Capital Power Corporation
5th Floor, TD Tower, 10088 - 102 Avenue
Edmonton, AB T5J 2Z1

For immediate release August 3, 2010

Capital Power reports second quarter 2010 results

EDMONTON, Alberta – Capital Power Corporation ("Capital Power", or the "Company") (TSX: CPX) today released its financial results for the three and six month periods ended June 30, 2010. Normalized net income, after adjusting for one-time items and fair value adjustments, was $1 million or $0.05 per share in the second quarter of 2010. For the six month period ending June 30, 2010, normalized net income was $13 million or $0.60 per share.

"The Company's performance in the second quarter of 2010 was below management's expectations," said Brian Vaasjo, President and Chief Executive Officer of Capital Power Corporation. "This was primarily attributable to two factors that were specific to the period. First, we experienced a greater-than-expected impact from the 21-day planned outage at our Genesee 2 facility; although we anticipated availability penalties from the planned outage, the penalties were higher-than-expected. This was due to high Alberta pool prices during the outage resulting partially from generation curtailments at all three units at Genesee to accommodate transmission system upgrades and from other plant outages in the province. Second, the commodity optimization strategies that led to strong earnings in the first quarter of 2010 moved against us in the second quarter, resulting in weak results from our commodity portfolio management area. In addition to these two factors the $0.37 loss per share in the quarter is primarily due to $58 million in fair value changes which are not indicative of economic performance. While these quarterly results were below expectations, our performance in the first half of the year is tracking close to our plan and our outlook for the year is unchanged from earlier guidance."

Operational and Financial Highlights(1) (unaudited) *(millions of dollars except per share and operational amounts)*	**Three months ended June 30, 2010**	**Six months ended June 30, 2010**
Electricity generation (GWh)	3,187	6,717
Generation plant availability (%)	86%	90%
Revenues	$313	$812
Gross margin(2)	$120	$336
Operating margin(2)	$55	$222
Normalized net income (loss)(2)	$1	$13
Normalized earnings per share(2)	$0.05	$0.60
Net income (loss)	$(8)	$5
Earnings (loss) per share	$(0.37)	$0.23
Dividends declared per share	$0.315	$0.63
Funds from operations(2)	$53	$165
Funds from operations excluding non-controlling interests in CPILP(2)	$34	$121
Capital expenditures	$133	$211

(1) The operational and financial highlights in this press release should be read in conjunction with Management's Discussion and Analysis and the Consolidated Financial Statements for the six months ended June 30, 2010.
(2) Gross margin, Operating margin, Normalized net income, Normalized earnings per share, Funds from operations, and Funds from operations excluding non-controlling interests in CPILP are non-GAAP financial measures and do not have standardized meanings under Canadian GAAP, and therefore, may not be comparable to similar measures used by other enterprises. Reconciliations of these non-GAAP financial measures to net income are included in the Company's Management's Discussion and Analysis dated August 2, 2010.

Corporate Updates

Canadian Federal Government Greenhouse Gas Regulation for Coal-Fired Generation

On June 23, 2010, the Canadian Environment Minister announced the Government of Canada's plan for new greenhouse gas (GHG) emission regulation for coal-fired electricity generation units. The proposed plan will apply a new GHG emissions performance standard to new coal-fired electricity generation units and those coal-fired units that have reached the end of their economic life. The purpose of the regulation is to ensure that conventional coal-fired electricity generation is phased out in an orderly manner and replaced with lower GHG emission power generation.

Very limited details are available but it is expected that the economic life will be set at 45 years with some exceptions to avoid stranding recent investments in older facilities. New performance standards will likely be similar to a natural gas combined cycle unit. Existing facilities that will be exempt from the regulation until they reach the end of their economic useful life are expected to be those that have commercial operation dates prior to January 1, 2012. Clarity regarding the draft regulations will be provided when they are published in the Canada Gazette which is expected to occur in early 2011, with final regulations expected later that year. Because the proposed regulations allow coal-fired generation assets to operate for their economic life and no additional charges for GHG emissions are anticipated, the regulations provide some certainty and are expected to be favourable to Capital Power's Genesee units and Keephills 3.

It is not clear whether the proposed federal GHG emission regulations will replace the Alberta Specified Gas Emitters Regulations (SGER). The current SGER will expire in 2014. If this date is extended then the Company's Alberta facilities may face continued charges under the SGER, which have historically been approximately $5 million per year. Currently there is insufficient information to reasonably predict what action the Alberta Government will take in respect of the SGER.

Wind Projects Update

On April 8, 2010, the Ontario Power Authority (OPA) selected the Company's Port Dover & Nanticoke Wind development project for the award of a contract through the OPA's Feed-in-Tariff (FIT) program. The 105-MW project is being proposed in an area in southern Ontario where the Company has optioned lands totaling over 8,900 acres. The project has an expected cost of up to $340 million and is anticipated to enter commercial operation in the fourth quarter of 2012. The contract to sell power has since been signed and under the terms of the OPA's FIT program, the contracted price for power at commercial operation of the project will be $135 per MWh escalated by inflation between the contract signing date and commercial operation date. Thereafter, 20 per cent of the contract price will escalate annually at inflation throughout the 20-year contract term. Construction of the Port Dover and Nanticoke Wind project is subject to regulatory approvals, including Ontario's Renewable Energy Approval process which is currently in progress for the project.

The Company has selected Vestas (NASDAQ OMX Copenhagen:VWS) for the supply and maintenance of wind turbines for this project, as well as for the proposed Quality Wind project in northeastern B.C. and the Kingsbridge II project in Ontario. The Quality Wind energy purchase agreement with BC Hydro was signed in April 2010 and the Environmental Assessment Certificate for the project was received from the Government of British Columbia in July 2010. Development of the Kingsbridge II project remains subject to approval under the OPA's FIT program.

Acquisition of Island Generation Facility

On August 2, 2010, Capital Power LP (CPLP) entered into an agreement to acquire the Island Generation Facility (Island Generation), a 275 MW gas-fired combined cycle power plant at Campbell River, British Columbia. The transaction is expected to close in the fourth quarter of 2010, subject to regulatory and other approvals. The purchase and sale agreement for the transaction is between CPLP and Kelson Canada Inc. Subject to market conditions, the Company expects to finance the purchase price of approximately $207 million, plus closing costs and normal working capital adjustments, with a combination of debt and equity.

Island Generation is fully contracted from April 1, 2010 to April 2022 under a tolling arrangement with BC Hydro. BC Hydro will be responsible for the fuel supply to the facility. Commissioned in 2002, Island Generation is consistent with Capital Power's fleet of young assets that deploy efficient technologies.

Forward-looking Information

Certain information in this news release is forward-looking within the meaning of Canadian securities laws as it relates to anticipated financial performance, events or strategies. When used in this context, words such as will, anticipate, believe, plan, intend, target, and expect or similar words suggest future outcomes. Forward-looking information in this news release includes, among other things, information relating to: (i) expected timing of commercial operation and expected project costs of the Port Dover & Nanticoke Wind project; (ii) expected contracted price for power under the OPA's FIT program for the Port Dover & Nanticoke Wind project; (iii) expectations regarding the impact on Capital Power of the plan for a new GHG emission regulation as announced by the Canadian Environment Minister in June 2010 and expectations with respect to additional charges for GHG emissions; (iv) expectations regarding the economic life of, and new performance standards for, coal-fired electricity generation units pursuant to the proposed new GHG regulation, and regarding the applicability of exemptions from the proposed new GHG regulation and the GHG requirement being brought into force; (v) expectations regarding the timing of the draft and final GHG regulations; (vi) impact of proposed federal GHG emission regulations on SGER and consequential impact on the Company's Alberta facilities; (vii) expectations regarding the expiry or extension of SGER; (viii) the expected closing date, purchase price and financing of the acquisition of the Island Generation Facility; and (ix) expectations regarding BC Hydro's responsibility for the fuel supply to the Island Generation Facility.

The statements contained in this news release are based on certain assumptions and analyses made by the Company 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 location of the projects and the sites on which it will be developed; (ii) costs of construction and development; (iii) the Company's financial position, credit facilities and sources of funding; (iv) the Company's assessment of commodity and power markets; (v) the Company's assessment of the markets and regulatory environments in which it operates; (vi) the Company's assessment of economic conditions; (vii) weather; (viii) availability and cost of labour and management resources; (ix) performance of contractors and suppliers; (x) availability and cost of financing; (xi) foreign exchange rates; (xii) management's analysis of applicable tax legislation; (xiii) the currently applicable and proposed tax laws will not change and will be implemented; (xiv) currently applicable and proposed environmental regulations will be implemented; (xv) counterparties will perform their obligations; (xvi) ability to successfully integrate and realize benefits of any acquisitions; (xvii) ability to implement strategic initiatives which will yield the expected benefits and results; (xviii) the Company's assessment of capital markets and ability to complete future share offerings; and (xix) the award of FIT contracts.

Whether actual results, performance or achievements will conform to the Company's expectations and predictions is subject to a number of known and unknown risks and uncertainties which could cause actual results and experience to differ materially from the Company's expectations. Such risks and uncertainties include, but are not limited to risks relating to: (i) operation of the Company's facilities; (ii) power plant availability and performance; (iii) unanticipated maintenance and other expenditures; (iv) availability and price of energy commodities; (v) electricity load settlement; (vi) regulatory and government decisions including changes to environmental, financial reporting and tax legislation; (vii) weather and economic conditions; (viii) competitive pressures; (ix) construction; (x) availability and cost of financing; (xi) foreign exchange; (xii) availability and cost of labour, equipment and management resources; (xiii) performance of counterparties, partners, contractors and suppliers in fulfilling their obligations to the Company; (xiv) developments in the North American capital markets; (xv) compliance with financial covenants; (xvi) ability to successfully realize the benefits of acquisitions and investments; and (xvii) the tax attributes of and implications of any acquisitions. If any such risks actually occur, they could materially adversely affect the Company's business, financial condition or results of operations. In that case the trading price of the Company's common shares could decline, perhaps materially.

Readers are cautioned not to place undue reliance on any such forward-looking statements, which speak only as of the date made. Forward-looking statements are provided for the purpose of providing information about management's current expectations, and plans relating to the future. Readers are cautioned that such information may not be appropriate for other purposes. The Company does not undertake or accept any obligation or undertaking to release publicly any updates or revisions to any forward-looking statements to reflect any change in the Company's expectations or any change in events, conditions or circumstances on which any such statement is based, except as required by law.

Analyst Conference Call and Webcast

Capital Power will be hosting a conference call and live webcast with analysts on August 3, 2010 at 1:00 pm (ET) to discuss second quarter results and the acquisition of the Island Generation Facility. The conference call dial-in numbers are:

(403) 532-8075 (Calgary)
(604) 681-0262 (Vancouver)
(647) 837-0597 (Toronto)
(877) 353-9586 (toll-free from Canada and USA)

Participant access code for the call: 95843#

A replay of the conference call will be available following the call at: (877) 353-9587 (toll-free) and entering pass code 370647. The replay will be available until midnight on August 10, 2010.

Interested parties may also access the live webcast on the Company's website at www.capitalpower.com with an archive of the webcast available following the conference call.

About Capital Power

Capital Power is a growth-oriented North American independent power producer, building on more than a century of innovation and reliable performance. The Company's vision is to be recognized as one of North America's most respected, reliable and competitive power generators. Headquartered in Edmonton, Alberta, Capital Power has interests in 31 facilities in Canada and the U.S. totaling approximately 3,500 megawatts of generation capacity. Capital Power and its subsidiaries develop, acquire and optimize power generation from a wide range of energy sources.

For more information, please contact:

Media Relations:
Colleen Wilson
(780) 392-5022
cwilson@capitalpower.com

Investor Relations:
Randy Mah
(780) 392-5305 or (866) 896-4636 (toll-free)
investor@capitalpower.com

CAPITAL POWER CORPORATION
Interim Report
June 30, 2010

Management's Discussion and Analysis

This management's discussion and analysis (MD&A), dated August 2, 2010, should be read in conjunction with the unaudited interim consolidated financial statements of Capital Power Corporation (the Company) and its subsidiaries for the six months ended June 30, 2010, the audited consolidated financial statements and MD&A of the Company for the six months ended December 31, 2009 and the cautionary statement regarding forward-looking information which begins on page 27. In this MD&A, any reference to the Company or Capital Power, except where otherwise noted or the context otherwise indicates, means Capital Power Corporation, together with its subsidiaries. In this MD&A, financial information for the three and six months ended June 30, 2010 is based on the unaudited interim consolidated financial statements of the Company, which were prepared in accordance with Canadian generally accepted accounting principles (GAAP), and are presented in Canadian dollars unless otherwise specified. In accordance with its terms of reference, the Audit Committee of the Company's Board of Directors reviews the contents of the MD&A and recommends its approval by the Board of Directors. The Board of Directors has approved this MD&A.

On July 9, 2009, the Company completed its initial public offering (IPO) and acquisition of power generation assets and operations (the Reorganization) from EPCOR Utilities Inc. (EPCOR). The Company commenced operations in July 2009 and its first fiscal year ended on December 31, 2009. Accordingly, the Company's unaudited financial statements for the six months ended June 30, 2010 do not include prior year comparative information. To facilitate the analysis of the Company's unaudited financial statements this MD&A includes unaudited pro forma consolidated financial information for the three and six months ended June 30, 2009. As the comparative periods predate the closing of the IPO, this comparative financial information is provided for reference purposes only and is not intended to be a comprehensive comparison of financial results.

The Company's outstanding share capital on June 30, 2010 consisted of 21.767 million common shares, 56.625 million special voting shares and one special limited voting share.

The Business

The Company's power generation operations and assets are owned by Capital Power LP (CPLP), a subsidiary of the Company. At June 30, 2010, the Company held approximately 21.75 million general partnership units and one common limited partnership unit of CPLP which represented approximately 27.8% and zero %, respectively, of CPLP, and EPCOR held 56.625 million exchangeable limited partnership units of CPLP (exchangeable for common shares of Capital Power on a one-for-one basis) representing approximately 72.2% of CPLP. The general partner of CPLP is wholly-owned by Capital Power and EPCOR's representation on the Board of Directors does not represent a controlling vote. Accordingly, Capital Power controls CPLP and the operations of CPLP have been consolidated for financial statement purposes.

The assets used in the operating business of the Company are primarily held through CPLP and its subsidiary entities. The interests held by the Company outside CPLP are not material to the Company's consolidated operations, assets, liabilities and operating business or the Company's consolidated financial statements and are primarily a consequence of the Company's organizational structure. The primary assets and liabilities of the Company that are held outside of CPLP are:

- The Company's indirect interest in the general partners of the Canadian limited partnerships through which CPLP's Canadian power generation facilities are held, representing an equity interest of 1% or less in each of these partnerships;
- The Company's indirect interest in a subsidiary entity (CP Regional Power Services Limited Partnership) that provides management and administrative services to Capital Power Income L.P. (CPILP) and the Company's Canadian limited partnerships, under various management and operation agreements;

- Future income tax assets and liabilities resulting primarily from the Company's interest in CPLP which, as a limited partnership is not a taxable entity; and

- Certain natural gas customer contracts for which a non-current liability has been recorded on the consolidated balance sheet to reflect the estimated loss in fair value of the contracts which arose at the time of acquisition of these contracts from EPCOR.

These items did not have a material impact on the Company's consolidated revenues, income from continuing operations, or income before income tax expense and non-controlling interests for the six months ended June 30, 2010 or on the Company's consolidated total assets or total liabilities as at June 30, 2010. CPLP's consolidated revenues, income from continuing operations, income before income tax expense and non-controlling interests for the six months ended June 30, 2010, and consolidated total assets and total liabilities as at June 30, 2010 represent 97% or more of the corresponding consolidated items of the Company.

Financial Highlights

(unaudited, $millions, except earnings (loss) per share)	Three months ended		Six months ended	
	June 30, 2010	June 30, 2009(2)	June 30, 2010	June 30, 2009(2)
Revenues	$ 313	$ 497	$ 812	$ 1,150
Gross margin(1)	120	250	336	449
Operating margin(1)	55	187	222	332
Net income (loss)	(8)	11	5	30
Earnings (loss) per share(4)	$ (0.37)	N/A	$ 0.23	N/A
Fully diluted earnings (loss) per share(3)(4)	$ (0.37)	N/A	$ 0.23	N/A
Normalized earnings per share(1)(4)	$ 0.05	N/A	$ 0.60	N/A
Funds from operations(1)(4)	53	N/A	165	N/A
Capital expenditures(4)	133	N/A	211	N/A
Long-term debt including current portion(4)	1,808	N/A	1,808	N/A
Total assets(4)	5,015	N/A	5,015	N/A

(1) The consolidated financial information, except for gross margin, operating margin, normalized earnings per share and funds from operations has been prepared in accordance with Canadian GAAP. See Non-GAAP Financial Measures.

(2) Financial highlights for the three and six months ended June 30, 2009 are unaudited pro forma consolidated financial information included in the Pro forma Consolidated Financial Information section.

(3) Fully diluted earnings (loss) per share is calculated after giving effect to the exchange of limited partnership units of CPLP (exchangeable for common shares of Capital Power on a one-for-one basis) held by EPCOR.

(4) Certain financial highlights are not applicable (N/A) for the three and six months ended June 30, 2009 as the unaudited pro forma financial information does not include a balance sheet, a statement of cash flows or earnings per share.

Funds from Operations

(unaudited, $millions)	Three months ended			
	June 30, 2010	March 31, 2010	Dec 31, 2009	Sept 30, 2009
Funds from operations excluding non-controlling interests in CPILP(1)	$ 34	$ 87	$ 49	$ 70
Funds from operations(1)	53	112	71	93

(1) Funds from operations and funds from operations excluding non-controlling interests in CPILP are non-GAAP measures. See Non-GAAP Financial Measures.

Funds from operations are cash provided by operating activities excluding changes in working capital. Funds from operations excluding non-controlling interests in CPILP were $53 million lower for the second quarter of 2010 compared with the first quarter of 2010. The decrease was primarily due to lower operating margin, excluding unrealized fair value changes, from the Alberta contracted plants. There was a scheduled outage at Genesee 2 in the second quarter of 2010 compared with no outages at the Alberta contracted plants in the first quarter of 2010. Accordingly, availability penalties and maintenance costs reduced funds from operations in the second quarter. In addition, operating margin, excluding unrealized fair value changes, from the Alberta commercial plants and portfolio was lower due to the impact of Alberta power prices on the merchant portfolio. The operating margin from other portfolio activities, excluding unrealized fair value changes, was also lower primarily due to lower margins from natural gas trading activities.

Funds from operations include CPILP's funds from operations, which decreased in the second quarter from the first quarter of 2010, primarily due to the seasonal fluctuations in operating margin at individual plants. Lower spring and summer pricing under the power sales contracts for the Ontario plants was partly offset by higher capacity revenues resulting from increased demand for generation at the Naval facilities in California.

Since the non-controlling interests in CPILP's funds from operations were approximately 70.0% at June 30, 2010 the Company uses funds from operations excluding non-controlling interests in CPILP to provide a more meaningful measure of the Company's operating cash flows.

Normalized Net Income and Normalized Earnings per Share

(unaudited, $millions except earnings (loss) per share)	Three months ended			
	June 30, 2010	March 31, 2010	Dec 31, 2009	Sept 30, 2009
Earnings (loss) per share	**$ (0.37)**	**$ 0.60**	**$ 0.33**	**$ 0.64**
Net income (loss)	**(8)**	**13**	**7**	**14**
Adjustments	9	(1)	(3)	(5)
Normalized net income[(1)]	**1**	**12**	**4**	**9**
Normalized earnings per share[(1)]	**$ 0.05**	**$ 0.55**	**$ 0.18**	**$ 0.42**

(1) Normalized net income and normalized earnings per share are non-GAAP measures. See Non-GAAP Financial Measures.

Normalized net income was lower in the second quarter compared with the first quarter of 2010, primarily due to lower operating margin, excluding unrealized fair value changes, from the Alberta contracted plants, Alberta commercial plants and portfolio, and other portfolio activities as described above under Funds from Operations.

The Company uses normalized net income and normalized earnings per share to measure performance by period on a comparable basis. Normalized net income is based on net income as reported in the consolidated financial statements and adjusted for items that are not reflective of performance in the period such as fair value changes, impairments, unusual tax adjustments and gains or losses on disposal of assets. Normalized earnings per share reflect normalized net income divided by 21.75 million weighted average common shares outstanding. See Non-GAAP Financial Measures.

Pro forma Consolidated Financial Information

The pro forma consolidated financial information for the three and six months ended June 30, 2009 has been prepared by management and presents the effects of the completion of the IPO, the Reorganization and the related use of the net proceeds of the IPO as if they occurred on January 1, 2008. The unaudited pro forma consolidated financial information for 2009 is based on currently available information and assumptions that management believes provide a reasonable basis for presenting the significant effects of the completion of the IPO and the Reorganization. In management's opinion, all material adjustments necessary to present fairly the pro forma consolidated financial information have been made. The unaudited pro forma consolidated financial information is presented for information purposes only and is not necessarily indicative of what the financial position and results of operations would have been had the completion of the IPO and the Reorganization occurred at the dates indicated, nor does it purport to be indicative of the financial position as of any future date or results of operations for any future period. Actual adjustments differed from the pro forma adjustments.

The unaudited pro forma consolidated financial information has been prepared in accordance with Canadian GAAP consistent with the significant accounting policies described in note 2 to the audited consolidated financial statements of the Company for the six months ended December 31, 2009. The presentation of the unaudited pro forma consolidated information conforms to the presentation of both the unaudited financial statements of the Company for the six months ended June 30, 2010 and the audited financial statements of the Company for the six months ended December 31, 2009.

(unaudited, $millions)	Three months ended		Six months ended	
	June 30, 2010	June 30, 2009[1]	June 30, 2010	June 30, 2009[1]
Revenues	$ 313	$ 497	$ 812	$ 1,150
Energy purchases and fuel	193	247	476	701
	120	250	336	449
Operations, maintenance and direct administration	61	58	105	107
Indirect administration	31	40	57	69
Property taxes	4	5	9	10
Depreciation, amortization and asset retirement accretion	52	44	98	91
Foreign exchange (gains) losses	(2)	2	(1)	2
Gain on sale of power syndicate agreement	-	-	(28)	(30)
Net financing expenses	19	8	37	43
	165	157	277	292
Income (loss) before income tax expense and non-controlling interests	(45)	93	59	157
Income tax expense (recovery)	(7)	11	(7)	3
Income (loss) before non-controlling interests	(38)	82	66	154
Non-controlling interests	(30)	71	61	124
Net income (loss)	**$ (8)**	**$ 11**	**$ 5**	**$ 30**

(1) Unaudited pro forma consolidated information for the three and six months ended June 30, 2009 conforms to the presentation adopted for the three and six months ended June 30, 2010.

Consolidated Net Income

(unaudited, $millions)	Three months	Six months
Pro forma consolidated net income for the periods ended June 30, 2009	**$ 11**	**$ 30**
Lower income taxes	18	10
Lower indirect administration	9	12
Higher Alberta commercial plants operating margin	4	1
Unrealized changes in the fair value of CPLP's derivative instruments and natural gas inventory held for trading	(46)	(68)
Unrealized changes in the fair value of CPILP's derivative instruments	(54)	(7)
Lower Alberta contracted plants operating margin	(21)	(26)
Lower (higher) net financing expenses	(11)	6
Higher (lower) CPILP operating margin	(9)	1
Higher depreciation	(8)	(7)
Lower other portfolio activities operating margin	(6)	(10)
Other	4	-
	(120)	(88)
Lower (higher) non-controlling interests:		
- CPLP	67	66
- CPILP	37	1
- Preferred share dividends paid by subsidiary company	(3)	(4)
	101	63
Decrease in net income	(19)	(25)
Net income (loss) for the periods ended June 30, 2010	**$ (8)**	**$ 5**

Net income decreased $19 million and $25 million for the three and six months ended June 30, 2010, respectively compared with the corresponding periods in 2009 due to the net impact of the following:

- Income taxes were lower primarily due to lower income before taxes and non-controlling interests.

- Indirect administration expenses decreased primarily due to lower business development costs. In addition, transition costs related to the Reorganization were incurred in the second quarter of 2009 whereas no corresponding expense was incurred in the periods ending June 30, 2010.
- The unrealized changes in the fair value of CPLP's derivative instruments and natural gas storage held for trading that were not designated as hedges for accounting purposes, reflected the impact of significant increases in the Alberta forward power prices on portfolio positions for these instruments in the second quarter of 2010 and significant decreases in Alberta forward power prices on portfolio positions in the first half of 2009, and less price volatility in the first six months of 2010 compared with the corresponding period in 2009.
- The unrealized changes in the fair value of CPILP's derivative instruments included losses on foreign exchange contracts in the first half of 2010 due to weakening future prices for the Canadian dollar relative to the U.S. dollar, compared with gains in the corresponding period in 2009 due to strengthening future prices. The fair value of natural gas supply contracts decreased in the six months ended June 30, 2010 and 2009 due to decreases in the future prices for natural gas. The decrease for natural gas contracts was smaller in the current year period as CPILP designated certain contracts as hedges for accounting purposes effective July 1, 2009 and the fair value losses relating to those contracts were recorded in other comprehensive income.
- The operating margin for Alberta contracted plants was reduced by net availability penalties of $12 million and maintenance costs of $13 million for the 21-day Genesee 2 outage in the second quarter of 2010 compared with no outages in the first and second quarters of 2009.
- Financing expenses included an unrealized loss of $4 million for the decrease in the fair value of two forward bond sale contracts entered into in the second quarter of 2010. The decrease in financing expenses for the six months ended June 30, 2010 was primarily related to higher interest capitalized for construction work in progress.
- The operating margin for the CPILP plants decreased in the second quarter due to lower prices realized on foreign exchange contracts, lower waste heat availability at the Ontario facilities and lower water flows at Curtis Palmer, partly offset by higher margins and lower maintenance expenses at the Naval facilities in California and higher water flows at the British Columbia hydroelectric plants.
- The operating margin for other portfolio activities decreased primarily due to lower natural gas speculative trading profit and fewer electricity import and export market trading opportunities as a result of lower price spreads and less volatility in prices in the first half of 2010.
- The decrease in non-controlling interests reflected lower income before income taxes from CPLP and CPILP.

Outlook

The following discussion should be read in conjunction with the Forward-looking Information section of this MD&A as this information contains forward-looking statements based on risks and assumptions as of the date of this MD&A and as disclosed in that section. These forward-looking statements are for the purpose of providing information about management's current expectations and plans relating to the future and may not be appropriate for other purposes.

Although results for the second quarter of 2010 were below expectations, the Company's outlook for the full year results remains consistent with the discussion in the Outlook Section of the December 31, 2009 MD&A, primarily due to the better than expected results in the first quarter. Other updates specific to the second half of 2010 are as follows.

In the second quarter of 2010, all three units at Genesee were affected by directions to curtail generation to accommodate transmission system upgrades. The curtailments contributed to spikes in the Alberta power price, foregone availability incentive revenues at Genesee 1 and 2 and trading activity undertaken by the Company to manage its Alberta portfolio position. Consistent with the Company's outlook at the end of the first quarter, these curtailments reduced the Company's operating margin in the second quarter by less than $2 million from plan. This estimate was based on the Company's forecast for Alberta power prices rather than the volatile pricing that actually occurred as a result of the curtailments and other plant outages in the region. Although no requirements for further curtailments for the balance of 2010 have been published, this does not eliminate all possibility of such a requirement in the future. The outage at Genesee 3 is still scheduled for the fourth quarter of 2010 at an estimated cost for maintenance of approximately $7 million.

The Company has a 94% total plant (excluding CPILP plants) availability target for 2010 which takes into account reduced availability for the scheduled outages at Genesee 2 in May and Genesee 3 in the fourth quarter. However, primarily due to issues with the Clover Bar Energy Centre units, the Company anticipates that the total plant (excluding CPILP plants) availability will be 90% for the year.

The second unit at Clover Bar Energy Centre was taken offline in March due to mechanical issues which are being addressed under warranty from the supplier, and the unit may not be back online until September 2010. The third unit at Clover Bar Energy Centre was out of service for fifteen days in the second quarter for an equipment issue that is also being repaired under warranty. The units at Clover Bar Energy Centre are peaking plants which are intended to enhance the Company's ability to physically manage its Alberta portfolio. Accordingly, the previously expected benefit of having all three units available to manage the portfolio was affected by these outages and continues to be affected by the outage at Unit 2. To mitigate this exposure, the Company will continue to depend on the units in operation and financial contracts while Unit 2 is offline. Once Unit 2 is back online, the Company will pursue making a business interruption insurance claim for these issues and, as is common, the Company's business interruption insurance does not compensate it for losses which occur in the first 45 days of an outage. It is not possible to make a reasonable estimate of the recoverable amount at this time.

In the second quarter of 2010, additional length was added to the Company's Alberta commercial portfolio position and at June 30, 2010 the forecast generation from the base-load plants for the balance of 2010 was substantially sold forward at an average price in the mid-$60/megawatt hour (MWh) range. For 2011, approximately 70% of the portfolio has been sold forward at an average contracted price in the mid-$60/MWh range.

Previous estimates of the earnings from CPILP for the remainder of 2010 may be adversely impacted by delays in the finalization of new PPAs for its facilities in North Carolina. The magnitude of the impact depends on the timing and final terms of the new PPAs, which are not determinable at this time.

Capital expenditures, excluding CPILP's capital expenditures, are expected to be approximately $172 million for the second half of 2010 or $361 million for the full year. This full year estimate includes the following changes to the forecast included in the December 31, 2009 MD&A: an addition of $60 million for wind power development projects and a $10 million reduction in spending on Keephills 3 which will be incurred in 2011. The changes in the estimated timing of capital expenditures for Keephills 3 are not expected to impact the total cost of the project.

Significant Events

Canadian Federal Government Greenhouse Gas Regulation for Coal-Fired Generation

On June 23, 2010, the Canadian Environment Minister announced the Government of Canada's plan for new greenhouse gas (GHG) emission regulation for coal-fired electricity generation units. The proposed plan will apply a new GHG emissions performance standard to new coal-fired electricity generation units and those coal-fired units that have reached the end of their economic life. The purpose of the regulation is to ensure that conventional coal-fired electricity generation is phased out in an orderly manner and replaced with lower GHG emission power generation.

Very limited details are available but it is expected that the economic life will be set at 45 years with some exceptions to avoid stranding recent investments in older facilities. New performance standards will likely be similar to a natural gas combined cycle unit. Existing facilities that will be exempt from the regulation until they reach the end of their economic useful life are expected to be those that have commercial operation dates prior to January 1, 2012. Clarity regarding the draft regulations will be provided when they are published in the Canada Gazette which is expected to occur in early 2011, with final regulations expected later that year. Because the proposed regulations allow coal-fired generation assets to operate for their economic life and no additional charges for GHG emissions are anticipated, the regulations provide some certainty and are expected to be favourable to Capital Power's Genesee units and Keephills 3.

It is not clear whether the proposed federal GHG emission regulations will replace the Alberta Specified Gas Emitters Regulations (SGER). The current SGER will expire in 2014. If this date is extended then the Company's Alberta facilities may face continued charges under the SGER, which have historically been approximately $5 million per year. Currently there is insufficient information to reasonably predict what action the Alberta Government will take in respect of the SGER.

Wind Projects Update

On April 8, 2010, the Ontario Power Authority (OPA) selected the Company's Port Dover & Nanticoke Wind development project for the award of a contract through the OPA's Feed-in-Tariff (FIT) program. The 105-MW project is being proposed in an area in southern Ontario where the Company has optioned lands totaling over 8,900 acres. The project has an expected cost of up to $340 million and is anticipated to enter commercial operation in the fourth quarter of 2012. The contract to sell power has since been signed and under the terms of the OPA's FIT program, the contracted price for power at commercial operation of the project will be $135 per MWh escalated by inflation between the contract signing date and commercial operation date. Thereafter, 20 per cent of the contract price will escalate annually at inflation throughout the 20-year contract term. Construction of the Port Dover and Nanticoke Wind project is subject to regulatory approvals, including Ontario's Renewable Energy Approval process which is currently in progress for the project.

The Company has selected Vestas (NASDAQ OMX Copenhagen:VWS) for the supply and maintenance of wind turbines for this project, as well as for the proposed Quality Wind project in northeastern B.C. and the Kingsbridge II project in Ontario. The Quality Wind energy purchase agreement with BC Hydro was signed in April 2010 and the Environmental Assessment Certificate for the project was received from the Government of British Columbia in July 2010. Development of the Kingsbridge II project remains subject to approval under the OPA's FIT program.

Subsequent Event

Acquisition of Island Generation Facility

On August 2, 2010, CPLP entered into an agreement to acquire the Island Generation Facility (Island Generation), a 275 MW gas-fired combined cycle power plant at Campbell River, British Columbia. The transaction is expected to close in the fourth quarter of 2010, subject to regulatory and other approvals. The purchase and sale agreement for the transaction is between CPLP and Kelson Canada Inc. Subject to market conditions, the Company expects to finance the purchase price of approximately $207 million, plus closing costs and normal working capital adjustments, with a combination of debt and equity.

Island Generation is fully contracted from April 1, 2010 to April 2022 under a tolling arrangement with BC Hydro. BC Hydro will be responsible for the fuel supply to the facility. Commissioned in 2002, Island Generation is consistent with Capital Power's fleet of young assets that deploy efficient technologies.

Results by Plant Category

The Company reports results of operations in the following categories: (i) Alberta commercial plants and portfolio optimization, (ii) Alberta contracted plants, (iii) Ontario and British Columbia contracted plants, (iv) CPILP plants, and (v) other portfolio activities.

Generation volume

(unaudited, GWh)	Three months ended		Six months ended	
Electricity generation[1]	June 30, 2010	June 30, 2009	June 30, 2010	June 30, 2009
Alberta commercial plants				
Genesee 3	432	464	915	949
Joffre	93	57	134	163
Clover Bar Energy Centre 1, 2 and 3[2]	102	4	145	9
Taylor Coulee Chute	3	7	3	7
Clover Bar Landfill Gas	10	8	20	18
Weather Dancer	-	1	-	1
	640	541	1,217	1,147
Alberta contracted plants				
Genesee 1	780	802	1,593	1,609
Genesee 2	571	821	1,396	1,642
	1,351	1,623	2,989	3,251
Ontario and British Columbia contracted plants				
Kingsbridge 1	22	25	48	57
Miller Creek	35	29	42	32
Brown Lake	11	13	24	27
	68	67	114	116
Total excluding CPILP plants	**2,059**	**2,231**	**4,320**	**4,514**
CPILP plants[3]	1,128	1,030	2,397	2,331
Total plants	**3,187**	**3,261**	**6,717**	**6,845**
Sundance PPA	**728**	**687**	**1,479**	**1,330**

(1) Electricity generation reflects the Company's share of plant output.

(2) Clover Bar Energy Centre includes Units 1, 2 and 3 as of their commercial operation dates, March 10, 2008, September 1, 2009 and December 16, 2009, respectively.

(3) CPILP excludes Castleton which was sold on May 26, 2009.

Plant availability

(unaudited)	Three months ended		Six months ended	
Generation plant availability[1]	June 30, 2010	June 30, 2009	June 30, 2010	June 30, 2009
Alberta commercial plants				
Genesee 3	96%	98%	98%	99%
Joffre	84%	82%	92%	90%
Clover Bar Energy Centre 1, 2 and 3[3]	52%	100%	62%	99%
Taylor Coulee Chute	90%	100%	94%	100%
Clover Bar Landfill Gas	96%	83%	96%	90%
Weather Dancer	0%	82%	41%	70%
	76%	94%	83%	96%
Alberta contracted plants				
Genesee 1	100%	99%	99%	99%
Genesee 2	75%	99%	86%	100%
	87%	99%	93%	99%
Ontario and British Columbia contracted plants				
Kingsbridge 1	100%	100%	99%	99%
Miller Creek	96%	97%	67%	86%
Brown Lake	99%	97%	98%	97%
	98%	98%	86%	93%
Average excluding CPILP plants[2]	**83%**	**97%**	**88%**	**98%**
CPILP plants[4]	90%	90%	92%	92%
Average all plants[2]	**86%**	**93%**	**90%**	**95%**
Sundance PPA	**90%**	**94%**	**95%**	**92%**

(1) Plant availability represents the percentage of time in the period that the plant was available to generate power regardless of whether it was running, and therefore is reduced by planned and unplanned outages.

(2) Average generation plant availability is an average of individual plant availability weighted by the capacity owned or operated by the Company.

(3) Clover Bar Energy Centre includes Units 1, 2 and 3 as of their commercial operation dates, March 10, 2008, September 1, 2009 and December 16, 2009, respectively.

(4) CPILP excludes Castleton which was sold on May 26, 2009.

The decrease in total plant electricity generation excluding the Sundance PPA, for the three and six months ended June 30, 2010 compared with the corresponding periods in 2009 primarily relates to the Genesee units 1, 2 and 3, partly offset by higher output from Joffre in the second quarter and Clover Bar Energy Centre in the first and second quarters of 2010.

In the second quarter of 2010, Genesee 2 experienced a 21-day outage and all three Genesee units were impacted by curtailments to facilitate transmission upgrades.

Joffre and Clover Bar Energy Centre are mid-merit and peaking plants, respectively, which operate when it is economical to do so. As a result of higher Alberta power prices and higher price volatility, both plants were dispatched more in the second quarter of 2010. Joffre was dispatched less in the first quarter of 2010 as a result of lower Alberta power prices and lower price volatility. Clover Bar Energy Centre included Units 1, 2, and 3 for the six months ended June 30, 2010 whereas only Unit 1 had been commissioned before the first quarter of 2009. Unit 2 was offline for the entire second quarter of 2010 due to a mechanical failure in the main turbine section and is not expected to be back online until September 2010. Unit 3 was offline for fifteen days in the second quarter of 2010 due to an equipment issue.

Miller Creek Units 1 and 2 were offline for scheduled maintenance for a combined total of 77 days during the first quarter of 2010 compared with 33 days for scheduled maintenance in the corresponding period in 2009.

The impact of the decrease in availability on the plant's output was more than offset by the impact of higher water flow levels in the first half of 2010 compared with the first half of 2009.

Financial results

(unaudited, $millions)	Three months ended		Six months ended	
	June 30, 2010	June 30, 2009[2]	June 30, 2010	June 30, 2009[2]
Revenues				
Alberta commercial plants and portfolio optimization	$ 197	$ 231	$ 432	$ 567
Alberta contracted plants	55	68	127	142
Ontario and British Columbia contracted plants	4	4	7	8
CPILP plants	116	135	255	280
Other portfolio activities	25	35	68	87
Inter-plant category transaction eliminations	(10)	(9)	(20)	(22)
	387	464	869	1,062
Unrealized changes in fair value of CPLP's power and natural gas derivative instruments and natural gas held for trading	(55)	(1)	(43)	70
Unrealized changes in fair value of CPILP's foreign exchange contracts	(19)	34	(14)	18
	(74)	33	(57)	88
	$ 313	**$ 497**	**$ 812**	**$ 1,150**
Gross margin[1]				
Alberta commercial plants and portfolio optimization	60	$ 52	$ 125	$ 120
Alberta contracted plants	43	58	102	120
Ontario and British Columbia contracted plants	4	4	7	8
CPILP plants	68	83	145	160
Other portfolio activities	8	18	23	35
Inter-plant category transaction eliminations	(9)	(11)	(18)	(21)
	174	204	384	422
Unrealized changes in fair value of CPLP's power and natural gas derivative instruments and natural gas held for trading	(36)	10	(27)	41
Unrealized changes in fair value of CPILP's foreign exchange and natural gas contracts	(18)	36	(21)	(14)
	(54)	46	(48)	27
	$ 120	**$ 250**	**$ 336**	**$ 449**
Operating margin[1]				
Alberta commercial plants and portfolio optimization	$ 47	$ 43	$ 102	$ 101
Alberta contracted plants	19	40	65	91
Ontario and British Columbia contracted plants	2	2	4	5
CPILP plants	41	50	94	93
Other portfolio activities	-	6	5	15
	109	141	270	305
Unrealized changes in fair value of CPLP's power and natural gas derivative instruments and natural gas held for trading	(36)	10	(27)	41
Unrealized changes in fair value of CPILP's foreign exchange and natural gas contracts	(18)	36	(21)	(14)
	(54)	46	(48)	27
	$ 55	**$ 187**	**$ 222**	**$ 332**

(1) The results by plant category, except for gross margin and operating margin, have been prepared in accordance with Canadian GAAP. See Non-GAAP Financial Measures.

(2) The presentation of results by plant category for the three and six months ended June 30, 2009 conforms to the presentation for the three and six months ended June 30, 2010. See Pro forma Consolidated Financial Information.

Spot price averages	Three months ended June 30, 2010	June 30, 2009	Six months ended June 30, 2010	June 30, 2009
Alberta power ($/MWh)	$ 81.15	$ 32.30	$ 61.08	$ 47.74
Eastern region power ($/MWh)	$ 36.65	$ 23.00	$ 35.25	$ 33.06
Western region power (Mid-C) ($/MWh)	$ 25.19	$ 26.72	$ 33.83	$ 35.11
Alberta natural gas (AECO) ($/Gj)(1)	$ 3.70	$ 3.38	$ 4.21	$ 4.03

Capital Power's Alberta portfolio's realized power price ($/MWh)(2)	66	58	67	60

(1) Gigajoule (Gj). AECO means a historical virtual trading hub located in Alberta and known as the Nova Inventory Transfer System operated by TransCanada Pipelines Limited.

(2) The price realized on the Company's commercial contracted sales and portfolio optimization activities.

Alberta commercial plants and portfolio optimization

The average Alberta power spot price was $40.78/MWh for the first quarter and $81.15/MWh for the second quarter of 2010. The quarter over quarter increase was primarily due to the Genesee plant curtailments and other plant de-rates on the Alberta electric system. Despite this volatility, the Company's quarterly average realized price for the Alberta commercial portfolio was consistent, (approximately $67/MWh for the first quarter and $66/MWh for the second quarter) as a significant portion of the Company's Alberta portfolio was sold forward at fixed prices under contracts with commercial and industrial customers or under merchant and wholesale financial contracts.

The gross margin and operating margin for the Alberta commercial plants and portfolio were higher in the three and six months ended June 30, 2010 compared with the corresponding periods in 2009 primarily due to higher dispatch of the Clover Bar Energy Centre and Joffre plants in the second quarter. Higher Alberta spot prices and higher volatility in those prices provided more opportunities to dispatch these plants and contribute to the operating margin in the second quarter of 2010. Although one of the Clover Bar Energy Centre units was offline for fifteen days in the second quarter and another unit was offline for the entire quarter, the Company managed the portfolio with the available units and financial contracts. The cost of the repair work on the units was covered by the original contractor and did not have a material impact on operating and maintenance expenses.

Partly offsetting the higher margins from Clover Bar Energy Centre and Joffre were lower margins realized on the merchant trading portfolio in the second quarter of 2010. The commodity portfolio optimization strategies that were successful in the first quarter of 2010 had an unfavourable impact in the second quarter and resulted in lower margins.

The decrease in revenues from the Alberta commercial plants and portfolio in the three and six months ended June 30, 2010 compared with the corresponding periods in 2009 primarily reflected the impact of higher Alberta power prices on a higher volume of derivative sell contracts that settled in the second quarter of 2010 compared with the second quarter of 2009. Revenues for the three and six months ended June 30, 2010 also decreased due to lower pricing for the supply of electricity to EPCOR's regulated rate tariff (RRT) customers, primarily for the first quarter of 2010 when Alberta power prices were lower compared with the first quarter of 2009. These decreases were partly offset by higher revenues from the Company's interest in the Sundance PPA (acquired PPA), and from the Clover Bar Energy Centre, Genesee 3 and Joffre plants in the second quarter of 2010 compared with the corresponding period in 2009, due to the impact of higher Alberta power prices on generation sales to the Alberta Electric System Operator and higher generation for the acquired PPA, Clover Bar Energy Centre and Joffre. Although generation was reduced as a result of the sale of the Company's interest in the Battle River PPA in January 2010, revenues from acquired PPAs increased due to the impact of higher Alberta power prices in the second quarter of 2010.

The decrease in revenue from the Company's RRT business in the six months ended June 30, 2010 did not have a significant impact on operating margin for the period as the Company's purchases and revenues for this business are equally impacted by changes in the Alberta power price and provide a low margin per MWh.

Alberta contracted plants

Revenues for the Alberta contracted plants decreased in the three and six months ended June 30, 2010, compared with the corresponding periods in 2009 primarily due to $12 million in availability penalties incurred during the 21-day scheduled maintenance outage at Genesee 2 in the second quarter of 2010. The penalties were approximately $6 million higher than anticipated due to higher pricing, which for availability incentive income and penalties is a function of a 30-day rolling average of Alberta power prices. In the first half of 2009, there were no outages and net availability incentive income of $15 million was earned for the period. Availability incentive was a net penalty of $2 million for the first half of 2010.

Maintenance costs of $13 million for the outage in 2010 also contributed to a lower operating margin for the Alberta contracted plants.

CPILP plants

CPILP plant revenues decreased by $19 million and $25 million in the three and six months ended June 30, 2010, respectively as a result of lower foreign exchange rates, lower prices realized on foreign exchange contracts and lower water flows at Curtis Palmer compared with the corresponding periods in 2009.

The operating margin for the CPILP plants decreased $9 million for the three months ended June 30, 2010 compared with the corresponding period in 2009 primarily due to lower prices realized on foreign exchange contracts, lower waste heat availability at the Ontario facilities and lower water flows at Curtis Palmer. This was partly offset by higher margins and lower maintenance expenses at the Naval facilities in California and higher water flows at the British Columbia hydroelectric plants.

Other portfolio activities

Other portfolio activities include natural gas trading in North American markets and electricity trading in the eastern Canada, U.S. Northeast and U.S. Pacific Northwest markets. Results from natural gas trading reflected lower speculative profit in the first half of 2010 compared with the corresponding period in 2009. In addition, there were fewer trading opportunities in the import and export electricity markets due to lower price spreads between markets and less volatility in prices in the periods ending June 30, 2010. Accordingly, revenues, gross margin and operating margin for both the natural gas and electricity portfolios decreased in the three and six months ended June 30, 2010 compared with the corresponding periods in 2009.

Unrealized changes in fair value of derivative instruments and natural gas inventory held for trading

Changes in the fair value of CPLP's derivative electricity and natural gas contracts and natural gas storage held for trading, that were not designated as hedges for accounting purposes, decreased the gross margin by $36 million in the second quarter and $27 million in first half of 2010. In 2009, the fair value changes of these instruments increased the gross margin by $10 million in the second quarter and $41 million for the first half of the year. These changes primarily reflected the impact of significant increases in the Alberta forward power prices on portfolio positions for these instruments in the second quarter of 2010 and significant decreases in Alberta forward power prices on portfolio positions in the first half of 2009. In addition, Alberta forward power prices were less volatile over the first half of 2010 compared with the corresponding period in 2009.

CPILP's revenues included net losses of $19 million and $14 million for changes in the fair value of foreign exchange contracts in the three and six months ended June 30, 2010, respectively due to weakening future prices for the Canadian dollar relative to the U.S. dollar compared with net gains of $34 million and $18 million, respectively in the corresponding periods in 2009 due to strengthening future prices.

CPILP's fuel expense included a fair value gain on natural gas supply contracts of $1 million in the second quarter and a loss of $7 million in first half of 2010 compared with a fair value gain of $2 million in the second quarter and a loss of $32 million in the second half of 2009. These fair value changes primarily reflect decreases in future prices for natural gas in the first quarter of both years. The fair value changes were smaller in 2010 because CPILP designated certain of its natural gas contracts as hedges for accounting purposes effective July 1, 2009. Accordingly, a $4 million increase and $31 million decrease in the fair value of the designated contracts for the three and six months ended June 30, 2010, respectively were recorded in other comprehensive loss / income. In the corresponding periods in 2009, none of the contracts were designated as hedges and all of the fair value changes on the natural gas contracts were recorded in fuel expense in the income statement.

Consolidated Other Expenses

Indirect administration

Indirect administration expenses include the cost of support departments and services such as treasury, finance, internal audit, legal, human resources, corporate risk management, asset management and health and safety, as well as business development expenses including carbon capture and storage and integrated gasification combined cycle projects. The decrease in indirect administration expense was primarily due to lower business development costs incurred in the three and six months ended June 30, 2010 compared with the corresponding periods in 2009. In addition, transition costs related to the Reorganization were incurred in the second quarter of 2009.

Net financing expenses

Financing expenses were $11 million higher and $6 million lower for the three and six months ended June 30, 2010, respectively compared with the corresponding periods in 2009. An unrealized loss of $4 million was recognized in financing expenses in the second quarter of 2010 for the decrease in the fair value of two forward bond sale contracts. These contracts were entered into in the second quarter of 2010 and there were no similar contracts in the first half of 2009. Higher capitalized interest with no additional increase in borrowings until the latter part of the second quarter of 2010 contributed to lower financing expenses for the six months ended June 30, 2010. The Company capitalizes borrowing costs as part of its capital construction projects and the amount capitalized is a function of the cost of the construction in progress. In the first six months of 2010, construction work in progress, particularly for Keephills 3, was higher compared with the corresponding period in 2009. See Liquidity and Capital Resources.

Depreciation expense

Depreciation expense was $8 million and $7 million higher for the three and six months ended June 30, 2010, respectively compared with the corresponding periods in 2009. The increases were primarily due to a write-down of information technology assets in the second quarter of 2010 and higher depreciation on Clover Bar Energy Centre as all three units were operational in the first six months of 2010 whereas only one unit was operational in the corresponding period in 2009.

Income taxes (reductions)

Income taxes for the three and six months ended June 30, 2010 were lower than for the corresponding periods in 2009 primarily due to lower income before income taxes and non-controlling interests.

Non-controlling interests

The non-controlling interests in CPILP reflect approximately 69.6% of CPILP net income which was lower for the three and six months ended June 30, 2010 than for the corresponding periods in 2009. The non-controlling interests in CPLP reflected approximately 72.2% of the net income from CPLP which was lower in the three and six months ended June 30, 2010 than the corresponding periods in 2009. Non-controlling interests for the six months ended June 30, 2010 also included 100% of the gain on sale of the Battle River PPA in the first quarter. The sale had no impact on the Company's net income as the Company's 27.8% share of the fair value of the Battle River PPA was recognized in the purchase price allocation for the Reorganization.

Income from CPLP included approximately 30.4% of the CPILP net income. Therefore the non-controlling interests in CPLP included approximately 21.9% (72.2% of 30.4%) of CPILP net income.

Non-GAAP Financial Measures

The Company uses (i) gross margin, (ii) operating margin, (iii) funds from operations, (iv) funds from operations excluding non-controlling interests in CPILP and (v) normalized earnings per share as financial performance measures. These terms are not defined financial measures according to Canadian GAAP and do not have standardized meanings prescribed by Canadian GAAP, and therefore may not be comparable to similar measures used by other enterprises. These measures should not be considered alternatives to net income, cash flow from operating activities or other measures of financial performance calculated in accordance with

Canadian GAAP. Rather, these measures are provided to complement Canadian GAAP measures in the analysis of the Company's results of operations from management's perspective.

Gross margin and operating margin

Capital Power uses gross margin and operating margin to measure the operating performance of plants and groups of plants from period to period. A reconciliation of gross margin and operating margin to net income is as follows:

(unaudited, $millions)	Three months ended		Six months ended	
	June 30, 2010	June 30, 2009	June 30, 2010	June 30, 2009
Revenues	$ 313	$ 497	$ 812	$ 1,150
Energy purchases and fuel	193	247	476	701
Gross margin	**120**	**250**	**336**	**449**
Operations, maintenance direct administration and property taxes	65	63	114	117
Operating margin	**55**	**187**	**222**	**332**
Indirect administration	31	40	57	69
Depreciation, amortization and asset retirement accretion	52	44	98	91
Foreign exchange losses (gains)	(2)	2	(1)	2
Gain on sale of power syndicate agreement	-	-	(28)	(30)
Net financing expenses	19	8	37	43
Income taxes (recovery)	(7)	11	(7)	3
Non-controlling interests				
- CPLP	(27)	40	49	115
- CPILP	(7)	30	5	6
- Preferred share dividends paid by CPI Preferred Equity Ltd.[1]	4	1	7	3
Net income (loss)	$ **(8)**	**$ 11**	**$ 5**	**$ 30**

[1] CPI Preferred Equity Ltd. is a subsidiary of CPILP.

Management considers operating margin to be representative of plant performance as it excludes corporate administration and business development expenses (indirect administration). The presentation of the pro forma consolidated information for the three and six months ended June 30, 2009 conforms to the presentation adopted for the three and six months ended June 30, 2010.

Funds from operations and funds from operations excluding non-controlling interests in CPILP

Capital Power uses funds from operations to measure the Company's ability to generate funds from current operations. Funds from operations are cash provided by operating activities excluding changes in working capital. Changes in working capital are impacted by the timing of cash receipts and payments and are not comparable from period to period. Therefore, the Company uses funds from operations as its primary operating cash flow measure. The Company measures its interest in cash flows by excluding the non-controlling interest in CPILP's cash flows. A reconciliation of (i) funds from operations and (ii) funds from operations excluding non-controlling interests in CPILP, to cash provided by operating activities is as follows:

(unaudited, $millions)	Three months ended			
	June 30, 2010	March 31, 2010	Dec 31, 2009	Sept 30, 2009
Funds from operations excluding non-controlling interests in CPILP	$ **34**	**$ 87**	**$ 49**	**$ 70**
Funds from operations due to non-controlling interests in CPILP	19	25	22	23
Funds from operations	53	112	71	93
Change in non-cash operating working capital	(22)	18	50	(40)
Cash provided by operating activities	**$ 31**	**$ 130**	**$ 121**	**$ 53**

Normalized net income and normalized earnings per share

The Company uses normalized earnings per share to measure performance by period on a comparable basis. Normalized earnings per share is based on net income according to Canadian GAAP adjusted for items that are not reflective of performance in the period such as fair value changes, impairments, unusual tax adjustments and gains or losses on disposal of assets. A reconciliation of net income (loss) to normalized net income, and earnings per share to normalized earnings per share is as follows:

(unaudited, $millions except earnings (loss) per share)	Three months ended			
	June 30, 2010	March 31, 2010	Dec 31, 2009	Sept 30, 2009
Earnings (loss) per share	**$ (0.37)**	**$ 0.60**	**$ 0.33**	**0.64**
Net income (loss)	**(8)**	**13**	**7**	**14**
Adjustments				
Unrealized changes in fair value of CPLP's derivative instruments and natural gas held for trading	7	-	(5)	(3)
Unrealized changes in fair value of CPILP's derivative instruments	1	-	(1)	(1)
Venture capital investment write-down	-	-	1	-
Income tax adjustments	1	(1)	2	(1)
	9	(1)	(3)	(5)
Normalized net income	**1**	**12**	**4**	**9**
Normalized earnings per share	**$ 0.05**	**$ 0.55**	**$ 0.18**	**$ 0.42**

Balance Sheet

The significant changes in the Consolidated Balance Sheets from December 31, 2009 to June 30, 2010 were as follows:

(unaudited, $millions)	Increase (decrease)	Explanation of increase (decrease)
Accounts receivable and income taxes recoverable	(57)	Primarily lower receivables from EPCOR for RRT energy supply and decrease in income tax recoverable.
Property, plant and equipment	141	Capital expenditures partly offset by depreciation and amortization.
Power purchase arrangements	(21)	Primarily amortization.
Net derivative instruments assets	(86)	Decrease in fair value of derivative instrument power and natural gas contracts.
Accounts payable and accrued liabilities [1]	(58)	Primarily lower accruals for energy purchases resulting from lower customer energy consumption in June 2010 compared with December 2009.
Long-term debt (including current portion)	89	Primarily net drawings on CPLP's and CPILP's credit facilities.
Net future income tax liabilities	(35)	Primarily the income tax impact of unrealized changes in the fair value of derivative instruments, decreased deferred income from partnerships and increased loss carry forwards.
Non-controlling interests[1]	(20)	Non-controlling interests' share of CPLP and CPILP distributions and other comprehensive loss, partly offset by non-controlling interests' share of CPLP and CPILP net income and CPILP unit issue.
Shareholders' equity	(10)	Common share dividends and other comprehensive loss, partly offset by net income.

(1) Accrued liabilities and non-controlling interests for December 31, 2009 have been recast to reflect the accrual of $18 million of distributions to non-controlling interests that were declared in the fourth quarter of 2009.

Liquidity and Capital Resources

Cash inflows (outflows)			
(unaudited, $millions)	Period ended June 30, 2010		
	Three months	Six months	Explanation
Cash from Operating Activities	$ 31	$ 161	See Funds from Operations
Investing	(129)	(141)	Capital expenditures, primarily for property plant and equipment, partly offset by proceeds on the sale of the final interest in the Battle River PPA in January 2010.
Financing	121	17	Net drawings under CPLP's and CPILP's credit facilities, partly offset by debt repayments to EPCOR, distributions to non-controlling interests and dividends paid to common shareholders.

On June 30, 2010 CPLP had $1,220 million of credit facilities, of which $670 million remained available, and CPILP had credit facilities of approximately $366 million, of which $278 million remained available. In addition, Capital Power Corporation had an undrawn bank line of credit of $5 million. In the second quarter of 2010, $1,200 of CPLP's credit facilities were extended to July 2013 and a $125 million credit facility of CPILP's was extended to June 2012, all at lower rates. CPILP is in the process of extending its two $100 million credit facilities.

CPLP made the following debt repayments to EPCOR in June 2010: $200 million of 6.95% debt and $45 million of 9% debt. To finance these debt repayments as well as capital expenditures, CPLP made a net draw of $386 million on its credit facilities in the second quarter of 2010. In the first quarter of 2010, CPLP made a net repayment of $60 million on amounts drawn under its credit facilities. The long-term debt payable to EPCOR was issued in connection with the Reorganization pursuant to a credit agreement entered into by CPLP and EPCOR on July 9, 2009.

In the six months ended June 30, 2010, CPILP made a net draw of $9 million under its revolving credit facilities consisting of a net repayment of $9 million in the first quarter and a net draw of $18 million in the second quarter. CPILP's outstanding long-term debt also reflects an increase of $5 million in the first six months of 2010 for foreign exchange on the translation of its U.S. dollar denominated debt.

On June 30, 2010, CPLP had $426 million of long-term debt and $124 million of letters of credit outstanding, and CPILP had $87 million of long-term debt and less than $1 million of letters of credit outstanding, under their respective credit facilities.

CPLP has received a corporate credit rating of BBB from S&P and a long-term debt credit rating of BBB from DBRS. The BBB rating assigned by S&P is the fourth highest rating of S&P's ten corporate credit ratings. According to S&P, a BBB corporate credit rating exhibits adequate capacity to meet financial commitments. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitments.

Having an investment grade credit rating impacts CPLP's ability to re-finance existing debt as it matures and to access cost competitive capital for future growth.

Capital Expenditures

(unaudited, $ millions)	2010		Total project		
	Six months ended June 30	Full year estimate[1]	Incurred to June 30, 2010[2]	Total project cost estimate[1]	Target or actual completion date
CPLP					
Keephills 3	$ 127	$ 240	$ 801	$ 955	2nd quarter 2011
Quality Wind and Port Dover & Nanticoke	33	51	33	795	2nd quarter 2013 and 4th quarter 2012
Other	29	70			
Total CPLP	189	361			
CPILP					
Oxnard turbine replacement	13	16	18	21	3rd quarter 2010
North Carolina plants enhancement	5	17	84	96	3rd quarter 2010
Other	4	6			
Total CPILP	22	39			
Total capital expenditures	211	400			

(1) Capital expenditures to be incurred over the life of the project and in the twelve months ended December 31, 2010 are based on management's estimates.

(2) Total project capital expenditures incurred to June 30, 2010 reflect capital expenditures since the inception of the project.

Construction of Keephills 3 remains on target to the revised project cost forecast as discussed in the 2009 annual MD&A, and on schedule. Hydro tests on the feed water and re-heater systems and the boiler were successfully completed in April 2010, marking the achievement of a major milestone for the project. The number of staff for construction peaked in the first quarter of 2010 and decreased in the second quarter as the project evolved from construction to commissioning. The commissioning team has increased staff levels in the second quarter as commissioning activities increased on the boiler, turbine and electrical systems.

CPILP completed the enhancements to the second unit at Southport in April 2010 and expects to complete the material handling improvements at Southport in the third quarter of 2010. CPILP completed the repowering of the natural gas turbine at Oxnard in the second quarter of 2010 and plans to invest in capital spares for the plant in the third quarter of 2010.

The Company's capital expenditures included in "other" in the table above are primarily for the improvement of existing facilities and environmental offsets.

Future cash requirements – excluding CPILP

The following estimates of future cash requirements are subject to variable factors including those discussed in Forward-looking Information. Capital Power's estimated cash requirements for the six months ended December 31, 2010, excluding CPILP's cash requirements, are expected to include approximately $172 million for capital expenditures, approximately $36 million for CPLP distributions to EPCOR, and approximately $14 million for Capital Power's quarterly dividends subject to approval by the Board of Directors. The estimate for CPLP distributions includes $18 million distributed on July 30, 2010 and the estimate for Capital Power's quarterly dividends includes $7 million paid on July 30, 2010 at $0.315 per share. The current portion of long-term debt on the balance sheet is primarily comprised of $33 million payable to EPCOR in June 2011.

If total cash requirements for the balance of 2010 remain as planned, it is expected that the sources of capital will be cash on hand, cash provided by operating activities, distributions from CPILP and the use of existing credit facilities. The Company expects to fund the construction of the Quality Wind and Port Dover & Nanticoke Wind projects using existing bank credit facilities. Once construction is complete, the Company expects to put long-term financing in place while maintaining the Company's overall leverage in the range of 40% to 50%.

In the second quarter of 2010, CPLP entered into two $100 million forward bond sale transactions for the purpose of hedging a portion of the exposure to interest rate risk on potential future borrowings. These forward contracts expire on March 1, 2011.

In April 2010, the Company filed two short form base shelf prospectuses which, market conditions permitting, provide the Company with the ability to obtain new debt and equity capital from external markets at the time of a requirement for a major investment of capital. Pursuant to one of the short form base shelf prospectuses Capital Power may raise up to $1 billion by issuing common shares, or subscription receipts exchangeable for common shares or other securities of the Company. Under this equity prospectus, EPCOR may also sell the common shares of the Company which it beneficially owns through its ownership of exchangeable limited partnership units of CPLP. Pursuant to the other short form base shelf prospectus, CPLP may raise up to $1 billion by issuing medium term notes with maturities of not less than one year. Both shelf prospectuses expire in May 2012.

Future cash requirements – CPILP

The following estimates of future cash requirements are subject to variable factors including those discussed in Forward-looking Information. CPILP's estimated cash requirements for the six months ended December 31, 2010 are expected to include approximately $17 million for capital expenditures, approximately $48 million for distributions subject to approval by the CPILP Board of Directors and approximately $7 million for preferred share dividends of a subsidiary company subject to the approval of the Board of Directors of the subsidiary company. The estimate for CPILP distributions includes $8 million distributed on July 23, 2010. The amount of distributions will vary depending on the number of unit holders who opt under CPILP's distribution reinvestment program to accumulate additional units in lieu of cash distributions. If CPILP's total cash requirements for the balance of 2010 remain as planned, it is expected that the sources of capital will be cash on hand, cash provided by operating activities and use of existing credit facilities.

In July 2010, CPILP filed a short form base shelf prospectus which, market conditions permitting, provides the partnership with the ability to obtain new debt and equity capital from external markets at the time of a requirement for a major investment of capital. Pursuant to the prospectus, CPILP may offer and sell limited partnership units, debt securities or subscriptions receipts exchangeable for partnership units or debt securities of the partnership, at an aggregate amount of up to $600 million. This base shelf prospectus expires in August 2012 and replaces CPILP's $1 billion shelf prospectus which was due to expire in August 2010.

Financial market stability remains an issue and if instability in the Canadian and U.S. financial markets were to return, it may adversely affect Capital Power's ability to raise new capital, to meet its financial requirements and to refinance indebtedness under existing credit facilities and debt agreements at their maturity dates. In addition, Capital Power has credit exposure with a number of counterparties to various agreements, most notably its PPA, trading and supplier counterparties. While the Company continues to monitor its exposure to its significant counterparties, there can be no assurance, particularly in light of the current economic environment, that all counterparties will be able to meet their commitments.

Contractual Obligations

The Rossdale plant which is owned by EPCOR, was taken out of service in January 2009 and is to be decommissioned. Certain structures at the plant site were designated as Provincial Historical Resources by the Province of Alberta and are thereby legally protected from demolition. These structures, and additional structures at the plant site, are also on the City of Edmonton's Register of Historic Resources. CPLP has an obligation to EPCOR to share in some of the costs for decommissioning and ongoing operations and maintenance of the Rossdale plant and related assets. The future costs to be borne by CPLP cannot yet be reasonably estimated. The loss, representing the fair value of the future payments, will be recognized in the period that it can be reasonably estimated.

There were no other changes to the Company's purchase obligations, commitments or contingencies during the second quarter of 2010, including payments for the next five years and thereafter, that would be material to the Company's business or financial position. For further information on these obligations, refer to the Company's December 31, 2009 MD&A, filed on SEDAR at www.sedar.com.

Off-balance Sheet Arrangements

As at June 30, 2010, the Company had no off-balance sheet arrangements.

Related Party Transactions

EPCOR, including its subsidiaries and its sole shareholder The City of Edmonton, is the only related party with which the Company had material transactions in the six months ended June 30, 2010. As part of the Reorganization in July 2009, EPCOR acquired 56.625 million exchangeable limited partnership units of CPLP, and 56.625 million accompanying special voting shares and one special limited voting share of the capital of Capital Power. At June 30, 2010, these partnership units and shares remained outstanding to EPCOR.

The Company's long-term debt payable to EPCOR, which was also issued in connection with the Reorganization, was $622 million at June 30, 2010. The interest incurred on this debt was $15 million and $30 million for the three and six months ended June 30, 2010, respectively, of which $12 million and $22 million, respectively were capitalized as property, plant and equipment for construction work in progress over the corresponding periods. The remainder was included in net financing expense.

The Company's revenues for power sold to EPCOR for resale to its customers were $87 million and $189 million for the three and six months ended June 30, 2010, respectively. The Company's purchases of distribution and transmission services from EPCOR were $7 million and $13 million for the three and six months ended June 30, 2010, respectively. The Company also had various transactions with EPCOR pursuant to the agreements which provide for the continuity of operations and services following the separation of the business of Capital Power from EPCOR. All of the above transactions were in the normal course of operations and were recorded at the exchange values which were based on normal commercial rates.

The balances outstanding at June 30, 2010 resulting from transactions with EPCOR were as follows:

(unaudited, $ millions)	June 30, 2010
Balance sheet	
Accounts receivable	$ 38
Other assets	7
Property, plant and equipment	22
Accounts payable and accrued interest on debt	11

Business Risks

Apart from the Canadian Environment Minister's announcement as described under Significant Events, there have been no material changes in the six months ended June 30, 2010 to the Company's business and operational risks as provided in the Company's December 31, 2009 MD&A. New risk policies and VaR statistical confidence interval were implemented in the first quarter of 2010, as discussed in the Company's March 31, 2010 MD&A.

Future Accounting Changes

International Financial Reporting Standards

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

In January 2008, EPCOR established a core team to develop a plan which would result in the first interim report for 2011 being in compliance with IFRS. In July 2009, Capital Power organized its own IFRS team to work in conjunction with the EPCOR core team to continue with the plan and implement IFRS in Capital Power in time to meet the 2011 reporting requirements. The terms of the services to be provided by EPCOR to Capital Power for IFRS support are outlined in the Services Agreement by and between Capital Power and EPCOR.

The diagnostic phase of the project was completed in April 2008. For each international standard, EPCOR identified the primary differences from Canadian GAAP and made an initial assessment of the impact of the required changes for the purpose of prioritizing and assigning resources. The assessments were subsequently reviewed from a Capital Power perspective. The following standards are likely to have a significant impact on Capital Power:

International Financial Reporting Standard
IFRS 3 Business Combinations
IAS 16 Property, Plant and Equipment
IAS 37 Provisions, Contingent Liabilities and Contingent Assets
IAS 36 Impairment of Assets
IAS 17 Leases
IAS 31 Interests in Joint Ventures
IFRS 7, IAS 32, IAS 39 Financial Instruments
IAS 21 The Effects of Changes in Foreign Exchange Rates
IAS 12 Income Taxes

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 Company will determine 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 or amended standards issued in 2010 will be made in conjunction with the Company's analysis of those standards in 2010.

The more significant impacts of IFRS on the Company are expected to be:

- IFRS 3 – Business Combinations requires non-controlling interests to be recognized at fair value on acquisition, or at the non-controlling interests' share of the amounts recognized for the acquisition excluding goodwill. Under Canadian GAAP, non-controlling interests are initially recognized at amounts based on the carrying amounts in the acquired entity's financial statements. Under IFRS 1 – First Time Adoption of International Financial Reporting Standards an entity may elect not to apply IFRS 3 retrospectively. The Company plans to take the exemption and not restate the transactions related to the Reorganization. As the Reorganization was the Company's only business combination, IFRS 3 will not impact the Company's financial statements upon transition to IFRS.
- Property, plant and equipment (PP&E) will be primarily impacted by IAS 16 – Property, Plant and Equipment and IAS 23 – Borrowing Costs. Unlike Canadian GAAP, IFRS does not allow certain costs related to the construction of PP&E, such as training costs, overheads and borrowing costs in excess of the actual entity's cost of debt, to be capitalized. As most of the assets were acquired as part of the July 2009 Reorganization, the impact of retrospectively adopting IAS 16 will not be significant.

  Accounting for the components of PP&E is required at a more detailed level under IFRS than under Canadian GAAP. IFRS require a separate component for assets with a distinct depreciation method or rate of deprecation. The Company has completed its analysis of its operations and has concluded on the appropriate level of componentization. The implementation of this standard is expected to result in increased depreciation expense for Capital Power. The Company expects to quantify this impact by the end of the third quarter of 2010.
- IAS 37 – Provisions, Contingent Liabilities and Contingent Assets requires asset retirement obligations to be measured at management's best estimate of the costs of decommissioning assets whereas Canadian GAAP requires such obligations to be measured at the cost of using third party services for decommissioning. Since the Company's decommissioning work is generally performed by the employees of the Company, the estimated decommissioning costs would be significantly less under IFRS than the Company's current estimates under Canadian GAAP. Accordingly, if the provisions of IAS 37 remain unchanged, there should be a decrease in the asset retirement obligation upon conversion to IFRS.

However, the International Accounting Standards Board issued an exposure draft which proposes to replace IAS 37 with a new standard that would require decommissioning liabilities to be measured using third party cost estimates. The Company is quantifying the provision under both scenarios. A revised standard is expected in the first half of 2011.

- IAS 36 – Impairment of Assets requires a one-step approach using discounted cash flow techniques for asset impairment testing and measurement. Canadian GAAP's two-step approach requires the application of discounted cash flow techniques to measure the impairment amount, but only after the use of undiscounted cash flow analysis has indicated the existence of an impairment. The adoption of IAS 36 may result in more frequent asset write downs since the carrying values of assets which are supported by undiscounted future cash flows may be determined to be impaired when the future cash flows are discounted in accordance with the IFRS requirements. Unlike Canadian GAAP, previous impairment losses may be reversed or reduced under IFRS if the circumstances which led to the impairment change.

  IAS 36 also requires impairment testing to be applied at a cash-generating unit level, which for Capital Power will likely be by plant or plant category. In addition, goodwill must be allocated to cash-generating units for impairment testing purposes. Under Canadian GAAP goodwill is not allocated to plants. Accordingly, the transition to IAS 36 increases the likelihood of a goodwill write down. The Company expects to have quantified the impact of IAS 36 in the third quarter of 2010.

- IAS 17 – Leases was assessed primarily in the context of the Company's power purchase arrangements (PPAs). The Company has completed its assessment of its PPAs and will finalize its positions and quantify any impact in the third quarter of 2010. Certain commercial arrangements not currently considered leases may be considered leases under IFRS. In addition, the classification of existing arrangements as capital leases or operating leases may change under IFRS.

- IAS 31 – Interests in Joint Ventures sets out the requirements for the accounting of joint ventures. This standard will be replaced in the third quarter of 2010. The Company has been monitoring the development of the standard, as the exposure draft proposed equity accounting for certain arrangements currently accounted for by the Company under proportionate consolidation. The Company has completed a review and documented the terms of all these arrangements and will assess the arrangements against the standard when it is issued.

- IFRS 1 – First Time Adoption of IFRS provides first time adopters with a number of elections, exempting them from retrospectively adopting certain IFRS. The following elections are relevant to Capital Power:

  An entity may deem the cost of an asset at the date of transition to be its fair value at that date. This election is available on an asset by asset basis.

  An entity may select any date prior to the transition date and elect to not apply IFRS 3 Business Combinations retrospectively to business combinations occurring prior to that date. The Company plans to take this election.

  On transition, an entity may elect to deem any balance for cumulative translation amounts to be zero and to reclassify the previous balance to retained earnings with no impact on the income statement.

  On transition, an entity is not required to reassess its determination of a contract as a lease. An entity may also choose to determine whether an arrangement existing at the date of transition contains a lease on the basis of facts and circumstances existing at that date, rather than at the date of inception of the lease.

  An entity may apply a simplified calculation for the restatement of decommissioning liabilities and associated property, plant and equipment and accumulated depreciation.

  An entity may elect to recognize all cumulative actuarial gains and losses relating to employee benefits at the date of transition.

  Capital Power has not made any decisions or recommendations with respect to any of the elections other than the election relating to Business Combinations.

Capital Power anticipates completing the quantification of the opening financial statement adjustments resulting from the application of all currently effective IFRS, including financial instruments, foreign exchange and income taxes, in the fourth quarter of 2010.

As the project progresses, the timing of the completion of certain items may be impacted by changes to the standards and changes in priorities resulting from external factors such as discussions with stakeholders. However, the Company believes the project has sufficient resources to meet the overall project timeline.

Financial Statements

There are a number of international standards which relate to financial statement presentation. Draft financial statements highlighting the disclosure and presentation requirements were presented to the Audit Committee in March 2010. The development of the financial statement presentation will evolve throughout the project as the impacts of implementing the various standards are quantified.

The Company has identified those areas requiring additional disclosure and has started developing processes to capture the additional information.

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 Company completed its system updates in the third quarter of 2009 based on system requirements identified during the project's planning phase in 2008. The Company's parallel general ledgers and fixed asset systems have been implemented which allow both IFRS and Canadian GAAP information to be captured. The processes and internal controls related to the capture and reporting of IFRS information are similar to those for Canadian GAAP. Both systems have been operational since the third quarter of 2009.

Policies and Internal Controls

In the determination of the financial statement adjustments, requirements for changes to the Company's policies and internal controls will be identified and documented. Based on the project's progress to date, the Company has not identified any requirements for significant changes to processes or controls. 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 fourth 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 the Company has not identified any provisions within the agreements which would be negatively impacted by the differences between IFRS and Canadian GAAP identified to date. The impact on the agreements will continue to be monitored as additional IFRS and Canadian GAAP differences are quantified.

The Company's investor relations department will work with the IFRS team in the third quarter of 2010 to prepare information for the investor analysts.

Training

The Company recognizes that training at all levels of the Company is essential to a successful conversion and integration. Accounting staff have attended four training sessions with more planned to occur throughout the conversion process. A training session for the Audit Committee occurred in March 2010 and the Audit Committee will receive regular updates throughout 2010.

Critical Accounting Estimates and Policies

In preparing the consolidated financial statements, management necessarily made estimates in determining transaction amounts and financial statement balances. The following are the Company's most significant accounting policies and the items for which critical estimates were made in the financial statements: revenue recognition under PPAs, financial instruments, long-lived assets, asset retirement obligations, income taxes, leases or arrangements containing a lease, foreign currency translation and the consolidation of CPLP and CPILP. For further information on the Company's accounting policies and estimates, refer to the Company's December 31, 2009 MD&A.

Financial Instruments

The Company's derivative instruments assets and liabilities used for risk management purposes are measured at fair value and consist of the following:

(unaudited, $ millions)	Energy cash flow hedges	Energy non-hedges	Foreign exchange non-hedges	Interest rate non-hedges	Total
Total derivative instruments net assets (liabilities) as at June 30, 2010	$ (47)	$ 44	$ 12	$ (4)	$ 5

At June 30, 2010, the fair value of energy derivative instruments designated and qualifying for hedge accounting was a net liability of $47 million which primarily reflected the impact of decreased future prices for natural gas relative to natural gas supply contract prices.

At June 30, 2010 the fair value of energy derivative instruments not designated as hedges for accounting purposes was a net asset of $44 million, which primarily reflected the impact of changes in the forward Alberta power prices on the Alberta power portfolio.

At June 30, 2010, the fair value of the Company's forward foreign currency contracts was a net derivative instrument asset of $12 million, which primarily reflected the impact of strengthening future prices for the Canadian dollar relative to the U.S. dollar on forward foreign exchange sales contracts used to hedge U.S. dollar denominated revenues. As at June 30, 2010, $381 million (US$338 million) or approximately 96% of expected future net US$ cash flows from CPILP's U.S. plants for 2010 to 2016 were economically hedged at a weighted average exchange rate of $1.13 to US$1.00. As at June 30, 2010, $14 million (US$13 million) or approximately 93% of expected future net US$ cash flows for CPLP capital expenditure commitments for 2010 and 2011 were economically hedged at a weighted average exchange rate of $1.07 to US$1.00.

At June 30, 2010, the fair value of the Company's forward bond sale contracts was a net derivative instrument liability of $4 million. These contracts were entered into in the second quarter of 2010 to hedge exposure to interest rate risk on potential future debt issues. The unrealized changes in the fair value of these contracts for the second quarter of 2010 were recognized in financing expenses, as discussed under Consolidated Expenses.

For the three and six months ended June 30, 2010, losses net of income taxes on derivative instruments designated as cash flow hedges, of $1 million and $18 million respectively, were recorded in other comprehensive income for the effective portion of cash flow hedges. Realized gains, net of income taxes, for the three and six months end June 30, 2010 of $17 million and $11 million respectively, were reclassified to energy purchases and revenues as appropriate. For the three and six months ended June 30, 2010, the change in the fair value of the ineffective portion of hedging derivatives recognized in the income statement, before non-controlling interests, was a loss of $1 million.

Internal Control over Financial Reporting

There were no changes in the Company's internal controls over financial reporting that occurred during the six months ended June 30, 2010 that have materially affected, or are reasonably likely to materially affect the Company's internal control over financial reporting.

Forward-looking Information

Certain information in this MD&A is forward-looking within the meaning of Canadian securities laws as it relates to anticipated financial performance, events or strategies. When used in this context, words such as will, anticipate, believe, plan, intend, target, and expect or similar words suggest future outcomes.

Forward-looking information in this MD&A includes, among other things, information relating to: (i) expected timing of commercial operation and expected project costs of the Port Dover & Nanticoke Wind project; (ii) expected contracted price for power under the OPA's FIT program for the Port Dover & Nanticoke Wind project;

(iii) expectations for the Company's and CPILP's sources of capital and use and availability of committed bank credit facilities and potential future borrowings; (iv) the Company's and CPILP's cash requirements for 2010, including capital expenditures, distributions and dividends; (v) expected funding of the Quality Wind and Port Dover & Nanticoke wind projects during construction and once completed while maintaining a leverage in the range of 40%-50%; (vi) expectations regarding future financial strength and access to and terms of future financings; (vii) expectation about the ability of the Alberta commercial plant portfolio to participate in rising power market opportunities during the time Clover Bar Energy Centre Unit 2 is offline and the impact of Unit 2 being offline on operating margin and cash flows from operations; (viii) expected timing of when Clover Bar Energy Centre Unit 2 will be brought back online; (ix) expectations regarding management's intent to pursue making a business interruption claim for the outage of Clover Bar Energy Centre Unit 2; (x) expectations regarding timing of spending on Keephills 3; (xi) expected total capital project costs as well as expected project completion dates; (xii) expected timing and maintenance cost impact of the Genesee 3 scheduled maintenance outage; (xiii) expectations regarding potential further curtailments of the Genesee plants in 2010; (xiv) expectations regarding ability to meet the availability target in 2010 in light of issues with Clover Bar Energy Centre units; (xv) expectations about future income and future CPILP distributions; (xvi) expected impact of transition to IFRS and expected project review completion dates; (xvii) expectations regarding the impact of delays in the finalization of new PPAs for the North Carolina facilities on CPILP's earnings; (xviii) expectations regarding the Company's obligation for some of the costs for decommissioning and ongoing operations and maintenance of EPCOR's Rossdale plant; (xix) expectations regarding the impact on Capital Power of the plan for a new GHG emission regulation as announced by the Canadian Environment Minister in June 2010 and expectations with respect to additional charges for GHG emissions; (xx) expectations regarding the economic life of, and new performance standards for, coal-fired electricity generation units pursuant to the proposed new GHG regulation, and regarding the applicability of exemptions from the proposed new GHG regulation; (xxi) expectations regarding the timing of the draft and final GHG regulations and the GHG regulations being brought into force; (xxii) impact of proposed federal GHG emission regulations on SGER and consequential impact on the Company's Alberta facilities; (xxiii) expectations regarding the expiry or extension of the SGER; (xxiv) the expected closing date, purchase price and financing of the acquisition of the Island Generation Facility; and (xxv) expectations regarding BC Hydro's responsibility for the fuel supply to the Island Generation Facility.

These statements are based on certain assumptions and analyses made by the Company 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 operation of the Company's facilities; (ii) power plant availability, including those subject to acquired PPAs; (iii) the Company's financial position and credit facilities and sources of funding; (iv) the Company's assessment of commodity and power markets; (v) the Company's assessment of the markets and regulatory environments in which it operates; (vi) weather; (vii) availability and cost of labour and management resources; (viii) performance of contractors and suppliers; (ix) availability and cost of financing; (x) foreign exchange rates; (xi) management's analysis of applicable tax legislation; (xii) the currently applicable and proposed tax laws will not change and will be implemented; (xiii) currently applicable and proposed environmental regulations will be implemented; (xiv) counterparties will perform their obligations; (xv) renewal and terms of PPAs; (xvi) ability to successfully integrate and realize benefits of its acquisitions; (xvii) ability to implement strategic initiatives which will yield the expected benefits; (xviii) ability to obtain necessary regulatory approvals for development projects; (xix) the Company's assessment of capital markets and ability to complete future share and debt offerings; (xx) locations of projects and the areas of which they will be developed, including the availability and use of certain optioned lands; and (xxi) costs of construction and development.

Whether actual results, performance or achievements will conform to the Company's expectations and predictions is subject to a number of known and unknown risks and uncertainties which could cause actual results and experience to differ materially from the Company's expectations. Such risks and uncertainties include, but are not limited to, risks relating to: (i) operation of the Company's facilities; (ii) power plant availability and performance; (iii) unanticipated maintenance and other expenditures; (iv) availability and price of energy commodities; (v) electricity load settlement; (vi) regulatory and government decisions including changes to environmental, financial reporting and tax legislation; (vii) weather and economic conditions; (viii) competitive pressures; (ix) construction; (x) availability and cost of financing; (xi) foreign exchange; (xii) availability and cost of labour, equipment and management resources; (xiii) performance of counterparties, partners, contractors and suppliers in fulfilling their obligations to the Company; (xiv) developments in the North American capital markets; (xv) compliance with financial covenants; (xvi) ability to successfully realize the benefits of acquisitions and investments; and (xvii) the tax attributes of and implications of any acquisitions. If any such risks actually occur, they could materially adversely affect the Company's business, financial condition or results of operations. In that case the trading price of the Company's common shares could decline, perhaps materially.

This MD&A includes the following updates to previously disclosed forward-looking statements: (i) expectations regarding capital expenditures in 2010 have been revised to reflect a change in the timing of spending on the Keephills 3 project; (ii) the timing of when Clover Bar Energy Centre Unit 2 is expected to be brought back online has been revised from August to September; (iii) the expected timing of the completion of the material handling improvements at CPILP's Southport plant has been revised from the second quarter of 2010 to the third quarter of 2010; (iv) a change in the expected timing of the quantification of increased depreciation expense resulting from the implementation of IFRS 16, from the second to the third quarter of 2010; and (v) a change in the expected timing of the completion of the quantification of the opening financial statement adjustments resulting from the application of currently effective IFRS, from the third quarter to the fourth quarter of 2010.

Readers are cautioned not to place undue reliance on any such forward-looking statements, which speak only as of the date made. Forward-looking statements are provided for the purpose of providing information about management's current expectations, and plans relating to the future. Readers are cautioned that such information may not be appropriate for other purposes. The Company does not undertake or accept any obligation or undertaking to release publicly any updates or revisions to any forward-looking statements to reflect any change in the Company's expectations or any change in events, conditions or circumstances on which any such statement is based, except as required by law.

Quarterly Information

Quarterly revenues, net income and funds provided by operating activities are affected by seasonal weather conditions, fluctuations in U.S. dollar exchange rates relative to the Canadian dollar, power and natural gas prices, planned and unplanned plant outages, as well as items outside the normal course of operations. Net income is also affected by changes in the fair value of the Company's derivative power, natural gas, foreign exchange and forward bond sale contracts, and natural gas held for trading.

Financial highlights

(unaudited, $millions except earnings (loss) per share)	Three months ended			
	June 30, 2010	March 31, 2010	Dec 31, 2009	Sept 30, 2009
Revenues[3]	313	499	497	511
Gross margin[1]	120	216	216	218
Operating margin[1]	55	167	154	169
Net income	(8)	13	7	14
Earnings (loss) per share	$ (0.37)	$ 0.60	$ 0.33	$ 0.64
Fully diluted earnings (loss) per share[2]	$ (0.37)	$ 0.60	$ 0.30	$ 0.59
Funds from operations[1]	53	112	71	93
Normalized earnings per share[1]	$ 0.05	$ 0.55	$ 0.18	$ 0.42
Capital expenditures	133	78	127	108
Long-term debt including current portion	1,808	1,634	1,719	1,771
Total assets	5,015	4,952	5,036	4,918

(1) The consolidated financial information, except for gross margin, operating margin, funds from operations and normalized earnings per share, has been prepared in accordance with Canadian GAAP. See Non-GAAP Financial Measures.

(2) Fully diluted earnings per share is calculated after giving effect to the exchange of limited partnership units of CPLP (exchangeable for common shares of Capital Power on a one-for-one basis) held by EPCOR.

(3) Revenues for the three months ended September 30, 2009 have been restated for a reclassification which resulted in a reduction in each of revenue and energy purchases by $14 million. The restatement had no impact on gross margin, operating margin or net income and the presentation is consistent with subsequent periods.

Generation volume and plant availability information

(unaudited, GWh)	Three months ended			
Electricity generation[1]	June 30, 2010	March 31, 2010	Dec 31, 2009	Sept 30, 2009
Alberta commercial plants				
Genesee 3	432	483	484	470
Joffre	93	41	73	89
Clover Bar Energy Centre 1, 2 and 3[2]	102	43	9	16
Taylor Coulee Chute	3	-	2	12
Clover Bar Landfill Gas	10	10	10	9
Weather Dancer	-	-	-	-
	640	577	578	596
Alberta contracted plants				
Genesee 1	780	813	618	837
Genesee 2	571	825	817	801
	1,351	1,638	1,435	1,638
Ontario and British Columbia contracted plants				
Kingsbridge 1	22	26	32	14
Miller Creek	35	7	14	47
Brown Lake	11	13	15	11
	68	46	61	72
Total plants excluding CPILP plants	**2,059**	**2,261**	**2,074**	**2,306**
CPILP plants	1,128	1,268	1,407	1,228
Total plants	**3,187**	**3,529**	**3,481**	**3,534**

(1) Electricity generation reflects the Company's share of plant output.

(2) Clover Bar Energy Centre includes Units 2 and 3 as of their commercial operation dates, September 1, 2009 and December 16, 2009, respectively.

(unaudited)	Three months ended			
Generation plant availability[1]	June 30, 2010	March 31, 2010	Dec 31, 2009	Sept 30, 2009
Alberta commercial plants				
Genesee 3	96%	100%	99%	97%
Joffre	84%	100%	94%	96%
Clover Bar Energy Centre 1, 2 and 3[2]	52%	72%	98%	96%
Taylor Coulee Chute	90%	98%	66%	100%
Clover Bar Landfill Gas	96%	96%	94%	90%
Weather Dancer	0%	83%	0%	55%
	76%	98%	97%	96%
Alberta contracted plants				
Genesee 1	100%	99%	74%	100%
Genesee 2	75%	99%	97%	95%
	87%	99%	85%	97%
Ontario and British Columbia contracted plants				
Kingsbridge 1	100%	99%	100%	99%
Miller Creek	96%	37%	97%	88%
Brown Lake	99%	97%	99%	97%
	98%	71%	99%	94%
Average excluding CPILP plants[3]	**83%**	**97%**	**92%**	**97%**
CPILP plants[3]	90%	95%	92%	93%
Average all plants[3]	**86%**	**96%**	**92%**	**95%**

(1) Plant availability represents the percentage of time in the period that the plant was available to generate power, regardless of whether it was running, and therefore is reduced by planned and unplanned outages.

(2) Clover Bar Energy Centre includes Unit 2 and Unit 3 as of their commercial operation dates, September 1, 2009 and December 16, 2009, respectively.

(3) Average generation plant availability is an average of individual plant availability weighted by owned or operated capacity.

The Company's target for plant availability excluding CPILP plants for 2010 is 94%. In the second quarter of 2010, 83% was achieved for this performance measure, reflecting a 21-day outage at Genesee 2 for scheduled maintenance and outages at Clover Bar Energy Centre Units 2 and 3 for mechanical issues.

Results by plant category

(unaudited, $ millions)	Three months ended			
	June 30, 2010	March 31, 2010	Dec 31, 2009	Sept 30, 2009[(2)]
Revenues				
Alberta commercial plants and portfolio optimization	$ 197	$ 235	$ 248	$ 238
Alberta contracted plants	55	72	61	70
Ontario/British Columbia contracted plants	4	3	4	4
CPILP plants	116	139	130	123
Other portfolio activities	25	43	40	23
Inter-plant category transaction eliminations	(10)	(10)	(9)	(10)
	387	482	474	448
Unrealized fair value changes in derivative instruments and natural gas inventory held for trading				
- CPLP	(55)	12	15	30
- CPILP	(19)	5	8	33
	(74)	17	23	63
	$ 313	**$ 499**	**$ 497**	**$ 511**
Gross margin[(1)]				
Alberta commercial plants and portfolio optimization	$ 60	$ 65	$ 53	$ 50
Alberta contracted plants	43	59	48	58
Ontario/British Columbia contracted plants	4	3	4	4
CPILP plants	68	77	74	77
Other portfolio activities	8	15	12	8
Inter-plant category transaction eliminations	(9)	(9)	(9)	(8)
	174	210	182	189
Unrealized fair value changes in derivative instruments and natural gas inventory held for trading				
- CPLP	(36)	9	26	16
- CPILP	(18)	(3)	8	13
	(54)	6	34	29
	$ 120	**$ 216**	**$ 216**	**$ 218**
Operating margin[(1)]				
Alberta commercial plants and portfolio optimization	$ 47	$ 55	$ 39	$ 41
Alberta contracted plants	19	46	27	47
Ontario/British Columbia contracted plants	2	2	3	3
CPILP plants	41	53	47	48
Other portfolio activities	-	5	4	2
Inter-plant category transaction eliminations	-	-	-	(1)
	109	161	120	140
Unrealized fair value changes in derivative instruments and natural gas inventory held for trading				
- CPLP	(36)	9	26	16
- CPILP	(18)	(3)	8	13
	(54)	6	34	29
	$ 55	**$ 167**	**$ 154**	**$ 169**

(1) The results by plant category, except for gross margin and operating margin, have been prepared in accordance with Canadian GAAP. See Non-GAAP Financial Measures.

(2) Revenues and energy purchases for the third quarter of 2009 have been restated. See Quarterly Information - Financial Highlights.

Factors impacting the 2010 second quarter results

Alberta power prices were volatile in the second quarter of 2010 and averaged $81/MWh for the period. This high pricing and volatility resulted in higher than normal dispatch of the Alberta commercial peaking and mid-merit plants. The favourable impact of this increased generation on the operating margin was partly offset by the impact of lower operating margins from portfolio optimization strategies that were successful in the first quarter of 2010 and had an unfavourable impact in the second quarter. The realized price for the portfolio in the second quarter of 2010 was $66/MWh which was $15/MWh lower than the average Alberta power price for the period.

The operating margin for the Alberta contracted plants reflected $12 million of availability penalties and $13 million in maintenance costs related to the 21-day scheduled outage at Genesee 2.

The operating margin from other portfolio activities reflected realized losses on speculative natural gas trading and fewer trading opportunities in the import and export power markets.

The unrealized changes in the fair value of CPLP's derivative instruments primarily reflected the impact of increased Alberta forward power prices on the portfolio positions.

The unrealized changes in the fair value of CPILP's derivative instruments primarily reflected losses on foreign exchange contracts due to weakening future prices for the Canadian dollar relative to the U.S. dollar.

Factors impacting results for the previous quarters

Significant items which impacted results for the previous quarters were as follows:

In the first quarter of 2010, the realized price for the Alberta commercial plant portfolio was $67/MWh which was $26/MWh higher than the average Alberta power price for the period. This favourable realized price was primarily a result of merchant trading of derivative sell contracts in the period.

In the fourth quarter of 2009, the planned outage at Genesee 1 resulted in availability penalty payments and approximately $10 million of maintenance costs. Unrealized gains for changes in the fair value of CPLP's derivative contracts in the fourth quarter of 2009 were the result of decreased forward Alberta power prices. Strengthening future prices for the Canadian dollar relative to the U.S. dollar resulted in an unrealized increase in the fair value of CPILP's foreign exchange contracts. Indirect administration expenses included an impairment loss of $4 million on a venture capital investment, an increase in information technology costs of $2 million and transition costs relating to the Reorganization. An income tax recovery that was recognized in the third quarter was reclassified and included in the acquisition of assets from EPCOR since it related to periods prior to July 1, 2009.

In the third quarter of 2009, the unrealized increase in the fair value of CPLP's derivative instruments was primarily due to the impact of decreased forward Alberta power prices on the portfolio. The unrealized increase in the fair value of CPILP's derivative instruments was primarily due to the impact of strengthening future prices for the Canadian dollar relative to the U.S. dollar on foreign exchange contracts. This was partly offset by a decrease in the fair value of CPILP's natural gas supply contracts for the period before they were designated as hedges for accounting purposes on July 1, 2009.

Quarterly Common Share Trading Information

The Company's common shares trade on the Toronto Stock Exchange under the symbol CPX and began trading on June 26, 2009.

(unaudited)	Three months ended				
	June 30, 2010	March 31, 2010	Dec 31, 2009	Sept 30, 2009	June 30, 2009
Share price					
High	$23.39	$23.00	$21.78	$22.39	$23.00
Low	$21.76	$20.97	$18.95	$19.50	$22.00
Close	$22.14	$22.50	$21.37	$19.75	$22.35
Volume traded (millions)	4.4	7.6	6.5	12.1	5.8

As at July 30, 2010, the Company had 21.767 million common shares outstanding, 56.625 million special voting shares outstanding and one special limited voting share outstanding. The weighted average number of common shares outstanding on a diluted basis was 78.377 million for the three months ended June 30, 2010 and 78.376 million for the six months ended June 30, 2010. All of the outstanding special voting shares and the outstanding special limited voting share are held indirectly by EPCOR.

As at July 30, 2010, CPLP had 21.750 million general partnership units outstanding, one common limited partnership unit outstanding and 56.625 million exchangeable limited partnership units outstanding, which are exchangeable for 56.625 million common shares of the Company. All of the outstanding general partnership units and the outstanding common limited partnership unit are held, indirectly, by the Company. All of the outstanding exchangeable limited partnership units are held indirectly by EPCOR.

As at July 30, 2010, CPILP had 55.1 million limited partnership units outstanding and 16.5 million of such units, representing 29.9% of the outstanding limited partnership units, were held by CPI Investments Inc. EPCOR held 51 Class A Shares of CPI Investments Inc. representing 51% of the votes and CPLP held 49 Class B Shares of CPI Investments Inc. representing 49% of the votes. CPLP had an effective 100% economic interest in CPI Investments Inc.

Additional Information

Additional information relating to Capital Power Corporation, including the Company's annual information form and continuous disclosure documents, is available on SEDAR at www.sedar.com.

CAPITAL POWER CORPORATION

Consolidated Statements of Income
(Unaudited, in millions of dollars except shares and per share amounts)

	Three months ended June 30, 2010	Six months ended June 30, 2010
Revenues	$ 313	$ 812
Energy purchases and fuel	193	476
	120	336
Operations, maintenance and direct administration	61	105
Indirect administration	31	57
Property taxes	4	9
Depreciation, amortization and asset retirement accretion	52	98
Foreign exchange gains	(2)	(1)
Gain on sale of power syndicate agreement (note 4)	-	(28)
Net financing expenses	19	37
	165	277
Income (loss) before income tax expense and non-controlling interests	(45)	59
Income tax recovery (note 7)	(7)	(7)
Income (loss) before non-controlling interests	(38)	66
Non-controlling interests (note 6)	(30)	61
Net income (loss)	$ (8)	$ 5
Earnings per share		
Basic	$ (0.37)	$ 0.23
Diluted	(0.37)	0.23
Weighted average number of common shares outstanding		
Basic	21,751,512	21,750,760
Diluted	78,376,512	78,375,760

See accompanying notes to interim consolidated financial statements.

CAPITAL POWER CORPORATION

Consolidated Balance Sheets
(Unaudited, in millions of dollars)

	June 30, 2010	December 31, 2009
Assets		
Current assets:		
Cash and cash equivalents	$ 89	$ 52
Accounts receivable	241	275
Income taxes recoverable	6	29
Inventories	54	58
Prepaid expenses	13	8
Derivative instruments assets (note 8)	128	146
Future income tax assets (note 7)	2	2
Assets held for sale (note 4)	-	36
	533	606
Property, plant and equipment	3,383	3,242
Power purchase arrangements	507	528
Contract and customer rights and other intangible assets	184	184
Derivative instruments assets (note 8)	93	155
Future income tax assets (note 7)	66	61
Goodwill	141	140
Other assets	108	120
	$ 5,015	$ 5,036
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 281	$ 339
Other current liabilities	9	8
Derivative instruments liabilities (note 8)	116	108
Future income tax liabilities (note 7)	7	21
Current portion of long-term debt	35	247
	448	723
Long-term debt (note 5)	1,773	1,472
Derivative instruments liabilities (note 8)	100	102
Other non-current liabilities	110	109
Future income tax liabilities (note 7)	79	95
	2,510	2,501
Non-controlling interests (note 6)	2,026	2,046
Shareholders' equity:		
Share capital	477	477
Contributed surplus	3	2
Retained earnings (deficit)	(2)	7
Accumulated other comprehensive income	1	3
Retained earnings (deficit) and accumulated other comprehensive income	(1)	10
	479	489
Commitments (note 10)		
Subsequent events (notes 9 and 13)		
	$ 5,015	$ 5,036

See accompanying notes to interim consolidated financial statements.

CAPITAL POWER CORPORATION

Consolidated Statements of Changes in Shareholders' Equity
(Unaudited, in millions of dollars)

	Three months ended June 30, 2010	Six months ended June 30, 2010
Share capital:		
Balance, beginning of period	$ 477	$ 477
Balance, end of period	477	477
Contributed surplus:		
Balance, beginning of period	2	2
Stock-based compensation	1	1
Balance, end of period	3	3
Retained earnings (deficit):		
Balance, beginning of period	13	7
Net income (loss)	(8)	5
Common share dividends	(7)	(14)
Balance, end of period	(2)	(2)
Accumulated other comprehensive income:		
Balance, beginning of period	3	3
Other comprehensive loss	(2)	(2)
Balance, end of period	1	1
Total shareholders' equity, end of period	$ 479	$ 479

See accompanying notes to interim consolidated financial statements.

CAPITAL POWER CORPORATION

Consolidated Statements of Comprehensive Income
(Unaudited, in millions of dollars)

	Three months ended June 30, 2010	Six months ended June 30, 2010
Net income (loss)	$ (8)	$ 5
Other comprehensive income (loss), net of income taxes:		
Changes in gains and losses on derivative instruments designated as cash flow hedges[1]	(1)	(18)
Reclassification of gains on derivative instruments designated as cash flow hedges to net income[2]	(17)	(11)
Reclassification of ineffective portion of cash flow hedges to net income[4]	1	1
Unrealized gain in self-sustaining foreign operations[3]	28	8
Non-controlling interests[4] (note 6)	(13)	18
	(2)	(2)
Comprehensive income (loss)	$ (10)	$ 3

[1] For the three and six months ended June 30, 2010, net of income tax recoveries of nil and $8, respectively.

[2] For the three and six months ended June 30, 2010, net of reclassification of income tax expenses of $2 and $1, respectively.

[3] For the three and six months ended June 30, 2010, net of income tax recoveries of $5 and $1, respectively.

[4] For the three and six months ended June 30, 2010, net of income tax expense of nil.

See accompanying notes to interim consolidated financial statements.

CAPITAL POWER CORPORATION

Consolidated Statements of Cash Flows
(Unaudited, in millions of dollars)

	Three months ended June 30, 2010	Six months ended June 30, 2010
Operating activities:		
Net income (loss)	$ (8)	$ 5
Adjustments to reconcile net income to cash flows from operating activities:		
Depreciation, amortization and asset retirement accretion	52	98
Gain on sale of power syndicate agreement (note 4)	-	(28)
Non-controlling interests in CPILP and CPLP (note 6)	(34)	54
Fair value changes on derivative instruments	57	50
Unrealized foreign exchange gains	(2)	-
Future income taxes	(8)	(9)
Other	(4)	(5)
	53	165
Change in non-cash operating working capital	(22)	(4)
	31	161
Investing activities:		
Property, plant and equipment and other assets	(133)	(211)
Proceeds on sale of power syndicate agreement (note 4)	-	64
Other	4	6
	(129)	(141)
Financing activities:		
Repayment of long-term debt	(177)	(246)
Proceeds from issue of long-term debt (note 5)	335	335
Distributions to non-controlling interests	(28)	(56)
Common share dividends paid	(7)	(14)
Other	(2)	(2)
	121	17
Foreign exchange gains on cash held in a foreign currency	1	-
Increase in cash and cash equivalents	24	37
Cash and cash equivalents, beginning of period	65	52
Cash and cash equivalents, end of period	$ 89	$ 89
Supplementary cash flow information:		
Interest (paid) net of interest received	$ (27)	$ (50)
Net income taxes (paid) recovered	(1)	7

See accompanying notes to interim consolidated financial statements.

1. Basis of presentation:

These unaudited interim consolidated financial statements of Capital Power Corporation (the Company or Capital Power) have been prepared by management in accordance with Canadian generally accepted accounting principles (GAAP) for interim financial statements and do not include all of the disclosures normally found in the Company's annual consolidated financial statements. These unaudited interim consolidated financial statements should be read in conjunction with the Company's audited consolidated financial statements for the six months ended December 31, 2009.

These financial statements have been prepared following the same accounting policies and methods as those used in preparing the most recent consolidated financial statements for the six months ended December 31, 2009.

The Company was incorporated on May 1, 2009, and did not have any results from operations or significant cash flows in the period from May 1 to June 30, 2009. Accordingly, there are no comparative statements of income, statements of changes in shareholders' equity, statements of comprehensive income and statements of cash flows for the periods ended June 30, 2009.

2. Nature of operations:

Interim results will fluctuate due to plant maintenance schedules, the seasonal demands for electricity and changes in energy prices. Consequently, interim results are not necessarily indicative of annual results.

3. Measurement uncertainty:

In accordance with Canadian GAAP, the Company uses estimates in preparing its consolidated financial statements. Interim consolidated financial statements necessarily employ a greater use of estimates than the annual consolidated financial statements. In the opinion of management of the Company, these interim consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the Company's accounting policies.

4. Sale of power syndicate agreement:

The Company's interest in the Battle River Power Syndicate Agreement (Battle River PSA) was disposed of on January 15, 2010 for proceeds of $64 million. The Company recognized a gain on disposal of $28 million less income taxes of $2 million in the first quarter of 2010. The Battle River PSA was previously acquired by the Company, effective July 1, 2009, as a part of the acquisition of assets from EPCOR Utilities Inc. At the acquisition date, the Company recognized fair value adjustments to the Battle River PSA asset for the Company's 27.75% share of the Battle River PSA gain on disposal. As a result, the impact on net income after non-controlling interests of the sale of the Battle River PSA in the six months ended June 30, 2010 is nil.

5. Long-Term Debt:

Unsecured three-year credit facilities of $700 million are available to the Company's subsidiary, Capital Power LP (CPLP). At June 30, 2010, the Company had $426 million in bankers' acceptances outstanding under this facility (December 31, 2009 - $100 million).

(Unaudited, tabular amounts in millions of dollars)

6. Non-controlling interests:

Results of operations which relate to non-controlling interests are as follows:

	Three months ended June 30, 2010	Six months ended June 30, 2010
Non-controlling interests in Capital Power Income L.P. (CPILP)	$ (7)	$ 5
Non-controlling interests in CPLP	(27)	49
Preferred share dividends paid by subsidiary company	4	7
	$ (30)	$ 61

Non-controlling interests reflected on the consolidated balance sheet are comprised of:

	June 30, 2010	December 31, 2009
Non-controlling interests in CPILP, beginning of period	$ 345	$ -
Non-controlling interests in CPILP in net assets acquired	-	383
Net income attributable to non-controlling interests	5	26
Other comprehensive loss attributable to non-controlling interests	(11)	(34)
Distributions to non-controlling interests	(33)	(33)
Issue of CPILP units to non-controlling interests	13	3
Non-controlling interests in CPILP, end of period	319	345
Non-controlling interests in CPLP, beginning of period	1,481	-
Non-controlling interests in CPLP in net assets acquired	-	130
Partnership units issued to non-controlling interests	-	1,302
Net income attributable to non-controlling interests	49	68
Other comprehensive (loss) income attributable to non-controlling interests	(7)	17
Distributions to non-controlling interests	(36)	(36)
Non-controlling interests in CPLP, end of period	1,487	1,481
Preferred shares issued by subsidiary companies, beginning of period	220	-
Preferred shares outstanding in acquired subsidiaries	-	122
Issue of preferred shares	-	98
Preferred shares issued by subsidiary companies, end of period	220	220
	$ 2,026	$ 2,046

(Unaudited, tabular amounts in millions of dollars)

7. Income taxes:

	Three months ended June 30, 2010	Six months ended June 30, 2010
Future income tax recovery	$ (7)	$ (21)
Current income taxes	-	14
	$ (7)	$ (7)

Income taxes differ from the amounts that would be computed by applying the federal and provincial income tax rates as follows:

	Three months ended June 30, 2010	Six months ended June 30, 2010
Income (loss) before income taxes and non-controlling interests	$ (45)	$ 59
Statutory income tax rates	28.0%	28.0%
Income taxes at statutory rate	(13)	16
Increase (decrease) resulting from:		
Taxable income attributable to non-controlling interests	4	(18)
Non-taxable amounts	(2)	(3)
Change in valuation allowance	2	3
Adjustment for enacted changes in income tax laws and rates and other tax rate differences	4	(3)
Other	(2)	(2)
	$ (7)	$ (7)

The tax effects of temporary differences that give rise to significant components of the future income tax assets and future income tax liabilities are presented below:

	June 30, 2010	December 31, 2009
Property, plant and equipment – differences in net book value and tax bases	$ (105)	$ (102)
Losses carried forward	92	79
Power purchase arrangements	(23)	(27)
Asset retirement obligations	14	13
Cumulative eligible capital	12	12
Deferred income from partnerships	(9)	(19)
Derivative Instruments	8	(5)
Other	(7)	(4)
Net future income tax liabilities	$ (18)	$ (53)
Presented on the balance sheet as follows:		
Current assets	$ 2	$ 2
Non-current assets	66	61
Current liabilities	(7)	(21)
Non-current liabilities	(79)	(95)
	$ (18)	$ (53)

(Unaudited, tabular amounts in millions of dollars)

8. Derivative instruments and hedge accounting:

Derivative financial and non-financial instruments are held for the purpose of energy purchases, merchant trading or financial risk management.

Derivative instruments assets and liabilities consist of the following:

	June 30, 2010				
	Energy		Foreign exchange	Interest rate	
	Cash flow hedges	Non-hedges	Non-hedges	Non-hedges	Total
Derivative instruments assets:					
Current	$ 15	$ 109	$ 4	$ -	$ 128
Non-current	20	55	18	-	93
Derivative instruments liabilities:					
Current	(26)	(84)	(2)	(4)	(116)
Non-current	(56)	(36)	(8)	-	(100)
Net fair value	$ (47)	$ 44	$ 12	$ (4)	$ 5
Net notional buys (sells):					
Megawatt hours of electricity (millions)	(4)	(2)			
Gigajoules of natural gas (millions)	42	7			
Foreign currency (U.S. dollars)			$ (325)		
Interest rate swaps				$ 200	
Range of contract terms in years	0.1 to 6.5	0.1 to 4.4	0.1 to 6.0	0.7	

(Unaudited, tabular amounts in millions of dollars)

8. Derivative instruments and hedge accounting, continued:

	December 31, 2009				
	Energy		Foreign exchange	Interest rate	
	Cash flow hedges	Non-hedges	Non-hedges	Non-hedges	Total
Derivative instruments assets:					
Current	$ 15	$ 126	$ 5	$ -	$ 146
Non-current	32	97	26	-	155
Derivative instruments liabilities:					
Current	(23)	(83)	(2)	-	(108)
Non-current	(37)	(61)	(4)	-	(102)
Net fair value	$ (13)	$ 79	$ 25	$ -	$ 91
Net notional buys (sells):					
Megawatt hours of electricity (millions)	(3)	(4)			
Gigajoules of natural gas (millions)	45	9			
Foreign currency (U.S. dollars)			$ (379)		
Interest rate swaps				$ -	
Range of contract terms in years	0.1 to 7.0	0.1 to 4.8	0.1 to 6.0		

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

	Three months ended June 30, 2010		Six months ended June 30, 2010	
	Unrealized gains (losses)	Realized gains (losses)	Unrealized gains (losses)	Realized gains (losses)
Energy cash flow hedges	$ (19)	$ 19	$ (36)	$ 12
Energy non-hedges	(34)	10	(34)	21
Foreign exchange non-hedges	(18)	1	(13)	4
Interest rate non-hedges	(4)	-	(4)	-

Realized gains and losses relate only to financial derivative instruments. Gains and losses on non-financial derivative instruments settlements are recorded in energy revenues or energy purchases and fuel, as appropriate.

The Company has elected to apply hedge accounting on certain derivatives it uses to manage commodity price risk relating to electricity and natural gas prices. For the three and six months ended June 30, 2010, the change in the fair value of the ineffective portion of hedging derivatives required to be recognized in the income statement, before non-controlling interests, was $1 million. Net losses of $1 million, net of income taxes of nil, related to derivative instruments designated as cash-flow hedges, are expected to settle and be reclassified to net income over the next twelve months. The Company's cash flow hedges extend up to 2016.

9. Risk management:

Market risk

Commodity price risk

The Company is exposed to commodity price risk as part of its normal business operations, including energy procurement activities in Alberta, Ontario, and the U.S. The Company's energy procurement activities consist of power generation, non-market traded and market traded electricity and natural gas purchase and sales contracts, and derivative contracts. The Company is primarily exposed to changes in the prices of electricity, and to a lesser extent is exposed to changes in the prices of natural gas and coal. The Company actively manages commodity price risk by optimizing its asset and contract portfolios utilizing the following methods variously:

- The Company reduces its exposure to the volatility of commodity prices related to electricity sales by entering into offsetting contracts such as contracts-for-differences and firm price physical contracts for periods of varying duration.
- The Company enters into fixed-price energy sales contracts and power purchase arrangements which limit the exposure to electricity prices. The Company has entered into long-term tolling arrangements whereby variable changes linked to the price of natural gas and coal are assumed by the counterparty.
- When it is economically feasible, the Company purchases natural gas under long-term fixed-price supply contracts to reduce the exposure to fluctuating natural gas prices on its natural gas-fired generation plants and physical obligations arising from retail customers.
- The Company enters into back-to-back electricity and natural gas physical and financial contracts in order to lock in a margin.

The Company also engages in taking market risk positions within authorized limits approved by Capital Power's executive team and Board of Directors. The trading portfolio consists of electricity and natural gas physical and financial derivative contracts which are transacted with the intent of benefiting from short-term actual or expected differences between their buying and selling prices or to lock in arbitrage opportunities.

The fair value of the Company's energy related derivatives at June 30, 2010 that are required to be measured at fair value with the respective changes in fair value recognized in net income are disclosed in note 8.

The Company employs specific volumetric limits and a Value-at-Risk (VaR) methodology to manage risk exposures to commodity prices on a consolidated basis. VaR measures the estimated potential loss in a portfolio of positions associated with the movement of a commodity price for a specified time or holding period and a given confidence level. Effective January 11, 2010, the Company has adopted a new risk management framework. Under this framework, Capital Power's current period VaR uses a statistical confidence interval of 99% over a five day holding period. This measure reflects a 1% probability that, over the five day period commencing with the point in time that the VaR is measured, the fair value of the overall commodity portfolio could decrease by an amount in excess of the VaR amount. The VaR methodology is a statistically-defined, probability-based approach that takes into consideration market volatilities and risk diversification by recognizing offsetting positions and correlations between products and markets. This technique makes use of historical data and makes an assessment of the market risk arising from possible future changes in commodity prices over the holding period.

9. Risk management, continued:

Market risk, continued

Commodity price risk, continued

VaR should be interpreted in light of the limitations of the methodologies used. These limitations include the following:

- VaR calculated based on a holding period may not fully capture the market risk of positions that cannot be liquidated or hedged within the holding period.
- The Company computes VaR of the portfolios at the close of business and positions may change substantially during the course of the day.
- VaR, at a 99% confidence level, does not reflect the extent of potential losses beyond that percentile. Losses on the other 1% of occasions could be substantially greater than the estimated VaR.

These limitations and the nature of the VaR measurements mean that the Company can neither guarantee that losses will not exceed the VaR amounts or that losses in excess of the VaR amounts will not occur more frequently than 1% of the time. As VaR is not a perfect measure of risk, the Company undertakes back testing and periodically calibrates the VaR calculation to a 99% confidence level.

The estimation of VaR takes into account positions from all wholly-owned subsidiaries and subsidiaries in which the Company has controlling interest, and reflects the Company's aggregate commodity positions from its trading and asset portfolios. Capital Power's Board of Directors has established methodology for the ongoing determination of Commodity Risk limits, under their risk management policy. Commodity risk is monitored and reported to the executive team on a daily basis. The portfolios are stress tested regularly to observe the effects of plausible scenarios taking into account historical maximum volatilities and maximum observed price movements. Based on the commodity portfolio as at June 30, 2010, there is a 99% probability that unfavorable daily market variations would not reduce the twelve month portfolio by more than $13 million.

Interest rate risk

The Company is exposed to changes in interest rates on its cash and cash equivalents, floating rate short-term and long-term loans and obligations and interest rate derivatives. The Company is exposed to interest rate risk from the possibility that changes in the interest rates will affect future cash flows or the fair values of its financial instruments. In some circumstances, floating rate funding may be used for short-term borrowings and other liquidity requirements. At June 30, 2010, the proportion of fixed rate debt was approximately 72% of total long-term debt outstanding (December 31, 2009 – 90%). The Company may also use derivative instruments to manage interest rate risk. At June 30, 2010, the Company held interest rate derivatives as disclosed in note 8.

Assuming that the amount and mix of fixed and floating rate loans, net debt, and interest rate derivatives remains unchanged from that held at June 30, 2010, a 100 basis point decrease or increase to interest rates would decrease or increase full year net income by $2 million and would have no direct impact on other comprehensive income.

The effect on net income does not consider the effect of an overall change in economic activity that would accompany such an increase or decrease in interest rates. There would be no impact on net income for debt and long-term loan arrangements issued and held by the Company at fixed interest rates.

(Unaudited, tabular amounts in millions of dollars)

9. Risk management, continued:

Liquidity risk

As at June 30, 2010, the Company had undrawn and committed bank credit facilities, and operating lines of credit and demand facilities, totaling $954 million (December 31, 2009 - $1,294 million), of which $650 million (December 31, 2009 - $600 million) is committed for at least two years.

In addition to the facilities noted above, the Company has shelf prospectuses under which it may raise funds in the form of debt or capital. As at June 30, 2010, the Company's subsidiary, CPILP, had a Canadian shelf prospectus, which was to expire in August 2010, under which it could raise up to $1 billion in partnership units or debt securities, of which a maximum of $600 million could be medium-term notes. As at June 30, 2010, CPILP has not drawn on the shelf prospectus (December 31, 2009 - nil). On July 2nd, 2010, CPILP issued a Canadian shelf prospectus under which it may raise up to $600 million in partnership units, debt securities or subscription receipts. This Canadian shelf prospectus expires in August 2012 and replaces the previous CPILP Canadian shelf prospectus that was to expire in August 2010. In the first quarter of 2010, CPC has issued a Canadian shelf prospectus, which expires in May 2012, under which it may raise up to $1 billion collectively in common shares of the Company and subscription receipts exchangeable for common shares and/or other securities of the Company. As at June 30, 2010, CPC has not drawn on the shelf prospectus. In the first quarter of 2010, the Company's subsidiary, CPLP, has issued a Canadian shelf prospectus, which expires in May 2012, under which it may raise up to $1 billion in medium-term notes. As at June 30, 2010 CPLP has not drawn on the shelf prospectus.

The following are the undiscounted cash flow requirements and contractual maturities of the Company's financial liabilities, including interest payments, and where applicable, net of financial assets that generate cash inflows to meet cash outflows on financial liabilities as at June 30, 2010:

	Due within 1 year	Due between 1 and 2 years	Due between 2 and 3 years	Due between 3 and 4 years	Due between 4 and 5 years	Due after more than 5 years	Total contractual cash flows
Non-derivative financial liabilities:							
Long-term debt	$ 35	$ 289	$ 30	$ 454	$ 217	$ 800	$ 1,825
Interest payments on long-term debt	99	85	80	68	57	356	745
Accounts payable and accrued liabilities [1]	261	-	-	-	-	-	261
Other current liabilities	9	-	-	-	-	-	9
Loan commitments	6	-	-	-	-	-	6
Derivative financial liabilities:							
Net forward foreign exchange contracts	2	1	1	2	2	3	11
Net commodity contracts-for-differences	75	28	3	-	-	-	106
Total	$ 487	$ 403	$ 114	$ 524	$ 276	$ 1,159	$ 2,963

[1] Excluding accrued interest on long-term debt of $20 million.

(Unaudited, tabular amounts in millions of dollars)

10. Commitments:

During the second quarter of 2010, the Company's Port Dover & Nanticoke Wind Project (PDNW) was selected for the award of a contract to sell power to a third party. The 105 megawatt (MW) PDNW project would be located in southern Ontario, and developed by a subsidiary of the Company at an expected cost of $340 million. Energy generated by PDNW would be sold under a 20-year contract with the third party. Construction of PDNW will commence upon receipt of all required regulatory approvals and commercial operation is expected to commence in the fourth quarter of 2012.

During the first quarter of 2010, the Company's Quality Wind Project (Quality Wind) was selected, by a third party, for the award of an Energy Purchase Agreement (EPA). The 142 MW wind power project would be located in northeastern British Columbia, and developed by a subsidiary of the Company at an expected cost of $455 million. Energy generated by Quality Wind would be sold under a 25-year EPA with the third party. Construction of Quality Wind will commence upon receipt of all required regulatory approvals and commercial operation is expected to commence no later than the spring of 2013.

11. Guarantees:

The Company has issued letters of credit for $121 million (December 31, 2009 - $119 million) to meet the credit requirements of energy market participants, to meet conditions of certain service agreements, and to satisfy legislated reclamation requirements.

Prior to the July 2009 acquisition of subsidiaries and assets from EPCOR Utilities Inc. (EPCOR), EPCOR issued parental guarantees on behalf of former EPCOR subsidiaries to meet the credit requirements of energy market participants, to meet conditions of certain service agreements, and to satisfy legislated reclamation requirements. At June 30, 2010, EPCOR continues to have outstanding parental guarantees on behalf of Capital Power totaling $19 million (December 31, 2009 - $1,295 million) related to subsidiaries of Capital Power.

12. Segment disclosures:

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

Geographic information

	Three months ended June 30, 2010				Six months ended June 30, 2010			
	Canada	U.S.	Inter-area eliminations	Total	Canada	U.S.	Inter-area eliminations	Total
Revenues - external	$ 243	$ 70	$ -	$ 313	$ 660	$ 152	$ -	$ 812
Inter-area revenues	3	1	(4)	-	7	5	(12)	-
Total revenues	$ 246	$ 71	$ (4)	$ 313	$ 667	$ 157	$ (12)	$ 812

	As at June 30, 2010				As at December 31, 2009			
	Canada	U.S.	Inter-area eliminations	Total	Canada	U.S.	Inter-area eliminations	Total
Property, plant and equipment	$ 2,856	$ 527	$ -	$3,383	$2,734	$ 508	$ -	$3,242
Goodwill	$ 104	$ 37	$ -	$ 141	$ 104	$ 36	$ -	$ 140

13. Subsequent event:

On August 2, 2010, the Company's subsidiary, CPLP, entered into an agreement to acquire the Island Generation Facility (Island Generation), a 275 MW gas-fired combined cycle power plant at Campbell River, British Columbia, from a third party. The transaction is expected to close in the fourth quarter of 2010, subject to regulatory and other approvals. Subject to market conditions, the Company expects to finance the purchase price of approximately $207 million, plus closing costs and normal working capital adjustments, with a combination of debt and equity.

Island Generation is fully contracted from April 1, 2010 to April 2022 under a tolling arrangement with a third party. The third party to the tolling arrangement will be responsible for the fuel supply to the facility.

14. Comparative figures:

The comparative balance sheet figures for accounts payable and accrued liabilities and non-controlling interests have been recast to reflect the accrual of $18 million of distributions to non-controlling interests that were declared in the fourth quarter of 2009 for which the accrual was previously omitted from the December 31, 2009 financial statements. In the opinion of management of the Company, the amount of the recast is not considered to be material.