
Incentive fee	**-**	2.3
Enhancement fee	**0.2**	2.4
General and administrative costs	**8.0**	5.9
	9.3	12.0
Acquisition and divestiture fees	**0.2**	1.9
Distributions	**32.2**	41.6
Transactions of discontinued operations		
Cost of fuel - Castleton demand charge	**1.1**	2.2
Operating and maintenance expense - Castleton	**1.4**	2.9
Transactions with PERH		
Revenue - base management fees	**2.5**	3.5

[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 years ended December 31, 2009 and 2008. Operating and maintenance expenses were $50.5 million for the year ended December 31, 2009, an increase of $5.4 million from 2008 due to the acquisition of Morris.

Operating and maintenance expense, cost of fuel, base fees and administration fees represent fees that are intended to reimburse CPC for the provision of operating and maintenance services and materials or commodities. Incentive and enhancement fees are intended to provide CPC with an incentive to maximize cash provided by operating activities that in turn are used to make distributions. Acquisition fees are intended to both reimburse CPC for its costs associated with acquiring and integrating new assets and to provide CPC with an incentive to grow the Partnership and increase its cash flows.

During the year ended December 31, 2009, the Partnership made cash distributions to CPC (and prior to June 30, 2009, EPCOR) in the amount proportionate to its ownership interest. At December 31, 2009, CPC owned 30.5% of the Partnership's units (at December 31, 2008 EPCOR owned 30.6% of the Partnership's units).

COMMITMENTS AND CONTINGENCIES

The Partnership's future purchase and debt repayment obligations, estimated based on existing contract terms, estimated inflation and foreign exchange rates as at December 31, 2009, are as follows:

Commitments
Years ended December 31

(millions of dollars)	Note	2010	2011	2012	2013	2014	Later years
Gas purchase contracts	(1)	53.5	51.9	55.4	43.9	47.2	104.3
Gas transportation contracts	(2)	17.6	18.0	15.1	15.4	15.7	33.7
Operating and maintenance contracts	(3)	26.6	27.1	27.6	28.2	28.7	74.5
Southport enhancements		16.8	-	-	-	-	-
Oxnard turbine upgrade		16.3	-	-	-	-	-
Long-term debt		1.4	78.3	-	-	199.7	446.4
Interest payments on long-term debt		39.1	38.6	38.2	38.2	38.2	319.9
Total		171.3	213.9	136.3	125.7	329.5	978.8

(1) Gas purchase contracts have expiry dates ranging from 2010 to 2016 with built-in escalators.
(2) Gas transportation contracts are based on estimates subject to changes in regulated rates for transportation and have expiry dates ranging from 2011 to 2017.
(3) Operating and maintenance contracts for the Ontario plants, Mamquam, Moresby Lake, Williams Lake, Curtis Palmer and Manchief are based on fixed fees escalated annually by inflation and have expiry terms ranging from 2017 to 2018. Operating and maintenance contracts for the remaining power plants flow-through expenses.

The Partnership is legally required to remove a majority of its power generation facilities at the end of their useful lives. The Partnership estimates that the undiscounted amount of payments required to settle its asset retirement obligations is approximately $146.0 million, calculated using inflation rates ranging from 2.1% to 3.0%. The expected timing for settlement of the obligations is between 2020 and 2090. The majority of the payments to settle the obligations are expected to occur between 2022 and 2070.

OFF-BALANCE SHEET ARRANGEMENTS

At December 31, 2009 the Partnership did not have any off balance sheet arrangements.

CRITICAL ACCOUNTING ESTIMATES

Since a determination of many assets, liabilities, revenues and expenses is dependent on future events, the preparation of the Partnership's consolidated financial statements requires the use of estimates and assumptions which are made using careful judgment. The Partnership's most significant accounting estimate relates to its calculation of depreciation and amortization expense.

Useful lives of assets

The useful lives of the Partnership's property, plant and equipment and PPA assets are estimated for purposes of determining depreciation and amortization expense, in determining asset retirement obligations and in testing for potential impairment of long-lived assets. The estimated useful lives of assets are determined based on judgment, current facts, past experience, designed physical life, potential technological obsolescence and contract periods.

The Partnership depreciates and amortizes its property, plant, equipment and PPA assets over their estimated useful lives. The Partnership amortizes its power generation plant and equipment, less estimated residual value, on a straight-line basis over their estimated remaining useful lives. Other equipment is capitalized and amortized over estimated service lives. PPAs are amortized on a straight line basis over the remaining lives of the contracts.

Fair values

Fair values are estimated to measure asset retirement obligations, to measure impairment, if any, of long-lived assets and goodwill, to determine purchase price allocations and to value derivative instruments.

Expected demolition, restoration and other related costs to settle the Partnership’s asset retirement obligations are estimated and discounted at an appropriate credit-adjusted risk-free rate to determine the fair value of the asset retirement obligations.

Undiscounted cash flows are used to test for asset impairment. If the carrying value of the asset is more than the undiscounted cash flows, an impairment loss is recognized to the extent the carrying value exceeds fair value.

For determining purchase price allocations for business combinations, the Partnership is required to estimate the fair value of certain assets and liabilities. Goodwill arising on a business combination is tested for impairment at least annually or more frequently if events and circumstances indicate that a possible impairment may arise earlier. To test for impairment, the fair value of the reporting unit is compared to the carrying value, including goodwill, of the reporting unit. If the carrying value of the reporting unit exceeds its fair value, the fair value of the reporting unit’s goodwill is compared with its carrying amount to measure the impairment loss, if any.

Estimates of fair value for asset retirement obligations, purchase price allocations, long-lived asset and goodwill impairment testing are based on discounted cash flow techniques employing management’s best estimates of future cash flows based on specific assumptions and using an appropriate discount rate.

Fair values of derivative instruments including foreign exchange contracts and natural gas supply contracts are based on quoted market prices. Changes in fair values are recorded in revenue and cost of fuel in the income statement, in other comprehensive income and in derivative instruments asset/liability on the balance sheet.

Because useful lives and fair values are used in determining potential impairments for each long-lived asset, it is not possible to provide a reasonable quantification of the range of these estimates that would be meaningful to readers.

There have been no material changes in the valuation techniques used from prior periods.

SIGNIFICANT ACCOUNTING POLICIES

Revenue recognition

Revenue is recognized when energy is delivered under various long-term contracts. Revenue from certain long-term contracts with fixed payments is recognized at the lower of: (i) the MWhs made available during the period multiplied by the billable contract price per MWh, and (ii) an amount determined by the MWhs made available during the period multiplied by the average price per MWh over the term of the contract from the date of acquisition. Any excess of the current period contract price over the average price is recorded as deferred revenue.

Finance income related to leases accounted for as direct financing leases is recognized in a manner that produces a constant rate of return on the net investment in the lease. The investment in the lease for purposes of income recognition is composed of net minimum lease payments and unearned finance income. Unearned finance income, being the difference between the total minimum lease payments and the carrying value of the leased property, is deferred and recognized in earnings over the lease term.

Foreign currency translation

The Partnership indirectly owns US subsidiaries, the functional currency of which is US dollars. Accordingly, these operations are translated using the current rate method whereby assets and liabilities are translated into Canadian dollars at the exchange rate in effect at the balance sheet date. Revenues and expenses are translated at rates in effect at the time of the transactions. The resulting foreign exchange gains and losses are accumulated as a component of partners' equity within accumulated other comprehensive income.

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:

Balance sheet item *(millions of dollars)*	**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	**0.8**	Tax impact from adoption of new standard.
Opening deficit	**(4.0)**	After tax impact to opening deficit resulting from adoption of new standard.

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. The classification of the Partnership's financial instruments which are measured at fair value within the valuation hierarchy are reflected in Note 16 of the financial statements.

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 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. In January 2008, a core team was established to develop a plan which will result in the Partnership's first interim report for 2011 being in compliance with IFRS.

The diagnostic phase of the project was completed in April 2008. For each international standard, the primary differences from Canadian GAAP were identified and an initial assessment of the impact of the required changes for the purpose of prioritizing and assigning resources was made. In making the assessment, the number of businesses impacted, the potential magnitude of the financial statement adjustment, the availability of policy choices, the impacts on systems and the impacts on internal controls were all considered.

The information obtained from the diagnostic phase was used to develop a detailed plan for convergence and implementation. The convergence and implementation work has five key sections: Financial Statement Adjustments, Financial Statements, Systems Updates, Policies and Internal Controls, and Training.

Financial Statement Adjustments

For each international standard, the Partnership determined the quantitative impacts to the financial statements, system requirements, accounting policy decisions, and changes to internal controls and business policies. The initial accounting policy decisions will be brought forward to the Audit Committee for their information as each standard is addressed. However, final accounting policy decisions for all standards in effect at the end of 2009 will be made in the fourth quarter of 2010, as they should not be determined in isolation of other policy decisions.

Policy decisions for any new standards or standards that are amended in 2010 will be made in conjunction with our analysis of those standards in 2010.

The following areas have been identified as having the most impact on the financial statements of the Partnership:

Property, plant and equipment (PP&E)

PP&E is primarily impacted by IAS 16 – Property, Plant and Equipment and IAS 23 – Borrowing Costs. IFRS are different from Canadian GAAP in that certain costs on constructed PP&E such as training costs, overheads and borrowing costs in excess of the actual entity's cost of debt may not be capitalized. As the portion of the Partnership's historical assets which are self-constructed is not significant, these changes are not expected to have a significant impact on transition.

IFRS are also more specific with respect to the level at which component accounting is required, requiring each component for which different depreciation methods or rates are appropriate to be accounted for separately. The implementation of this standard will result in an increase in annual depreciation costs.

Quantification of the impact is expected during the second half of 2010.

Impairment of Assets

IAS 36 – Impairment of Assets uses a one-step approach for testing and measuring asset impairments. IFRS requires discounted cash flows to determine whether impairment exists, whereas Canadian GAAP only required the use of discounted cash flows to determine the amount of any impairment only if the use of undiscounted cash flows indicated the existence of impairment. This may require more frequent write downs as asset carrying values supported by undiscounted cash flows may be impaired by the use of discounting under IFRS. However, unlike Canadian GAAP, previous impairment losses may be reversed or reduced if the circumstances which lead to the impairment change.

IAS 36 also requires that impairment testing be done on a cash-generating unit level, which for the Partnership will likely be at a plant basis. Any goodwill amounts must be allocated to cash-generating units and included in the impairment test for each plant. Under Canadian GAAP goodwill is not allocated to plants. This change may result more frequent write downs of goodwill.

Quantification of the impact is expected during the second half of 2010.

Leases

Under IAS 17 – Leases, the criteria for determining whether a lease is capital or operating are different than under Canadian GAAP. The Partnership is evaluating its PPA's under the IAS 17 criteria to determine if they contain a lease and evaluating leases to determine if they are capital or operating. For those arrangements not currently considered to be leases, classification as an operating lease under IAS 17 will not have an impact on the balance sheet or income statement but will require additional note disclosure. A change in the classification of a PPA currently not considered a lease or considered to be an operating lease to capital lease under IAS 17 would have the following impact (i) a reclassification from property, plant and equipment to lease receivable, (ii) depreciation would no longer be recorded and (iii) a portion of the PPA payments would be recognized as principal repayment and a portion as financing income.

Quantification of the impact is expected during the second half of 2010.

IFRS 1 – First Time Adoption of IFRS

IFRS 1 provides first time adopters with a number of elections, exempting them from retrospectively adopting certain IFRS. The following elections are relevant to the Partnership.

- Fair Value or revaluation as deemed cost - An entity may choose to use fair value at the date of transition as deemed cost. This election is available on an asset by asset basis. Management currently does not intend to fair value any assets.
- Business Combinations – An entity can select any date prior to the transition date and elect not to retrospectively adopt IFRS to business combinations occurring prior to that date. Management currently intends to utilize this exemption for all business combinations occurring before January 1, 2010.
- Cumulative translation differences – An entity may elect to deem any cumulative translation differences to be zero. These amounts are reclassified within partners' equity from accumulated other comprehensive loss to deficit without any impact to the income statement or balance sheet. Management currently intents to take this election in respect of cumulative translation losses of $131.9 million.
- Leases – An entity does not need to reassess the determination of a lease on transition. An entity can also choose to determine whether an arrangement existing at the date of transition to IFRS's contains a lease on the basis of facts and circumstances existing at that date, rather than the inception date of the lease. Management currently does not intend to utilize this election as the impact of implementing the lease standard is not expected to be significant in any case.
- Decommissioning liabilities – An entity may use a simplified calculation to calculate and restate the decommissioning liability, property, plant and equipment and depreciation. A decision on whether to utilize this exemption will be made during the second half of 2010.

The Partnership anticipates completion of the quantification of the opening adjustments for all standards currently in effect during the second half of 2010.

As the project progresses, the timing of completion of certain items may change as changes to standards and other external factors such as discussions with certain stakeholders may result in a change in priorities. However, we believe the project has sufficient resources to meet the overall project timeline.

Financial Statements

There are also a number of international standards which relate to financial statement presentation. Draft financial statements highlighting the disclosure and presentation requirements were reviewed by and discussed with the LP Audit Committee in the first quarter of 2009. The development of the financial statement presentation will evolve throughout the project as the impacts of implementing the various standards are quantified.

Systems Updates

Systems must be able to capture 2010 financial information under both the prevailing Canadian GAAP and IFRS to allow comparative reporting in 2011, the first year of reporting under IFRS. The Partnership completed its system updates in the third quarter of 2009 to capture both and are implementing the operational procedures to capture the applicable accounting data through 2010.

Policies and Internal Controls

In the determination of the financial statement adjustments, requirements for changes to Partnership policies and internal controls will be identified and documented. As there may be factors other than IFRS impacting policies and internal controls, the formal documentation and approval of revised policies and internal controls will not occur until the third quarter of 2010.

The impact of IFRS on certain agreements, such as debt, shareholder and compensation agreements, has also been included in the plan. Assessments of most agreements have been completed and will continue to be monitored as IFRS differences are quantified.

Training

The Partnership recognizes that training at all levels is essential to a successful conversion and integration. Accounting staff have attended three training sessions with more planned to occur throughout the conversion process. The Board of Directors and Audit Committee have attended a training session, and the Audit Committee receives regular updates on the conversion project. Further training for the Board of Directors and Audit Committee will occur throughout the 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.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

As of December 31, 2009, management conducted an evaluation of the design and effectiveness of the Partnership's disclosure controls and procedures to provide reasonable assurance that material information relating to the Partnership is made known to management by others, particularly during the period in which the Partnership's annual filings are being prepared and that information required to be disclosed by the Partnership in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation. The evaluation took into consideration the Partnership's Disclosure Policy, the internal sub-certification process that has been implemented and the functioning of its Disclosure Committee. In addition, the evaluation covered the Partnership's processes, systems and capabilities relating to public disclosures and the identification and communication of material information. Based on that evaluation, the President (acting as Chief Executive Officer) and the Chief Financial Officer of the General Partner have concluded that the Partnership's disclosure controls and procedures are appropriately designed and effective.

Also as of December 31, 2009, management conducted an evaluation of the design and effectiveness of internal controls over financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. Based on that evaluation, the President and the Chief Financial Officer have concluded that the Partnership's internal controls over financial reporting are appropriately designed and effective.

These evaluations were conducted in accordance with the standards of the Committee of Sponsoring Organizations, a recognized control model, and the requirements of the Canadian Securities Administrators' National Instrument 52-109.

During the year, 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 year ended December 31, 2009 that have materially affected or are reasonably likely to materially affect the Partnership's internal control over financial reporting.

FINANCIAL INSTRUMENTS

The Partnership has various financial instruments that are classified for financial reporting purposes as "available for sale", "held for trading", "held to maturity", or "loans and receivables". Financial liabilities are classified as either "held for trading" or "other liabilities". Initially, all financial assets and financial liabilities are recorded on the balance sheet at fair value with subsequent measurement determined by the classification of each financial asset and liability.

The Partnership classifies its cash and cash equivalents and current and non-current derivative instruments assets and liabilities as held for trading and measures them at fair value. Accounts receivable are classified as loans and receivables and accounts payable and distributions payable are classified as other financial liabilities and are measured at amortized cost. The fair values of accounts receivable, accounts payable and distributions payable are not materially different from their carrying amounts due to their short-term nature. The investment in PERH is classified as available for sale and the net investment in lease is classified as loans and receivables. The net investment in lease relates to the Oxnard PPA, which is considered a direct financing lease for accounting purposes.

The classification, carrying amounts and fair values of the Partnership's other financial instruments held are summarized as follows:

	Carrying amount		
As at December 31, 2009 *(millions of dollars)*	Loans and receivables	Other financial liabilities	Fair value
Other assets - net investment in lease	26.9	-	27.1
Other assets - receivable from Equistar	9.1	-	9.1
Long-term debt (including current portion)	-	(720.8)	(667.7)

Risk management and hedging activities

The Partnership is exposed to changes in energy commodity prices, foreign currency exchange rates and interest rates. The Partnership uses various risk management techniques, including derivative instruments such as forward contracts, to reduce this exposure. These derivative instruments are recorded at fair value on the balance sheet unless the Partnership elects the fair value exemption for non-financial derivatives that are entered into and continue to be held for the purpose of receipt or delivery of a non-financial item in accordance with the Partnership's expected purchase, sale or usage requirements. The derivative instruments assets and liabilities used for risk management purposes are measured at fair value and consist of the following:

As at December 31, 2009 *(millions of dollars)*	Natural gas hedges	Natural gas non-hedges	Foreign exchange non-hedges	Total
Total derivative instruments net assets (liabilities)	(33.9)	8.5	25.7	0.3

Natural gas derivatives designated as accounting hedges

At December 31, 2009, the net fair value of energy derivative instruments designated and qualifying for hedge accounting was a net liability of $33.9 million and is included in derivative instruments assets and derivative instruments liabilities on the consolidated balance sheet. The net derivative liability is primarily due to a decrease in the forward Alberta natural gas prices relative to the derivative contract prices. Unrealized gains and losses for fair value changes on derivatives that qualify for hedge accounting are recorded in other comprehensive income and reclassified to net income as cost of fuel as appropriate when realized.

On July 31, 2009, the Partnership applied hedge accounting to certain of its natural gas purchase contracts. An unrealized loss of $9.2 million for the decrease in the fair value of these contracts for the period from the inception of the hedge to December 31, 2009 was recognized in other comprehensive income. Prior to the application of the hedge, the unrealized changes in the fair value of these contracts were recognized in net income.

Derivatives not designated as accounting hedges

At December 31, 2009, the net fair value of natural gas derivative instruments not designated as hedges for accounting was a net asset of $8.5 million and is included in derivative instruments assets and derivative instruments liabilities on the consolidated balance sheet. The net derivative asset is primarily due to an increase in the forward Alberta natural gas prices relative to the derivative contract prices.

At December 31, 2009, the fair value of the Partnership's forward foreign currency contracts was a net derivative instrument asset of $25.7 million. The net asset was due to the impact of a strengthening Canadian dollar relative to the US dollar on forward foreign exchange sales contracts used to hedge US dollar denominated cash flows. The weighted average fixed exchange rate for contracts outstanding at December, 2009 was $1.13 per US $1.00. Unrealized and realized gains and losses on foreign exchange derivatives are recorded in revenues.

All non-financial derivative instruments are measured at fair value unless they are designated as contracts used for the purpose of receipt or delivery of a non-financial item in accordance with the Partnership's expected purchase, sale or usage requirements as defined by accounting standards, or are designated and qualify for hedge accounting. Some of the Partnership's natural gas purchase contracts that are used to meet power generation were not designated as contracts used in accordance with the Partnership's expected purchase requirements and therefore are recorded at fair value in the balance sheet.

Risk management and hedge accounting

The Partnership uses various financial and non-financial derivatives primarily for risk management purposes. Unrealized changes in the fair value of financial and non-financial derivatives that either do not qualify for hedge accounting or the Partnership elects not to apply hedge accounting, and non-financial derivatives that do not qualify for the expected purchase, sale or usage requirements of the contract, are recorded in revenues or cost of fuel, as appropriate. The corresponding unrealized changes in the fair value of the associated economically hedged exposures are not recognized in income. Accordingly, derivative instruments that are recorded at fair value can produce volatility in net income as a result of fluctuating forward commodity prices, exchange rates and interest rates which are not offset by the unrealized fair value changes of the exposure being hedged on an economic basis. As a result, accounting gains or losses relating to changes in fair values of derivative instruments do not necessarily represent the underlying economics of the hedging transaction.

For example, the Partnership records certain of its natural gas contracts at fair value because a small portion of this natural gas has been historically resold and not used in the production of electricity. Even though the economic impact from changes in natural gas prices is modest, for accounting purposes even a small change in natural gas prices can have a large impact on net income. At December 31, 2009, holding all other variables unchanged, a $1/GJ increase (decrease) in the price of natural gas is estimated to increase (decrease) net income by $7 million and other comprehensive income by approximately $31.

Other comprehensive income

Changes in the fair value of the effective hedge portion of the derivative contracts designated as accounting hedges, are recorded in other comprehensive income. The ineffective portion of the contracts is recorded in net income.

For the year ended December 31, 2009, losses on derivative instruments designated as cash flow hedges, net of income taxes, of $6.4 million were recorded in other comprehensive income for the effective portion of cash flow hedges, while losses of $0.3 million for the ineffective portion of cash flow hedges was required to be recognized in net income. Of the $6.4 million in net unrealized fair value gains related to derivative instruments designated as cash flow hedges included in accumulated other comprehensive income at December 31, 2009, net gains of $1.0 million, net of taxes of $nil are expected to settle and be reclassified to net income over the next twelve months.

BUSINESS RISKS

The Partnership operates assets under long-term power and steam sales and energy supply contracts, which combined with an excellent ongoing maintenance program, minimize exposures to operational risk and commodity price and supply fluctuations. The most significant risks to the Partnership are those noted below.

Operational risk

The operation of power plants involves many risks, including: (i) the breakdown or failure of, and the necessity to repair, upgrade or replace, power and steam generation equipment, transmission lines, pipelines or other equipment, structures or processes; (ii) the inability to secure critical or back-up parts for generator equipment on a timely basis; (iii) fire, explosion or other property damage; (iv) the inability to obtain adequate fuel supplies, site control and operation and maintenance and other site services; (v) performance of generation equipment below expected levels, including those pertaining to efficiency and availability; (vi) non-compliance with all operating permits and licences (including environmental permits and emissions restrictions) under applicable laws and regulations; and (vii) the inability to retain, at all times, adequate skilled personnel, the occurrence of any of which could have a material adverse effect on the Partnership.

The failure of facilities to operate to certain capacity levels can result in the facilities having their contracted capacity reduced and in certain cases having to make payments on account of reduced capacity to power purchasers. Contract counterparties have remedies available to them on account of the Partnership's failure to operate facilities to contract requirements, including the recovery of damages or the termination of contractual arrangements.

Under some of the plants' PPAs, if minimum amounts of power are not provided on a monthly basis, a reduction in payments from the PPA buyer will occur.

Plant personnel have developed procedures to minimize the plant downtime required for both scheduled and unscheduled maintenance. The Partnership's maintenance practices are supported by an inventory of strategic spare parts, which can reduce downtime considerably in the event of failure. Safety standards are in place at all plants. In addition, the Partnership maintains reasonable insurance to cover losses resulting from equipment breakdown and business interruption, although there can be no assurance it will cover all losses.

PPA contract expiry risk

Of the Partnership's fleet of power plants, 18 have PPAs in place that expire between April 2011 and 2027. In order to stabilize future cash flows, the Partnership will seek to re-contract its existing plants under new or extended contracts and acquire new plants that meet its investment criteria. The commercial environment for North American power generation is very competitive and therefore there is no assurance that the Partnership will be successful in re-contracting its existing plants or will be able to recontract at existing or economic rates. Failure by the Partnership to enter into a subsequent PPA on terms and at prices that permit the operation of a facility on a profitable basis could have a material adverse effect on the Partnership's operations and financial condition, and may even require the Partnership to temporarily or permanently cease operations at the affected facility.

The PPAs for the North Carolina facilities expired on December 31, 2009. To date, the Partnership and Progress have been unable to finalize new PPAs that are acceptable to both parties. The Partnership filed for arbitration with the NCUC and is seeking long-term PPAs with pricing terms consistent with Progress's actual avoided costs. The NCUC has required that each party file a statement with its initial position with respect to the appropriate rates and terms for new power purchase agreements for the facilities by April 15, 2010. The NCUC will schedule an arbitration hearing by further order. The Partnership expects the arbitration hearing to be scheduled for late May and a decision to be rendered within 60 days following the hearing. The

NCUC has ordered that Progress continue to pay for the output of the Roxboro and Southport facilities pursuant to the terms of the PPAs that expired December 31, 2009 until the arbitration is finalized and NCUC issued a confirmation order for rate purposes. There is no assurance that new PPAs will be entered into between the Partnership and Progress or that new PPAs will result in positive cash provided by operating activities for the facilities or achieve previous expectations of accretion from the North Carolina enhancement project.

The Navy has the right to terminate the Naval Facility NUSCs for convenience on one year's notice. These agreements grant the Partnership access rights to the Naval Facilities that are operated to produce and sell electricity under the Naval Facility PPAs. The termination would result in the loss of the Naval Facilities' steam host and subsequently its QF status which in turn would allow SDG&E to terminate the Naval Facility PPAs (see Business Risks - Qualifying Facility Status Risk).

The drop in power demand coupled with the high cost of capital and ongoing environmental regulatory uncertainty is expected to curtail the construction of new power generation facilities in North America. As demand returns, this should have a positive impact on PPA renewals that come due after the recessionary pressures have eased.

Energy supply risk

The Partnership requires energy supplies in such forms as natural gas, waste heat, coal, wood waste, tire-derived fuel and water, to generate electricity. A disruption in the supply of any energy supplies required by the Partnership could have a material adverse impact on the Partnership's business, financial condition and results of operation.

Wood waste is required to fuel the Partnership's two Canadian biomass wood waste plants, Williams Lake and Calstock. In addition, the enhancements that are in process at the North Carolina plants will increase the level of wood waste consumption at those plants. Weakness in the North American economy has placed economic hardships on forestry mills, which has caused mills to shut down or scale back production in British Columbia, Ontario and in the US. In the event that the Partnership's wood waste suppliers curtail or shut down operations, the Partnership's biomass wood waste operations could be adversely affected.

The Partnership's five Ontario plants (namely, Nipigon, Kapuskasing, North Bay, Calstock and Tunis) also generate electricity in part from the use of waste heat gases from adjoining natural gas compressor stations. Supply of the waste heat gases is secured under long-term contracts; however the availability of the waste heat gases varies depending on the output of the compressor stations along the TransCanada Canadian Mainline system, and the hosts' altering those operations under the terms of a Waste Heat Optimization Agreement. In addition, the availability of waste heat gases is also dependent on the compressor stations remaining in use and their ability to supply the waste heat gases. In 2009, waste heat contributed to approximately 11% of power revenue at the Ontario plants. Declining waste heat availability that began in 2007 continued through 2009 due to lower throughput on the TransCanada Canadian Mainline system and may remain lower than pre-2007 levels in the near term until throughput increases on the TransCanada Canadian Mainline system.

Performance of hydroelectric facilities is dependent upon the availability of water. Variances in water flows, which may be caused by shifts in weather or climate patterns, the timing and rate of melting and other uncontrollable weather related factors affecting precipitation, could result in volatility of hydroelectric plant revenues. In addition, the hydroelectric facilities are exposed to potential dam failure, which could affect water flows and have a material adverse impact on revenues from the associated plants and the Partnership. There is an increasing level of regulation respecting the use, treatment, rate of flow and discharge of water, and respecting the licensing of water rights. A continued tightening of such regulations could have a material adverse effect on the Partnership's business, financial condition and results of operation.

The Roxboro and Southport facilities purchase coal from local suppliers in the Southeast US The coal is transported to the power plants by rail service. Any disruption in rail service due to unforeseen circumstances could impair the operations of these power plants if alternative transportation cannot be arranged in a timely manner.

Commodity price risk

The Partnership's power plant operations are susceptible to the risks associated with the uncertainty of the competitive marketplace in which the power plants operate, especially the volatility in market prices for electricity and fuel supply beyond any fixed price contract term. Natural gas prices also impact the ability of the Partnership to earn enhancement revenue and diversion sales from the curtailment of electricity production in favour of selling the unused natural gas at prevailing market prices.

The price of fuel supplies is dependent upon a number of factors, including: the projected supply and demand for such fuel supplies; the quality of the fuel (particularly in regards to wood waste); and the cost of transporting such fuel supplies to the Partnership's facilities. Changes in any of these factors could increase the Partnership's cost of generating electricity or decrease the Partnership's revenues either of which could have a material adverse effect on the Partnership's business, financial condition and results of operation

Certain natural gas-fired facilities in the US have PPAs that extend beyond existing supply contracts. The failure to contract additional fuel supply at a cost that is equal to or better than existing contracted prices once existing contracts expire may lead to increased operating costs, disruptions in operations and reduced operating margins.

Natural gas prices also impact the ability of the Partnership to earn enhancement revenue and diversion sales from the curtailment of electricity production in favour of selling the unused natural gas at prevailing market prices.

Electricity prices under the PPAs for the Naval Facilities and the Oxnard facility are based on the purchasing utilities' SRAC. The SRAC formula is determined by the CPUC and is subject to adjustment. In the future, the CPUC may make adjustments to the SRAC formula to change the basis on which future electricity prices will be determined for these facilities and such adjustments, which would affect the price of electricity and/or the price the Navy may have to pay for steam, may adversely affect the value of the affected PPAs to the Partnership.

Existing coal supply contracts will meet the 2010 requirements for Roxboro and Southport. However, there can be no assurance of if, when or upon what terms, including pricing, the existing supply agreements will be renewed or replaced.

Certain of the Partnership's PPAs have fuel cost pass through mechanisms where revenues increase (decrease) as fuel costs increase (decrease). Because these costs are flowed through, they have minimal impact on net income or cash provided by operating activities. Other facilities dispatch (operation) is subject to the competitiveness of its fuel source versus other fuel sources in the region. This primarily effects the Manchief and North Carolina facilities as well as excess energy from the Morris facility. The impact of a change in natural gas prices on the overall dispatch of the Partnership's fleet as a whole is not expected to have a material impact on cash provided by operating activities or net income of the Partnership.

Environment, health and safety risk

The Partnership's operations are subject to federal, provincial, state and local environmental, health and safety laws, regulations and guidelines. If the Partnership fails to comply with environmental, health and safety requirements, regulators could impose penalties and fines on the Partnership or curtail its operations. The Partnership's facilities could experience incidents, malfunctions or other unplanned events that could result in spills or emissions in excess of permitted levels and result in personal injury, penalties and property damage. As environmental laws, regulations and guidelines change, the Partnership may incur unforeseen capital expenditures and operating costs in order to comply, or may be unable to comply with more stringent standards causing the Partnership to close certain facilities.

The Partnership has implemented environmental, health and safety management programs designed to continuously improve environmental, health and safety performance and is working towards alignment with the requirements of the ISO 14001 Environmental and the ISO 18000 Health and Safety Management Systems, a set of industry guidelines to achieve effective environmental, health and safety policies and procedures.

As the Partnership's electricity generation business is an emitter of carbon dioxide, mercury and various local air contaminants, it must comply with emerging federal, state and provincial requirements including programs to offset emissions. As additional regulation is implemented, it is likely the Partnership will incur increased costs.

Overall, the Partnership has a good fleet of power plants from an environmental perspective. The biomass facilities significantly reduce the release of carbon dioxide (CO_2) that would otherwise occur with the decomposition of wood waste. The hydro facilities are not emitters. The Ontario natural gas fired generation facilities utilize waste heat from adjacent gas compressor stations that reduce the use of natural gas. The combined heat and power facilities in the US maximize the use of energy by exporting steam to site hosts as a by-product of power generation. Steps are currently underway to ensure compliance with tighter emission standards at the North Carolina facilities (see Liquidity and Capital Resources – Capital Expenditures).

The Partnership has obtained all environmental licenses, permits, approvals and other authorizations required for the operation of the power plants. Except as outlined below, the Partnership is satisfied that its operating practices are in material compliance with applicable environmental laws and regulatory requirements. The power plants are operated in an environmentally sound manner and the environmental management systems are aligned with the corporate policies and procedures of CPC, which are binding upon the General Partner and the Manager.

Through 2008 Calstock frequently exceeded its opacity limits. In 2009 Calstock resolved this issue through repairs to the electrostatic precipitator (ESP). The ESP was refurbished as planned and on budget at $0.7 million. Although opacity remains a concern while burning the landfill waste wood alone, a blend of fuel supply is utilized to mitigate opacity and particulate issues. However, Calstock is not meeting two other conditions in its Certificate of Approval (CoA): (i) attaining the minimum combustion gas temperature and residence time, and (ii) the maximum carbon monoxide concentration in the stack. The Partnership has notified the Ontario Ministry of Environment that it will be submitting an amendment to the CoA in 2010 which will more accurately reflect the operating conditions of the plant.

Canada

Greenhouse gas regulation

In December 2009 the United Nations held its fifteenth climate change conference referred to as the Conference of the Parties in Copenhagen, Denmark, where more than 190 countries, including Canada, participated. Instead of a binding agreement for greenhouse gas (GHG) emissions reduction targets the meeting produced a non-binding framework, referred to as the Copenhagen Accord, which required each nation to, among other things, submit economy wide emission targets by January 31, 2010. Canada submitted its target on January 31, 2010 which included a 17% reduction of GHG emissions from 2005 by 2020, to be aligned with the final economy-wide emissions target of the US in enacted legislation. This target is lower and with a different base line year, than the targets published in 2008 in the "Turning the Corner" framework, which stated a 20% reduction by 2020, from 2006 levels. It is widely anticipated negotiations to develop a formal binding agreement will occur through 2010. Due to the expected impact climate change regulations may have on international trade the Canadian Environment Minister indicated that Canada will wait to establish Canadian climate change regulations in concert, and generally consistent, with the US, which has already been demonstrated as Canada has adopted the same GHG emission reduction target as the US. Notwithstanding the announcement of the new target, there is insufficient information at this time to determine the impact of the Canadian climate change regulations on the Partnership, although to the extent additional regulation is passed it is likely the Partnership will incur increased costs.

Air emission regulations

The Canadian government is also considering regulations which may place stricter limits on nitrogen oxide (NOx) and sulphur dioxide (SO_2) emissions from fossil-fired generating stations in Canada. Working groups, including industry participants, have been established by the Canadian government to develop the elements of a regulatory framework to minimize NOx and SO_2. The proposed federal framework appears to be consistent with requirements currently in place in certain provinces, and the Partnership is actively monitoring the progress but there is insufficient information to assess the financial implication to operations, although as additional regulation is passed it is likely the Partnership will incur increased costs.

Ontario regulations

On May 27, 2009, the Ontario Government introduced to the Ontario Legislature 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. However, the timing and specifics of such a GHG cap and trade system are not known at this time, although public consultation occurred through the fall of 2009 and final regulations may not be implemented until 2012. There is insufficient information at this time to determine the impact of this proposed system on the Partnership, although as additional regulation is passed it is likely the Partnership will incur increased costs.

United States

Greenhouse Gas Regulation

The United States Environmental Protection Agency introduced a federal Greenhouse Gas Mandatory Reporting Rule (MRR) which came into effect December 29, 2009. In addition, the State of California has also implemented mandatory GHG reporting. The Partnership is able to meet the reporting requirements of both jurisdictions.

In December 2009 the US Environmental Protection Agency (USEPA) reached a finding that the current and projected concentrations of GHG in the atmosphere threaten the public health and welfare of current and future generations. This finding does not impose any regulatory requirements but is a prerequisite to any future GHG regulations imposed by USEPA. It is widely expected that instead of regulations established by USEPA that the US Congress will work to establish some form of GHG legislation.

Several US Senators have proposed Climate Change bills with the American Clean Energy Act and Security Act and the Clean Energy Job and American Power Act as the two prominent bills. These two bills are receiving the majority of the attention, but there are several other bills that have been recently proposed. With multiple bills proposed and no clear direction from the climate change meeting in Copenhagen, the direction of US federal climate change legislation remains unclear. Consistent with the Copenhagen Accord the United States submitted its GHG emission reduction targets to be in the range of 17% reduction of GHG emissions from 2005, the base line year, by 2020. It also indicated that pending legislation would entail a 30% reduction in 2025 and a 42% reduction in 2030, in line with the goal to reduce emissions 83% by 2050. Notwithstanding the announcement of the new target there is insufficient information to determine the impact of the United States climate change regulations on the Partnership, although to the extent additional regulation is passed, it is likely the Partnership will incur increased costs.

Several states have proposed or implemented various climate change legislation. Seven New England states have implemented the Regional Greenhouse Gas Initiative (RGGI). The regulations are implemented on a state-by-state basis. Kenilworth is exempt based on size.

The Western Climate Initiative (WCI), a collaborative of Western states and certain Canadian provinces, including BC and Ontario, to reduce GHGs, may impact the operation of the California facilities, the Frederickson facility in Washington, the Williams Lake facility in British Columbia and the Ontario facilities. With respect to federal GHG regulation, RGGI and the WCI, the Partnership is monitoring the regulatory process to understand the potential impact of these initiatives, but at this time there is insufficient information to assess the full financial and operational implications on these facilities. To the extent that additional regulation is passed, the Partnership could incur increased costs.

Air Emission Regulations

The US Clean Air Act (CAA) currently has the greatest environmental regulatory impact on the Partnership's US operations. A majority of the Partnership's US facilities operate under CAA permits issued directly to the facilities. The Partnership has actively managed these permits, including modifications in an attempt to maximize operational parameters and flexibility.

The Partnership performs on-going assessments of the potential impact of future legislation and regulatory requirements for certain air emissions under the CAA. In July, 2008, the US Court of Appeals for the District of Columbia Circuit vacated the CAA Clean Air Interstate Rule (CAIR) which was designed to control NOx and SO_2 emissions through a regional cap and trade program. In December 2008, a full panel of the same court decided to remand CAIR to the USEPA rather than vacating the rules. The December 2008 ruling leaves CAIR and the CAIR trading programs in place until the USEPA issues a new rule to replace CAIR in accordance with the July 2008 decision. The USEPA informed the Court that development and finalization of a replacement rule could take about two years. Despite the delay, it is anticipated that CAIR may require reductions in NOx and SO_2 at the Southport and Roxboro facilities. The Partnership has elected to move forward with planned capital upgrades to emissions control equipment to reduce NOx and SO_2 emissions and improve economic performance. Assuming that CAIR remains in effect, the Partnership may have to purchase additional NOx and SO_2 credits in the short term (2010-2011), but should subsequently have allocations of allowances in excess of those needed for compliance. Such excess allowances would be available for sale. The cost of the NOx and SO_2 credits is estimated at $1.5 million per annum. Given the continuing uncertainty about the future of CAIR, the Partnership will continue to monitor and assess the situation.

The Clean Air Mercury Rule (CAMR) was vacated prior to the CAIR vacation but unlike CAIR, the CAMR vacation is final. The state of North Carolina could still promulgate maximum available control technology standards under Section 112(j) of the CAA, which would establish facility specific mercury limits. While the USEPA intends to propose new air toxics standards for coal and oil-fired electric generating units by the end of the first quarter of 2010, the fuel mix and other controls at the North Carolina facilities should preclude additional requirements for further mercury controls.

Acquisition and development risk

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 from contracts that expire and may not be replaced with contracts under similar terms. The acquisition of power generation companies and assets is subject to substantial risks, including the failure to identify material problems during due diligence, the risk of over-paying for assets and the inability to arrange financing for an acquisition as may be required or desired. Despite extensive due diligence procedures prior to any acquisition, there can be no assurances that any future acquisitions will perform as expected or that the returns from such acquisitions will support the indebtedness incurred to acquire them.

Development of power generation facilities is subject to substantial risks, including various engineering, construction, stakeholder, government and environmental risks. Generally, in developing a power generation facility, there are numerous tasks the Partnership must complete, including: government permits and approvals, site agreements and construction contracts, access to power grids and electrical transmission agreements, fuel supply and transportation agreements, equipment, and financing. There can be no assurance that the Partnership will be successful in completing such tasks on a timely basis or at all. The development and future operation of power generation facilities can be adversely affected by changes in government policy and regulation, environmental concerns, increases in capital costs, increases in interest rates, competition in the industry, labour availability, labour disputes, increases in material costs and other matters beyond the direct control of the Partnership.

In the event that a project is not completed or does not operate at anticipated performance levels, the Partnership may not be able to recover its investment which could materially and adversely affect the Partnership's financial position, operating results and business.

The Partnership attempts to mitigate these risks by performing detailed project analyses and due diligence prior to and during construction or acquisition. Corrective actions are taken when necessary to increase the likelihood of investment recovery. The Partnership also seeks to enter into favourable long-term contracts for the projects' output whenever possible.

Government risk

The Partnership is subject to risks associated with changes in federal, provincial, state or local laws, regulations and permitting requirements. It is not possible to predict changes in laws or regulations that could impact the Partnership's operations, income tax status or ability to renew permits, as required. The introduction of price caps or, in the case of Ontario, the continuation of price caps, may suppress price increases under the Partnership's PPAs.

Foreign exchange risk

The Partnership owns and operates power facilities in the US, has borrowings outstanding that are denominated in US dollars and has net cash flow that is generated in US dollars. Therefore, fluctuations in the exchange rate between the US dollar and the Canadian dollar could impact the Partnership's income and cash flows and have an adverse effect on financial performance and condition.

The Partnership manages the foreign exchange risk of its future anticipated US dollar-denominated cash flows from its US plants net of debt service obligations on US dollar borrowings through the use of foreign exchange contracts for periods up to seven years. At December 31, 2009, US$395.0 million or approximately 102% of future net cash flows had been economically hedged for 2010 to 2015 at a weighted average exchange rate of 1.13 per US $1.00.

By year, the amounts hedged and average rates are as follows:

	2010	2011	2012	2013	2014	2015
Forward foreign exchange sales (milions of US dollars)	58.4	71.3	72.0	71.7	60.8	60.8
Average exchange rate (US / CDN)	1.11	1.13	1.12	1.15	1.09	1.14

Counterparty credit risk

Counterparty credit risk is the possible financial loss associated with the potential inability of counterparties to satisfy their contractual obligations to the Partnership, including payment and performance. In the event of default by a purchasing counterparty, existing PPAs and steam purchase agreements may not be replaceable on similar terms, particularly those agreements that have favourable pricing for the Partnership relative to their current markets. The Partnership is also dependant upon counterparties with respect to its cogeneration hosts and suppliers of fuel to its plants. In the wholesale electricity market, should a counterparty default, the Partnership may not be able to effectively replace such counterparty in order to manage short or long electricity positions, resulting in reduced revenues or increased power costs. Failure of any such counterparties could impact the operations of some of the Partnership's plants and could adversely impact the Partnership's financial results. Furthermore, a prolonged deterioration in economic conditions, such as the recent economic recession, could increase the foregoing risks and could have a material adverse affect on the Partnership.

Counterparty credit risk is managed by making appropriate credit assessments of counterparties on an ongoing basis, dealing with creditworthy counterparties, diversifying the risk by using several counterparties and where appropriate and contractually allowed, requiring the counterparty to provide appropriate security.

While the Equistar reorganization under Chapter 11 of the US Bankruptcy Code continues, the Morris facility will not receive approximately US$11 million of payments for pre-petition services to Equistar under the Morris ESA. Equistar retains the right to reject the Morris ESA, and in such event, the Morris facility may not be able to recover pre-petition amounts owing, future amounts that may be earned under the ESA would not be earned, and the Morris facility could lose its QF status. If Equistar rejects the ESA, the Partnership could attempt to negotiate new ESA terms with Equistar, but there can be no assurance that these negotiations would be successful or that the negotiated rates would be as favorable as those in the current ESA (see Business Risks – Qualifying Facility Status Risk).

Qualifying facility status risk

Similar to being dependent on counterparties for steam sales, certain US facilities are also dependent on their QF status. The loss of QF status could have adverse consequences to the Partnership and the facility could become subject to rate regulation by FERC under the US Federal Power Act and additional state regulation. Loss of QF status could also trigger defaults under covenants to maintain QF status in the facilities' PPAs, SPAs and financing agreements and result in termination, penalties or acceleration of indebtedness under such agreements. Loss of QF status on a retroactive basis could lead to, among other things, fines and penalties or claims by a utility customer for a refund of payments previously made. If a power purchaser were to cease taking and paying for electricity or were to seek to obtain refunds of past amounts paid because of the loss of QF status, the Partnership cannot provide assurance that the costs incurred in connection with the facility could be recovered through sales to other purchasers. If a steam host facility were to become insolvent, it could result in the loss of QF status if operations cease.

Tax risk

The SIFT Legislation included in Bill C-52 was enacted in 2007 and will result in changes to how certain publicly traded trusts and partnerships, including the Partnership, are taxed. The SIFT Legislation generally operates to apply a tax at the SIFT level on certain income at tax rates comparable to the combined federal and provincial corporate tax rate and then re-characterize that income net of tax payable pursuant to the SIFT Legislation as taxable dividends in the hands of Unitholders beginning in 2011.

On December 15, 2008, the fifth protocol to the US - Canada Income Tax Treaty (Treaty) entered into force. The protocol contains extensive changes to the current Treaty. Although the Treaty contains positive changes such as the elimination of non-resident withholding tax on interest, it also included the addition of a treaty denial provision applicable to payments obtained from or through certain hybrid entities. The treaty denial provision was effective January 1, 2010. While the Partnership does not expect to be immediately impacted by the treaty denial provision, the provision could negatively impact the Partnership's ability to repatriate future profits arising from US operations to Canada. As such, the Partnership is considering restructuring its US subsidiaries in order to remove this potential impediment.

Over the last several years, numerous proposals have been made to tighten the US rules (Earning Stripping Rules) with respect to the deductibility of interest paid by US corporations to, or guaranteed by related parties, who do not fully pay US tax on such interest income. On November 28, 2007, the US Treasury Department issued a report on three international tax issues including the Earnings Stripping Rules that concluded that broad based tightening of the Earnings Stripping Rules was warranted. On February 1, 2010, the President of the U.S. transmitted the 2011 Budget to the Congress. The Budget includes measures proposing to tighten for certain entities only the Earning Stripping Rules effective for tax periods beginning after December 31, 2010. The measures need passage by both houses of Congress before they are enacted but assuming they are substantively enacted as proposed, the measures are not expected to apply to the Partnership or its subsidiaries.

The Partnership's operations are complex and the computation of the provision for income taxes involves tax interpretations, regulations, and legislation that are continually changing. In addition, the Partnership's tax filings are subject to audit by taxation authorities. While the Partnership believes that its tax filings have been made in accordance with all such tax interpretations, regulations, and legislation, the Partnership cannot guarantee that it will not have disagreements with the Canada Revenue Agency or other taxation authorities with respect to the Partnership's tax filings. Future changes in tax legislation, not limited to changes or potential changes discussed above may have an adverse impact on the Partnership, its Unitholders and the value of the Units.

The Partnership monitors the development of any potential changes in tax legislation in order to manage the risks by proactively planning for any changes.

Weather and catastrophic event risk

Weather conditions and other unforeseen natural events could force the Partnership's facilities to cease operations which could adversely affect the Partnership.

A natural disaster or other catastrophic event, such as an earthquake, hurricane, fire, explosion, flood, severe storm, terrorist attack or other comparable event at any of the Partnership's facilities, could disrupt operations at or cause substantial damage to such facilities. While the Partnership has obtained insurance, including earthquake insurance, to mitigate financial costs arising from such events, there is no assurance that such insurance will fully cover such risks and costs or will continue to be available to the Partnership on terms which are commercially reasonable.

The occurrence of a significant weather and/or catastrophic event that disrupts the ability of the Partnership's generation assets to produce or sell power for an extended period, including events which preclude customers from purchasing electricity, could have a material adverse effect on the Partnership's assets, liabilities, business, financial condition and results of operations.

Conflict of interest risk related to the Partnership's relationship with CPC

As a result of CPC's relationship with the Partnership, certain conflicts of interest could arise and the Partnership may find that its interests are not aligned with those of CPC.

The Partnership's terms of reference for the board of directors of the General Partner denotes that the board of directors shall be composed of not more than eight members, at least four of whom shall be independent directors who are not officers, directors or employees of CPC or its affiliates and are free from any direct or indirect interest, any business or other relationship that could interfere with a director's independence or ability to act in the best interests of the General Partner and the Partnership. There are four senior officers of CPC who are members of the General Partner's board of directors and are not considered independent. The Chairman, who is an executive officer of CPC, has a casting vote in case of a tie vote at any meeting of the board of directors. Any non-arms' length agreements are evaluated solely by a committee of independent directors of the Partnership. From time to time such agreements are monitored by that committee.

General economic conditions and business environment

Volatility of natural gas prices, coal prices, future electricity prices, fluctuations in interest rates, product supply and demand, market competition, the competitive labour market, risks associated with technology, risks of a widespread influenza or other pandemic, the Partnership's ability to generate sufficient cash provided by operating activities to meet its current and future obligations, the Partnership's ability to access external sources of debt and equity capital, impact of bankruptcy of insurers or critical suppliers of products and services, spare parts and lease turbines, general economic and business conditions, the Partnership's ability to make capital investments and the amounts of capital investments, risks associated with existing and potential future lawsuits and other regulations, assessments and audits (including income tax) against the Partnership and its subsidiaries, political and economic conditions in the geographic regions in which the Partnership and its subsidiaries operate, difficulty in obtaining necessary regulatory approvals and such other risks and uncertainties described from time to time in the Partnership's reports and filings with the Canadian securities authorities could materially adversely impact the Partnership's business, prospects, financial condition, results of operation or cash flows. The Partnership's ability to mitigate these risks is dependent, to some degree, on the Manager's ability to anticipate such risks and, where possible, to develop appropriate mitigation plans.

Preferred Share guarantee – unit distribution risk

The Series 1, Series 2 and Series 3 Preferred Shares are fully and unconditionally guaranteed by the Partnership on a subordinated basis as to (i) payment of dividends, as and when declared, (ii) payment of amounts due on redemption of the Series 1, Series 2 and Series 3 Shares, and (iii) payment of amounts due on liquidation, dissolution or winding up of CPI Preferred Equity Ltd.

As long as the declaration or payment of dividends on the Series 1, Series 2 or Series 3 Preferred Shares are in arrears, the Partnership will not make any distributions on the Units. The market value of the Units may decline if the Partnership is unable to meet its cash distribution targets in the future, and that decline may be significant.

Structural subordination risk

The right of the Partnership, as a shareholder of any of its subsidiaries, to realize on the assets of a subsidiary in the event of the bankruptcy or insolvency of the subsidiary would be subordinate to the rights of unsubordinated creditors of such subsidiary, holders of unsubordinated preferred shares of such subsidiary, including the Series 1, Series 2 and Series 3 Preferred Shares, and claimants preferred by statute.

Limited liability risk

A unitholder may lose the protection of limited liability if it takes part in the management or control of the business of the Partnership or does not comply with applicable legislation governing limited partnerships.

There is no assurance that risk management steps taken will avoid future loss due to the occurrence of the above described or unforeseen risks.

OUTLOOK

The long-term outlook for the Partnership has not changed substantially from prior reporting periods. Our assets and contracts are expected to provide long-term stable cash flows. While the date of Canadian SIFT taxes nears, the Partnership does not expect to make any material cash income tax payments until 2015 or 2016 in both Canada and the US, due to tax attributes consisting primarily of tax losses and undepreciated capital cost pools available to the Partnership to deduct against future taxable income.

The Partnership expects cash provided by operating activities before working capital changes will be lower in 2010 compared to 2009, however the Partnership's longer-term outlook indicates the current distribution of $1.76 can be comfortably maintained until at least the end of 2014 based on existing cash flows regardless of whether the Partnership remains a partnership or converts to a corporation. The major items that are expected to give rise to the decline in cash provided by operating activities from 2009 to 2010 are:

- Ontario Plant operating margin. Lower waste heat margins and higher natural gas transportation costs will be partially offset by power price escalations and higher enhancement and diversion contribution;
- Williams Lake operating margin. Lower excess energy prices at Williams Lake;
- Higher financing costs with issuance of preferred shares in November 2009; and
- Lower contracted prices on foreign exchange contracts that will settle in 2010 versus 2009;

Partially offsetting these decreases, the Partnership expects higher dispatch at the North Carolina plants and renewal of their PPA's with economic terms.

The Partnership expects maintenance capital expenditures in 2010 to be $2 million to $4 million higher than in 2009.

In 2009, the North Carolina facilities experienced dispatch at minimal levels, which is a direct result of low natural gas prices. These facilities are fuelled by wood waste, tire-derived fuel and coal. 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 a recovery of natural gas prices and outages at other plants in the region in early 2010, the dispatch of the North Carolina facilities has improved.

The PPAs for the North Carolina facilities expired on December 31, 2009. The Partnership and Progress have been in negotiations but, to date, have been unable to finalize new PPAs that are acceptable to both parties. The Partnership filed for arbitration with the NCUC and is seeking long-term PPAs with pricing terms consistent with Progress's actual avoided costs. The Partnership expects that a decision is likely to be made late in the second quarter or early in the third quarter of 2010. The NCUC has ordered that Progress continue to pay for the output of the Roxboro and Southport facilities pursuant to the terms of the PPAs that expired December 31, 2009 until the arbitration is finalized and NCUC issued a confirmation order for rate purposes. By regulation, Progress is required to offer contracts to any certified QF at Progress' avoided cost. The North Carolina plants are currently certified as QFs.

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 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 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.

The Partnership expects Equistar will emerge from Chapter 11 proceedings in 2010 with no impact to the operations of the Morris facility.

Despite the economic downturn in 2009, the Partnership was successful on several fronts including the amendments to the PPA at Tunis to mitigate a natural gas price exposure, working with BC Hydro to optimize available wood supplies at Williams Lake, completing a $100 million preferred share offering, launching a Premium Distribution and Distribution Reinvestment Plan, completing the enhancement project at Roxboro and the upgrade at North Island, and completing the sale of Castleton. As the Partnership moves forward into 2010, the tenuous economic recovery at the end of 2009 is expected to continue and ongoing environmental legislation and regulatory changes are expected to create some level of uncertainty in the near term. While the Partnership recognizes that these issues will create challenges, the Partnership is confident that its conservative financial profile and strong operating and commercial expertise have it well positioned to be successful in the long-term.

QUARTERLY INFORMATION

Selected Quarterly and Annual Consolidated Financial Data

	2009				
Three months ended	**Mar. 31**	**Jun. 30**	**Sep. 30**	**Dec. 31**	**Total**
(millions of dollars except unit and per unit amounts)					
Revenues					
Ontario Plants	43.7	32.5	29.0	40.2	145.4
Williams Lake	11.0	10.1	10.8	11.0	42.9
Mamquam and Moresby Lake	2.5	5.5	2.9	4.8	15.7
Northwest US Plants	15.7	16.4	15.6	15.4	63.1
California Plants	21.8	24.7	29.4	21.1	97.0
Curtis Palmer	10.2	13.0	6.9	12.0	42.1
Northeast US Gas Plants (2)	27.5	21.4	21.0	20.7	90.6
North Carolina Plants	10.5	6.7	6.2	3.9	27.3
PERC management fees	0.9	1.0	1.0	0.7	3.6
Fair value changes on foreign exchange contracts	(16.2)	33.9	32.7	8.4	58.8
	127.6	165.2	155.5	138.2	586.5
Operating Margin (1)					
Ontario Plants	19.8	9.7	7.2	16.0	52.7
Williams Lake	6.9	5.8	8.4	6.7	27.8
Mamquam and Moresby Lake	1.5	4.4	1.6	3.6	11.1
Northwest US Plants	8.9	9.3	9.0	9.5	36.7
California Plants	1.5	9.5	15.8	3.0	29.8
Curtis Palmer	8.7	11.6	5.4	10.6	36.3
Northeast US Gas Plants (2)	3.9	4.7	6.3	3.5	18.4
North Carolina Plants	(2.3)	(3.2)	(0.9)	(3.6)	(10.0)
PERC management fees	0.6	0.7	0.6	0.6	2.5
Fair value changes on foreign exchange contracts	(16.2)	33.9	32.7	8.4	58.8
Fair value changes on natural gas supply contracts	(34.1)	1.3	(20.2)	0.6	(52.4)
	(0.8)	87.7	65.9	58.9	211.7
Other costs					
Depreciation, amortization and accretion	23.8	23.3	22.9	23.3	93.3
Management and administration	4.3	2.9	3.7	4.3	15.2
Financial charges and other, net	10.9	10.5	10.2	10.7	42.3
Foreign exchange losses	0.5	0.1	0.1	0.3	1.0
Equity losses from the PERH investment	1.7	0.6	0.8	-	3.1
	41.2	37.4	37.7	38.6	154.9
Net income (loss) from continuing operations before income tax and preferred share dividends	(42.0)	50.3	28.2	20.3	56.8
Income tax expense (recovery)	(11.0)	6.3	(4.2)	-	(8.9)
Preferred share dividends of a subsidiary company	1.6	1.7	1.7	2.9	7.9
Net income (loss) from continuing operations	(32.6)	42.3	30.7	17.4	57.8
Per unit	($0.60)	$0.78	$0.57	$0.32	$1.07
Net income (loss)	(33.3)	42.8	30.7	17.4	57.6
Per unit	($0.62)	$0.79	$0.57	$0.32	$1.07
Cash provided by operating activities of continuing operations	33.7	33.1	33.8	39.1	139.7
Per unit (1)	$0.63	$0.61	$0.63	$0.72	$2.59
Distributions	34.0	23.7	23.7	23.8	105.2
Per unit	$0.63	$0.44	$0.44	$0.44	$1.95
Capital Expenditures	17.0	25.9	33.0	30.0	105.9
Weighted Average Units Outstanding (millions)	53.9	53.9	53.9	54.0	53.9

(1) The selected quarterly and annual consolidated financial data has been prepared in accordance with Canadian generally accepted accounting principles except for operating margin and cash provided by operating activities per unit. See Non-GAAP Measures.

(2) Restated to reflect the operations of Castleton as discontinued operations. Castleton sold in May 2009.

Selected Quarterly and Annual Consolidated Financial Data

	2008				
Three months ended	Mar. 31	Jun. 30	Sep. 30	Dec. 31	Total
(millions of dollars except unit and per unit amounts)					
Revenues					
Ontario Plants	43.2	38.7	37.7	42.3	161.9
Williams Lake	10.9	7.2	10.7	9.4	38.2
BC Hydro Plants	2.5	5.6	4.1	4.5	16.7
Northwest US Plants	14.9	14.1	16.1	17.0	62.1
California Plants	29.8	41.3	45.6	28.6	145.3
Curtis Palmer	10.7	8.4	5.6	9.7	34.4
Northeast US Gas Plants [2]	7.7	6.8	6.6	24.3	45.4
North Carolina Plants	12.9	15.0	20.8	11.2	59.9
PERC management fees	0.8	0.9	0.9	0.9	3.5
Fair value changes on foreign exchange contracts	(15.3)	5.9	(14.6)	(44.1)	(68.1)
	118.1	143.9	133.5	103.8	499.3
Operating Margin [1]					
Ontario Plants	21.5	12.2	17.5	18.3	69.5
Williams Lake	8.4	2.7	7.7	6.4	25.2
BC Hydro Plants	1.3	4.4	3.1	3.2	12.0
Northwest US Plants	8.7	8.4	4.8	10.1	32.0
California Plants	3.0	9.7	16.5	3.0	32.2
Curtis Palmer	9.5	7.1	4.6	8.1	29.3
Northeast US Gas Plants [2]	0.8	0.9	0.4	3.9	6.0
North Carolina Plants	0.7	0.4	1.5	(1.4)	1.2
PERC management fees	0.6	0.6	0.6	0.7	2.5
Fair value changes on foreign exchange contracts	(15.3)	5.9	(14.6)	(44.1)	(68.1)
Fair value changes on natural gas supply contracts	67.6	102.8	(160.5)	(40.3)	(30.4)
	106.8	155.1	(118.4)	(32.1)	111.4
Other costs					
Depreciation, amortization and accretion	22.1	21.7	22.8	21.7	88.3
Management and administration	3.5	5.0	4.7	7.0	20.2
Financial charges and other, net	9.1	9.1	9.2	10.8	38.2
Foreign exchange losses (gains)	13.2	(2.7)	15.9	(0.2)	26.2
Equity losses from the PERH investment	1.7	0.4	1.7	2.5	6.3
Asset impairment charge	-	-	-	24.1	24.1
	49.6	33.5	54.3	65.9	203.3
Net income (loss) from continuing operations before income tax and preferred share dividends	57.2	121.6	(172.7)	(98.0)	(91.9)
Income tax expense (recovery)	2.3	14.8	(22.1)	(26.4)	(31.4)
Preferred share dividends of a subsidiary company	1.6	1.7	1.6	1.7	6.6
Net income (loss) from continuing operations	53.3	105.1	(152.2)	(73.3)	(67.1)
Per unit	$0.99	$1.95	($2.82)	($1.36)	($1.24)
Net income (loss)	53.4	104.9	(153.0)	(73.1)	(67.8)
Per unit	$0.99	$1.95	($2.84)	($1.36)	($1.26)
Cash provided by operating activities of continuing operations	41.6	39.4	20.0	56.5	157.5
Per unit [1]	$0.77	$0.73	$0.37	$1.05	$2.92
Cash Distributions	34.0	33.9	34.0	33.9	135.8
Per unit	$0.63	$0.63	$0.63	$0.63	$2.52
Capital Expenditures	3.4	10.0	5.1	21.5	40.0
Weighted Average Units Outstanding (millions)	53.9	53.9	53.9	53.9	53.9

(1) The selected quarterly and annual consolidated financial data has been prepared in accordance with Canadian generally accepted accounting principles except for operating margin and cash provided by operating activities per unit. 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. Castleton sold in May 2009.

Operating Margin[1] and Plant Output

	Three months ended December 31				Year ended December 31			
(millions of dollars except GWh)	**GWh**	**2009**	GWh	2008	**GWh**	**2009**	GWh	2008
Ontario Plants	**352**	**16.0**	375	18.3	**1,330**	**52.7**	1,263	69.5
Williams Lake	**146**	**6.7**	145	6.4	**362**	**27.8**	499	25.2
BC Hydro Plants	**70**	**3.6**	63	3.2	**232**	**11.1**	245	12.0
Northwest US Plants	**293**	**9.5**	261	10.1	**990**	**36.7**	872	32.0
California Plants	**274**	**3.0**	268	3.0	**971**	**29.8**	941	32.2
Curtis Palmer	**108**	**10.6**	85	8.1	**356**	**36.3**	328	29.3
Northeast US Gas Plants [2]	**158**	**3.5**	125	3.9	**657**	**18.4**	253	6.0
North Carolina Plants	**4**	**(3.6)**	62	(1.4)	**65**	**(10.0)**	554	1.2
PERC management fees	**-**	**0.6**	-	0.7	**-**	**2.5**	-	2.5
Fair value changes	**-**	**9.0**	-	(84.4)	**-**	**6.4**	-	(98.5)
	1,405	**58.9**	1,384	(32.1)	**4,963**	**211.7**	4,955	111.4

Weighted Average Plant Availability [1]

	Three months ended December 31		Year ended December 31	
	2009	2008	**2009**	2008
Ontario Plants	**96%**	98%	**93%**	97%
Williams Lake	**100%**	99%	**98%**	90%
BC Hydro Plants	**87%**	97%	**86%**	87%
Northwest US Plants	**96%**	98%	**97%**	95%
California Plants	**99%**	88%	**93%**	91%
Curtis Palmer	**100%**	86%	**94%**	86%
Northeast US Gas Plants [2]	**99%**	100%	**99%**	98%
North Carolina Plants	**56%**	73%	**69%**	92%
Weighted Average Total	**92%**	94%	**92%**	93%

(1) Operating margin is a non-GAAP financial measure. See Non-GAAP Measures.

(2) 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.

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

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 to the end of the third quarter of 2008 is also affected by unrealized foreign exchange gains and losses primarily on the Partnership's US dollar-denominated long-term debt. 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. In addition, net income is affected by 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. Under the power sales contracts for the Ontario plants, the

Partnership receives higher per MWh prices in the winter months (October to March) and lower prices in the summer months (April to September). The lower summer prices reduce the threshold for economic curtailments thereby increasing the profitability of enhancements, natural gas prices being equal. Contributions from 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. 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. 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 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 first and second quarters of 2008 and the second and fourth quarters 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, third and fourth quarters of 2009. Losses were recorded 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.

Factors impacting the fourth quarter financial results

The Partnership reported cash provided by operating activities of continuing operations of $39.1 million or $0.72 per unit for the three months ended December 31, 2009 compared to $56.5 million or $1.05 per unit for the same period in 2008. Cash provided by operating activities per unit is defined above under Non-GAAP Measures. The $17.4 million decrease in cash provided by operating activities of continuing operations for the three months ended December 31, 2009 compared to the same period in 2008 is primarily due to the following:

- A decrease in working capital of $3.8 million in 2009 compared to $22.0 million in 2008. Working capital decreased in 2009 and 2008 primarily due to the timing of payments and receipts;
- Operating margin was $2.2 million lower at the Ontario plants primarily due to lower revenues from waste heat;

- Operating margin was $2.2 million lower at the North Carolina plants due to lower generation due to lower natural gas prices resulting in increased competition from natural gas plants in the region; and
- Higher preferred share dividends of $1.2 million as a result of issuing new preferred shares in November 2009.

Decreases were partially offset by the following:

- An increase of $6.0 million in the cash flow from Morris, which was acquired on October 31, 2008. The contribution of Morris in 2008 includes a provision of $2.4 million against amounts receivable from Equistar (see Business Risks – Counterparty Credit Risk); and
- Operating margin was $2.5 million higher at Curtis Palmer due to a step-up in pricing under the PPA of 18% in December 2008 and higher generation due to higher water flows.

Revenue for the three month period ended December 31, 2009 was $138.3 million compared to $103.8 for the same period in 2008. The increase was primarily due to net gains on the change in the fair value of foreign exchange contracts in 2009 compared to losses in 2008. Offsetting these net gains were lower electricity prices at the California plants driven by lower natural gas prices and lower dispatch at the North Carolina plants.

The Partnership reported net income from continuing operations of $16.7 million or $0.31 per unit for the three months ended December 31, 2009 compared to net loss from continuing operations of $73.3 million or $1.36 per unit for the same period in 2008. Net income from continuing operations increased by $90.0 million primarily due to net fair value gains of $9.0 million on foreign exchange and natural gas contracts in the three months ended December 31, 2009 compared to net fair value losses of $84.4 million in the same period in 2008. Also contributing to the increase was an impairment charge of $24.1 million in the three months ended December 31, 2008 on the investment in the common shares of PERH. These increases are partially offset by an increase in income tax expense of $27.1 million for the three months ended December 31, 2009 compared to the same period in 2008 primarily 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.

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 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 the anticipated total cost of the Southport and Roxboro enhancement project, (iii) expected improved plant efficiency, operation and financial performance at North Island, (iv) planned capital upgrades at Oxnard including the anticipated cost and timing, (v) expectations regarding the Partnership's cash provided by operating activities, capital expenditures, working capital and distributions relative to its net income in 2010, (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) expectations regarding the time at which the Partnership will be taxable and the impact of SIFT taxes and changes to withholding obligations, (viii) expectations regarding lower operating margins at Williams Lake and the

Ontario plants, (ix) expectations relating to the emergence of Equistar from Chapter 11 proceedings (x) expectations on the throughput on the TransCanada Canadian Mainline and related expectations regarding lower waste heat availability at the Ontario facilities and increased natural gas transportation costs, (xi) expectations regarding the financing of the Partnership's capital expenditures, (xii) expectations with regard to dispatch at the North Carolina facilities, (xiii) expectations in respect of new PPA's for the North Carolina facilities and the Partnership's long-term outlook for the North Carolina plants, (xiv) anticipated completion of the Southport facility modifications and the impact of the Southport and Roxboro facility modifications on the operation and economic performance of the facilities and their emissions, (xv) expected maintenance capital spending of $22 million to $24 million in 2010 and expectations that over a five year planning cycle maintenance capital expenditures will average $20 million to $22 million annually for the Partnership's existing facilities, (xvi) expectations regarding the introduction of new emissions regulation and the costs to comply with, and other impacts of, current and anticipated emissions regulation, (xvii) the expected impact of transition to IFRS and expected project review completion dates, and (xviii) expectations regarding the Partnership's strategic plan including in respect of expansions, enhancements and acquisitions.

These statements are based on certain assumptions and analysis 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, but are not limited to: (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) that current expectations regarding throughput on the TransCanada Canadian Mainline will continue, (ix) the level of plant availability and dispatch, (x) the performance of contractors and suppliers, (xi) the renewal or replacement and terms of PPAs including the terms and timing of new PPAs at the North Carolina facilities, (xii) the ability of the Partnership to successfully realize the benefits of its capital projects, (xiii) the ability of the Partnership to implement its strategic initiatives and whether such initiatives will yield the expected benefits, (xiv) expected water flows, (xv) management's analysis of the Equistar reorganization under Chapter 11 of the US Bankruptcy Code, (xvi) the ability of the Partnership to adequately source alterative sources of supply of wood waste, and (xvii) factors and assumptions noted under Outlook in respect of the forward looking statements and information noted in that section.

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) changing demand for natural gas transportation on the TransCanada Canadian Mainline, (viii) ongoing compliance by the Partnership with its current debt covenants, (ix) developments within the North American capital markets, (x) the availability and cost of permanent long term financing in respect of acquisitions and investments, (xi) unanticipated maintenance and other expenditures, (xii) the Partnership's ability to successfully realize the benefits of its capital projects, (xiii) changes in regulatory and government decisions including changes to emission regulations, (xiv) waste heat availability and water flows, (xv) changes in existing and proposed tax and other legislation in Canada and the US and including changes in the Canada-US tax treaty, (xvi) the tax attributes of and implications of any acquisitions, and (xvii) the availability and cost of equipment. See Business Risks in this MD&A and Risk Factors in the Partnership's Annual Information Form for its year ended December 31, 2009 filed on SEDAR.

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 CPA.UN.

			2009		
Three months ended (unaudited)	**Mar. 31**	**Jun. 30**	**Sep. 30**	**Dec. 31**	**Annual**
Unit Price					
High	**$18.98**	**$16.21**	**$16.30**	**$15.77**	**$18.98**
Low	**$12.90**	**$11.65**	**$13.62**	**$13.35**	**$11.65**
Close	**$13.80**	**$15.25**	**$15.26**	**$15.48**	**$15.48**
Volume traded (millions)	**3.3**	**9.2**	**4.3**	**6.2**	**23.0**

			2008		
Three months ended (unaudited)	Mar. 31	Jun. 30	Sep. 30	Dec. 31	Annual
Unit Price					
High	$23.78	$24.70	$23.50	$20.65	$24.70
Low	$19.65	$21.52	$19.83	$15.50	$15.50
Close	$21.90	$22.41	$20.32	$17.72	$17.72
Volume traded (millions)	4.8	4.5	3.6	5.1	18.0

As at March 4, 2010, the Partnership had 54.3 million units outstanding. The weighted average number of units outstanding for the year ended December 31, 2009 was 53.9 million consistent with 2008.

ADDITIONAL INFORMATION

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