
For immediate release

October 25, 2011

Capital Power reports third quarter 2011 results

EDMONTON, Alberta – Capital Power Corporation (Capital Power, or the Company) (TSX: CPX) today released its results for the third quarter ended September 30, 2011. Normalized earnings attributable to common shareholders, after adjusting for one-time items and fair value adjustments was \$21 million, or \$0.43 per share, in the third quarter of 2011, compared with \$14 million, or \$0.64 per share, in the comparable period in 2010. Funds from operations, excluding non-controlling interests in Capital Power Income L.P. (CPILP), totaled \$116 million in the third quarter of 2011, up 33% from \$87 million in the third quarter of 2010. For the nine-month period ending September 30, 2011, normalized earnings attributable to common shareholders was \$35 million, or \$0.87 per share. Funds from operations excluding non-controlling interests in CPILP totaled \$264 million compared with \$199 million in the nine-month period ending September 30, 2010.

“Third quarter consolidated financial performance was in line with our expectations”, said Brian Vaasjo, President and CEO of Capital Power. “Alberta spot power prices averaged \$95 per megawatt hour in the third quarter, which resulted in higher than anticipated margins for the Alberta commercial plants and portfolio optimization segment and higher availability incentive revenue for the Alberta contracted plants. However, this was offset by lower earnings contributions from our three New England plants due to lower than expected power prices in that region.”

“The operating performance of our plants was excellent in the third quarter”, added Mr. Vaasjo. “Average plant availability, excluding CPILP plants, was 97 per cent and electricity generation reached nearly 5,520 gigawatt hours. The quarter was highlighted by the commercial operation launch on September 1 of the 495 megawatt (MW) Keephills 3 generating plant with our joint partner TransAlta Corporation. Keephills 3 is the most technologically advanced coal-fired plant in Canada and it increases our generation portfolio to more than 1,700 megawatts in Alberta’s attractive power market. We also announced a limited partnership agreement for our K2 Wind Ontario project, a 270 MW wind power project, with Samsung Renewable Energy Inc. and Pattern Renewal Holdings Canada. The addition of K2 will increase Capital Power’s geographically diversified wind portfolio to approximately 525 megawatts.”

Operational and Financial Highlights⁽¹⁾ (unaudited)	Three months ended September 30		Nine months ended September 30	
<i>(millions of dollars except per share and operational amounts)</i>	2011	2010	2011	2010
Electricity generation (GWh)	5,515	3,635	13,467	10,351
Generation plant availability (excluding CPILP plants) (%)	97%	93%	94%	90%
Revenues and other income	433	513	1,363	1,327
Gross income	244	236	628	570
Earnings before interest, taxes, depreciation and amortization (EBITDA) ⁽²⁾	132	83	279	289
Normalized earnings attributable to common shareholders ⁽²⁾	21	14	35	26
Normalized earnings per share ⁽²⁾	\$0.43	\$0.64	\$0.87	\$1.19
Net income (loss) attributable to shareholders	15	16	(7)	20
Earnings (loss) per share	\$0.29	\$0.74	\$(0.27)	\$0.92
Dividends declared per share	\$0.315	\$0.315	\$0.95	\$0.95
Funds from operations ⁽²⁾	144	112	334	276
Funds from operations excluding non-controlling interests in CPILP ⁽²⁾	116	87	264	199
Cash flow per share ⁽²⁾	\$1.21	\$1.11	\$3.01	\$2.53
Dividend coverage ratio ⁽²⁾	3.4	3.2	2.5	2.2
Capital expenditures	107	68	316	251

(1) The operational and financial highlights in this press release should be read in conjunction with Management's Discussion and Analysis and the unaudited Condensed Interim Consolidated Financial Statements for the nine months ended September 30, 2011.

(2) Earnings before interest, taxes, depreciation and amortization (EBITDA), Normalized earnings attributable to common shareholders, Normalized earnings per share, Funds from operations, Funds from operations excluding non-controlling interests in Capital Power Income L.P. (CPILP), Cash flow per share, and Dividend coverage ratio are non-IFRS financial measures and do not have standardized meanings under IFRS, and therefore, may not be comparable to similar measures used by other enterprises. See Non-IFRS Financial Measures. Reconciliations of these non-IFRS financial measures to Net income attributable to shareholders, Earnings per share and Cash provided by operating activities are included in the Company's Management's Discussion and Analysis dated October 25, 2011, which is available under the Company's profile on SEDAR at www.SEDAR.com.

Significant Events

\$231 million common share offering

In July 2011, the Company closed an offering to sell 9,200,000 common shares at a price of \$25.10 per share to a syndicate of underwriters for gross proceeds of approximately \$231 million, less underwriters' fees of approximately \$9 million. The net proceeds from the common share offering were used to purchase an additional 9,200,000 common limited partnership units of Capital Power L.P. (CPLP). CPLP used the funds to repay a portion of the outstanding indebtedness under its credit facilities, which was drawn to fund the acquisitions of the New England facilities, and for general corporate purposes including financing development projects and working capital requirements. This transaction reduced EPCOR Utilities Inc.'s ownership interest in CPLP to approximately 48.9% effective for the third quarter from 54.1% at June 30, 2011.

Development of K2 Wind Ontario project

On August 3, 2011, CPLP entered into a limited partnership agreement with Samsung Renewable Energy Inc. (Samsung) and Pattern Renewable Holdings Canada ULC (Pattern) for the development, construction and operation of a 270 megawatt (MW) wind power project to be known as K2 Wind Ontario (K2). Formerly referred to as the Kingsbridge II Wind Power Project, K2 will be developed in the Township of Ashfield-Colborne-Wawanosh in southwestern Ontario. The project has an expected total capital cost of \$874 million, most of which will be funded through project financing.

The Ontario Power Authority has signed a PPA for K2. The completion of the project is subject to obtaining necessary corporate approvals, executing definitive agreements, and receiving regulatory approvals. The partners expect that construction would begin in 2013, with commercial operation in 2014.

At commencement of commercial operation, each of the three partners will have an equal economic interest in the project. Capital Power will contribute the project lease agreements and development work completed to August 3, 2011, while Samsung and Pattern will contribute the PPA and transmission access rights. Capital Power will continue to lead the provincial Renewal Energy Approval process for the project which it has been doing since 2006. Samsung will serve as the engineering procurement and construction contractor, and the K2 partnership will finalize the turbine model and supplier.

Keephills 3 power plant begins commercial operation

On September 1, 2011, the Company and TransAlta Corporation (TransAlta) completed the 495 MW (gross) Keephills 3 generating facility, which is now in commercial operation. The facility is the most technologically advanced coal-fired plant in Canada and the Company's share of its final cost is expected to be approximately \$955 million. Costs for the plant, excluding mine capital, are being equally shared by its owners – Capital Power, which led the construction, and TransAlta, which operates the plant.

Update on Atlantic Power Corporation's acquisition of CPILP

In June 2011, CPILP and Atlantic Power Corporation (Atlantic Power) entered into an arrangement agreement under which Atlantic Power would acquire, directly and indirectly, all of the outstanding limited partnership units of CPILP, including Capital Power's ownership interest, for \$19.40 per limited partnership unit, payable in cash or shares of Atlantic Power. Approval votes by Atlantic Power shareholders and CPILP unitholders have been scheduled for November 1, 2011, and if successful, will likely result in the transaction closing shortly thereafter. If the transaction is completed in November, the distribution for the month ended October 31, 2011 will be CPILP's final distribution.

Analyst Conference Call and Webcast

Capital Power will be hosting a conference call and live webcast with analysts on October 26, 2011 at 1:00 pm (ET) to discuss third quarter results. 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: 21543#

A replay of the conference call will be available following the call at: (877) 353-9587 (toll-free) and entering conference reference number 549495# followed by participant code 21543#. The replay will be available until midnight on November 30, 2011.

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.

Non-IFRS Financial Measures

The Company uses (i) EBITDA, (ii) funds from operations, (iii) funds from operations excluding non-controlling interests in CPILP, (iv) cash flow per share, (v) normalized earnings attributable to common shareholders, (vi) normalized earnings per share as financial performance measures, and (vii) dividend coverage ratio. These terms are not defined financial measures according to IFRS and do not have standardized meanings prescribed by IFRS, 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 IFRS. Rather, these measures are provided to complement IFRS measures in the analysis of the Company's results of operations from management's perspective. Reconciliations of EBITDA to net income, funds from operations and funds from operations excluding non-controlling interests in CPILP to cash flows from operating activities, normalized earnings attributable to common shareholders to net income attributable to common shareholders, and normalized earnings per share to earnings per share are contained in the Company's Management's Discussion and Analysis dated October 26, 2011 for the nine months ended September 30, 2011 which is available under the Company's profile on SEDAR at www.SEDAR.com.

Forward-looking Information

Certain information in this press 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 press release includes, among other things, information relating to: (i) expectations regarding the date that construction would begin and commercial operation date of the K2 wind project, the total cost of the project and method of funding the project, the project's generation capacity and its impact on the Company's wind portfolio, the area of development, the ability to obtain corporate and regulatory approvals; the partners economic interest in the project at commercial operation; finalization of the project's turbine model and supplier; and each partner's contribution to the project; (ii) the Company's share of its final expected cost of the Keephills 3 generating facility; and (iii) expectations regarding the timing of closing and outcome of the CPILP strategic review transactions.

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) the Company's financial position and credit facilities and sources of funding; (iii) the Company's assessment of the markets and regulatory environments in which it operates; (iv) weather; (v) availability and cost of labour and management resources; (vi) performance of contractors and suppliers; (vii) availability and cost of financing; (viii) counterparties will perform their obligations; (ix) ability to implement strategic initiatives which will yield the expected benefits; (x) ability to obtain necessary regulatory approvals for development projects; (xi) the Company's assessment of capital markets, common share ownership distribution, and ability to complete future share and debt offerings; (xii) locations of projects and the areas of which they will be developed, including the availability and use of certain optioned lands; (xiii) costs of construction and development; (xiv) ability to obtain court and regulatory approvals, and unitholders' and shareholders' favourable votes in relation to the CPILP strategic review transaction; and (xv) ability to obtain corporate and regulatory approvals for the K2 project.

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) regulatory and government decisions including changes to environmental, financial reporting and tax legislation; (ii) weather and

economic conditions; (iii) construction; (iv) availability and cost of financing; (v) availability and cost of labour, equipment and management resources; (vi) performance of counterparties, partners, contractors and suppliers in fulfilling their obligations to the Company; and (vii) the completion of the CPILP strategic review transactions and the K2 project. 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.

About Capital Power Corporation

Capital Power is a growth-oriented North American independent power producer, building on more than a century of innovation and reliable performance. Capital Power'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 35 facilities in Canada and the U.S. totalling nearly 5,100 megawatts of generation capacity. Capital Power and its subsidiaries develop, acquire and optimize power generation from a wide range of energy sources.

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CAPITAL POWER CORPORATION

Interim Report

September 30, 2011

Management's Discussion and Analysis

This management's discussion and analysis (MD&A), dated October 25, 2011, should be read in conjunction with the unaudited condensed interim consolidated financial statements of Capital Power Corporation and its subsidiaries for the nine months ended September 30, 2011, the audited consolidated financial statements and MD&A of the Company for the year ended December 31, 2010, and the cautionary statement regarding forward-looking information which begins on page 35. 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 nine months ended September 30, 2011 and September 30, 2010 is based on the unaudited condensed interim consolidated financial statements of the Company, which were prepared in accordance with International Financial Reporting Standards (IFRS), 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 to the Board of Directors. The Board of Directors has approved this MD&A as of October 25, 2011.

On January 1, 2011, IFRS, as issued by the International Accounting Standards Board, became the Canadian generally accepted accounting principles (GAAP) for the basis of preparation of financial statements for publicly accountable enterprises. The information presented in this MD&A, including information relating to comparative periods in 2010, is presented in accordance with IFRS unless otherwise noted as being presented under previous Canadian GAAP (previous CGAAP). A discussion of the Company's transition to IFRS, including the impact of significant accounting policy choices and the selection of IFRS 1 elections and exemptions, is included in the Company's MD&As for the year ended December 31, 2010 and the three months ended March 31, 2011. A discussion of the reconciliations of equity as at September 30, 2010 and comprehensive income for the nine months ended September 30, 2010 reported under previous CGAAP to reporting under IFRS can be found in the IFRS section which begins on page 31.

The Company's outstanding share capital on September 30, 2011 consisted of 49.727 million common shares, 5 million Cumulative Rate Reset Preference Shares, Series 1, 47.416 million special voting shares and one special limited voting share.

Corporate Strategy

The Company's corporate strategy remains unchanged from that disclosed in the 2010 annual MD&A. In the second quarter of 2011, the Company updated the financial, geographic and technology criteria it uses to evaluate growth opportunities, as discussed in the June 30, 2011 MD&A. As a result, the Company is no longer pursuing small hydro and biomass growth opportunities and is considering solar power opportunities.

Financial Highlights

(unaudited, \$millions, except earnings (loss) per share)	Three months ended		Nine months ended	
	Sept 30, 2011	Sept 30, 2010	Sept 30, 2011	Sept 30, 2010
Revenues and other income	433	513	1,363	1,327
Gross income	244	236	628	570
EBITDA ⁽¹⁾	132	83	279	289
Net income (loss)	44	(3)	36	55
Net income (loss) attributable to shareholders of the Company	15	16	(7)	20
Normalized earnings attributable to common shareholders ⁽¹⁾	21	14	35	26
Earnings (loss) per share	\$ 0.29	\$ 0.74	\$(0.27)	\$ 0.92
Fully diluted earnings (loss) per share ⁽²⁾	\$ 0.29	\$ 0.03	\$(0.27)	\$ 0.51
Normalized earnings per share ⁽¹⁾	\$ 0.43	\$ 0.64	\$ 0.87	\$ 1.19
Funds from operations ⁽¹⁾	144	112	334	276
Funds from operations excluding non-controlling interests in CPILP ⁽¹⁾	116	87	264	199
Cash flow per share ⁽¹⁾	\$ 1.21	\$ 1.11	\$ 3.01	\$ 2.53
Dividend coverage ratio ⁽¹⁾	3.4	3.2	2.5	2.2
Capital expenditures	107	68	316	251

⁽¹⁾ The consolidated financial information, except for earnings before interest, income tax, depreciation and amortization (EBITDA), normalized earnings attributable to common shareholders, normalized earnings per share, funds from operations, funds from operations excluding non-controlling interest in Capital Power Income L.P. (CPILP), cash flow per share, and dividend coverage ratio has been prepared in accordance with IFRS. See Non-IFRS Financial Measures.

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

Normalized Earnings and Normalized Earnings per Share

The Company uses normalized earnings attributable to common shareholders and normalized earnings per share to measure performance by period on a comparable basis. Normalized earnings attributable to common shareholders are based on earnings used in the calculation of earnings per share as reported in the consolidated financial statements, adjusted for items that are not reflective of performance in the period such as fair value changes, impairment charges, unusual tax adjustments and gains or losses on disposal of assets and on unusual contracts.

Normalized earnings attributable to common shareholders for the three and nine months ended September 30, 2011 were lower in comparison to management's expectations and higher than for the corresponding periods of 2010. For the third quarter, the decrease from management's expectations was primarily attributable to lower than expected contributions from the New England plants since their acquisition in April 2011. The increase from third quarter of 2010 was primarily due to higher Alberta commercial plants and portfolio optimization EBITDA, higher Alberta contracted plants EBITDA, and contributions from the Island Generation and New England plants which were acquired in October 2010 and April 2011, respectively.

For the nine months ended September 30, 2011, the increase in normalized earnings attributable to common shareholders primarily reflected higher EBITDA from the Alberta contracted plants and contributions from the Island Generation and New England plants since their acquisitions, partly offset by losses realized on the settlement of forward bond contracts and an increase in the Company's pension obligation.

Normalized earnings per share for the third quarter of 2011 and 2010 reflected normalized earnings attributable to common shareholders divided by 48.33 million and 21.77 million weighted average common shares outstanding, respectively. See Non-IFRS Financial Measures.

Funds from Operations

Funds from operations measure the Company's ability to generate cash flow from its current operating activities to fund capital expenditures, debt repayments and distributions to the Company's shareholders by period on a comparable basis. This measure is based on cash provided by operating activities, including interest and current income tax expense rather than interest and income taxes paid, and excluding changes in working capital, which are not comparable from period to period.

Since the non-controlling interests in CPILP's funds from operations were approximately 70.8% at September 30, 2011 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. See Non-IFRS Financial Measures.

The increase in funds from operations excluding the non-controlling interests in CPILP for the third quarter of 2011 compared with the corresponding period in 2010 was primarily due to contributions from the New England facilities and Island Generation which were acquired in the second quarter of 2011 and the fourth quarter of 2010, respectively.

Consolidated Net Income

	Three months	Nine months
Net income (loss) for the periods ended September 30, 2010	\$ (3)	\$ 55
Higher CPILP plants EBITDA, excluding unrealized fair value changes	69	59
Lower depreciation and amortization expense	14	11
Higher (lower) Alberta commercial plants and portfolio optimization EBITDA	13	(4)
Higher Alberta contracted plants EBITDA	10	19
North East U.S. commercial plants and portfolio optimization EBITDA since acquisition in April 2011	10	20
Higher Ontario and British Columbia contracted plants EBITDA	6	22
Unrealized changes in the fair value of forward bond contracts	2	13
Higher other finance expense	(8)	(24)
Lower Corporate EBITDA	(5)	(63)
Unrealized changes in the fair value of CPLP's energy and foreign exchange derivative instruments and natural gas inventory held for trading	(19)	(25)
Unrealized changes in the fair value of CPILP's derivative instruments	(30)	(6)
Gain on sale of power syndicate agreement in January 2010	-	(28)
Other	(5)	(4)
Increase (decrease) before tax	57	(10)
Increase in income tax	(10)	(9)
Increase (decrease) in net income	47	(19)
Net income for the periods ended September 30, 2011	\$ 44	\$ 36

Net income increased \$47 million and decreased \$19 million for the three and nine months ended September 30, 2011, respectively compared with the corresponding periods in 2010 due to the net impact of the following:

- CPILP EBITDA excluding unrealized fair value changes was higher primarily due to impairment losses of \$66 million recognized in the third quarter of 2010 reflecting lower expectations for the availability of waste heat fuel supply at CPILP's Ontario plants. This favourable variance was partly offset by costs incurred in the second and third quarters of 2011 associated with the proposed sale of CPILP to Atlantic Power (see Significant Events), and the reversal of an allowance for a doubtful accounts receivable in the second quarter of 2010.
- Depreciation expense was lower for the three and nine months ended September 30, 2011 compared with the corresponding periods in 2010 primarily because depreciation was not recognized on CPILP's assets held for sale since they were classified as such at the end of the second quarter of 2011. In addition, depreciation on the Genesee assets decreased as a result of the change in the estimated useful life of the coal plants from 35 years to 45 years effective January 1, 2011. These decreases were partly offset by depreciation on the Island Generation, New England plant assets and Keephills 3.
- Alberta commercial plants and portfolio optimization EBITDA was higher in the third quarter of 2011 primarily due to the impact of higher Alberta power prices on the portfolio position, which averaged \$95/megawatt hour (MWh) compared to \$36/MWh in the third quarter of 2010, higher dispatch of the Clover Bar Energy Centre and Joffre facilities, and higher net penalty payments received during the outage at one of the Company's acquired power purchase arrangement (PPA) units at Sundance in the third quarter of 2011, partly offset by an estimated \$8 million business interruption insurance recovery relating to Clover Bar Energy Centre Unit 2 which was recorded in the third quarter of 2010.

For the nine months ended September 30, 2011 compared with the corresponding period in 2010, the increase in EBITDA in the third quarter of 2011 was more than offset by the decrease in the first quarter of 2011. In the first quarter of 2011, significant increases in Alberta power prices had an unfavourable impact on the Company's Alberta portfolio whereas lower Alberta power prices had a favourable impact on the portfolio in the first quarter of 2010.

- Alberta contracted plants EBITDA was higher in the three and nine months ended September 30, 2011 primarily due to higher net availability incentive revenues resulting from higher rolling average power prices. In addition, the scheduled maintenance outage at Genesee 1 in the second quarter of 2011 resulted in \$5 million of availability penalties compared with \$12 million related to the Genesee 2 outage in the second quarter of 2010.
- North East U.S. commercial plants and portfolio optimization EBITDA reflected contributions from the Rumford, Tiverton and Bridgeport facilities and trading in the North East U.S. power market since they were acquired in April 2011.
- Ontario and British Columbia contracted plants EBITDA was higher primarily due to contributions from Island Generation following the Company's acquisition of the facility in the fourth quarter of 2010.
- Unrealized changes in the fair value of forward bond contracts reflected a \$5 million loss and \$2 million gain in the three and nine months ended September 30, 2011, respectively compared with losses of \$7 million and \$11 million in the three and nine months ended September 30, 2010, respectively.
- Other finance expenses for the three and nine months ended September 30, 2011 were higher than for the corresponding periods in 2010 primarily due to interest on borrowings related to the acquisition of the New England facilities in 2011.
- Corporate EBITDA for the three months ended September 30, 2011 was lower than in the corresponding period of 2010 primarily due to higher foreign exchange losses on the translation of U.S. dollar denominated debt and higher business development costs, partly offset by a \$7 million obligation to EPCOR recognized in the third quarter of 2010 for operations and maintenance costs for the Rosedale plant to be incurred over the ten-year period ending in 2019. The decrease in Corporate EBITDA for the nine months ended September 30, 2011 reflected the decrease in the third quarter as well as an impairment loss of \$43 million related to Capital Power's management and operations agreements with CPILP, a \$5 million unfavourable pension valuation adjustment based on an actuarial valuation and a \$4 million loss realized on the settlement of foreign exchange contracts. There were no comparable items in the nine months ended September 30, 2010. See Corporate under Results by Plant Category.
- In the third quarter of 2011, unrealized changes of CPLP's derivative instruments primarily reflected a \$4 million decrease in the fair value of the North East U.S. portfolio heat rate options. There was no comparable amount in 2010 as CPLP commenced trading in electricity heat rate options in this market after the acquisition of the New England plants in the second quarter of 2011. In addition, during the third quarter of 2011 the change in fair value of CPLP's derivative electricity and natural gas contracts and natural gas inventory held for trading that were not designated as hedges for accounting purposes was immaterial compared to an increase of \$14 million in the third quarter of 2010 which was primarily due to the impact of decreases in Alberta forward power prices on portfolio positions.

In the nine months ended September 30, 2011, the net change in the fair value of these instruments primarily reflected an unrealized loss of \$41 million on the Alberta electricity portfolio partly offset by a \$2 million unrealized gain on the North East U.S. heat rate options compared with a \$15 million unrealized loss on the Alberta electricity portfolio in the corresponding period of 2010. The unrealized loss on the Alberta electricity portfolio in the 2011 period was higher than in the 2010 period as there was a larger increase in Alberta forward power prices in the 2011 period.

- The unrealized changes in the fair value of CPILP's derivative instruments in the third quarter of 2011 primarily reflected decreases in the fair value of foreign exchange contracts compared with increases in the third quarter of 2010. The unrealized changes in fair value for the nine months ended September 30 primarily reflected a \$19 million decrease in the fair value of foreign exchange contracts in 2011 and a \$10 million decrease in the fair value of natural gas supply contracts in 2010.

- On January 15, 2010, the Company sold its remaining 15% interest in the Battle River Power Syndicate Agreement (PSA) for cash proceeds of \$64 million resulting in a gain of \$28 million. There was no comparable sale of assets in the first nine months of 2011.
- Income taxes were higher for the three and nine months ended September 30, 2011 compared with the corresponding periods in 2010 primarily due to an income tax recovery recorded in the third quarter of 2010 for the impact of the enactment of the SIFT legislation on CPILP, and higher taxable income in the three and nine months ended September 30, 2011. These increases were partly offset by a deferred income tax expense related to the Company's review of strategic alternatives for its investment in CPILP recorded in the third quarter of 2010 and reversed in the second quarter of 2011.

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.

At September 30, 2011, the Company's progress towards its performance measure targets for 2011 was as follows:

Performance Measures	2011 Targets	Status at Sept 30, 2011
Allocated Capital		
Committed capital for acquisitions / developments that are in-line with targeted rates of return	\$1.5 billion or higher	Approximately \$1.4 billion committed
Operational		
Plant availability average	94% or greater	94%
Capital expenditures for plant maintenance and Genesee mine extension	Approximately \$56 million	\$38 million
Construction / Development		
Capital Power's final costs in the construction of Keephills 3 plant	\$955 million or less with commercial operation date in the second quarter of 2011	\$955 million; commercial operation began on September 1, 2011
Quality Wind and Port Dover & Nanticoke wind projects	Continue on time and on budget with commercial operation dates in 2012	Quality Wind in-line with target; Port Dover & Nanticoke's commercial operation date anticipated in 2013.
Financial		
Normalized earnings per share ⁽¹⁾	\$1.16 ⁽²⁾	\$0.87
Funds from operations excluding non-controlling interests in CPILP ⁽¹⁾	Modestly higher than the 2010 result of \$257 million	\$264 million
Cash flow per share ⁽¹⁾	Modestly higher than the 2010 result of \$3.28	\$3.01
Dividend coverage ratio ⁽¹⁾	Modestly higher than the 2010 result of 2.1 times	2.5 times

⁽¹⁾ Normalized earnings per share, funds from operations excluding non-controlling interests in CPILP, cash flow per share and dividend coverage ratio are non-IFRS measures. See Non-IFRS Financial Measures.

⁽²⁾ The original earnings per share target of \$1.20 under previous CGAAP equates to approximately \$1.16 under IFRS.

The New England plant acquisitions, Halkirk wind project, K2 Wind Ontario project, and the North Carolina plant acquisitions (see Significant Events) contributed approximately \$1.4 billion towards the Company's target of \$1.5 billion of capital committed in 2011.

The Company's plant availability performance measure is back on track to meet the 2011 target if plant operations perform as expected for the fourth quarter of 2011. Although Unit 3 at Clover Bar Energy Centre was offline from January 15, 2011 to June 17, 2011 due to an unplanned outage, Keephills 3, Joffre and Clover Bar Energy Centre performed better than anticipated in the third quarter. Plant availability for all plants excluding the CPILP plants averaged 97% for the third quarter of 2011 which increased the year-to-date average to 94% from

91% at the end of the second quarter. An outage at Unit 2 of Clover Bar Energy Centre for an engine overhaul, which was anticipated to occur in November and December 2011, is no longer required as the work was completed in July and August when the engine had to be returned to the supplier for other repairs. A leased engine was installed while the engine was being repaired so that the unit was out of service for only eight days. The repaired engine was reinstalled on September 2, 2011.

Capital expenditures for maintenance of the CPLP plants and Genesee mine are expected to be approximately \$71 million. The increase compared to the target of \$56 million is primarily due to capital maintenance for the New England plants and land purchases for the Genesee mine.

The construction of Keephills 3 has been completed and the facility commenced commercial operation on September 1, 2011. The final capital costs for the Company's share of the project are expected to be approximately \$955 million.

At the beginning of the third quarter, the Company's forecast for normalized earnings per share for 2011 was approximately \$1.40 provided in the March 31, 2011 MD&A less the impact of the loss on the settlement of bond forward contracts and the pension adjustment which were recognized in the second quarter of 2011. This forecast was based on Alberta power prices settling on average in the range of low \$70/MWh. Alberta power spot prices averaged \$95/MWh in the third quarter resulting in a higher margin for the Alberta commercial plants and portfolio optimization and higher availability incentive revenue for the Alberta contracted plants than anticipated. However, this was offset by lower contributions from the New England plants due to lower power prices in the area. Accordingly, if Alberta power prices for the balance of 2011 settle on average in the range of high \$70/MWh, the Company continues to expect normalized earnings per share for 2011 to be in line with the guidance provided in the June 30, 2011 MD&A. The Company anticipates the following updates to previous guidance included in the Company's 2010 annual MD&A for the fourth quarter of 2011:

- At September 30, 2011, the Alberta portfolio positions were as follows for the remainder of 2011 and for 2012 and 2013:

Alberta Power Price Sensitivity	Oct to Dec 2011	Full year 2012	Full year 2013
% Sold forward	70%	43%	16%
Contracted price	Mid-\$60/MWh	Mid-\$60/MWh	Mid-\$60/MWh

- Depreciation expense for 2011 is expected to include approximately \$20 million (\$5 million for the fourth quarter of 2011) for the depreciation on current and prior years' shutdown maintenance costs that are capitalized under IFRS. Under previous CGAAP, the costs were expensed as incurred.
- The estimated useful lives of the Company's Genesee and Keephills 3 plants were extended from 35 years to 45 years. The impact on depreciation expense in 2011 is expected to be a decrease of approximately \$14 million (\$3 million for the fourth quarter of 2011) from previous estimates.
- The three New England plants contributed \$20 million to the Company's EBITDA excluding unrealized changes in the fair value of derivative contracts from May 2011 to September 2011, which was below management's expectations. The Company expected stronger financial performance through the summer months as air conditioning load in the region generally leads to higher dispatch. However, realized spark spreads and dispatch of the plants were lower than expected resulting in lower EBITDA. Declines in forward power prices have resulted in lower expectations for future spark spreads and the Company has revised its pricing view of the New England market. The acquisitions are now expected to contribute approximately \$29 million to \$33 million to EBITDA before unrealized changes in the fair value of derivative contracts in 2011. This expectation includes the negative impact of \$3 million for Connecticut generator tax which was introduced in June 2011. The Company believes that market fundamentals in the Eastern region will normalize in future years which will have a positive impact on the New England plant results.

An unrealized gain of \$4 million was recognized in the five months since the acquisition of the New England plants for the reversal of unrealized losses relating to heat rate options which were included in the acquisition and settled in the period. The unrealized losses reflected a decrease in the fair value of these contracts at the time of the acquisition and were included in the purchase price. An additional \$4 million of unrealized gains are expected to be recognized when the remaining heat rate options that were included in

the acquisition are settled, The Company's previous expectations of \$51 million to \$55 million of contributions towards EBITDA included this \$8 million of unrealized gains.

- Financing costs in 2011 include interest on the \$300 million medium-term notes issued in April 2011 and the US\$295 million senior notes issued in June 2011.
- In March 2011, the Company issued 9,300,000 common shares to the public to partially finance the New England plant acquisitions. In accordance with the terms of the CPLP partnership agreement, net income from CPLP for the year will be allocated to the partners (subsidiaries of EPCOR and Capital Power) on the same basis as distributions for the year are allocated. Since the public share offering closed before the date of record for the first quarter distribution by CPLP, the transaction effectively occurred January 1, 2011 for purposes of allocating net income to the partners. As a result, Capital Power's and EPCOR's share of net income were approximately 46% and 54%, respectively for the first and second quarters. In July 2011, the Company issued 9,200,000 common shares which reduced EPCOR's ownership interest in Capital Power to approximately 48.9% effective for the third quarter. See Significant Events.

The 2011 targets and normalized earnings per share forecasts are based on numerous assumptions including power and natural gas price forecasts, as described in the Forward-looking Information section. However, they do not include the effects of the planned divestiture of the Company's interest in CPILP as discussed under Significant Events, including the impairment loss recorded in the second quarter and the anticipated gain on sale and associated loss for the reclassification of foreign currency translation losses from accumulated other comprehensive income, to be recorded in the fourth quarter as they are not considered to be normalized earnings. They also do not include the impacts from potential future acquisitions or development activities, or potential impacts from unplanned plant outages including outages at facilities of other market participants and the related impacts on market power prices.

The Company's targets for cash flow (funds from operations excluding non-controlling interests in CPILP, cash flow per share and dividend coverage ratio) are on track to meet the 2011 targets for these measures.

The Company's estimated capital expenditures in 2011 in the following table only include payments to acquire property, plant and equipment and intangible assets and exclude the cost of the New England plant acquisitions and potential new development projects.

(unaudited, \$millions) Capital Expenditures			Year ended Dec 31, 2011 Estimated ⁽¹⁾
CPLP	Sustaining	Plant maintenance	\$ 40
		Genesee mine maintenance ⁽²⁾	24
		New England plant maintenance	7
		Information technology	13
		Other	14
			98
CPLP	Growth	Halkirk	190
		Keephills 3	63
		Quality Wind	133
		Port Dover & Nanticoke	41
			427
CPLP Total			525
CPILP	Sustaining	Plant maintenance	25
	Growth		5
CPILP Total			30
			555

⁽¹⁾ Capital expenditures for the year ended December 31, 2011 are based on management's estimates.

⁽²⁾ Capital expenditures for Genesee mine maintenance represent only those capital additions funded by the Company for the Genesee mine operation.

The capital expenditure estimates in the table above reflect the following updates to the guidance included in the 2010 annual MD&A:

- Estimated plant maintenance capital expenditures are approximately \$16 million higher due to the impact of IFRS whereby costs for major maintenance are capitalized rather than expensed.
- Estimated Genesee mine maintenance capital expenditures are approximately \$8 million higher due to increased opportunities to purchase lands for the ongoing expansion of the mine.
- Approximately \$7 million of plant maintenance capital expenditures are anticipated for the three New England plants.
- The total estimated capital expenditures in 2011 for the Halkirk wind project costs are \$190 million, including \$33 million spent in the second quarter for the acquisition of intangible assets and approximately \$157 million for construction of the project throughout 2011.
- Estimated total capital expenditures for Keephills 3 are back in line with the expectations disclosed in the 2010 annual MD&A. At March 31, 2011, the delay in schedule for additional cleaning of the boiler caused the Company to increase the estimated project cost by \$20 million to \$30 million. However, the plant commenced commercial operation one month earlier than was anticipated at March 31, 2011 which led to lower capitalized borrowing costs incurred during construction and higher commissioning revenue net of expenses which were included as a reduction of the cost of the project.
- Estimated capital expenditures in 2011 for the Quality Wind project are approximately \$15 million lower due to the deferral of certain planned expenditures to 2012. The change is not anticipated to impact the planned completion date of the fourth quarter of 2012 or the total cost of \$455 million.
- The construction schedule for the Port Dover & Nanticoke wind project was revised to accommodate completion of the land title transfers and regulatory proceedings resulting in \$57 million of planned expenditures being deferred to 2012. The change is not anticipated to impact the total project cost of \$340 million, but the project's completion date may be delayed until 2013 given the delay in regulatory approvals.

Significant Events

\$231 million common share offering

In July 2011, the Company closed an offering to sell 9,200,000 common shares at a price of \$25.10 per share to a syndicate of underwriters for gross proceeds of approximately \$231 million, less underwriters' fees of approximately \$9 million. The net proceeds from the common share offering were used to purchase an additional 9,200,000 common limited partnership units of CPLP. CPLP used the funds to repay a portion of the indebtedness outstanding under its credit facilities, which was drawn to fund the acquisitions of the New England facilities, and for general corporate purposes including financing development projects and working capital requirements. This transaction reduced EPCOR's ownership interest in CPLP to approximately 48.9% effective for the third quarter from 54.1% at June 30, 2011.

Development of K2 Wind Ontario project

On August 3, 2011, CPLP entered into a limited partnership agreement with Samsung Renewable Energy Inc. (Samsung) and Pattern Renewable Holdings Canada ULC (Pattern) for the development, construction and operation of a 270 megawatt (MW) wind power project to be known as K2 Wind Ontario (K2). Formerly referred to as the Kingsbridge II Wind Power Project, K2 will be developed in the Township of Ashfield-Colborne-Wawanosh in southwestern Ontario. The project has an expected total capital cost of \$874 million, most of which will be funded through project financing.

The Ontario Power Authority has signed a PPA for K2. The completion of the project is subject to obtaining necessary corporate approvals, executing definitive agreements, and receiving regulatory approvals. The partners expect that construction would begin in 2013, with commercial operation in 2014.

At commencement of commercial operation, each of the three partners will have an equal economic interest in the project. Capital Power will contribute the project lease agreements and development work completed to August 3, 2011, while Samsung and Pattern will contribute the PPA and transmission access rights. Capital Power will continue to lead the provincial Renewal Energy Approval process for the project which it has been doing since 2006. Samsung will serve as the engineering procurement and construction contractor, and the K2 partnership will finalize the turbine model and supplier.

Keephills 3 power plant begins commercial operation

On September 1, 2011, the Company and TransAlta Corporation (TransAlta) completed the 495 MW (gross) Keephills 3 generating facility, which is now in commercial operation. The facility is the most advanced coal-fired plant in Canada and the Company's share of its final cost is expected to be approximately \$955 million. Costs for the plant, excluding mine capital, are being equally shared by its owners – Capital Power, which led the construction, and TransAlta, which operates the plant.

Update on Atlantic Power Corporation's acquisition of CPILP

In June 2011, CPILP and Atlantic Power Corporation (Atlantic Power) entered into an arrangement agreement under which Atlantic Power would acquire, directly and indirectly, all of the outstanding limited partnership units of CPILP, including Capital Power's ownership interest, for \$19.40 per limited partnership unit, payable in cash or shares of Atlantic Power. Approval votes by Atlantic Power shareholders and CPILP unitholders have been scheduled for November 1, 2011, and if successful, will likely result in the transaction closing shortly thereafter. If the transaction is completed in November, the distribution for the month ended October 31, 2011 will be CPILP's final distribution.

Concurrent with and contingent upon the completion of the transaction, Capital Power will acquire CPILP's Roxboro and Southport plants in North Carolina. The transaction values these facilities at approximately \$121 million and Capital Power will acquire the facilities for approximately 6.2 million partnership units of CPILP. Atlantic Power will acquire Capital Power's remaining partnership units of CPILP which will own the remaining eighteen facilities outside North Carolina. Upon closing, Capital Power will have received approximately \$320 million in combined consideration for its ownership interest in CPILP and the consideration will include the North Carolina facilities and cash or stock in Atlantic at Capital Power's election subject to proration. In addition, the Company's management and operations contracts with CPILP will be terminated or assigned in consideration of payment of an aggregate of \$10 million to Capital Power.

At June 30, 2011, the Company tested the CPILP net assets and management and operations contracts for impairment at the cash generating unit level, by comparing their recoverable amounts with their carrying amounts. The negotiated consideration for these assets less an estimate for disposal costs was used as the estimated recoverable amount. As a result, the management and operations contracts were determined to be impaired and an impairment loss of \$43 million was recorded in the second quarter.

The carrying amounts of the disposal group of assets and liabilities, after recognizing the impairment loss, were reclassified as assets and liabilities held for sale commencing with the Company's statement of financial position at June 30, 2011. Upon closing of the transactions in the fourth quarter of 2011, the Company anticipates that a pre-tax gain of approximately \$125 million (\$54 million attributable to common shareholders) will be recognized for the difference between the net proceeds and the carrying amount of the Company's interest in CPILP net assets classified as assets held for sale.

The Company also anticipates that upon closing of the transactions the cumulative translation account relating to CPILP's U.S. operations, other than the North Carolina plants, will be reclassified from accumulated other comprehensive loss to the income statement. The Company's accumulated translation account represents the foreign currency translation differences for foreign operations, which have been recognized since the Company's transition to IFRS on January 1, 2010, and will be reclassified to net income upon disposal of the foreign operations. At September 30, 2011, accumulated other comprehensive income included \$1 million of foreign currency translation gains attributable to common shareholders for the CPILP foreign operations to be disposed of in the fourth quarter. This amount plus the corresponding translation gains or losses for the period from October 1, 2011 to the date of the sale are expected to be reclassified to net income in the fourth quarter.

The calculations of the gain on disposal of the assets held for sale and the foreign currency translation gain that will be recognized in income in the fourth quarter of 2011 are based on estimates and carrying amounts as of September 30, 2011 that could change materially by the time the transaction closes.

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) North East U.S. commercial plants and portfolio optimization, (v) CPILP plants, (vi) Other portfolio activities, and (vii) Corporate.

Generation volume

(unaudited, GWh)	Three months ended		Nine months ended	
Electricity generation⁽¹⁾	Sept 30, 2011	Sept 30, 2010	Sept 30, 2011	Sept 30, 2010
Alberta commercial plants				
Genesee 3	496	475	1,455	1,390
Keephills 3 ⁽²⁾	336	-	386	-
Joffre	90	67	245	201
Clover Bar Energy Centre 1, 2 and 3	57	37	259	182
Taylor Coulee Chute	12	7	14	10
Clover Bar Landfill Gas	9	9	26	29
	1,000	595	2,385	1,812
Alberta contracted plants				
Genesee 1	843	841	2,272	2,434
Genesee 2	845	824	2,465	2,220
	1,688	1,665	4,737	4,654
Ontario and British Columbia contracted plants				
Kingsbridge 1	12	18	67	66
Miller Creek	49	46	80	88
Brown Lake	8	5	37	29
Island Generation	-	-	107	-
	69	69	291	183
North East U.S. commercial plants ⁽³⁾				
Rumford	170	-	238	-
Tiverton	422	-	711	-
Bridgeport	872	-	1,517	-
	1,464	-	2,466	-
Total excluding CPILP plants	4,221	2,329	9,879	6,649
CPILP plants	1,294	1,306	3,588	3,702
Total plants	5,515	3,635	13,467	10,351
Sundance PPA	545	680	2,004	2,159

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

⁽²⁾ Keephills 3 includes pre-commissioning output until commissioning date of September 1, 2011. Revenues and expenses related to commissioning activities were capitalized as part of the cost of the facility in property, plant and equipment.

⁽³⁾ North East U.S. commercial plants include Bridgeport and the Rumford & Tiverton facilities as of their dates of acquisition April 28, 2011 and April 29, 2011, respectively.

Plant availability

(unaudited)	Three months ended		Nine months ended	
Generation plant availability⁽¹⁾	Sept 30, 2011	Sept 30, 2010	Sept 30, 2011	Sept 30, 2010
Alberta commercial plants				
Genesee 3	100%	99%	100%	98%
Keephills 3 ⁽²⁾	100%	-	100%	-
Joffre	99%	98%	92%	94%
Clover Bar Energy Centre 1, 2 and 3	91%	63%	74%	62%
Taylor Coulee Chute	100%	100%	98%	96%
Clover Bar Landfill Gas	86%	92%	89%	95%
	97%	86%	88%	84%
Alberta contracted plants				
Genesee 1	100%	100%	91%	100%
Genesee 2	100%	97%	100%	90%
	100%	99%	95%	95%
Ontario and British Columbia contracted plants				
Kingsbridge 1	99%	99%	99%	99%
Miller Creek	92%	96%	90%	76%
Brown Lake	53%	93%	84%	96%
Island Generation	100%	-	100%	-
	98%	97%	98%	90%
North East U.S. commercial plants ⁽³⁾				
Rumford	95%	-	96%	-
Tiverton	97%	-	97%	-
Bridgeport	96%	-	97%	-
	96%	-	97%	-
Average excluding CPILP plants⁽⁴⁾	97%	93%	94%	90%
CPILP plants	96%	97%	92%	94%
Average all plants⁽⁴⁾	97%	95%	93%	92%
Sundance PPA	72%	88%	87%	93%

⁽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⁾ Alberta commercial plants include Keephills Unit 3 as of its date of commissioning of September 1, 2011

⁽³⁾ North East U.S. commercial plants include Bridgeport and the Rumford & Tiverton facilities as of their dates of acquisition April 28, 2011 and April 29, 2011, respectively.

⁽⁴⁾ Average generation plant availability is an average of individual plant availability weighted by the capacity owned or operated by the Company.

The increase in total plant electricity generation, excluding generation from the Sundance PPA, for the three and nine months ended September 30, 2011 compared with the corresponding periods in 2010 was primarily due to generation from the New England facilities after their acquisitions in April 2011, commissioning generation from Keephills 3 in July and August 2011 and generation from Keephills 3 following its commencement of operations on September 1, 2011. Joffre, Clover Bar Energy Center, and Genesee Units 2 and 3 also had higher generation in the three and nine months ended September 30, 2011 than in the corresponding periods in 2010. Generation from Island Generation, which was acquired in October 2010, also contributed to increased generation in the nine months ended September 30, 2011 compared to the corresponding period of 2010.

Genesee Unit 1 had a 21-day outage from March 28 to April 18, 2011 and Genesee unit 2 had a 21-day outage during the second quarter of 2010, both of which were for scheduled maintenance.

Joffre and Clover Bar Energy Centre are mid-merit and peaking plants, respectively, which operate when it is economical to do so. Average Alberta power prices were higher in the three and nine months ended September 30, 2011 compared with the corresponding periods of 2010 and resulted in increased opportunities to dispatch these plants. Availability of Clover Bar Energy Centre was negatively impacted by outages in both 2010 and 2011. In 2011, Unit 2 went offline from July 11 to July 18 due to cracks in the combustor. A leased replacement

engine was installed on July 18 and the original engine was repaired and returned to service on September 2. Unit 3 was offline from January 15, 2011 to June 17, 2011 due to blade damage in its high pressure compressor and the repair work was covered under warranty by the manufacturer. In 2010, Unit 2 was offline from March 8 to September 22 due to a mechanical failure in the main turbine section and the repair work was covered under warranty. Unit 3 was also offline for 18 days in the first quarter of 2010 and 15 days in the second quarter of 2010.

Sundance Unit 6 went offline on August 18, 2011 due to a transformer failure and remained offline until October 14, 2011 for planned maintenance. There were no significant outages at the Sundance units in the nine months ended September 30, 2010.

Financial results

(unaudited, \$millions)	Three months ended		Nine months ended	
	Sept 30, 2011	Sept 30, 2010	Sept 30, 2011	Sept 30, 2010
Revenues and other income				
Alberta commercial plants and portfolio optimization ⁽¹⁾	\$ 144	\$ 247	\$ 625	\$ 678
Alberta contracted plants	87	73	228	203
Ontario and British Columbia contracted plants	12	3	38	9
North East U.S. commercial plants and portfolio optimization ⁽¹⁾	71	-	122	-
CPILP plants	139	130	396	385
Other portfolio activities	19	20	71	85
Corporate	5	5	17	21
Inter-plant category transaction eliminations	(16)	(14)	(53)	(46)
	461	464	1,444	1,335
Unrealized changes in fair value of CPLP's power and natural gas derivative instruments, and natural gas held for trading	(5)	38	(62)	(5)
Unrealized changes in fair value of CPILP's foreign exchange contracts	(23)	11	(19)	(3)
	(28)	49	(81)	(8)
	\$ 433	\$ 513	\$1,363	\$1,327
Gross income				
Alberta commercial plants and portfolio optimization	\$ 88	\$ 70	\$ 195	\$ 194
Alberta contracted plants	72	59	186	160
Ontario and British Columbia contracted plants	12	3	38	9
North East U.S. commercial plants and portfolio optimization ⁽¹⁾	19	-	34	-
CPILP plants	81	76	228	221
Other portfolio activities	7	13	25	34
Corporate	6	6	18	22
Inter-plant category transaction eliminations	(14)	(12)	(39)	(43)
	271	215	685	597
Unrealized changes in fair value of CPLP's power and natural gas derivative instruments and natural gas held for trading	(4)	14	(38)	(13)
Unrealized changes in fair value of CPILP's foreign exchange and natural gas contracts	(23)	7	(19)	(13)
	(27)	21	(57)	(26)
	\$ 244	\$ 236	\$ 628	\$ 570
EBITDA⁽²⁾				
Alberta commercial plants and portfolio optimization	\$ 72	\$ 59	\$ 154	\$ 158
Alberta contracted plants	57	47	139	120
Ontario and British Columbia contracted plants	8	2	28	6
North East U.S. commercial plants and portfolio optimization ⁽¹⁾	10	-	20	-
CPILP plants	47	(22)	129	70
Other portfolio activities	-	5	2	6
Corporate	(34)	(29)	(135)	(72)
	160	62	337	288
Unrealized changes in fair value of CPLP's energy and foreign exchange derivative instruments and natural gas held for trading	(5)	14	(39)	(14)
Unrealized changes in fair value of CPILP's foreign exchange and natural gas contracts	(23)	7	(19)	(13)
	(28)	21	(58)	(27)
Gain on sale of power syndicate agreement	-	-	-	28
	\$ 132	\$ 83	\$ 279	\$ 289

⁽¹⁾ Alberta commercial plants include Keephills Unit 3 as of its date of commissioning of September 1, 2011. Revenues and expenses related to commissioning activities, prior to September 1, 2011 were capitalized as part of the cost of the facility in property, plant and equipment.

⁽²⁾ North East U.S. commercial plants include Bridgeport and the Rumford & Tiverton facilities as of their dates of acquisition, April 28, 2011 and April 29, 2011, respectively.

⁽³⁾ The results by plant category, except for EBITDA, have been prepared in accordance with IFRS. See Non-IFRS Financial Measures.

(unaudited)	Three months ended		Nine months ended	
Spot price averages	Sept 30, 2011	Sept 30, 2010	Sept 30, 2011	Sept 30, 2010
Alberta power (\$/MWh)	95	36	76	52
Eastern region power (\$/MWh)	33	43	31	38
Western region power (Mid-C) (\$/MWh)	33	33	34	34
Alberta natural gas (AECO) (\$/Gj) ⁽¹⁾	4	3	4	3

Capital Power's Alberta portfolio's realized power price (\$/MWh)⁽²⁾	74	66	65	66
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⁽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 \$95/MWh and \$76/MWh for the three and nine months ended September 30, 2011, respectively compared with \$36/MWh and \$52/MWh in the corresponding periods in 2010, respectively. The increase in the average spot price in the third quarter was primarily due to increased demand, and reduced supply resulting from several plant outages in the area including the Company's acquired PPA units at Sundance and Saskatchewan tie line restrictions. The higher prices in the third quarter of 2011 compared with the corresponding period in 2010 resulted in higher margins realized on the merchant trading portfolio. In addition, higher volatility in prices in the third quarter of 2011 provided increased opportunities to dispatch Clover Bar Energy Centre and the Joffre facility which contributed to a higher gross margin and EBITDA for the third quarter of 2011. Net availability penalty revenue for the Sundance acquired PPA was also higher due to higher rolling average power prices during the outage at the Sundance units. Prices for availability incentive revenues and penalties are a function of a 30-day rolling average of Alberta power prices. These increases in EBITDA in the third quarter of 2011 compared with the third quarter of 2010 were partly offset by the recognition of an estimated business insurance recovery of \$8 million in the third quarter of 2010 related to the Clover Bar Energy Centre Unit 2 outage from March 8, 2010 to September 22, 2010. The outage was due to a mechanical failure in the main turbine section and the cost of the repair work was covered by the original contractor for the unit.

For the nine months ended September 30, 2011, the increase in gross income and EBITDA described above for the third quarter was offset by lower results in the first quarter when a sudden increase in Alberta power prices had an unfavourable impact on the commodity optimization portfolio. The high prices were due to colder than normal weather and changes in power supply due to the shutdown of two large coal plants. In the first quarter of 2010, lower Alberta power prices had a favourable impact on the portfolio resulting in higher margins.

Revenues for the three and nine months ended September 30, 2011 were lower than for the corresponding periods in 2010 primarily due to the expiry of the Company's contract with EPCOR for the supply of electricity to its rate-regulated tariff (RRT) customers on June 30, 2011, and losses on merchant financial sell contracts in 2011 compared with gains on these contracts in 2010. These decreases were partly offset by the impact of higher Alberta power prices on the generation volume from the plants. The decrease in revenue from the Company's RRT business did not have a significant impact on EBITDA as the Company's purchases and revenues for this business were impacted by changes in the Alberta power price and provided a low margin per MWh.

Alberta contracted plants

Revenues, gross income and EBITDA for Alberta contracted plants were higher in the three and nine months ended September 30, 2011, compared with the corresponding periods in 2010 primarily due to higher net availability incentive revenues, resulting from higher rolling average power prices. In the second quarter of 2011, the 21-day scheduled maintenance outage at Genesee 1 resulted in \$5 million of availability penalties compared with \$12 million related to the Genesee 2 21-day outage in the second quarter of 2010 as rolling average power prices were significantly lower during the outage in 2011. These increases were partly offset by a number of small increases in operating expenses including transmission and power charges for higher production, and new initiatives to comply with anticipated environmental requirements.

Ontario and British Columbia contracted plants

The higher revenues, gross income and EBITDA for the Ontario and British Columbia contracted plants primarily reflected contributions from the Island Generation facility following its acquisition in the fourth quarter of 2010.

North East U.S. commercial plants & portfolio

The North East U.S. commercial plants and portfolio optimization reflected contributions from the Tiverton, Rumford and Bridgeport facilities following their acquisitions in the second quarter of 2011.

CPILP plants

CPILP revenues and gross income excluding unrealized fair value changes were higher for the three and nine months ended September 30, 2011 compared with the corresponding periods of 2010 primarily due to higher generation at the Curtis Palmer plant resulting from higher water flows and increased generation at the North Carolina plants, partly offset by lower revenue at the Northeast U.S. natural gas plants. This increase in revenues for the nine months ended September 30, 2011 was partly offset by lower fuel recovery revenues at the California, Kenilworth and Morris plants in the first quarter caused by lower natural gas supply prices and lower generation, both of which also resulted in a decrease in fuel costs.

CPILP EBITDA excluding unrealized fair value changes was higher primarily due to impairment losses of \$66 million recognized in the third quarter of 2010 reflecting lower expectations for the availability of waste heat fuel supply at CPILP's Ontario plants. This favourable variance was partly offset by costs incurred in the second and third quarters of 2011 associated with the sale of CPILP to Atlantic Power (see Significant Events), and the reversal of an allowance for a doubtful accounts receivable in the second quarter of 2010.

Other portfolio activities

Other portfolio activities include trading of environmental credits and natural gas in North American markets, and electricity trading in the U.S. Pacific Northwest markets. The decrease in gross margin and EBITDA in the three and nine months ended September 30, 2011 was primarily due to a gain recognized in the third quarter of 2010 for a change in the provision for estimated future losses on certain natural gas retail contracts. The estimate was based on a decrease in forward natural gas prices in the third quarter of 2010. This decrease was partly offset by higher emission credit sales in the three and nine months ended September 30, 2011. The decrease in revenue in the nine months ended September 30, 2011 compared with the corresponding period in 2010 was primarily due to fewer trading opportunities in the natural gas and U.S. Pacific Northwest electricity markets, partly offset by higher emission credit sales.

Corporate

Corporate includes revenues for cost recoveries, the cost of support services such as treasury, finance, internal audit, legal, human resources, corporate risk management, asset management and, environment, health and safety, as well as business development expenses. The cost recovery revenues are primarily intercompany revenues which are offset by interplant category transactions in the consolidated results.

Corporate EBITDA for the third quarter of 2011 was lower than for the third quarter of 2010 primarily due to higher foreign exchange losses on the translation of U.S. dollar denominated debt and higher costs related to increased business development activity, partly offset by a \$7 million obligation to EPCOR recognized in the third quarter of 2010 for operations and maintenance costs for the Rosedale plant to be incurred over the ten-year period ending in 2019. The decrease in Corporate EBITDA for the nine months ended September 30, 2011 reflected the decrease in EBITDA in the third quarter as well as an impairment loss of \$43 million related to Capital Power's management and operations agreements with CPILP, a \$5 million unfavourable pension valuation adjustment and \$6 million of losses realized on the settlement of foreign exchange contracts. The impairment loss was recorded in the second quarter of 2011 as a result of the Company's agreement with Atlantic Power to terminate or assign the contracts in exchange for \$10 million. The pension valuation adjustment was recorded in the second quarter of 2011 and was based on an actuarial valuation of the Company's supplemental pension plan obligation which incorporated refinements to estimates made at the time of the Company's spinoff from EPCOR. With the reduction in uncertainty associated with the estimates, the Company does not anticipate material adjustments for future valuations. The foreign exchange contracts were entered into

in anticipation of U.S. cash payments primarily related to the acquisition of the New England facilities. No foreign exchange contracts were settled in the first three quarters of 2010.

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

In the third quarter of 2011, the fair value of CPLP's North East U.S. portfolio heat rate options decreased \$4 million. There was no comparable amount in 2010 as CPLP commenced trading in electricity heat rate options in this market after the acquisition of the New England plants in the second quarter of 2011. In the third quarter of 2011, the change in fair value of CPLP's derivative electricity and natural gas contracts and natural gas inventory held for trading that were not designated as hedges for accounting purposes was immaterial compared to an increase of \$14 million in the third quarter of 2010 which was primarily due to the impact of decreases in Alberta forward power prices on portfolio positions.

In the nine months ended September 30, 2011, the net change in the fair value of these instruments primarily reflected an unrealized loss of \$41 million on the Alberta electricity portfolio partly offset by a \$2 million unrealized gain on the North East U.S. heat rate options compared with a \$15 million unrealized loss on the Alberta electricity portfolio in the corresponding period of 2010. The unrealized loss on the Alberta electricity portfolio in the 2011 period was larger than in the 2010 period as there was a larger increase in Alberta forward power prices in the 2011 period.

In the three and nine months ended September 30, 2011, the fair value of CPILP's foreign exchange contracts decreased \$23 million and \$19 million, respectively. In the three and nine months ended September 30, 2010, the fair value of these contracts increased \$11 million and decreased \$3 million, respectively. These changes in fair value were primarily due to increases in the forward prices for U.S. dollars relative to Canadian dollars for the three and nine months ended September 30, 2011 and decreases for the corresponding periods in 2010. The changes in the fair value of CPILP's natural gas supply contracts were immaterial in the three and nine months ended September 30, 2011. The fair value of these contracts decreased \$4 million and \$10 million in the three and nine months ended September 30, 2010, respectively. In both years, CPILP designated certain of its natural gas supply contracts as hedges for accounting purposes and the changes in the fair value of these contracts were recorded in other comprehensive income. The unrealized losses recorded in CPILP's EBITDA in the three and nine months ended September 30, 2010 were related to the contracts that were not designated as hedges and resulted from decreases in forward natural gas prices. Although forward natural gas prices decreased in the three and nine months ended September 30, 2011, the decreases were smaller and the unrealized losses were offset by the reversal of the previously recorded unrealized losses on contracts that settled in these periods.

Gain on sale of power syndicate agreement

On January 15, 2010, the Company sold its remaining 15% interest in the Battle River Power Syndicate Agreement (PSA) for cash proceeds of \$64 million resulting in a pre-tax gain of \$28 million. There was no comparable gain on sale of assets during the nine months of 2011. The sale of the Battle River PSA did not have an impact on earnings attributable to the common shareholders of the Company as approximately \$11 million was added to the carrying amount of the asset when it was acquired from EPCOR representing the Company's 27.8% interest in the asset's fair value increment. Accordingly this increment was attributable to the equity holders of the Company and not the non-controlling interests.

Consolidated Other Expenses and Non-controlling Interests

(unaudited, \$millions)	Three months ended		Nine months ended	
	Sept 30, 2011	Sept 30, 2010	Sept 30, 2011	Sept 30, 2010
Unrealized loss (gain) for changes in fair value of forward bond sale contracts	5	7	(2)	11
Other finance expense	27	19	78	54
Total finance expense	32	26	76	65
Depreciation and amortization	45	59	167	178
Income tax expense (recovery) expense	11	1	-	(9)
Net income (loss) attributable to non-controlling interests	29	(19)	43	35

Finance expense

In the third quarter of 2011, the Company entered into \$200 million of forward bond sale contracts which decreased in fair value by \$5 million. In the nine months ended September 30, 2011, the unrealized loss recognized in the third quarter was offset by the reversal of an unrealized loss relating to 2010 for forward contracts that settled in the first quarter of 2011. In the three and nine months ended September 30, 2010, unrealized losses of \$7 million and \$11 million, respectively, reflected the decrease in the fair value of \$200 million of forward bond sale contracts entered into in the second quarter of 2010. Other finance expenses for the three and nine months ended September 30, 2011 were higher than for the corresponding periods in 2010 primarily due to interest on borrowings related to the acquisition of Island Generation in October 2010 and the New England facilities in April 2011. In the nine months ended September 30, 2011, finance expense also included a loss of \$12 million realized on the settlement of forward bond sale contracts, compared with no contract settlements in the corresponding period in 2010. Forward bond contracts economically hedge exposure to interest rate risk on anticipated debt issues and settled losses are offset by future interest payments incurred at a rate that is lower than the rate that was locked in by the respective hedge.

Depreciation and amortization

Depreciation and amortization expense was lower for the three and nine months ended September 30, 2011 compared with the corresponding periods in 2010 primarily because depreciation has not been recognized on CPILP's assets held for sale since they were classified as such at the end of the second quarter of 2011. In addition, depreciation on the Genesee assets decreased as a result of the change in the estimated useful life of the coal plants from 35 years to 45 years effective January 1, 2011. These decreases were partly offset by depreciation on the Island Generation and New England plant assets since their acquisitions in October 2010 and April 2011, respectively and on Keephills 3 since it was commissioned in the third quarter of 2011.

Income tax expense

Income tax expense was higher for the three and nine months ended September 30, 2011 compared with the corresponding periods in 2010, primarily due to an income tax recovery recorded in the third quarter of 2010 for the impact of the enactment of the SIFT legislation on CPILP, as well as higher taxable income in the three and nine months ended September 30, 2011. These increases were partly offset by a deferred income tax expense related to the Company's review of strategic alternatives for its investment in CPILP which was recorded in the third quarter of 2010 and reversed in the second quarter of 2011. This expense was recorded in the third quarter of 2010 to reflect the Company's intention of realizing an income tax liability by selling its partnership units in CPILP. However, the transaction with Atlantic Power as discussed under Significant Events contemplates an indirect sale that has different income tax consequences than a sale of partnership units. As a result the deferred tax expense was reversed in the second quarter of 2011.

Non-controlling interests

Net income attributable to non-controlling interests in CPILP included approximately 70.8% (70.2% at September 30, 2010) of CPILP net income, and net income attributable to non-controlling interests in CPLP included approximately 51.4% (72.2% at September 30, 2010) of the net income from CPLP (net of preferred share dividends). Net income attributable to non-controlling interests also included the Genesee coal mine partner's share of the consolidated coal costs and preferred share dividends paid by a subsidiary. Net income from CPILP was higher as depreciation was not recognized on the assets held for sale in the third quarter of 2011 and

impairment losses were recognized in the third quarter of 2010. As a result, income attributable to non-controlling interests was higher in the third quarter of 2011 compared with the corresponding period of 2010.

Net income attributable to non-controlling interests for the nine months ended September 30, 2011 included approximately \$4 million of the \$43 million impairment loss on the Company's management and operations contracts with CPILP as the majority of the contracts in terms of their carrying amounts, are owned by Capital Power Corporation rather than CPLP. Net income attributable to non-controlling interests for the nine months ended September 30, 2010 included 100% of the gain on sale of the Battle River PPA. The sale had no impact on the net income attributable to common shareholders as their 27.8% share of the fair value of the Battle River PPA was recognized in the purchase price allocation for its acquisition of power generation assets and operations (the Reorganization) from EPCOR Utilities Inc. on July 9, 2009.

The net income from CPILP that was attributable to CPLP was approximately 29.2% (29.8% at September 30, 2010). Therefore the net income attributable to the non-controlling interests in CPLP included approximately 15.0% (51.4% of 29.2%) of CPILP net income in the third quarter of 2011 and 21.5% (72.2% of 29.8%) in the third quarter of 2010.

Non-IFRS Financial Measures

The Company uses (i) EBITDA, (ii) funds from operations, (iii) funds from operations excluding non-controlling interests in CPILP, (iv) cash flow per share, (iv) normalized earnings attributable to common shareholders, (v) normalized earnings per share, and (vi) dividend coverage ratio as financial performance measures. These terms are not defined financial measures according to IFRS and do not have standardized meanings prescribed by IFRS, 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 IFRS. Rather, these measures are provided to complement IFRS measures in the analysis of the Company's results of operations from management's perspective.

EBITDA

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

(unaudited, \$millions)	Three months ended		Nine months ended	
	Sept 30, 2011	Sept 30, 2010	Sept 30, 2011	Sept 30, 2010
Revenues	\$ 414	\$ 492	\$ 1,309	\$ 1,277
Other income	19	21	54	50
Energy purchases and fuel	(189)	(277)	(735)	(757)
Gross income	244	236	628	570
Other raw materials and operating charges	(43)	(20)	(109)	(61)
Staff costs and employee benefits expense	(40)	(43)	(121)	(131)
Other administrative expenses	(16)	(18)	(46)	(37)
Property taxes	(6)	(5)	(17)	(14)
Impairments	-	(66)	(43)	(66)
Foreign exchange losses	(7)	(1)	(13)	-
Gain on sale of power syndicate agreement	-	-	-	28
EBITDA	132	83	279	289
Depreciation and amortization	(45)	(59)	(167)	(178)
Finance expense	(32)	(26)	(76)	(65)
Income tax recovery (expense)	(11)	(1)	-	9
Net income (loss)	\$ 44	\$ (3)	\$ 36	\$ 55
Attributable to:				
Non-controlling interests	29	(19)	43	35
Shareholders of the Company	15	16	(7)	20

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

Capital Power uses funds from operations as a measure of the Company's ability to generate cash from its current operating activities to fund capital expenditures, debt repayments and distributions to the Company's shareholders. Funds from operations are cash provided by operating activities, including finance and current income tax expenses, and excluding changes in working capital. The Company includes interest and current income tax expenses recorded during the period, rather than interest and income taxes paid which are impacted by the timing of cash receipts and payments and are not comparable from period to period. Changes in working capital are also impacted by the timing of cash receipts and payments and are not comparable from period to period. Since the non-controlling interests in CPILP's funds from operations were approximately 70.8% at September 30, 2011 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. A reconciliation of (i) funds from operations and (ii) funds from operations excluding non-controlling interests in CPILP, to cash flows from operating activities is as follows:

(unaudited, \$millions)	Three months ended		Nine months ended	
	Sept 30, 2011	Sept 30, 2010	Sept 30, 2011	Sept 30, 2010
Funds from operations excluding non-controlling interests in CPILP	\$ 116	\$ 87	\$ 264	\$ 199
Funds from operations due to non-controlling interests in CPILP	28	25	70	77
Funds from operations	144	112	334	276
Adjustments:				
Unrealized changes in the fair value of forward bond contracts	(4)	(7)	2	(11)
Settlement of forward bond contracts	-	-	(12)	-
Miscellaneous financing charges	(2)	(2)	(6)	(9)
Finance expense	32	26	76	65
Interest paid	(13)	(18)	(44)	(46)
Income taxes (paid) recovered	(1)	3	(13)	10
Current income tax expense (recovery) excluding future income taxes	(1)	(2)	-	12
Change in non-cash operating working capital	(13)	17	(27)	(9)
Cash flows from operating activities	\$ 142	\$ 129	\$ 310	\$ 288

Cash flow per share is calculated using the weighted average common shares of Capital Power Corporation and exchangeable common limited partnership units of CPLP that were outstanding during the period. The CPLP exchangeable common limited partnership units are exchangeable for common shares of Capital Power Corporation on a one-for-one basis.

(unaudited, \$millions except cash flow per share)	Three months ended		Nine months ended	
	Sep 30, 2011	Sep 30, 2010	Sep 30, 2011	Sep 30, 2010
Funds from operations excluding non-controlling interests in CPILP	\$ 116	\$ 87	\$ 264	\$ 199
Weighted average common shares outstanding (millions)	48.33	21.77	40.42	21.76
Exchangeable common limited partnership units of CPLP outstanding (millions)	47.42	56.63	47.42	56.63
Weighted average shares and partnership units outstanding (millions)	95.75	78.40	87.84	78.39
Cash flow per share	\$ 1.21	\$ 1.11	\$ 3.01	\$ 2.53

Normalized earnings 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 earnings used in the calculation of earnings per share according to IFRS and adjusted for items that are not reflective of performance in the period such as fair value changes, impairment charges, unusual tax adjustments, gains and losses on disposal of assets or on unusual contracts such as the contract for maintenance of EPCOR's Rosedale plant, and the foreign exchange loss on the translation of the U.S. dollar denominated debt recognized in the third quarter of 2011. The foreign exchange

gain on the translation of the New England plant assets which were financed by this U.S. debt was recognized in other comprehensive income as the operation is considered self-sustaining for accounting purposes. However, the U.S. debt is not part of the self-sustaining operation as the Company has a centralized finance function. As a result of this mismatch in the income statement, the foreign exchange loss was excluded from normalized earnings. A reconciliation of net income (loss) attributable to shareholders to normalized earnings attributable to common shareholders, and earnings (loss) per share to normalized earnings per share is as follows:

(unaudited, \$millions except earnings (loss) per share)	Three months ended		Nine months ended	
	Sept 30, 2011	Sept 30, 2010	Sept 30, 2011	Sept 30, 2010
Earnings (loss) per share	\$ 0.29	\$ 0.74	\$ (0.27)	\$ 0.92
Net income (loss) attributable to shareholders	15	16	(7)	20
Preferred share dividends	(1)	-	(4)	-
Earnings (loss) attributable to common shareholders	14	16	(11)	20
Adjustments, net of tax				
Unrealized changes in fair value of CPLP's derivative instruments and natural gas held for trading	2	(2)	13	6
Unrealized changes in fair value of CPILP's derivative instruments	2	-	2	1
Foreign exchange losses on translation of U.S. dollar debt	2	-	2	-
Impact of change in non-controlling interest percentage on adjustments of previous quarters	1	-	1	-
Impairment loss on manager and operating contracts	-	-	30	-
Impact of asset impairments recognized by subsidiaries	-	(5)	-	(5)
Obligation to EPCOR for Rosedale plant	-	2	-	2
Income tax adjustments	-	3	(2)	2
	7	(2)	46	6
Normalized earnings attributable to common shareholders	21	14	35	26
Weighted average number of common shares outstanding (millions)	48.33	21.77	40.42	21.76
Normalized earnings per share	\$ 0.43	\$ 0.64	\$ 0.87	\$ 1.19

Dividend Coverage Ratio

Capital Power uses the dividend coverage ratio as a measure of the Company's ability to pay dividends and distributions to its shareholders and CPLP's exchangeable common limited partnership unitholders from funds it generates from operations. The measure is calculated as funds from operations excluding non-controlling interests in CPILP less sustaining capital expenditures divided by dividends and distributions.

(unaudited, \$millions except dividend coverage ratio)	Three months ended		Nine months ended	
	Sept 30, 2011	Sept 30, 2010	Sept 30, 2011	Sept 30, 2010
Funds from operations excluding non-controlling interests in CPILP	\$ 116	\$ 87	\$ 264	\$ 199
CPLP sustaining capital expenditures	(11)	(6)	(45)	(35)
CPLP's share of CPILP sustaining capital expenditures	(1)	-	(4)	(1)
Funds available for distribution	\$ 104	\$ 81	\$ 215	\$ 163
Common share dividends	16	7	41	21
Distributions to exchangeable common limited partnership unitholders of CPLP	15	18	45	54
Total distributions for the period ended	31	25	86	75
Dividend coverage ratio	3.4	3.2	2.5	2.2

Financial Position

In the second quarter of 2011, the proposed sale of CPILP to Atlantic Power, as discussed under Significant Events, resulted in the reclassification of the associated assets and liabilities as held for sale. The Company also completed the acquisitions of the New England facilities and Halkirk wind project in the second quarter of 2011. After removing the effects of these events, the significant changes in the Consolidated Statements of Financial Position from December 31, 2010 to September 30, 2011 were as follows:

(unaudited, \$millions)		Increase (decrease)			
	Sept 30, 2011	Dec 31, 2010	Assets Held for Sale	Acquisitions	Other Explanation
Accounts receivable and income taxes recoverable	245	286	(58)	24	(7) Primarily due to lower customer energy consumption and customer contracts that expired in 2011 including the EPCOR RRT energy supply contract which expired in June 2011.
Assets classified as held for sale	1,493	-	1,493	-	- Reflects proposed sale of CPILP.
Intangible assets	271	651	(374)	43	(49) Primarily due to impairment of the CPILP management and operations contracts and amortization, partly offset by the impact of the weakening Canadian dollar on the translation of intangible assets of U.S. subsidiaries.
Property, plant and equipment	3,773	3,678	(858)	626	327 Primarily due to capital expenditures and the impact of the weakening of the Canadian dollar on the translation of property, plant and equipment of U.S. subsidiaries, partly offset by depreciation.
Net derivative instruments assets (liabilities)	(31)	14	77	(10)	(112) Primarily due to decreases in the fair value of derivative power contracts impacted by increasing Alberta forward power prices.
Accounts payable and accrued liabilities	232	282	(41)	25	(34) Primarily due to lower accruals for energy purchases resulting from lower customer energy consumption and customer contracts that expired in 2011 including the EPCOR RRT energy supply contract which expired in June 2011.
Liabilities classified as held for sale	929	-	929	-	- Reflects proposed sale of CPILP.
Loans and borrowings (including current portion)	1,595	1,869	(713)	-	439 Primarily due to the \$300 million debt offering and US\$295 million private placement of senior notes completed during the second quarter of 2011 and the impact of the strengthening U.S. dollar on the translation of the senior notes, partly offset by net repayments under credit facilities.
Provisions (including current portion)	217	175	(56)	-	98 Primarily due to the recognition of an asset retirement obligation relating to the New England plants.
Share Capital	1,274	820	-	-	454 Primarily due to the issuance of common share capital in March 2011 and July 2011.
Non-controlling interests	1,749	1,779	-	-	(30) Non-controlling interests' share of CPLP and CPILP distributions and CPLP's and CPILP's other comprehensive loss, partly offset by non-controlling interests' share of CPLP and CPILP net income.

Liquidity and Capital Resources

(unaudited, \$millions)		Nine months ended		Increase
Cash inflows (outflows)		Sept 30, 2011	Sept 30, 2010	(decrease)
Operating activities		310	288	22
Investing activities		(937)	(195)	(742)
Financing activities		670	(82)	752

Operating activities

See Funds from Operations.

Investing activities

The year-over-year increase in cash used in investing activities primarily reflects the acquisitions of the New England facilities and the Halkirk wind project during the second quarter of 2011 as well as higher construction activity on the Quality Wind and Port Dover & Nanticoke projects. Cash used in investing activities for the nine months ended September 30, 2010 was partly offset by cash proceeds from the sale of the Battle River PSA compared with no asset sales in the corresponding period in 2011.

Financing activities

The cash flows from financing activities in the nine months ended September 30, 2011 primarily reflected proceeds from the Company's \$300 million debt offering in April, US\$295 million private placement of senior notes in June, and \$232 million and \$231 million common share offering in March and July 2011 (see Significant Events), respectively. These cash inflows were partly offset by the repayment of \$33 million of debt owing to EPCOR in the second quarter of 2011. During the nine-months ended September 30, 2010, the Company issued \$335 million of debt and made \$245 million of debt repayments to EPCOR which were financed with draws on credit facilities.

On September 30, 2011, CPLP had \$1,220 million of credit facilities, of which \$1,002 million remained available as CPLP had \$71 million of long-term debt and \$147 million of letters of credit outstanding under the facilities. CPLP made a net repayment of \$146 million in the nine months ended September 30, 2011, under its revolving credit facilities. CPLP's long-term debt repayments also included \$6 million relating to the translation of its U.S. dollar denominated debt for the nine months ended September 30, 2011. In addition, Capital Power Corporation had an undrawn bank line of credit of \$5 million.

CPLP's available credit facilities will provide it with adequate funding for ongoing development projects and the \$226 million of principal debt repayments due in the next twelve months.

On September 30, 2011, CPILP had credit facilities of approximately \$366 million, of which \$253 million remained available as CPILP had \$80 million of long-term debt and \$32 million of letters of credit outstanding under the facilities. CPILP made a net repayment of \$7 million in the nine months ended September 30, 2011, under its credit facilities.

CPLP has received a corporate credit rating of BBB from S&P and on June 28, 2011, S&P reaffirmed the corporate rating but revised its outlook from stable to negative. CPLP has received 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. The BBB rating assigned by DBRS is the fourth highest rating of DBRS' ten rating categories for long-term debt obligations. According to DBRS, long-term debt rated BBB is of adequate credit quality. Protection of interest and principal is considered acceptable, but the entity is fairly susceptible to adverse changes in financial and economic conditions, or there may be other adverse conditions present which reduce the strength of the entity and its rated securities.

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

Capital Expenditures

(unaudited, \$millions)	2011		Total project		Expected or actual completion date
	Nine months ended Sept 30	Full year estimate ⁽¹⁾	Incurred to Sept 30, 2011 ⁽²⁾	Total cost estimate ⁽¹⁾	
CPLP					
Keephills 3	\$ 62	\$ 63	\$ 954	\$ 955	3 rd quarter 2011
Quality Wind	98	133	121	455	4 th quarter 2012
Port Dover & Nanticoke	23	41	46	340	2013
Halkirk	82	190	82	357	2 nd half 2012
Sustaining	45	98			
Total CPLP	310	525			
CPILP					
North Carolina plants enhancement	2	5	93	96	2011
Maintenance capital	15	25			
Total CPILP	17	30			
Total capital expenditures ⁽³⁾	327	555			
Emission credits	22				
Less capitalized interest	(33)				
Payments to acquire property, plant and equipment and other assets	316				

⁽¹⁾ Capital expenditures to be incurred over the life of the project and in the year ended December 31, 2011 are based on management's estimates.

⁽²⁾ Total project capital expenditures incurred to September 30, 2011 reflect capital expenditures incurred since the inception of the project.

⁽³⁾ Capital expenditures include capitalized interest. Capital expenditures excluding capitalized interest are presented on the Statement of Cash Flows as payments to acquire property, plant and equipment and other assets.

Keephills 3 commenced commercial operation on September 1, 2011.

Estimated capital expenditures in 2011 for the Quality Wind project are approximately \$15 million lower than previously anticipated due to the deferral of certain planned expenditures to 2012. The change is not anticipated to impact the planned completion date of the fourth quarter of 2012 or the total cost of \$455 million.

Construction of the Port Dover & Nanticoke project was delayed by completion of the land title transfers and regulatory proceedings, which resulted in \$57 million of planned expenditures being deferred to 2012. The delay is not expected to impact the total cost of the project, but the project's completion date may be delayed until 2013 pending regulatory proceedings.

In the second quarter of 2011, the Company acquired the Halkirk wind project. The expenditures incurred to date include \$33 million for permits and land lease rights, and an \$18 million payment to the supplier of the wind turbines.

Sustaining capital expenditures include spending on plant maintenance, the Genesee mine, information technology for a new energy trading and risk management system, and leasehold improvements for offices in Calgary and Edmonton. The full year estimate was updated in the first and second quarters of 2011 to add \$7 million for maintenance of the New England plants and \$8 million for land purchases for the Genesee mine, respectively.

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 three months ended December 31, 2011, excluding CPILP's cash requirements and cash requirements for acquisitions, are expected to include approximately \$215 million for capital expenditures, approximately \$15 million for CPLP distributions to EPCOR, subject to approval by the CPLP Board of Directors, approximately \$16 million for Capital Power's quarterly common share dividends, subject to approval by the Capital Power Corporation Board of Directors, and approximately \$1 million for quarterly preferred share dividends.

The current portion of long-term debt on the statement of financial position of \$226 million is primarily comprised of \$225 million payable to EPCOR in the next twelve months.

The Company expects to fund the construction of the Quality Wind, Port Dover & Nanticoke and Halkirk 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%. The Company's other cash requirements identified above, are expected to be funded with cash on hand, cash provided by operating activities, use of existing bank credit facilities, and disposition of the interest in CPILP.

The Company's two short form base shelf prospectuses provide, market conditions permitting, 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. Under 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, and up to \$1 billion by issuing medium-term notes with maturities of not less than one year. As of the date of this MD&A, Capital Power has \$316 million of equity and \$400 million of debt available under these short form base shelf prospectuses. 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 three months ended December 31, 2011 are expected to include approximately \$13 million for capital expenditures, approximately \$25 million for distributions subject to approval by the CPILP Board of Directors and approximately \$3 million for preferred share dividends of a subsidiary company. In conjunction with CPILP's agreement with Atlantic Power to sell its partnership units, CPILP announced the termination of its distribution reinvestment program in the second quarter of 2011. If CPILP's total cash requirements for the remainder of 2011 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. The expectations described above for CPILP's future cash requirements do not take into consideration the impact of the proposed sale of CPILP.

CPILP's short form base shelf prospectus, market conditions permitting, provides the partnership with the ability to obtain new debt and equity capital from external markets at an aggregate amount of up to \$600 million. This base shelf prospectus expires in August 2012.

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 material changes to the Company's commitments since December 31, 2010 include those related to the \$300 million medium-term notes issued in April 2011, the US\$295 million private placement of senior notes issued in June 2011, the proposed sale of its interest in CPILP and purchase of CPILP's North Carolina facilities, and the development of the Halkirk project. Otherwise, there were no changes to the Company's purchase obligations, commitments or contingencies since December 31, 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, 2010 MD&A.

Off-balance Sheet Arrangements

As at September 30, 2011, the Company had no off-balance sheet arrangements.

Related Party Transactions

EPCOR, including its subsidiaries, and its sole shareholder The City of Edmonton, are the only related parties which the Company had material transactions with in the nine months ended September 30, 2011. At September 30, 2011, EPCOR owned 47.416 million exchangeable limited partnership units of CPLP and 47.416 million accompanying special voting shares and one special limited voting share in the capital of Capital Power Corporation.

The Company's long-term debt payable to EPCOR, which was issued in connection with the Reorganization, was \$583 million at September 30, 2011 compared with \$619 million at December 31, 2010.

The Company's related party transactions for the nine months ended September 30, 2011 and September 30, 2010 were as follows:

(unaudited, \$ millions)		Nine-months ended	
Statement of Income (Loss)		Sept 30, 2011	Sept 30, 2010
Revenues	(1)	\$ 261	\$ 297
Energy purchases and fuel	(2)	16	22
Net finance expense	(3)	20	10

(1) Included in the Company's revenues are power sales to EPCOR, including its subsidiaries, and the City of Edmonton for resale to its customers. For the nine months ended September 30, 2011, the Company had \$236 million of power sales to EPCOR and its subsidiaries, and \$25 million to the City of Edmonton. For the nine-month period in 2010, the Company had \$276 million and \$21 million of power sales to EPCOR and the City of Edmonton, respectively.

(2) The Company purchased distribution and transmission services from EPCOR and 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.

(3) For the nine months ended September 30, 2011 and 2010, \$11 million and \$32 million, respectively, of the interest incurred on the long-term debt payable to EPCOR was capitalized as property, plant and equipment for construction work in progress. The remainder was included in net financing expense.

The above transactions were in the normal course of operations and were recorded at the exchange values which were based on normal commercial rates.

Business Risks

The Company's business and operational risks remains substantially unchanged from that disclosed in the Company's December 31, 2010 MD&A. Recent developments in business and operational risks are described below.

Failure to complete the CPILP transaction with Atlantic Power

If the CPILP transaction with Atlantic Power is not completed, the ongoing business of CPILP may be adversely affected because CPILP will have to consider alternative transactions. Additionally, if the transaction is not completed and the arrangement agreement with Atlantic Power is terminated, CPILP may be required to pay a break-up fee in the amount of \$35 million. The arrangement agreement with Atlantic Power also contains a provision that, subject to limited exceptions, restricts CPILP's ability to solicit, encourage, facilitate or discuss competing third-party proposals to acquire units or assets of CPILP. If the transaction is not completed and CPILP determines to seek another business combination, it may not be able to negotiate a transaction with another party on terms comparable to, or better than, the terms of the transaction with Atlantic Power. The foregoing risks may have an adverse effect on the business, operations, financial results and unit price of CPILP.

U.S. – Cross State Air Pollution Regulations

The U.S. Environmental Protection Agency (EPA) has finalized the Cross State Air Pollution Regulations (CSAPR), designed to reduce the amount of nitrogen oxide (NOx) and sulphur dioxide (SO₂) emissions from electric generating units that are transported to down-wind states starting January 1, 2012. CSAPR replaced the Clean Air Transport Rule. Based on earlier drafts of the regulation, the Company did not expect the North Carolina facilities to be subject to CSAPR and expected NOx and SO₂ emissions regulations other than CSAPR would continue to apply to the plants.

The cost of emissions credits required to comply with CSAPR have been volatile since the regulation was finalized as a result of lawsuits filed against the EPA contesting the initial allocation of emissions credits, concerns regarding the federal implementation versus the state implementation of this program, uncertainty within the marketplace of the commencement of the program on January 1, 2012 and the impact of other additional State regulations. The Company has submitted a request for reconsideration of the emissions credits that have been allocated to the North Carolina plants. There is currently insufficient information to determine the impact of CSAPR on the Company, although as additional regulation is passed it is likely that the Company will incur increased costs.

International Financial Reporting Standards

Capital Power's September 30, 2011 condensed interim consolidated financial statements are prepared in accordance with International Accounting Standard (IAS) 34 Interim Financial Reporting. The comparative periods included in these financial statements have been restated to IFRS and the Company has applied IFRS 1 First-time Adoption of International Financial Reporting Standards. The Company's previously issued interim and financial reports for periods prior to and including the year ended December 31, 2010, were prepared in accordance with previous CGAAP.

The following tables provide a summary of principal adjustments made by the Company in restating its previously published Canadian GAAP financial statements for the three and nine months ended September 30, 2010. Optional exemptions and exceptions were applied and discussed in the March 31, 2011 condensed interim consolidated financial statements and MD&A.

Equity

(unaudited, \$millions)	As at Sept 30, 2010		
	Attributable to shareholders	Attributable to Non-controlling interests	Total equity
Previous CGAAP	479	2,020	2,499
Adjustments:			
IAS 16 Property, plant and equipment and IAS 37 Provisions	2	(18)	(16)
IAS 36 Impairments	(2)	(112)	(114)
IFRS 1 First time adoption of IFRS	4	44	48
Other impacts	10	106	116
IFRS	493	2,040	2,533

Total comprehensive income

(unaudited, \$millions)	Three months ended Sept 30, 2010		
	Attributable to shareholders	Attributable to non-controlling interests	Total comprehensive income
Previous CGAAP	7	25	32
Adjustments:			
IAS 16 Property, plant and equipment and IAS 37 Provisions	5	(4)	1
IAS 36 Impairments	3	(68)	(65)
IFRS 1 First time adoption of IFRS	(1)	(3)	(4)
Other impacts	2	17	19
IFRS	16	(33)	(17)

(unaudited, \$millions)	Nine months ended Sept 30, 2010		
	Attributable to shareholders	Attributable to non-controlling interests	Total comprehensive income
Previous CGAAP	10	68	78
Adjustments:			
IAS 16 Property, plant and equipment and IAS 37 Provisions	3	(7)	(4)
IAS 36 Impairments	4	(68)	(64)
IFRS 1 First time adoption of IFRS	(1)	(4)	(5)
Other impacts	2	16	18
IFRS	18	5	23

IAS 16 Property, plant and equipment (PP&E)

IFRS are more specific with respect to the level at which components of assets are to be accounted for. The appropriate components have been identified and the most significant difference from previous CGAAP is that overhaul costs are capitalized under IFRS. Additionally, certain costs relating to the Genesee mine that were previously capitalized under CGAAP have been expensed under IFRS due to componentization. The contract between the Genesee mine operator and the Company requires Capital Power to fully fund the operating activities of the mine, including depreciation, whereas capital asset funding is shared between the two parties. Certain costs that were previously capitalized would have been expensed under the requirements of IAS 16 and fully funded by Capital Power. As a result, the Company recorded transitional adjustments to recognize deferred revenue and other liabilities and to align the two parties' accounting policies.

IAS 37 Provisions

In accordance with IAS 37, provisions are required to be measured at the best estimate of the expected expenditure, such as for an asset retirement, using discount rates appropriate for each liability. Under previous CGAAP such provisions were measured at fair value. Under IFRS, provisions are re-measured at each reporting period for any changes in cash flow estimates, timing of decommissioning activity and discount rates. Accordingly, the Company re-measured its provisions using revised cash flow estimates for the Genesee mine asset retirement obligation, and revised discount rates for all of its plant decommissioning liabilities. The Company also re-measured amounts provided for the unavoidable costs of its Alberta retail and commercial natural gas contracts using revised cash flow and discount rate assumptions.

IAS 36 Impairments

In accordance with IAS 36, as discussed in the March 31, 2011 MD&A, the Company reviewed the recoverable amount for its cash generating units (CGUs) for which goodwill was required to be allocated, at both the date of transition to IFRS and as at December 31, 2010. For all other CGUs, management assessed whether there were any events at the date of transition to IFRS, at September 30, 2010 and at December 31, 2010 which would require an assessment for impairment. Recoverable amounts were calculated on a fair value less cost to sell basis, using discounted cash flow models based on the Company's long-term planning model. This one step approach, at the CGU level, under IFRS differs from the two-step approach under previous CGAAP, which required the application of discounted cash flow techniques to measure the impairment amount, but only after the use of undiscounted cash flow analysis indicated the existence of an impairment. Some CGUs consist of a single plant resulting in more CGUs subject to impairment testing under IFRS than under previous CGAAP.

As a result of the changes to the determination of recoverable amounts and the allocation of the goodwill to the CGUs, the Company recognized \$116 million of impairments as at September 30, 2010. These impairments included \$109 million for certain CPILP facilities due to the impact of weakening economic conditions in their respective markets and \$7 million for the Company's management contracts with CPILP.

IFRS 1 First time adoption of IFRS

The Company elected under IFRS 1 to use fair value as the deemed cost of its PP&E for certain plants. As a result, the PP&E balance at September 30, 2011 increased by \$48 million. Income before tax decreased by \$1 million and \$3 million for the three and nine months ended September 30, 2010 respectively, due to higher depreciation and amortization on the increased PP&E balances.

IFRS 1 also provides for an election to deem any cumulative translation differences to be zero on transition to IFRS. As a result of the Company taking this IFRS 1 election, \$4 million was reclassified within equity, from accumulated other comprehensive income to retained earnings at January 1, 2010.

These adjustments impact equity in proportion to the Company's owners' respective shares of the adjustments and accordingly resulted in an increase of \$4 million in the equity attributable to shareholders and an increase of \$44 million to non-controlling interests as at September 30, 2010.

Other impacts

In accordance with IAS 17 Leases, the Kingsbridge PPA was determined to be a finance lease as IAS 17 had different qualitative guidelines than previous CGAAP in the determination of the classification of leases between operating and finance (or capital under previous CGAAP). As a result, PP&E was decreased by \$50 million, finance lease receivable was increased by \$62 million, trade and other receivables increased by \$2 million and retained earnings was increased by \$14 million as at September 30, 2010.

In accordance with the requirements of IAS 31 Interests in Joint Ventures, the Company controls the Genesee mine joint venture. As a result, the Company consolidated the non-controlling interest's share of the Genesee mine which increased PP&E and non-controlling interests by \$87 million each as at September 30, 2010.

The Company elected under IFRS 1 to recognize all actuarial gains and losses in other comprehensive income. Under previous CGAAP, the Company recognized actuarial gains and losses using the corridor approach whereby amounts that exceeded the corridor were recognized in income over the average remaining service period of the active employees. At the date of transition, all previously unrecognized cumulative actuarial gains and losses were recognized in retained earnings. As at September 30, 2010, the provision was increased and other comprehensive income was decreased by \$1 million.

In accordance with IAS 39, an asset classified as available for sale is recorded at fair value with any changes in the fair value recognized in other comprehensive income. Accordingly, other financial assets were increased by \$3 million as at September 30, 2010, for the difference between the fair value and the previously reported carrying amount of one of the Company's equity investments. Since this adjustment is unrealized, accumulated other comprehensive income was correspondingly increased.

As a result of IAS 39's requirement for hedge effectiveness testing to incorporate a company's credit risk, accumulated other comprehensive income increased by \$2 million as at September 30, 2010, with a corresponding decrease in retained earnings.

Other impacts in the tables above also include the tax impact of the adjustments recognized.

Future Accounting Changes

The following new and amended standards will be effective in future periods as indicated and may have an impact on CPC's financial statements. The Company is currently assessing the impact of adopting these standards and amendments on its consolidated financial statements:

International Accounting Standards (IAS/IFRS)	Effective Date
IAS 1 – Presentation of Financial Statements	July 1, 2012
IFRS 10 – Consolidated Financial Statements	January 1, 2013
IFRS 11 – Joint Arrangements	January 1, 2013
IFRS 12 – Disclosures of Interests in Other Entities	January 1, 2013
IFRS 13 – Fair Value Measurement	January 1, 2013
IAS 19 – Employee Benefits	January 1, 2013
IFRS 9 - Financial Instruments	January 1, 2015

IAS 1 – In June 2011, the International Accounting Standards Board (IASB) issued amendments to IAS 1 which will require entities to group items within other comprehensive income on the basis of whether or not they will be reclassified to profit or loss in a future period. The amendments are to be applied retrospectively. Early adoption is permitted.

IFRS 10 – In May 2011, the IASB issued IFRS 10 which replaces IAS 27 – *Consolidated and Separate Financial Statements* and SIC – 12 *Consolidation – Special Purpose Entities*. IFRS 10 establishes principles for the presentation and preparation of consolidated financial statements. The new standard provides a revised definition of control and a single consolidation model as the basis for consolidation for all types of entities. The standard also provides additional guidance to assist in the determination of control. Capital Power will review the entities in which it holds an interest to assess whether application of this new standard will require changes to the consolidation of these entities. IFRS 10 is to be applied retrospectively. Early adoption is permitted but must be applied simultaneously with IFRS 11 – *Joint Arrangements* and IFRS 12 – *Disclosure of Interests in Other Entities*.

IFRS 11 – IFRS 11 was issued in May 2011 and supersedes IAS 31 – *Interests in Joint Ventures* and SIC 13 – *Jointly Controlled Entities – Non-Monetary Contributions by Venturers*. The standard provides an improved method for classifying joint arrangements and may result in a different method of accounting for the Company's existing arrangements. Capital Power currently accounts for its joint arrangements using the proportionate consolidation method. The Company will review its existing joint arrangements and determine if the classification of these arrangements differs under the new standard and may require the application of the equity method of accounting. IFRS 11 is to be applied retrospectively. Early adoption is permitted but must be applied simultaneously with IFRS 10 – *Consolidated Financial Statements* and IFRS 12 – *Disclosure of Interests in Other Entities*.

IFRS 12 – In May 2011, the IASB issued IFRS 12, a new and comprehensive standard on disclosure requirements for all forms of interests in other entities, including subsidiaries, joint arrangements, associates and unconsolidated structured entities. IFRS 12 is to be applied retrospectively. Early adoption is permitted but must be applied simultaneously with IFRS 11 – *Joint Arrangements* and IFRS 10 – *Consolidated Financial Statements*.

IFRS 13 – In May 2011, the IASB issued IFRS 13 which defines fair value, sets out in a single IFRS a framework for measuring fair value and requires disclosures about fair value measurements. IFRS 13 applies to fair value measurements required or permitted by other IFRSs, but does not (a) introduce any new requirements to measure an asset or a liability at fair value, (b) change what is measured at fair value in IFRSs or (c) address how to present changes in fair value. Earlier adoption of the amendment is permitted.

IAS 19 – In June 2011, the IASB issued an amendment to IAS 19 which introduced improvements related to: (a) eliminating the option to defer the recognition of actuarial gains and losses, known as the corridor method, (b) requiring a new presentation approach that improves the visibility of different types of gains and losses, and (c) enhancing the disclosure requirements to provide better information about the characteristics of defined benefit plans and the risks that entities are exposed to through participation in these plans. Earlier application of the amendment is permitted.

IFRS 9 – In November 2009, the IASB issued IFRS 9 – *Financial Instruments* which addresses the classification and measurement requirements of financial assets. The standard was amended in October 2010 to include the requirements for the classification and measurement of financial liabilities. The changes are to be applied retrospectively and early adoption is permitted.

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, non-financial assets, provisions, income taxes, leases or arrangements containing a lease, foreign currency translation, purchase price allocations for acquisitions and the consolidation of CPILP, CPLP and Genesee coal mine. For further information on the Company's accounting policies and estimates, refer to the Company's December 31, 2010, March 31, 2011 and June 30, 2011 MD&A.

Financial Instruments

The Company's derivative instruments assets and liabilities used for risk management purposes are measured at fair value and consisted 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 September 30, 2011	(114)	(4)	14	(4)	(108)
Less: Derivative instruments net assets (liabilities) held by CPILP and classified as assets held for sale	(89)	(2)	14	-	(77)
Derivative instruments net assets (liabilities) as at September 30, 2011	(25)	(2)	-	(4)	(31)

In the second quarter of 2011, CPILP entered into an arrangement agreement for the proposed sale of CPILP as discussed under Significant Events. As a result, certain assets and liabilities relating to the Company's interest in CPILP were classified as assets and liabilities held for sale commencing in the second quarter of 2011. Accordingly, the following explanations relate to the Company's derivative instruments that are not classified as held for sale.

At September 30, 2011, the fair value of energy derivative instruments designated and qualifying for hedge accounting was a net liability of \$25 million which primarily reflected the impact of increased forward Alberta power prices on power derivative contracts relative to the contract prices.

At September 30, 2011, the fair value of energy derivative instruments not designated as hedges for accounting purposes was a net liability of \$2 million, which primarily reflected the impact of changes in the forward Alberta power prices on the Alberta power portfolio.

At September 30, 2011, 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 August 2011 and will mature in December 2011. The unrealized changes in the fair value of these contracts for the third quarter of 2011 were recognized in financing expenses, as discussed under Consolidated Other Expenses and Non-controlling Interests.

For the nine months ended September 30, 2011 and September 30, 2010, losses net of income taxes on derivative instruments designated as cash flow hedges, of \$90 million and \$28 million respectively, were recorded in other comprehensive income for the effective portion of cash flow hedges. Realized losses, net of income taxes, for the nine months ended September 30, 2011 of \$39 million and for the nine months ended September 30, 2010 of \$5 million were reclassified to energy purchases and revenues as appropriate. For the nine months ended September 30, 2011 and September 30, 2010, the change in the fair value of the ineffective portion of hedging derivatives recognized in the statement of income, before non-controlling interests, was a loss of \$2 million and \$1 million, respectively.

Internal Control over Financial Reporting

There were no changes in the Company's internal controls over financial reporting that occurred during the nine months ended September 30, 2011 that have materially affected, or are reasonably likely to materially affect the Company's internal control over financial reporting. The Company's transition to IFRS did not result in any significant changes to the Company's internal controls.

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. By their nature, such statements are subject to significant risk, assumptions and uncertainties, which could cause Capital Power's actual results and experience to be materially different than the anticipated results.

Forward-looking information in this MD&A includes, among other things, information relating to: (i) expectations for the Company's and CPILP's sources of capital and use, adequacy and availability of committed bank credit

facilities and potential future borrowings; (ii) the Company's and CPILP's cash requirements for 2011, including interest and principal repayments, capital expenditures, distributions and dividends; (iii) expectations regarding future growth and emerging opportunities in the Company's target markets including the focus on certain technologies; (iv) expectations regarding allocated capital to be committed in 2011; (v) expectations regarding the Company's operational performance, including plant availability average and capital expenditures for maintenance of CPLP plants and Genesee mine; (vi) expectations regarding full year financial performance for 2011, including normalized earnings per share, funds from operations excluding non-controlling interests in CPILP, cash flow per share, and dividend coverage ratio; (vii) expected impact on capitalization and full year depreciation as a result of maintenance costs which are capitalized under IFRS; (viii) expected impact on depreciation as a result of the extension of in useful life of the Genesee and Keephills 3 plants; (ix) expected impact on 2011 EBITDA and additional unrealized gains to be recognized upon settlement of the remaining heat rate options as a result of the three New England plant acquisitions; (x) expectations regarding the future pricing and market fundamentals in the New England market and the expected impact on the Company's earnings; (xi) expected impact on financing costs due to the issuance of the medium-term notes debentures in April 2011 and the private placement of senior notes in June 2011; (xii) expected total capital project costs and capital expenditures as well as expected project completion dates and expected payments under contractual obligations; (xiii) expectations regarding the total project cost of the Halkirk wind project; (xiv) expectations regarding the final project cost for Keephills 3; (xv) expectations regarding timing of spending on the Quality Wind and Port Dover & Nanticoke project and the impact on the commercial operation date and total project cost; (xvi) expectations regarding Alberta power prices for 2011; (xvii) expectations regarding the date that construction would begin and commercial operation date of the K2 wind project, the total cost of the project and method of funding the project, the project's generation capacity, the area of development, the ability to obtain corporate and regulatory approvals; the partners economic interest in the project at commercial operation; finalization of the project's turbine model and supplier; and each partner's contribution to the project; (xviii) expectations regarding the outcome of the CPILP strategic review and the agreement with Atlantic Power pursuant to which Atlantic Power will acquire all of the outstanding limited partnership units of CPILP, Capital Power will acquire CPILP's Roxboro and Southport plants, and Capital Power will cease to manage CPILP; (xix) expectations regarding the timing of closing of the CPILP strategic review transactions, total consideration to be received, including disposal costs to be incurred and use of cash consideration, and the gain on sale and foreign translation gain attributable to common shareholders, to be recognized in connection with the CPILP strategic review transaction in the fourth quarter; (xx) expected funding of the Quality Wind, Port Dover & Nanticoke, and Halkirk wind projects during construction and once completed while maintaining overall leverage in the range of 40% - 50%; and (xxi) expectations regarding the impact of CSAPR on the Company and the allocation of emission credits to the North Carolina plants.

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 and dispatch, including Sundance which is subject to an acquired PPA; (iii) the Company's financial position and credit facilities and sources of funding; (iv) the Company's assessment of commodity and power markets, including power prices and forward power prices for 2011; (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) 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, common share ownership distribution, 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; (xxi) costs of construction and development; (xxii) current risk management strategies including hedges will be in place; (xxiii) total cash requirements; (xxiv) ability to obtain court and regulatory approvals, and unitholders' and shareholders' favourable votes in relation to the CPILP strategic review transaction; (xxv) carrying amounts of assets held for

sale; (xxvi) ability to obtain corporate and regulatory approvals for the K2 project; and (xxvii) factors and assumptions noted under Outlook in respect of the forward looking statements and information noted in that section.

Whether actual results, performance or achievements will conform to the 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, including unplanned plant outages at facilities of other market participants; (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, investments and divestitures; (xvii) the tax attributes of and implications of any acquisitions; (xviii) the completion of the CPILP strategic review transactions and the K2 project; (xix) ability to secure new contracts and terms of such contracts; (xx) risks and uncertainties noted under Outlook in respect of the forward looking information and statements noted in that section. See also Business Risks section in this MD&A and also as disclosed in the Company's December 31, 2010 annual MD&A. 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) the full year sustaining capital estimate has been updated to add \$8 million for land purchases for the Genesee mine; (ii) expectations regarding normalized earnings per share have been updated to include revised expectations regarding Alberta power prices in 2011 and the impact of the loss on the settlement of bond forward contracts and the pension adjustment; (iii) the outage at Clover Bar Energy Centre Unit 2 has been deferred beyond 2011; (iv) the earnings contribution from the three New England plants for 2011 has been updated due to the Company's revised pricing view on the New England market, expectation of additional unrealized gains to be recognized upon settlement of the remaining heat rate options, and also to include an additional \$3 million for a Connecticut energy tax which was introduced in June 2011; (v) expectations regarding capital expenditures in relation to Quality Wind planned for 2011 has been revised due to the deferral of certain expenditures; and (vi) expectations regarding the capital expenditures for Keephills 3 has been updated to reflect expected final costs incurred on the project.

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)	Sept 30, 2011	June 30, 2011	Mar 31, 2011	Three months ended		June 30, 2010	Mar 31, 2010	Dec 31, 2009 ⁽²⁾
				Dec 31, 2010	Sept 30, 2010			
Revenues and other income	433	472	458	437	513	313	501	497
Gross income	244	217	167	205	236	117	217	216
EBITDA ⁽¹⁾	132	65	82	96	83	37	169	116
Net income (loss)	44	(22)	14	22	(3)	(34)	92	39
Net income (loss) attributable to shareholders	15	(25)	3	(3)	16	(8)	12	7
Earnings (loss) per share	\$ 0.29	\$ (0.67)	\$ 0.06	\$ (0.13)	\$ 0.74	\$ (0.37)	\$ 0.55	\$ 0.33
Normalized earnings per share ⁽¹⁾	\$ 0.43	\$ 0.07	\$ 0.33	\$ 0.21	\$ 0.64	\$ 0.05	\$ 0.51	\$ 0.18

⁽¹⁾ The consolidated financial information, except for EBITDA and normalized earnings per share, has been prepared in accordance with IFRS. See Non-IFRS Financial Measures.

⁽²⁾ The results for the fourth quarter of 2009 have been prepared in accordance with previous CGAAP.

Generation volume and plant availability information

(unaudited, GWh)	Three months ended							
Electricity generation⁽¹⁾	Sept 30, 2011	June 30, 2011	Mar 31, 2011	Dec 31, 2010	Sept 30, 2010	June 30, 2010	Mar 31, 2010	Dec 31, 2009
Alberta commercial plants								
Genesee 3	496	477	482	272	475	432	483	484
Keephills 3 ⁽²⁾	336	50	-	-	-	-	-	-
Joffre	90	57	98	82	67	93	41	73
Clover Bar Energy Centre 1, 2 and 3	57	40	162	179	37	102	43	9
Taylor Coulee Chute	12	2	-	1	7	3	-	2
Clover Bar Landfill Gas	9	9	8	9	9	10	10	10
	1,000	635	750	543	595	640	577	578
Alberta contracted plants								
Genesee 1	843	661	768	854	841	780	813	618
Genesee 2	845	789	831	826	824	571	825	817
	1,688	1,450	1,599	1,680	1,665	1,351	1,638	1,435
Ontario and British Columbia contracted plants								
Kingsbridge 1	12	24	31	39	18	22	26	32
Miller Creek	49	26	5	7	46	35	7	14
Brown Lake	8	15	14	14	5	11	13	15
Island Generation	-	55	52	273	-	-	-	-
	69	120	102	333	69	68	46	61
North East U.S. commercial plants ⁽³⁾								
Rumford	170	68	-	-	-	-	-	-
Tiverton	422	289	-	-	-	-	-	-
Bridgeport	872	645	-	-	-	-	-	-
	1,464	1,002	-	-	-	-	-	-
Total plants excluding CPILP plants	4,221	3,207	2,451	2,556	2,329	2,059	2,261	2,074
CPILP plants	1,294	1,155	1,139	1,311	1,306	1,128	1,268	1,407
Total plants	5,515	4,362	3,590	3,867	3,635	3,187	3,529	3,481

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

⁽²⁾ Keephills 3 includes pre-commissioning output until September 1, 2011. Revenues and expenses related to commissioning activities were capitalized as part of the cost of the facility in property, plant and equipment.

⁽³⁾ North East U.S. commercial plants include Bridgeport and the Rumford & Tiverton as of their dates of acquisition of April 28, 2011, and April 29, 2011, respectively.

(unaudited) Generation plant availability ⁽¹⁾	Three months ended							
	Sept 30, 2011	June 30, 2011	Mar 31, 2011	Dec 31, 2010	Sept 30, 2010	June 30, 2010	Mar 31, 2010	Dec 31, 2009
Alberta commercial plants								
Genesee 3	100%	100%	100%	56%	99%	96%	100%	99%
Keephills 3 ⁽²⁾	100%	-	-	-	-	-	-	-
Joffre	99%	78%	99%	99%	98%	84%	100%	94%
Clover Bar Energy Centre 1, 2 and 3	91%	65%	65%	95%	63%	52%	72%	98%
Taylor Coulee Chute	100%	94%	100%	100%	100%	90%	98%	66%
Clover Bar Landfill Gas	86%	86%	95%	88%	92%	96%	96%	94%
	97%	82%	87%	83%	86%	76%	90%	97%
Alberta contracted plants								
Genesee 1	100%	81%	92%	100%	100%	100%	99%	74%
Genesee 2	100%	99%	100%	97%	97%	75%	99%	97%
	100%	90%	96%	98%	99%	87%	99%	85%
Ontario and British Columbia contracted plants								
Kingsbridge 1	99%	99%	98%	100%	99%	100%	99%	100%
Miller Creek	92%	99%	78%	12%	96%	96%	37%	97%
Brown Lake	53%	99%	100%	99%	93%	99%	97%	99%
Island Generation	100%	100%	99%	99%	-	-	-	-
	98%	100%	97%	91%	97%	98%	74%	99%
North East U.S. commercial plants ⁽³⁾								
Bridgeport	95%	100%	-	-	-	-	-	-
Rumford	97%	99%	-	-	-	-	-	-
Tiverton	96%	97%	-	-	-	-	-	-
	96%	99%	-	-	-	-	-	-
Average excluding CPILP plants⁽⁴⁾	97%	91%	93%	91%	93%	83%	93%	92%
CPILP plants ⁽⁴⁾	96%	88%	92%	97%	97%	90%	95%	92%
Average all plants⁽⁴⁾	97%	90%	92%	95%	95%	86%	94%	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) Alberta commercial plants include Keephills Unit 3 as of its date of commissioning of September 1, 2011.

(3) North East U.S. commercial plants include Bridgeport and the Rumford & Tiverton facilities as of their dates of acquisition of April 28, 2011, and April 29, 2011, respectively.

(4) 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 2011 is 94%. In the third quarter of 2011, 97% was achieved for this performance measure.

Results by plant category

(unaudited, \$millions)	Sept 30, 2011	June 30, 2011	Mar 31, 2011	Three months ended		June 30, 2010	Mar 31, 2010	Dec 31, 2009 ⁽³⁾
				Dec 31, 2010	Sept 30, 2010			
Revenues and other income								
Alberta commercial plants and portfolio optimization ⁽¹⁾	\$ 144	\$ 215	\$ 266	\$ 237	\$ 247	\$ 197	\$ 235	\$ 248
Alberta contracted plants	87	64	77	76	73	57	73	61
Ontario/British Columbia contracted plants	12	13	13	12	3	3	3	4
North East U.S. commercial plants and portfolio optimization ⁽²⁾	71	51	-	-	-	-	-	-
CPILP plants	139	129	128	139	130	116	139	130
Other portfolio activities	19	18	34	26	20	22	43	40
Corporate	5	6	6	6	5	10	6	-
Inter-plant category transaction eliminations	(16)	(17)	(20)	(15)	(14)	(18)	(15)	(9)
	461	479	504	481	464	387	484	474
Unrealized fair value changes in derivative instruments and natural gas inventory held for trading								
- CPLP	(5)	(8)	(49)	(55)	38	(55)	12	15
- CPILP	(23)	1	3	11	11	(19)	5	8
	(28)	(7)	(46)	(44)	49	(74)	17	23
	\$ 433	\$ 472	\$ 458	\$ 437	\$ 513	\$ 313	\$ 501	\$ 497
Gross income								
Alberta commercial plants and portfolio optimization ⁽¹⁾	\$ 88	\$ 57	\$ 50	\$ 58	\$ 70	\$ 59	\$ 65	\$ 53
Alberta contracted plants	72	52	62	56	59	42	58	48
Ontario/British Columbia contracted plants	12	13	13	12	3	3	3	4
North East U.S. commercial plants and portfolio optimization ⁽²⁾	19	15	-	-	-	-	-	-
CPILP plants	81	75	72	85	76	68	77	74
Other portfolio activities	7	9	9	3	13	6	15	12
Corporate	6	6	6	6	6	10	6	-
Inter-plant category transaction eliminations	(14)	(12)	(13)	(15)	(12)	(17)	(14)	(9)
	271	215	199	205	215	171	210	182
Unrealized fair value changes in derivative instruments and natural gas inventory held for trading								
- CPLP	(4)	-	(34)	(14)	14	(36)	9	26
- CPILP	(23)	2	2	14	7	(18)	(2)	8
	(27)	2	(32)	-	21	(54)	7	34
	\$ 244	\$ 217	\$ 167	\$ 205	\$ 236	\$ 117	\$ 217	\$ 216
EBITDA⁽³⁾								
Alberta commercial plants and portfolio optimization ⁽¹⁾	\$ 72	\$ 44	\$ 38	\$ 45	\$ 59	\$ 46	\$ 53	\$ 42
Alberta contracted plants	57	35	47	41	47	29	44	25
Ontario/British Columbia contracted plants	8	10	10	8	2	2	2	3
North East U.S. commercial plants and portfolio optimization ⁽²⁾	10	10	-	-	-	-	-	-
CPILP plants	47	37	45	39	(22)	43	49	39
Other portfolio activities	-	2	-	(5)	5	(5)	6	(1)
Corporate	(34)	(75)	(26)	(33)	(29)	(23)	(20)	(26)
	160	63	114	95	62	90	134	82
Unrealized fair value changes in derivative instruments and natural gas inventory held for trading								
- CPLP	(5)	-	(34)	(15)	14	(37)	9	26
- CPILP	(23)	2	2	14	7	(18)	(2)	8
	(28)	2	(32)	(1)	21	(55)	7	34
Gains on acquisitions and disposals	-	-	-	2	-	-	28	-
	\$ 132	\$ 65	\$ 82	\$ 96	\$ 83	\$ 37	\$ 169	\$ 116

(1) Alberta commercial plants include Keephills Unit 3 as of its date of commissioning of September 1, 2011.

(2) North East U.S. commercial plants include Bridgeport and the Rumford & Tiverton facilities as of their dates of acquisition of April 28, 2011, and April 29, 2011, respectively.

(3) The results by plant category, except for EBITDA, have been prepared in accordance with IFRS. See Non-IFRS Financial Measures.

(4) The results for the fourth quarter of 2009 have been prepared in accordance with previous CGAAP.

(unaudited, \$/MWh)		Three months ended						
Alberta power prices	Sept 30, 2011	June 30, 2011	Mar 31, 2011	Dec 31, 2010	Sept 30, 2010	June 30, 2010	Mar 31, 2010	Dec 31, 2009
Average Alberta power spot price	\$ 95	\$ 52	\$ 82	\$ 46	\$ 36	\$ 81	\$ 41	\$ 46
Capital Power's Alberta portfolio's average realized power price	74	56	64	64	66	66	67	57

Factors impacting the 2011 third quarter results

In the third quarter of 2011, the average Alberta power price increased significantly due to warmer temperatures, reduced supply resulting from several plant outages in the area, and Saskatchewan tie-line restrictions. Higher Alberta power prices had a favourable impact on the Company's Alberta portfolio position. Sundance Unit 6 went offline on August 18, 2011 due to a transformer failure and remained offline until October 14, 2011 for planned maintenance. The penalty revenues received for this outage were based on high rolling average power prices and had a favourable impact on Alberta commercial plant and portfolio optimization EBITDA. The high rolling average power prices also had a favourable impact on availability incentive income for the Alberta contracted plants which had 100% availability in the quarter. Corporate EBITDA included a \$6 million foreign exchange loss related to the translation of U.S. denominated debt.

Factors impacting results for the previous quarters

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

In the second quarter of 2011 North East U.S. commercial plants and portfolio optimization EBITDA reflected contributions from the Rumford, Tiverton and Bridgeport facilities and trading in the North East U.S. power market since their acquisition in April 2011. Alberta contracted plants EBITDA included \$5 million of availability incentive penalties relating to a scheduled maintenance outage at Genesee 1. Corporate general and administrative expenses included an impairment loss of \$43 million on Capital Power's management and operations contracts with CPILP. Corporate expenses also increased for a \$4 million valuation adjustment to the Company's supplemental pension obligation based on an actuarial valuation. Finance expense included a \$10 million loss related to the settlement of forward bond sale contracts. Income taxes included the reversal of a provision recorded in the second quarter of 2010 for future income taxes associated with the possible sale of the Company's interest in CPILP.

In the first quarter of 2011, the average Alberta power price increased significantly primarily due to colder weather than normal and the shutdown of two large coal plants in the region. The sudden increase in Alberta power prices had an unfavourable impact on the Company's Alberta portfolio position.

In the fourth quarter of 2010, high Alberta power spot prices provided opportunities to dispatch the Alberta commercial peaking and mid-merit plants. This was offset by reduced generation from Genesee 3 due to a 42-day scheduled maintenance outage. In December 2010, a subsidiary of EPCOR exchanged 9,209,000 of its exchangeable limited partnership units in CPLP for common shares of Capital Power on a one-for-one basis reducing EPCOR's ownership interest in CPLP to approximately 60.5% from its initial interest of 72.2%.

In the third quarter of 2010, the expected recovery of \$8 million in business insurance proceeds relating to the outage of Clover Bar Energy Centre Unit 2 from March 8 until September 22 was recorded in the results for Alberta commercial plants and portfolio optimization. CPILP's EBITDA included impairment losses of \$66 million reflecting lower expectations for the availability of waste heat fuel supply at CPILP's Ontario plants. Corporate EBITDA included \$7 million for the recognition of the obligation to EPCOR for operations and maintenance costs for the Rosedale plant over the ten-year period ending in 2019. Income taxes reflected the recognition of a future income tax liability relating to the investment in CPILP, as a result of the strategic alternatives review.

In the second quarter of 2010 the EBITDA for the Alberta contracted plants reflected availability penalties related to the 21-day scheduled outage at Genesee 2.

In the fourth quarter of 2009, the planned outage at Genesee 1 resulted in availability penalty payments. An income tax recovery that was recognized in the third quarter was reclassified in the fourth quarter and included in the acquisition of assets from EPCOR since it related to periods prior to 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							
Share price (\$/ common share)	Sept 30, 2011	June 30, 2011	Mar 31, 2011	Dec 31, 2010	Sept 30, 2010	June 30, 2010	Mar 31, 2010	Dec 31, 2009
High	26.38	28.00	26.44	24.84	24.20	23.39	23.00	21.78
Low	21.50	24.90	22.80	23.25	21.75	21.76	20.97	18.95
Close	25.45	25.00	25.92	23.65	24.10	22.14	22.50	21.37
Volume traded (millions)	7.6	9.5	8.9	3.4	2.4	4.4	7.6	6.5

As at October 24, 2011, the Company had 49.728 million common shares outstanding, 47.416 million special voting shares outstanding, 5 million Cumulative Rate Reset Preference Shares, Series 1 outstanding and one special limited voting share outstanding. The weighted average number of common shares outstanding on a diluted basis was 48.334 million for the quarter ended September 30, 2011. All of the outstanding special voting shares and the outstanding special limited voting share are held indirectly by EPCOR.

As at October 24, 2011, CPLP had 21.750 million general partnership units outstanding, 27.724 million common limited partnership units outstanding and 47.416 million exchangeable common limited partnership units outstanding, which are exchangeable for 47.416 million common shares of the Company. All of the outstanding general partnership units and the outstanding common limited partnership units are held, indirectly, by the Company. All of the outstanding exchangeable limited partnership units are held indirectly by EPCOR.

As at October 24, 2011, CPILP had 56.598 million limited partnership units outstanding and 16.514 million of such units, representing 29.2% 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 other continuous disclosure documents, is available on SEDAR at www.sedar.com.

CAPITAL POWER CORPORATION

Condensed Interim Consolidated Statements of Income (Loss)
(Unaudited, in millions of Canadian dollars, except per share amounts)

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010 (note 12)	2011	2010 (note 12)
Revenues	\$ 414	\$ 492	\$ 1,309	\$ 1,277
Other income	19	21	54	50
Energy purchases and fuel	(189)	(277)	(735)	(757)
Gross income	244	236	628	570
Other raw materials and operating charges	(43)	(20)	(109)	(61)
Staff costs and employee benefits expense	(40)	(43)	(121)	(131)
Depreciation and amortization	(45)	(59)	(167)	(178)
Impairments (note 6)	-	(66)	(43)	(66)
Other administrative expenses	(16)	(18)	(46)	(37)
Property taxes	(6)	(5)	(17)	(14)
Foreign exchange losses	(7)	(1)	(13)	-
Operating income	87	24	112	83
Gain on sale of power syndicate agreement	-	-	-	28
Finance expense	(32)	(26)	(76)	(65)
Income (loss) before tax	55	(2)	36	46
Income tax (expense) recovery (note 3)	(11)	(1)	-	9
Net income (loss)	\$ 44	\$ (3)	\$ 36	\$ 55
Attributable to:				
Non-controlling interests	\$ 29	\$ (19)	\$ 43	\$ 35
Shareholders of the Company	\$ 15	\$ 16	\$ (7)	\$ 20
Earnings (loss) per share (all from continuing operations attributable to common shareholders of the Company):				
Basic (note 7)	\$ 0.29	\$ 0.74	\$ (0.27)	\$ 0.92
Diluted (note 7)	\$ 0.29	\$ 0.03	\$ (0.27)	\$ 0.51

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

Condensed Interim Consolidated Statements of Comprehensive Income (Loss)
(Unaudited, in millions of Canadian dollars)

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
Net income (loss)	\$ 44	\$ (3)	\$ 36	\$ 55
Other comprehensive income (loss):				
Available-for-sale assets:				
Unrealized (losses) gains on available-for-sale financial assets ¹	(4)	2	(3)	4
Cash flow hedges:				
Unrealized losses on derivative instruments ²	(16)	(11)	(92)	(29)
Reclassification of losses on derivative instruments to income for the period ³	23	16	39	5
Reclassification of ineffective portion to income for the period ⁴	-	-	2	1
Net investment in foreign subsidiaries:				
Unrealized gain (loss) ⁵	78	(21)	70	(13)
Other comprehensive income (loss), net of tax	81	(14)	16	(32)
Total comprehensive income (loss)	\$ 125	\$ (17)	\$ 52	\$ 23
Attributable to:				
Non-controlling interests	\$ 86	\$ (33)	\$ 57	\$ 5
Shareholders of the Company	\$ 39	\$ 16	\$ (5)	\$ 18

¹ For the three and nine months ended September 30, 2011, net of income tax recoveries of \$1. For the three and nine months ended September 30, 2010, net of income tax expenses of \$1 and \$2 respectively.

² For the three and nine months ended September 30, 2011, net of income tax recoveries of \$2 and \$12 respectively. For the three and nine months ended September 30, 2010, net of income tax recoveries of \$10 and \$18 respectively.

³ For the three and nine months ended September 30, 2011, net of reclassification of income tax recoveries of \$3 and \$5 respectively. For the three and nine months ended September 30, 2010, net of reclassification of income tax recoveries of \$1 and nil respectively.

⁴ For the three and nine months ended September 30, 2011, net of reclassification of income tax expense of nil. For the three and nine months ended September 30, 2010, net of reclassification of income tax expenses of nil.

⁵ For the three and nine months ended September 30, 2011, net of income tax recoveries of \$3 and \$2 respectively. For the three and nine months ended September 30, 2010, net of income tax expenses of \$1.

CAPITAL POWER CORPORATION

Condensed Interim Consolidated Statements of Financial Position
(Unaudited, in millions of Canadian dollars)

	September 30, 2011	December 31, 2010
Assets		
Current assets:		
Cash and cash equivalents	\$ 80	\$ 56
Trade and other receivables	245	286
Inventories	58	60
Derivative financial instruments assets (note 8)	52	152
Assets classified as held for sale (note 6)	1,493	-
	1,928	554
Non-current assets:		
Other assets	25	19
Derivative financial instruments assets (note 8)	17	76
Finance lease receivables	59	85
Other financial assets	41	89
Deferred tax assets	17	40
Intangible assets (note 5)	271	651
Property, plant and equipment	3,773	3,678
Goodwill	47	104
Total assets	\$ 6,178	\$ 5,296
Liabilities and Equity		
Current liabilities:		
Trade and other payables	\$ 232	\$ 282
Derivative financial instruments liabilities (note 8)	80	125
Loans and borrowings (note 9)	226	235
Deferred revenue and other liabilities	6	10
Provisions	25	20
Liabilities classified as held for sale (note 6)	929	-
	1,498	672
Non-current liabilities:		
Derivative financial instruments liabilities (note 8)	20	89
Loans and borrowings (note 9)	1,369	1,634
Deferred revenue and other liabilities	73	61
Deferred tax liabilities	47	73
Provisions	192	155
	1,701	2,012
Equity:		
Equity attributable to shareholders of the Company		
Share capital (note 10)	1,274	820
Retained earnings (deficit)	(51)	8
Other reserves	7	5
Retained earnings (deficit) and other reserves	(44)	13
	1,230	833
Non-controlling interests	1,749	1,779
Total equity	2,979	2,612
Total liabilities and equity	\$ 6,178	\$ 5,296

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

Condensed Interim Consolidated Statements of Changes in Equity
(Unaudited, in millions of Canadian dollars)

	Share capital (note 10)	Cash flow hedges ¹	Cumulative translation account ¹	Available- for-sale financial assets ¹	Defined benefit plan actuarial gains and losses ¹	Employee benefits reserve	Retained earnings (deficit)	Equity attributable to shareholders of the Company	Non- controlling interests	Total
Equity as at January 1, 2011	\$ 820	\$ 5	\$ (5)	\$ 1	\$ (2)	\$ 6	\$ 8	\$ 833	\$ 1,779	\$ 2,612
Net income (loss)	-	-	-	-	-	-	(7)	(7)	43	36
Other comprehensive income (loss):										
Net change in fair value of available- for-sale financial assets	-	-	-	(4)	-	-	-	(4)	-	(4)
Cash flow derivative hedge losses	-	(104)	-	-	-	-	-	(104)	-	(104)
Reclassification of losses to income	-	44	-	-	-	-	-	44	-	44
Reclassification of ineffective portion to income	-	2	-	-	-	-	-	2	-	2
Unrealized gain on foreign currency translation	-	-	68	-	-	-	-	68	-	68
Tax on items recognized directly in equity	-	7	2	1	-	-	-	10	-	10
Attributed to non- controlling interests	-	29	(45)	2	-	-	-	(14)	14	-
Other comprehensive income (loss)	\$ -	\$ (22)	\$ 25	\$ (1)	\$ -	\$ -	\$ -	\$ 2	\$ 14	\$ 16
Total comprehensive income (loss)	-	(22)	25	(1)	-	-	(7)	(5)	57	52
Issue of share capital	468	-	-	-	-	(1)	2	469	(2)	467
Transaction costs	(18)	-	-	-	-	-	-	(18)	-	(18)
Deferred taxes	4	(1)	-	-	-	-	(9)	(6)	-	(6)
Distributions to non-controlling interests	-	-	-	-	-	-	-	-	(97)	(97)
Additional investment by non-controlling interests	-	-	-	-	-	-	-	-	9	9
Issue of partnership units	-	-	-	-	-	-	-	-	14	14
Common share dividends	-	-	-	-	-	-	(41)	(41)	-	(41)
Preferred share dividends	-	-	-	-	-	-	(4)	(4)	-	(4)
Preferred share dividends paid by subsidiary	-	-	-	-	-	-	-	-	(11)	(11)
Share-based payment transactions	-	-	-	-	-	2	-	2	-	2
Equity as at September 30, 2011	\$ 1,274	\$ (18)	\$ 20	\$ -	\$ (2)	\$ 7	\$ (51)	\$ 1,230	\$ 1,749	\$ 2,979

¹ Accumulated other comprehensive income (loss). Other reserves on the statements of financial position are the aggregate of accumulated other comprehensive income (loss) and the employee benefits reserve.

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

Condensed Interim Consolidated Statements of Changes in Equity
(Unaudited, in millions of Canadian dollars)

	Share capital (note 10)	Cash flow hedges ¹	Cumulative translation account ¹	Available- for-sale financial assets ¹	Employee benefits reserve	Retained earnings (deficit)	Equity attributable to shareholders of the Company	Non- controlling interests	Total
Equity as at January 1, 2010	\$ 477	\$ 7	\$ -	\$ -	\$ 2	\$ 7	\$ 493	\$ 2,123	\$ 2,616
Net income	-	-	-	-	-	20	20	35	55
Other comprehensive income (loss):									
Net change in fair value of available-for-sale financial assets	-	-	-	6	-	-	6	-	6
Cash flow derivative hedge losses	-	(47)	-	-	-	-	(47)	-	(47)
Reclassification of losses to income	-	5	-	-	-	-	5	-	5
Reclassification of ineffective portion to income	-	1	-	-	-	-	1	-	1
Unrealized loss on foreign currency translation	-	-	(12)	-	-	-	(12)	-	(12)
Tax on items recognized directly in equity	-	18	(1)	(2)	-	-	15	-	15
Attributed to non-controlling interests	-	25	9	(4)	-	-	30	(30)	-
Other comprehensive income (loss)	\$ -	\$ 2	\$ (4)	\$ -	\$ -	\$ -	\$ (2)	\$ (30)	\$ (32)
Total comprehensive income (loss)	-	2	(4)	-	-	20	18	5	23
Distributions to non-controlling interests	-	-	-	-	-	-	-	(104)	(104)
Additional investment by non-controlling interests	-	-	-	-	-	-	-	6	6
Issue of partnership units	-	-	-	-	-	-	-	20	20
Common share dividends	-	-	-	-	-	(21)	(21)	-	(21)
Preferred share dividends paid by subsidiary	-	-	-	-	-	-	-	(10)	(10)
Share-based compensation	-	-	-	-	3	-	3	-	3
Equity as at September 30, 2010	\$ 477	\$ 9	\$ (4)	\$ -	\$ 5	\$ 6	\$ 493	\$ 2,040	\$ 2,533

¹ Accumulated other comprehensive income (loss). Other reserves on the statements of financial position are the aggregate of accumulated other comprehensive income (loss) and the employee benefits reserve.

CAPITAL POWER CORPORATION

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

	Nine months ended September 30,	
	2011	2010
Cash flows from operating activities:		
Net income	\$ 36	\$ 55
Non-cash adjustments to reconcile net income to net cash flows from operating activities:		
Depreciation and amortization	167	178
Gain on sale of power syndicate agreement	-	(28)
Impairments (note 6)	43	66
Finance expense	76	65
Fair value changes on derivative instruments	55	37
Unrealized foreign exchange losses	8	2
Income tax recovery (note 3)	-	(9)
Other items	9	(33)
Interest paid ¹	(44)	(46)
Income taxes paid	(13)	(5)
Income taxes recovered	-	15
	337	297
Change in non-cash operating working capital	(27)	(9)
Net cash flows from operating activities	310	288
Cash flows from investing activities:		
Business acquisitions, net of acquired cash (note 4)	(643)	-
Payments to acquire property, plant and equipment and other assets	(316)	(251)
Proceeds on sale of power syndicate agreement	-	64
Other cash flows from investing activities	22	(8)
Net cash flows used in investing activities	(937)	(195)
Cash flows from financing activities:		
Proceeds from issue of loans and borrowings	584	335
Repayment of loans and borrowings	(192)	(267)
Proceeds from issue of common shares	468	-
Share issue costs	(18)	-
Issue costs on loans and borrowings	(6)	(3)
Distributions paid to non-controlling interests	(83)	(84)
Common share dividends paid (note 10)	(35)	(21)
Preferred share dividends paid (note 10)	(4)	-
Preferred share dividends paid by subsidiary	(11)	(10)
Financing interest paid ¹	(33)	(32)
Net cash flows from (used in) financing activities	670	(82)
Foreign exchange losses on cash held in a foreign currency	-	(1)
Net increase in cash and cash equivalents	43	10
Cash and cash equivalents at beginning of period	56	52
Cash and cash equivalents at end of period	\$ 99	\$ 62

¹ Total interest paid.

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

Notes to the Condensed Interim Consolidated Financial Statements

September 30, 2011 and 2010

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

1. Reporting entity:

Capital Power Corporation (the Company or Capital Power) builds, owns and operates power plants and manages its related electricity and natural gas portfolios by undertaking trading and marketing activities.

The registered and head office of the Company is located at 10423 101 Street, Edmonton, Alberta, Canada, T5H 0E9. The common shares of the Company are traded on the Toronto Stock Exchange under the symbol "CPX".

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.

2. Basis of presentation and conversion to IFRS:

These condensed interim consolidated financial statements have been prepared by Management in accordance with International Accounting Standards (IAS) 34, Interim Financial Reporting. These condensed interim consolidated financial statements reflect part of the period covered by the Company's first International Financial Reporting Standards (IFRS) annual financial statements and IFRS 1 First time Adoption of International Financial Reporting Standards has been applied. The condensed interim consolidated financial statements do not include all of the information required for full annual financial statements.

These condensed interim consolidated financial statements should be read in conjunction with the Company's 2010 annual financial statements prepared in accordance with previous Canadian generally accepted accounting principles (GAAP) as well as the Company's March 31, 2011 condensed interim consolidated financial statements prepared in accordance with IFRS. The Company's March 31, 2011 condensed interim consolidated financial statements include certain disclosures not repeated in the September 30, 2011 condensed interim consolidated financial statements, including disclosure of IFRS 1 elections made by the Company, the Company's significant accounting policies in accordance with IFRS, the Company's use of judgments and estimates, reconciliations of equity and total comprehensive income reported under previous Canadian GAAP to those reported under IFRS as at January 1, 2010, as at and for the three months ended March 31, 2010, and as at and for the year ended December 31, 2010, and certain other supplementary annual disclosures for the year ended December 31, 2010.

An explanation of how the transition to IFRS has affected the financial position and financial performance of the Company as at and for the three and nine months ended September 30, 2010 is provided in note 12. This note includes reconciliations of equity and total comprehensive income reported under previous Canadian GAAP to those reported under IFRS as at and for the three and nine months ended September 30, 2010.

These condensed interim consolidated financial statements have been prepared under the historical cost basis, except for the revaluation of the Company's derivative instruments, cash, equity investments and cash-settled share based payments, which are stated at fair value. In addition, the Company's defined benefit pension assets are recognized at fair value.

These condensed interim consolidated financial statements were approved and authorized for issue by the Board of Directors on October 25, 2011.

CAPITAL POWER CORPORATION

Notes to the Condensed Interim Consolidated Financial Statements

September 30, 2011 and 2010

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

2. Basis of presentation and conversion to IFRS, continued:

Future accounting standards

A number of new standards, and amendments to standards and interpretations, are not yet effective for the quarter ended September 30, 2011 and have not been applied in preparing these condensed interim consolidated financial statements. The following standards and interpretations have been issued by the International Accounting Standards Board and the International Financial Reporting Interpretations Committees with effective dates relating to the annual periods starting on or after the effective dates as follows:

International Accounting Standards (IAS/IFRS)	Effective Date
IAS 1 – Presentation of Financial Statements	July 1, 2012
IFRS 10 – Consolidated Financial Statements	January 1, 2013
IFRS 11 – Joint Arrangements	January 1, 2013
IFRS 12 – Disclosures of Interests in Other Entities	January 1, 2013
IFRS 13 – Fair Value Measurement	January 1, 2013
IAS 19 – Employee Benefits	January 1, 2013
IFRS 9 – Financial Instruments	January 1, 2015

The amendments to IAS 1 provide improvements to the presentation of components of other comprehensive income. It requires entities to group items within other comprehensive income that may be reclassified to profit or loss.

IFRS 10 replaces IAS 27 Consolidated and Separate Financial Statements and SIC – 12 Consolidation – Special Purpose Entities. IFRS 10 establishes principles for the presentation and preparation of consolidated financial statements. It provides a single consolidation model that identifies control as the basis for consolidation for all types of entities. IFRS 12 provides comprehensive disclosure requirements for all forms of interests in other entities, including subsidiaries, joint arrangements, associates and special purpose vehicles.

IFRS 11 supersedes IAS 31 – Interests in Joint Ventures and SIC 13 – Jointly Controlled Entities – Non-Monetary Contributions by Venturers. The standard requires a single method to account for interests in jointly controlled entities. All joint ventures are required to be recognized as an investment and be accounted for on an equity basis.

IFRS 12 is a new and comprehensive standard on disclosure requirements for all forms of interests in other entities, including subsidiaries, joint arrangements, associates and unconsolidated structured entities.

IFRS 13 defines fair value, sets out in a single IFRS a framework for measuring fair value and requires disclosures about fair value measurements. IFRS 13 applies when other IFRSs require or permit fair value measurements. It does not introduce any new requirements to measure an asset or a liability at fair value, change what is measured at fair value in IFRSs or address how to present changes in fair value.

The amendments to IAS 19 relate to the recognition and disclosure requirements for defined benefit plans and result in the following key changes: (a) to eliminate the corridor method that defers the recognition of gains and losses, (b) to streamline the presentation of changes in assets and liabilities arising from defined benefit plans, and (c) to enhance the disclosure requirements for defined benefit plans.

IFRS 9 applies to the classification and measurement of financial assets and financial liabilities. It is the first of three phases of a project to develop standards to replace IAS 39 - Financial Instruments and was initiated in response to the crisis in financial markets.

The extent of the impact of adoption of these standards and interpretations on the consolidated financial statements of the Company has not been determined.

CAPITAL POWER CORPORATION

Notes to the Condensed Interim Consolidated Financial Statements

September 30, 2011 and 2010

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

3. Income tax:

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
Current income tax				
Current income tax	\$ (1)	\$ (2)	\$ -	\$ 12
Deferred income tax				
Impact of previously unrecognized amounts	-	6	(7)	6
Relating to origination and reversal of temporary differences	8	(3)	2	(26)
Relating to changes in tax rates / new taxes	2	-	-	(4)
Adjustments in respect of prior periods	-	4	-	4
Relating to write-downs of deferred tax asset	2	(4)	5	(1)
Income tax expense (recovery)	\$ 11	\$ 1	\$ -	\$ (9)

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
Income (loss) before tax	\$ 55	\$ (2)	\$ 36	\$ 46
Income tax at the statutory rates of 26.5% and 28.0%, respectively	15	-	10	13
Increase (decrease) resulting from				
Taxable income attributable to non-controlling interests	(7)	5	(8)	(10)
Amounts previously not recognized on investments in subsidiaries	-	6	(7)	6
Change in valuation allowance	2	(4)	5	(1)
Non-taxable amounts	1	(4)	-	(10)
Adjustment for enacted changes in income tax laws and rates	2	-	-	(4)
Prior period tax adjustments	-	4	-	4
Change due to enactment of SIFT legislation	-	(10)	-	(10)
Other	(2)	4	-	3
Income tax expense (recovery)	\$ 11	\$ 1	\$ -	\$ (9)

4. Acquisitions of subsidiaries:

On April 28, 2011, a subsidiary of the Company acquired one hundred per cent of the equity interests in Bridgeport Energy, LLC, which owns the Bridgeport Energy facility (Bridgeport Energy), from a third party. Bridgeport Energy is a natural gas-fired combined cycle power generation facility located in Bridgeport, Connecticut, with a nominal capacity of 520 MW. The total fair value of consideration paid was \$344 million (US\$362 million) in cash, which consists of the acquisition's \$338 million (US\$355 million) base purchase price, plus normal working capital adjustments of \$6 million (US\$7 million), and was allocated to the assets acquired and liabilities assumed based on their estimated fair values as described below.

CAPITAL POWER CORPORATION

Notes to the Condensed Interim Consolidated Financial Statements

September 30, 2011 and 2010

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

4. Acquisitions of subsidiaries, continued:

On April 29, 2011, a subsidiary of the Company acquired one hundred per cent of the equity interests in Tiverton Power Inc. and Rumford Power Inc. (Tiverton and Rumford), which own generating facilities located in Tiverton, Rhode Island and Rumford, Maine respectively, from a third party. Both plants are natural gas-fired combined cycle power generation facilities serving the New England region in the U.S. Northeast, and have a maximum combined capacity of 549 MW. The total fair value of consideration paid was the base purchase price of \$299 million (US\$315 million) in cash, and was allocated to the assets acquired and liabilities assumed based on their estimated fair values as described below.

	Bridgeport Energy	Tiverton and Rumford
Trade and other receivables	\$ 12	\$ 12
Inventories	4	4
Intangible assets	7	3
Deferred tax assets	-	2
Property, plant and equipment	337	289
Goodwill	20	3
Trade and other payables	(13)	(12)
Derivative financial instruments liabilities - current	-	(2)
Derivative financial instruments liabilities - non-current	(8)	-
Deferred tax liabilities	(15)	-
Fair value of net assets acquired	\$ 344	\$ 299

The above acquisitions support the Company's growth strategy and are consistent with the Company's technology and operating focus.

The \$12 million and \$12 million allocated to trade and other receivables for the Bridgeport Energy and Tiverton and Rumford acquisitions above represent both the estimated fair value and the gross contractual amounts receivable. As at April 28, 2011 and April 29, 2011 for each acquisition respectively, the Company estimated that all of the contractual cash flows pertaining to the acquired trade and other receivables were collectible.

The goodwill recognized on the above acquisitions is not deductible for tax purposes and is attributable to:

- the potential to build an additional peaking facility near the existing Bridgeport Energy facility which would take advantage of higher on-peak pricing and higher load requirements in the facility's operating region; and
- the potential for synergies, within the New England area, in operating costs, asset and energy management and energy marketing due to the two acquisitions being located in the same area.

The results of operations of Bridgeport Energy and Tiverton and Rumford are included in the Company's consolidated statements of income and statements of changes in equity from the dates of acquisition. Such results of operations and the related assets and liabilities at the statement of financial position date are included in the consolidated statement of financial position. Since the acquisition date of April 28, 2011, \$35 million and \$72 million of revenues and net losses of \$7 million and \$1 million from Bridgeport Energy are included in the consolidated statements of income for the three and nine months ending September 30, 2011 respectively. Since the acquisition date of April 29, 2011, \$32 million and \$51 million of revenues and net losses of \$1 million and net income of \$2 million from Tiverton and Rumford are included in the consolidated statements of income for the three and nine months ending September 30, 2011 respectively. Had the acquisitions occurred at January 1, 2011, the combined entity of the Company, Bridgeport Energy and Tiverton and Rumford would have had a total of \$414 million of revenues and \$44 million of net income for the three months ended September 30, 2011 and \$1,414 million of revenues and \$34 million of net income for the nine months ended September 30, 2011.

In conjunction with the above acquisitions, the Company incurred \$1 million and \$3 million in acquisition costs which have been recorded on the Company's statement of income as other administrative expenses for the three and nine months ended September 30, 2011 respectively.

CAPITAL POWER CORPORATION

Notes to the Condensed Interim Consolidated Financial Statements

September 30, 2011 and 2010

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

4. Acquisitions of subsidiaries, continued:

Changes in the working capital adjustments in the third quarter of 2011 resulted in changes to the fair values allocated to the net assets acquired, including trade and other receivables, property, plant and equipment, goodwill, trade and other payables and deferred tax assets and liabilities, as compared to the amounts disclosed within the condensed interim consolidated financial statements for the quarter ended June 30, 2011. As of the release date of these financial statements, information required to finalize the working capital adjustments and tax balances associated with the acquisitions is outstanding and as a result the purchase prices and the allocations to the acquired assets and assumed liabilities above are preliminary and are subject to change. The Company expects to finalize these purchase price allocations in the fourth quarter of 2011.

5. Intangible assets:

On May 25, 2011, a subsidiary of the Company, CPLP, acquired one hundred per cent of Halkirk I Wind Project LP and Halkirk I Wind Project Ltd (Halkirk Wind Project) and as a result the intangible assets owned by those entities. In connection with the acquisition, Capital Power will build, own and operate the 150 MW Halkirk Wind Project located in east central Alberta for an estimated total project cost of \$357 million, of which \$82 million has been incurred as at September 30, 2011. The total \$82 million incurred to date includes the total fair value of consideration paid for the intangible assets of \$33 million in cash. The acquired intangible assets include various permits required to construct the Halkirk Wind Project, land lease rights and the fair value of a 20-year agreement whereby the Company will sell Renewable Energy Credits (RECs) produced by the Halkirk Wind Project to a third party. The agreement to sell RECs will be amortized over its 20 year useful life while the other intangible assets will be amortized over the life of the Halkirk Wind Project plant assets. Amortization for all intangible assets associated with the Halkirk Wind Project will begin upon commencement of commercial operations of the Halkirk Wind Project, which is expected in the last half of 2012.

CAPITAL POWER CORPORATION

Notes to the Condensed Interim Consolidated Financial Statements

September 30, 2011 and 2010

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

6. Assets classified as held for sale:

On June 20, 2011, the Company announced that its indirect subsidiary, Capital Power Income L.P. (CPILP), entered into an agreement with a third party, Atlantic Power Corporation (Atlantic), pursuant to which Atlantic will acquire directly and indirectly, all of the outstanding limited partnership units of CPILP, including Capital Power's approximate 29.2% ownership interest in CPILP. In connection with the agreement, Capital Power will acquire CPILP's Roxboro and Southport plants in North Carolina (North Carolina Assets) for \$121 million, which will reduce the number of outstanding limited partnership units of CPILP held by the Company by approximately 6.2 million units. Atlantic will acquire CPILP and its remaining eighteen facilities outside of North Carolina. Upon closing of the transaction, which is expected to occur in the fourth quarter of 2011, Capital Power will receive approximately \$320 million in combined consideration for its ownership interest in CPILP. The consideration will include stock in Atlantic, cash and the North Carolina Assets described above. In connection with this transaction, the management contracts between Capital Power and CPILP will be terminated for consideration of \$10 million.

At September 30, 2011, the disposal group consisted of assets and liabilities as follows:

	September 30, 2011
Assets classified as held for sale	
Cash and cash equivalents	\$ 19
Trade and other receivables	58
Inventories	13
Derivative financial instruments assets – current and non-current	15
Finance lease receivables	23
Other financial assets	44
Deferred tax assets	5
Intangible assets	374
Property, plant and equipment	858
Goodwill	84
	\$ 1,493
Liabilities classified as held for sale	
Trade and other payables	\$ (41)
Derivative financial instruments liabilities – current and non-current	(92)
Loans and borrowings – current and non-current	(713)
Deferred revenue and other liabilities – current and non-current	(13)
Deferred tax liabilities	(14)
Provisions – non-current	(56)
	\$ (929)

CAPITAL POWER CORPORATION

Notes to the Condensed Interim Consolidated Financial Statements

September 30, 2011 and 2010

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

6. Assets classified as held for sale, continued:

Immediately before the initial classification of the above assets to assets held for sale, the Company determined, based on the negotiated consideration to be received as compared to the existing carrying amounts for the assets to be reclassified to assets held for sale, that it was necessary to test the management contracts for additional impairments and to test certain other cash generating units (CGUs), consisting of various CPILP plants, within the disposal group for potential reversals of impairments. As a result the Company recorded additional impairments of \$43 million on the management contracts immediately prior to reclassification to assets held for sale in the period, consisting of \$7 million within the U.S. geographic area and \$36 million within the Canadian geographic area. The Company did not record reversals of any previous impairments taken on its CGUs.

For purposes of calculating the above impairments and testing for reversals of impairments, the Company used the fair value less costs to sell of the CGUs within the disposal group as the recoverable amount of the assets. The fair value less costs to sell was established as the negotiated consideration in the agreements described above, less the Company's estimate of the directly attributable incremental costs related to the disposal.

Following the impairment recorded above, the fair value less costs to sell exceeded the carrying amount of the disposal group and as such no further adjustments were required upon initial classification as assets held for sale.

As at September 30, 2011, accumulated other comprehensive income, included within other reserves within the consolidated statement of financial position, included accumulated losses of \$3 million relating to the Company's investment in CPILP. Of the \$3 million of losses relating to CPILP, \$1 million of gains relates to foreign currency translation losses previously recognized directly in accumulated other comprehensive income and will be reclassified to net income upon close of the disposal transactions.

7. Earnings (loss) per share:

Basic earnings (loss) per share

The earnings (loss) and weighted average number of common shares used in the calculation of basic earnings (loss) per share are as follows:

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
Income (loss) for the period attributable to shareholders of the Company	\$ 15	\$ 16	\$ (7)	\$ 20
Preferred share dividends of the Company ¹	(1)	-	(4)	-
Earnings (loss) used in the calculation of basic earnings (loss) per share	\$ 14	\$ 16	\$ (11)	\$ 20

¹ Includes preferred share dividends in respect of the current periods only.

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
Weighted average number of common shares used in the calculation of basic earnings per share	48,334,251	21,767,200	40,416,559	21,756,237

CAPITAL POWER CORPORATION

Notes to the Condensed Interim Consolidated Financial Statements

September 30, 2011 and 2010

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

7. Earnings (loss) per share, continued:

Diluted earnings (loss) per share

The earnings (loss) used in the calculation of diluted earnings (loss) per share are as follows:

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
Earnings (loss) used in the calculation of basic earnings (loss) per share	\$ 14	\$ 16	\$ (11)	\$ 20
Effect of exchangeable limited partnership units issued to EPCOR for common shares ¹	-	(14)	-	20
Earnings (loss) used in the calculation of diluted earnings (loss) per share	\$ 14	\$ 2	\$ (11)	\$ 40

¹ The exchangeable limited partnership units issued to EPCOR may be exchanged for common shares of Capital Power on a one-for-one basis. For the three and nine months ended September 30, 2011, the potential exchange of such units for common shares of the Company were not included in the calculation of diluted earnings (loss) per share as they were anti-dilutive. For the three and nine months ended September 30, 2010, the exchange of such units for common shares of the Company had a dilutive impact. The assumed unit exchange would result in a deduction of the net loss attributable to the non-controlling interest in CPLP for the three months ended September 30, 2010 of \$1 million and an addition of the net income attributable to the non-controlling interest in CPLP for the nine months ended September 30, 2010 of \$44 million. Additionally, the income tax provision of the Company would need to be adjusted to reflect the non-controlling interest's share of CPLP income taxes of approximately \$13 million and \$24 million for the three and nine months ended September 30, 2010 respectively.

The weighted average number of common shares for the purposes of diluted earnings (loss) per share reconciles to the weighted average number of common shares used in the calculation of basic earnings (loss) per share as follows:

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
Weighted average number of common shares used in the calculation of basic earnings (loss) per share	48,334,251	21,767,200	40,416,559	21,756,237
Effect of dilutive share purchase options ¹	170,308	-	-	-
Effect of exchangeable limited partnership units issued to EPCOR for common shares	-	56,625,000	-	56,625,000
Weighted average number of common shares used in the calculation of diluted earnings (loss) per share	48,504,559	78,392,200	40,416,559	78,381,237

¹ For the three and nine months ended September 30, 2011, the average market price of the Company's common shares exceeded the exercise price of certain of the granted share purchase options. For the three months ended September 30, 2011 this resulted in a dilutive effect on earnings (loss) per share. Since the Company recorded a loss for the nine months ended September 30, 2011, the assumed exercise of the stock options decreased the loss per share and as such did not have a dilutive effect on earnings (loss) per share. For the three and nine months ended September 30, 2010, the average market price of the Company's common shares was below the exercise price of all granted share purchase options and as a result none of the share purchase options had a dilutive effect on earnings (loss) per share.

CAPITAL POWER CORPORATION

Notes to the Condensed Interim Consolidated Financial Statements

September 30, 2011 and 2010

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

8. Derivative financial instruments and hedge accounting:

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

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

	September 30, 2011				
	Energy		Foreign exchange	Interest rate	Total
	Cash flow hedges	Non-hedges	Non-hedges	Non-hedges	
Derivative instruments assets:					
Current	\$ 2	\$ 50	\$ -	\$ -	\$ 52
Non-current	6	11	-	-	17
Derivative instruments liabilities:					
Current	(25)	(51)	-	(4)	(80)
Non-current	(8)	(12)	-	-	(20)
Net fair value	\$ (25)	\$ (2)	\$ -	\$ (4)	\$ (31)
Net notional buys (sells):					
Megawatt hours of electricity (millions)	(3)	(11)			
Gigajoules of natural gas (millions)	-	6			
Foreign currency (U.S. dollars)			-		
Bond forwards				\$ 200	
Range of contract terms in years	0.1 to 5.3	0.1 to 6.3	-	0.2	
	December 31, 2010				
	Energy		Foreign exchange	Interest rate	Total
	Cash flow hedges	Non-hedges	Non-hedges	Non-hedges	
Derivative instruments assets:					
Current	\$ 28	\$ 113	\$ 11	\$ -	\$ 152
Non-current	16	30	30	-	76
Derivative instruments liabilities:					
Current	(24)	(92)	(3)	(6)	(125)
Non-current	(77)	(7)	(5)	-	(89)
Net fair value	\$ (57)	\$ 44	\$ 33	\$ (6)	\$ 14
Net notional buys (sells):					
Megawatt hours of electricity (millions)	(3)	(2)			
Gigajoules of natural gas (millions)	38	9			
Foreign currency (U.S. dollars)			\$ (302)		
Bond forwards				\$ 200	
Range of contract terms in years	0.1 to 6.0	0.1 to 7.0	0.1 to 5.5	0.2	

CAPITAL POWER CORPORATION

Notes to the Condensed Interim Consolidated Financial Statements

September 30, 2011 and 2010

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

8. Derivative financial instruments and hedge accounting, continued:

Fair values of derivative instruments are determined, when possible, using exchange or over-the-counter price quotations by reference to quoted bid, ask or closing market prices as appropriate, in the most advantageous active market for that instrument. The extent to which fair values of derivative instruments are based on observable market data is determined by the extent to which the market for the underlying commodity is judged to be active. When traded markets are not considered to be sufficiently active or do not exist, the Company uses appropriate valuation and price modeling techniques commonly used by market participants to estimate fair value. The Company may also rely on price forecasts prepared by third party market experts to estimate fair value when there are limited observable prices available. Fair values determined using valuation models require the use of assumptions concerning the amounts and timing of future cash flows. Fair value amounts reflect management's best estimates and maximize, when available, the use of external readily observable market data including future prices, interest rate yield curves, foreign exchange rates, quoted Canadian dollar swap rates, counterparty credit risk, the Company's own credit risk and volatility. When a valuation technique utilizes unobservable market data, no inception gains or losses are recognized, until market quotes or data becomes observable. It is possible that the assumptions used in establishing fair value amounts will differ from future outcomes and the impact of such variations could be material.

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

	Three months ended September 30, 2011		Three months ended September 30, 2010	
	Unrealized gains (losses)	Realized gains (losses)	Unrealized gains (losses)	Realized gains (losses)
Energy cash flow hedges	\$ 8	\$ (26)	\$ (4)	\$ (18)
Energy non-hedges	(3)	(2)	9	(3)
Foreign exchange non-hedges	(23)	1	11	-
Interest rate non-hedges	(4)	-	(7)	-

CAPITAL POWER CORPORATION

Notes to the Condensed Interim Consolidated Financial Statements

September 30, 2011 and 2010

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

8. Derivative financial instruments and hedge accounting, continued:

	Nine months ended September 30, 2011		Nine months ended September 30, 2010	
	Unrealized gains (losses)	Realized gains (losses)	Unrealized gains (losses)	Realized gains (losses)
Energy cash flow hedges	\$ (58)	\$ (44)	\$ (40)	\$ (6)
Energy non-hedges	(36)	(12)	(25)	18
Foreign exchange non-hedges	(19)	3	(2)	4
Interest rate non-hedges	2	(12)	(11)	-

Realized gains and losses relate only to financial derivative instruments. Included in revenues for the three and nine months ended September 30, 2011 were losses on financial derivative instruments held at fair value through income or loss of \$64 million and \$145 million respectively (three and nine months ended September 30, 2010 – gains of \$70 million and losses of \$12 million respectively). Included in energy purchases and fuel for the three and nine months ended September 30, 2011 were gains on financial instruments held at fair value through income or loss of \$12 million and \$43 million respectively (three and nine months ended September 30, 2010 – losses of \$70 million and gains of \$1 million respectively). Included in foreign exchange losses for the three and nine months ended September 30, 2011 were losses on financial instruments held at fair value through income or loss of \$1 million and \$6 million respectively (three and nine months ended September 30, 2010 – losses of \$1 million and nil respectively). Included in finance expense for the three and nine months ended September 30, 2011 were losses on financial instruments held at fair value through income or loss of \$4 million and \$10 million respectively (three and nine months ended September 30, 2010 – losses of \$7 million and \$11 million respectively). Gains and losses on non-financial derivative instrument settlements are recorded in energy purchases and fuel or revenues as appropriate.

If hedge accounting requirements are not met, unrealized and realized gains and losses on financial energy derivatives are recorded in revenues or energy purchases and fuel as appropriate. If hedge accounting requirements are met, realized gains and losses on financial energy derivatives are recorded in revenues or energy purchases and fuel, as appropriate, while unrealized gains and losses are recorded in other comprehensive income. Unrealized and realized gains and losses on financial foreign exchange derivatives are recorded in revenues or foreign exchange gains and losses while such gains and losses on financial interest rate derivatives are recorded in finance expense.

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 nine months ended September 30, 2011, the changes in the fair value of the ineffective portion of hedging derivatives required to be recognized as losses in the statement of income were nil and \$2 million respectively (three and nine months ended September 30, 2010 – losses of nil and \$1 million respectively).

Net after tax losses related to derivative instruments designated as cash flow hedges are expected to settle and be reclassified to net income in the following periods:

	September 30, 2011
Within one year	\$ (21)
Between 1 – 5 years	(1)
After more than 5 years	-
	\$ (22)

The Company's cash flow hedges extend up to 2016.

CAPITAL POWER CORPORATION

Notes to the Condensed Interim Consolidated Financial Statements

September 30, 2011 and 2010

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

9. Loans and borrowings:

On April 18, 2011, the Company's subsidiary, CPLP, issued \$300 million of unsecured medium-term notes due in 2015 with interest payable semi-annually at 4.6% commencing on June 1, 2011.

On June 15, 2011, Capital Power U.S. Financing LP, an indirect subsidiary of the Company, closed a US\$295 million private placement of unsecured senior notes. The unsecured senior notes consist of two notes with 10 and 15-year terms. The 10-year note of \$241 million (US\$230 million) is due in 2021 with a coupon rate of 5.21%. The 15-year note of \$68 million (US\$65 million) is due in 2026 with a coupon rate of 5.61%.

10. Share capital:

Authorized shares

	Number of shares authorized
Common shares	unlimited
Preference shares, issuable in series	unlimited
Special voting shares	unlimited
Special limited voting share	one

Issued, called up and fully paid shares

	September 30, 2011		December 31, 2010	
	Issued	Outstanding	Issued	Outstanding
Common shares	49,726,629	\$ 1,152	30,980,500	\$ 698
Preferred shares, series 1	5,000,000	122	5,000,000	122
Special voting shares	47,416,000	-	47,416,000	-
Special limited voting share	1	-	1	-
		\$ 1,274		\$ 820

In the first quarter of 2011, the Company closed an offering to sell 9,315,000 common shares, to a syndicate of underwriters, at an offering price of \$24.90 per common share for gross proceeds of \$232 million, less issue costs of \$9 million. Deferred tax assets of \$2 million related to the share issue costs are recorded in the common share balance.

In the third quarter of 2011, the Company closed an offering to sell an additional 9,200,000 common shares, to a syndicate of underwriters, at an offering price of \$25.10 per common share for gross proceeds of \$231 million, less issue costs of \$9 million. Deferred tax assets of \$2 million related to the share issue costs are recorded in the common share balance.

Subsequent to the issues of common shares by the Company, 9,315,000 and 9,200,000 additional common limited partnership units, within the first quarter and third quarter of 2011 respectively, of the Company's subsidiary, CPLP, were issued to another subsidiary of the Company and as a result these transactions reduced EPCOR's ownership interest in CPLP to approximately 48.9% as at September 30, 2011 (December 31, 2010 – 60.5%).

CAPITAL POWER CORPORATION

Notes to the Condensed Interim Consolidated Financial Statements

September 30, 2011 and 2010

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

10. Share capital, continued:

For the three and nine months ended September 30, 2011, dividends of \$16 million and \$41 million respectively, or 31.5 cents per share and 94.5 cents per share respectively, have been declared and dividends of \$13 million and \$35 million respectively, or 31.5 cents per share and 94.5 cents per share respectively, have been paid by the Company to the common shareholders (three and nine months ended September 30, 2010 - \$7 million and \$21 million respectively, or 31.5 cents per share and 94.5 cents per share respectively, declared and paid). During the three and nine months ended September 30, 2011, dividends of \$1 million and \$4 million respectively, or 28.8 cents per share and 90.6 cents per share respectively, have been declared and paid by the Company to preferred shareholders (three and nine months ended September 30, 2010 – nil).

11. Segment information:

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, Connecticut, Illinois, Maine, New Jersey, New York, North Carolina, Rhode Island and Washington, as this is how management assesses performance and determines resource allocations.

The Company's results from operations within each geographic area are:

	Three months ended September 30, 2011				Three months ended September 30, 2010			
	Canada	U.S.	Inter-area eliminations	Total	Canada	U.S.	Inter-area eliminations	Total
Revenues and other income - external	\$ 274	\$ 159	\$ -	\$ 433	\$ 428	\$ 85	\$ -	\$ 513
Inter-area revenues and other income	1	-	(1)	-	(4)	1	3	-
Total revenues and other income	\$ 275	\$ 159	\$ (1)	\$ 433	\$ 424	\$ 86	\$ 3	\$ 513

	Nine months ended September 30, 2011				Nine months ended September 30, 2010			
	Canada	U.S.	Inter-area eliminations	Total	Canada	U.S.	Inter-area eliminations	Total
Revenues and other income - external	\$ 1,004	\$ 359	\$ -	\$ 1,363	\$ 1,090	\$ 237	\$ -	\$ 1,327
Inter-area revenues and other income	2	1	(3)	-	3	6	(9)	-
Total revenues and other income	\$ 1,006	\$ 360	\$ (3)	\$ 1,363	\$ 1,093	\$ 243	\$ (9)	\$ 1,327

CAPITAL POWER CORPORATION

Notes to the Condensed Interim Consolidated Financial Statements

September 30, 2011 and 2010

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

11. Segment information, continued:

	As at September 30, 2011			As at December 31, 2010		
	Canada	U.S.	Total	Canada	U.S.	Total
Property, plant and equipment	\$ 2,955	\$ 818	\$ 3,773	\$ 3,174	\$ 504	\$ 3,678
Intangible assets	245	26	271	373	278	651
Goodwill	-	47	47	29	75	104
Other assets	25	-	25	19	-	19
Assets classified as held for sale	573	920	1,493	-	-	-
	\$ 3,798	\$ 1,811	\$ 5,609	\$ 3,595	\$ 857	\$ 4,452

12. Transition to IFRS:

In accordance with the Canadian Institute of Chartered Accountants' adoption of IFRS, the Company has prepared financial statements which comply with IFRS applicable for periods beginning on or after January 1, 2010. This note explains the principal adjustments made by the Company in restating its previously published Canadian GAAP financial statements for the three and nine months ended September 30, 2010.

The Company has applied optional exemptions and exceptions in its transition from Canadian GAAP to IFRS as described in its March 31, 2011 condensed interim consolidated financial statements.

CAPITAL POWER CORPORATION

Notes to the Condensed Interim Consolidated Financial Statements

September 30, 2011 and 2010

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

12. Transition to IFRS, continued:

Reconciliation of equity

The reconciliation of equity reported under previous Canadian GAAP to equity under IFRS (First time adoption) as at September 30, 2010 (end of comparative period) was as follows:

	Canadian GAAP	IAS 16 & IAS 37 Impacts (a)	IAS 36 Impact (b)	IFRS 1 elections (c)	Other impacts (d)	Presentation Reclassifications (e)	IFRS
Cash and cash equivalents	\$ 62	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 62
Trade and other receivables ¹	239	-	-	-	2	-	241
Inventories	79	5	-	-	-	-	84
Derivative financial instruments assets	170	-	-	-	-	-	170
Deferred tax assets	2	-	-	-	-	(2)	-
Total current assets	552	5	-	-	2	(2)	557
Other assets	106	-	-	-	-	(86)	20
Derivative financial instruments assets	97	-	-	-	-	-	97
Finance lease receivables	-	-	-	-	62	25	87
Other financial assets	-	-	-	-	3	61	64
Deferred tax assets	60	-	-	-	(24)	2	38
Intangible assets	673	-	(15)	-	-	-	658
Property, plant and equipment	3,376	36	(63)	48	37	32	3,466
Goodwill	141	-	(36)	-	-	-	105
Total non-current assets	4,453	36	(114)	48	78	34	4,535
Total assets	\$ 5,005	\$ 41	\$ (114)	\$ 48	\$ 80	\$ 32	\$ 5,092

¹ Includes accounts receivable, income taxes recoverable and prepaid expenses.

CAPITAL POWER CORPORATION

Notes to the Condensed Interim Consolidated Financial Statements

September 30, 2011 and 2010

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

12. Transition to IFRS, continued:

Reconciliation of equity, continued:

As at September 30, 2010:

	Canadian	IAS 16 & IAS 37 Impacts	IAS 36 Impact	IFRS 1 elections	Other impacts	Presentation Reclassifications	IFRS
	GAAP	(a)	(b)	(c)	(d)	(e)	
Trade and other payables	\$ 267	\$ 3	\$ -	\$ -	\$ -	\$ (23)	\$ 247
Derivative financial							
instruments liabilities	139	(1)	-	-	-	-	138
Loans and borrowings	34	-	-	-	-	-	34
Deferred revenue and other							
liabilities	6	-	-	-	-	-	6
Deferred tax liabilities	17	-	-	-	-	(17)	-
Provisions	-	(7)	-	-	-	23	16
Total current liabilities	463	(5)	-	-	-	(17)	441
Derivative financial							
instruments liabilities	114	(7)	-	-	-	-	107
Loans and borrowings	1,739	-	-	-	-	-	1,739
Deferred revenue and other							
liabilities	115	17	-	-	-	(75)	57
Deferred tax liabilities	75	-	-	-	(37)	17	55
Provisions	-	52	-	-	1	107	160
Total non-current liabilities	2,043	62	-	-	(36)	49	2,118
Share capital	477	-	-	-	-	-	477
Retained earnings	(2)	2	(2)	-	8	-	6
Other reserves	4	-	-	4	2	-	10
Equity attributable to							
shareholders of the							
Company	479	2	(2)	4	10	-	493
Non-controlling interests	2,020	(18)	(112)	44	106	-	2,040
Total equity	2,499	(16)	(114)	48	116	-	2,533
Total liabilities and equity	\$ 5,005	\$ 41	\$ (114)	\$ 48	\$ 80	\$ 32	\$ 5,092

CAPITAL POWER CORPORATION

Notes to the Condensed Interim Consolidated Financial Statements

September 30, 2011 and 2010

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

12. Transition to IFRS, continued:

Notes to the reconciliations

The tables above present the aggregate transitional adjustments from previous Canadian GAAP to IFRS. The following notes summarize the key differences noted on transition to IFRS.

(a) IAS 16 Property, Plant and Equipment & IAS 37 Provisions:

The contract between the Genesee mine operator and the Company requires the operating activities of the mine, including depreciation on the operator's share of the mine assets, to be fully funded by the Company, whereas the capital funding is shared by the two parties. As a result, certain costs that were previously capitalized would have been expensed under the requirements of IAS 16 and fully funded by Capital Power resulting in an increase to non-current deferred revenue and other liabilities of \$11 million as at September 30, 2010. As a result of this change, trade and other payables of \$2 million were recorded as at September 30, 2010. In addition, the Company recorded a transitional adjustment to align accounting policies between the Company and the Genesee mine operator resulting in an increase of \$5 million in inventory, a decrease of \$3 million to property, plant and equipment and an increase in non-current deferred revenue and other liabilities of \$2 million as at September 30, 2010.

Under Canadian GAAP, the Joffre joint venture's overhaul costs for the Joffre cogeneration facility were expensed and the joint venture's recovery of overhaul costs from one of the joint venture partners was recognized as revenue in the period that the cost was incurred. Under the requirements of IAS 16, the overhaul costs are capitalized as a component of property, plant and equipment and recoveries are recognized in income over the period that the corresponding asset is depreciated. Therefore deferred revenue and other liabilities increased by \$4 million as at September 30, 2010, on transition to IFRS for recoveries received by the joint venture of costs that had been expensed under Canadian GAAP and reclassified to property, plant and equipment under IFRS. As a result of this change, trade and other payables of \$1 million were recorded as at September 30, 2010.

Under IFRS, accounting for the components of property, plant and equipment is required at a more detailed level than under Canadian GAAP. IAS 16 requires separate depreciation for those components with a distinct depreciation method or rate of depreciation. As a result of applying the componentization requirements of IAS 16 effective July 1, 2009, the net book value of property, plant and equipment decreased by \$11 million, reflecting increased depreciation net of overhaul costs capitalized, as at September 30, 2010.

IAS 37 requires provisions to be measured at the best estimate of the expected expenditure using discount rates appropriate for each liability. Under Canadian GAAP the provision was measured at fair value. The provision is to be re-measured at each reporting period for any changes in cash flow estimates, timing of decommissioning activity and discount rates. Accordingly, the Company re-measured its decommissioning liabilities (asset retirement obligations) using revised cash flow estimates with respect to the Genesee Mine as well as for revised discount rates for all decommissioning liabilities. The re-measurement of the decommissioning liabilities resulted in a decrease of \$8 million to the current provision and an increase of \$48 million to the non-current provision as at September 30, 2010. The re-measurement of the decommissioning liability also resulted in an increase of \$50 million to the associated property, plant and equipment as at September 30, 2010.

CAPITAL POWER CORPORATION

Notes to the Condensed Interim Consolidated Financial Statements

September 30, 2011 and 2010

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

12. Transition to IFRS, continued:

Notes to the reconciliations, continued

(a) IAS 16 Property, Plant and Equipment & IAS 37 Provisions, continued:

Under IFRS, amounts provided for the unavoidable costs of the Company's Alberta retail and commercial natural gas contracts are recognized as provisions in the financial statements. Accordingly, the Company has reclassified \$1 million from current derivative financial instruments liabilities to current provisions as at January 1, 2010. As well, related to these contracts, the Company recognized an additional \$11 million in non-current provisions as at January 1, 2010 of which \$7 million was reclassified from non-current derivative financial instruments liabilities as at January 1, 2010. As a result of changes in cash flow assumptions and discount rates, the non-current provision recorded at January 1, 2010 was decreased by \$7 million as at September 30, 2010.

These adjustments impact equity in proportion to the Company's owners' respective shares of the adjustments and accordingly resulted in an increase of \$2 million in the equity attributable to shareholders and a decrease of \$18 million to non-controlling interests as at September 30, 2010.

(b) IAS 36 – Impairment of Assets:

IAS 36 requires that impairment testing be done on a CGU level, which is the smallest identifiable group of assets that generates cash inflows. For Capital Power, some CGUs consist of a single plant resulting in more CGUs subject to impairment testing under IFRS than under Canadian GAAP. In addition, any goodwill amounts must be allocated and included in the impairment test for each CGU. Accordingly, this change may result in more frequent write downs of goodwill under IFRS.

IAS 36 also requires a one-step approach to determine the recoverable amount of a CGU. Canadian GAAP's two-step approach required the application of discounted cash flow techniques to measure the impairment amount, but only after the use of undiscounted cash flow analysis indicated the existence of an impairment. The adoption of IAS 36 is expected to result in more frequent write downs since the carrying amount of assets which are supported by undiscounted 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 if the circumstances which lead to the impairment change, except for impairment losses attributed to goodwill.

In accordance with IAS 36, the Company reviewed the recoverable amount for its CGUs with allocated goodwill at both the date of transition to IFRS and as at December 31, 2010. The key assumptions used in those reviews are disclosed in note 14(d) of the March 31, 2011 condensed interim consolidated financial statements. For all other CGUs, management assessed whether there were any triggering events at the date of transition to IFRS, as at September 30, 2010 and as at December 31, 2010. Recoverable amounts were calculated on a fair value less cost to sell basis, using discounted cash flow models based on the Company's long-term planning model. As a result of the review of recoverable amounts it was determined that certain of the Company's CGUs were impaired.

CAPITAL POWER CORPORATION

Notes to the Condensed Interim Consolidated Financial Statements

September 30, 2011 and 2010

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

12. Transition to IFRS, continued:

Notes to the reconciliations, continued

(b) IAS 36 – Impairment of Assets, continued:

The impacts of the impairments by CGU and by line item, excluding the impacts on depreciation and foreign currency translation, as at September 30, 2010 were:

	Goodwill	Intangible assets	Property, plant and equipment	Total
CPILP manager contracts	\$ -	\$ 7	\$ -	\$ 7
Calstock	9	5	28	42
Greeley	-	-	7	7
Kapuskasing	10	2	5	17
Moresby Lake	2	-	-	2
Naval Training Centre	1	1	-	2
North Bay	10	-	1	11
Roxboro	-	-	11	11
Tunis	3	2	12	17
	\$ 35	\$ 17	\$ 64	\$ 116

The impairments noted above for Greeley, Naval Training Centre, Roxboro and \$2 million of the CPILP manager contract impairments are reported in the U.S. geographic area while the impairments for Calstock, Kapuskasing, Moresby Lake, North Bay, Tunis and \$5 million of the CPILP manager contract impairments are reported in the Canadian geographic area.

As a result of the change in impairment testing under IFRS to a one-step discounted cash flow test, the Company has determined that the carrying amount of the CPILP manager contracts was in excess of the fair value less cost to sell for the contracts, resulting in the impairment noted above.

The impairment recorded for the Calstock facility at January 1, 2010 was a result of higher than expected wood waste costs due to declines in wood waste availability caused by weakness in the Ontario forestry sector. The impairments recorded for the Greeley and Roxboro facilities at January 1, 2010 were due to the impact of weakening economic conditions in their respective markets.

The additional impairment recorded for the Calstock facility, as well as the impairments recorded for the Kapuskasing, North Bay and Tunis facilities in the third quarter of 2010 were primarily due to lower expectations for waste heat as a result of lower expected throughput on the pipeline that provides the waste heat.

The total adjustments resulting from IAS 36, including resulting impacts on depreciation and foreign currency translation gains and losses, impact equity in proportion to the Company's owners' respective shares of the adjustments and accordingly resulted in a decrease of \$2 million in the equity attributable to shareholders and a decrease of \$112 million to non-controlling interests as at September 30, 2010.

CAPITAL POWER CORPORATION

Notes to the Condensed Interim Consolidated Financial Statements

September 30, 2011 and 2010

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

12. Transition to IFRS, continued:

Notes to the reconciliations, continued

(c) IFRS 1 – First Time Adoption of IFRS:

IFRS 1 – First Time Adoption of IFRS provides an election to deem any cumulative translation differences to be zero on transition to IFRS. As a result of the Company taking the IFRS 1 election to adjust the balance of its cumulative translation account to nil at the date of transition, \$4 million was reclassified within equity, between accumulated other comprehensive income and retained earnings at January 1, 2010.

IFRS 1 also provides an optional election on transition to IFRS which allows the use of fair value as deemed cost on items of property, plant and equipment. The Company has elected under IFRS 1 to fair value certain items of property, plant and equipment resulting in an increase to property, plant and equipment, net of resulting foreign exchange and depreciation changes, of \$48 million as at September 30, 2010.

These adjustments impact equity in proportion to the Company's owners' respective shares of the adjustments and accordingly resulted in an increase of \$4 million in the equity attributable to shareholders and an increase of \$44 million to non-controlling interests as at September 30, 2010.

(d) Other Impacts:

In accordance with IAS 17 – Leases, the Kingsbridge PPA was determined to be a finance lease. The transitional adjustment was a result of IAS 17 and Canadian GAAP having different qualitative guidelines in the determination of the classification of leases between operating and finance (or capital under Canadian GAAP). As a result, property, plant and equipment was decreased by \$50 million, finance lease receivable was increased by \$62 million, trade and other receivables was increased by \$2 million and retained earnings was increased by \$14 million as at September 30, 2010.

In accordance with IAS 31 – Interests in Joint Ventures, the Company has concluded that it controls the Genesee mine joint venture and as a result is required to consolidate this investment under IFRS. As a result, property plant and equipment was increased by \$87 million as at September 30, 2010, with the full amount of the changes being attributed to non-controlling interests.

The Company has elected, under IFRS 1, to recognize all actuarial gains and losses in other comprehensive income. Under Canadian GAAP, the Company recognized actuarial gains and losses into income or loss using the corridor approach whereby amounts that exceeded the corridor were recognized into income or loss over the average remaining service period of the active employees. At the date of transition, all previously unrecognized cumulative actuarial gains and losses were recognized in retained earnings. As at September 30, 2010, the provision was increased and other comprehensive income was decreased by \$1 million.

IAS 39 - Financial Instruments, requires an asset classified as available for sale to be recorded at fair value with any changes in the fair value recognized in other comprehensive income. Accordingly, other financial assets were increased by \$3 million as at September 30, 2010, for the difference between the fair value and the previously reported carrying amount for one of the Company's equity investments. Since this adjustment is unrealized, accumulated other comprehensive income was correspondingly increased.

CAPITAL POWER CORPORATION

Notes to the Condensed Interim Consolidated Financial Statements

September 30, 2011 and 2010

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

12. Transition to IFRS, continued:

Notes to the reconciliations, continued

(d) Other Impacts, continued:

In addition to the IAS 39 impact above, under IAS 39, hedge effectiveness testing must incorporate the entity's credit risk. The net impact of the IAS 39 changes was a decrease to accumulated other comprehensive income of \$2 million as at September 30, 2010, with a corresponding increase to retained earnings.

The Company's share-based payments contain graded vesting provisions and as such, in accordance with IFRS 2 – Share-based payments, are treated as a series of individual awards with compensation measured and recognized separately for each tranche, within a grant, that has a different vesting date. Under GAAP, the Company treated each grant as a single award and used an average life to recognize the compensation for each grant on a straight-line basis. The net impact of the IFRS 2 change was an increase in the employee benefits reserve of \$1 million as at September 30, 2010.

Other impacts also include the impact of tax on the IFRS adjustments recognized. To recognize the income tax impact of the IFRS transition adjustments, deferred tax assets were decreased by \$24 million and deferred tax liabilities were decreased by \$37 million as at September 30, 2010.

These adjustments impact equity in proportion to the Company's owners' respective shares of the adjustments and accordingly resulted in an increase of \$10 million in the equity attributable to shareholders and an increase of \$106 million to non-controlling interests as at September 30, 2010.

(e) Presentation reclassifications:

IAS 1 – Presentation of Financial Statements, provides presentation requirements for the statement of financial position. Accordingly, the following items have been reclassified:

- Financial assets must be presented separately from other assets. Accordingly, \$25 million was reclassified from other assets to finance lease receivables and \$61 million was reclassified from other assets to other financial assets as at September 30, 2010.
- Provisions must be presented as a separate item on the statement of financial position. Accordingly, \$23 million was reclassified from accounts payable to current provisions and \$107 million was reclassified from other non-current liabilities to non-current provisions as at September 30, 2010.
- Deferred tax balances are to be classified as non-current. Therefore, as at September 30, 2010, the current deferred tax assets and liabilities of \$2 million and \$17 million respectively, were reclassified to non-current deferred tax assets and liabilities respectively.
- International Financial Reporting Interpretations Committee (IFRIC) 18 requires that contributions received with respect to the construction of property, plant and equipment and used to provide goods or services, be classified as deferred revenue. Accordingly, \$32 million of contributions that were previously reported as reductions of property, plant and equipment were reclassified as increases in deferred revenue and other liabilities as at September 30, 2010.

CAPITAL POWER CORPORATION

Notes to the Condensed Interim Consolidated Financial Statements

September 30, 2011 and 2010

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

12. Transition to IFRS, continued:

Reconciliation of total comprehensive income (loss)

The reconciliation of total comprehensive loss reported under previous Canadian GAAP for the three months ended September 30, 2010 to total comprehensive loss reported under IFRS was as follows:

	Canadian GAAP	IAS 16 & IAS 37 Impacts (f)	IAS 36 Impact (g)	IFRS 1 elections (h)	Other impacts (i)	Presentation Reclassifications (j)	IFRS
Revenues	\$ 494	\$ -	\$ -	\$ -	\$ (2)	\$ -	\$ 492
Other income	14	5	-	-	1	1	21
Energy purchases and fuel	(279)	-	-	-	2	-	(277)
Gross income	229	5	-	-	1	1	236
Operations, maintenance and direct administration	(48)	-	-	-	-	48	-
Indirect administration	(38)	-	-	-	-	38	-
Other raw materials and operating charges	-	5	-	-	-	(25)	(20)
Staff costs and employee benefits expense	-	-	-	-	-	(43)	(43)
Depreciation and amortization	(48)	(9)	1	(1)	(2)	-	(59)
Impairments	-	-	(66)	-	-	-	(66)
Other administrative expenses	-	-	-	-	-	(18)	(18)
Property taxes	(5)	-	-	-	-	-	(5)
Foreign exchange losses	(1)	-	-	-	-	-	(1)
Operating income	89	1	(65)	(1)	(1)	1	24
Finance expense	(25)	-	-	-	-	(1)	(26)
Income (loss) before tax	64	1	(65)	(1)	(1)	-	(2)
Income tax expense	(17)	-	-	-	16	-	(1)
Net income (loss)	47	1	(65)	(1)	15	-	(3)
Other comprehensive loss	(15)	-	-	(3)	4	-	(14)
Total comprehensive income (loss)	32	1	(65)	(4)	19	-	(17)
Attributable to:							
Non-controlling interests	\$ 25	\$ (4)	\$ (68)	\$ (3)	\$ 17	\$ -	\$ (33)
Shareholders of the Company	\$ 7	\$ 5	\$ 3	\$ (1)	\$ 2	\$ -	\$ 16

CAPITAL POWER CORPORATION

Notes to the Condensed Interim Consolidated Financial Statements

September 30, 2011 and 2010

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

12. Transition to IFRS, continued:

Reconciliation of total comprehensive income (loss), continued

The reconciliation of total comprehensive income reported under previous Canadian GAAP for the nine months ended September 30, 2010 to total comprehensive income reported under IFRS was as follows:

	Canadian GAAP	IAS 16 & IAS 37 Impacts (f)	IAS 36 Impact (g)	IFRS 1 elections (h)	Other impacts (i)	Presentation Reclassifications (j)	IFRS
Revenues	\$ 1,281	\$ -	\$ -	\$ -	\$ (4)	\$ -	\$ 1,277
Other income	39	6	-	-	2	3	50
Energy purchases and fuel	(755)	(4)	-	-	2	-	(757)
Gross income	565	2	-	-	-	3	570
Operations, maintenance and direct administration	(153)	-	-	-	-	153	-
Indirect administration	(95)	-	-	-	-	95	-
Other raw materials and operating charges	-	20	-	-	-	(81)	(61)
Staff costs and employee benefits expense	-	-	-	-	(1)	(130)	(131)
Depreciation and amortization	(146)	(28)	2	(3)	(5)	2	(178)
Impairments	-	-	(66)	-	-	-	(66)
Other administrative expenses	-	-	-	-	-	(37)	(37)
Property taxes	(14)	-	-	-	-	-	(14)
Operating income	157	(6)	(64)	(3)	(6)	5	83
Gains on acquisitions and disposals	28	-	-	-	-	-	28
Finance expense	(62)	2	-	-	-	(5)	(65)
Income before tax	123	(4)	(64)	(3)	(6)	-	46
Income tax (expense) recovery	(10)	-	-	-	19	-	9
Net income	113	(4)	(64)	(3)	13	-	55
Other comprehensive loss	(35)	-	-	(2)	5	-	(32)
Total comprehensive income	78	(4)	(64)	(5)	18	-	23
Attributable to:							
Non-controlling interests	68	(7)	(68)	(4)	16	-	5
Shareholders of the Company	\$ 10	\$ 3	\$ 4	\$ (1)	\$ 2	\$ -	\$ 18

CAPITAL POWER CORPORATION

Notes to the Condensed Interim Consolidated Financial Statements

September 30, 2011 and 2010

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

12. Transition to IFRS, continued:

Notes to the reconciliations

The tables above present the aggregate transitional adjustments from previous Canadian GAAP to IFRS. The following notes summarize the key differences noted on transition to IFRS.

(f) IAS 16 Property, Plant and Equipment & IAS 37 Provisions:

As noted in the reconciliation of equity on transition, as a result of the Company re-measuring its commercial natural gas contracts, other income increased by \$5 million and \$6 million for the three and nine months ended September 30, 2010 respectively.

Energy purchases and fuel costs increased by nil and \$4 million for the three and nine months ended September 30, 2010 respectively as a result of the increase to coal costs due to costs related to the Genesee mine that were previously capitalized under GAAP which are expensed under IFRS.

Other raw materials and operating charges decreased by \$5 million and \$20 million for the three and nine months ended September 30, 2010 respectively as a result of capitalizing the overhaul costs which had previously been expensed under GAAP.

The impacts to depreciation and amortization as a result of implementing IAS 16 were increases of \$8 million and \$24 million for the three and nine months ended September 30, 2010 respectively.

Depreciation and amortization expense was increased by \$1 million and \$4 million for the three and nine months ended September 30, 2010 respectively as a result of implementing IAS 37 which resulted in an increase in the value of decommissioning assets on transition.

Finance costs decreased by nil and \$2 million for the three and nine months ended September 30, 2010 respectively as a result of accretion expense being lower as a result of implementing IAS 37.

(g) IAS 36 Impairments:

The Company recognized certain impairments against property, plant and equipment, intangible assets and goodwill on transition to IFRS. As a result of these impairments, the Company's depreciation and amortization expense decreased by \$1 million and \$2 million for the three and nine months ended September 30, 2010 respectively.

During the third quarter of 2010, additional asset impairments were recorded for \$66 million.

(h) IFRS 1 First Time Adoption of IFRS:

As noted in the reconciliation of equity on transition, the Company elected to use the fair value at transition date as deemed cost for certain plants. As a result of this election, the Company's depreciation and amortization expense has increased by \$1 million and \$3 million for the three and nine months ended September 30, 2010 respectively.

(i) Other Impacts:

As noted in the reconciliation of equity on transition, one of the Company's power purchase arrangements was determined to be a finance lease which resulted in a reduction to property, plant and equipment and an increase to finance lease receivable. As such, there were reductions to electricity sales revenues of \$2 million and \$4 million for the three and nine months ended September 30, 2010 respectively, increases to other income of \$1 million and \$2 million for the three and nine months ended September 30, 2010 respectively and reductions to depreciation and amortization of \$1 million and \$2 million for the three and nine months ended September 30, 2010 respectively.

As noted in the reconciliation of equity on transition, the Company has concluded that it controls the Genesee mine joint venture and as a result is required to consolidate this investment under IFRS. As a result, depreciation and amortization increased by \$3 million and \$7 million for the three and nine months ended September 30, 2010 respectively, with the full amount of the changes being attributed to non-controlling interests.

CAPITAL POWER CORPORATION

Notes to the Condensed Interim Consolidated Financial Statements

September 30, 2011 and 2010

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

12. Transition to IFRS, continued:

Notes to the reconciliations, continued

(i) Other impacts, continued:

The impacts of incorporating the Company's credit risk in the hedge effectiveness testing under IAS 39 were decreases to energy purchases and fuel of \$2 million for the three and nine months ended September 30, 2010 with offsetting charges to other comprehensive income (OCI).

The impacts of recognizing the Company's share-based payments with graded vesting provisions as a series of individual awards under IFRS 2 were increases to staff costs and employee benefits expense of nil and \$1 million for the three and nine months ended September 30, 2010 respectively.

As a result of the IFRS adjustments, the impacts to income taxes for the three and nine months ended September 30, 2010 were decreases to expenses of \$16 million and \$19 million respectively.

The remaining adjustments impact OCI:

- The impacts of using Primary Energy Recycling Corporation's share price as a proxy to determine the fair value of the Company's investment in Primary Energy Recycling Holdings LLC, were increases to OCI of \$2 million (net of \$1 million in income tax expense) and \$4 million (net of \$2 million in income tax expense) for the three and nine months ended September 30, 2010 respectively.
- The impacts of incorporating the entity's credit risk into the hedge effectiveness testing were decreases in OCI of \$2 million (net of income tax expense of nil) for the three and nine months ended September 30, 2010.
- As a result of the adjustments made by the Company on transition and up to September 30, 2010, there were net increases to OCI for decreases in the unrealized losses on translating the Company's foreign operations of \$1 million (net of \$3 million in income tax recovery) and nil (net of \$2 million in income tax recovery) for the three and nine months ended September 30, 2010 respectively.

(j) Presentation reclassifications:

The following items have been reclassified:

- In accordance with IFRIC 18, International Financial Reporting Interpretations Committee (IFRIC) 18 requires that contributions received with respect to the construction of property, plant and equipment and used to provide goods or services, be classified as deferred revenue. Accordingly, revenue should be recorded as the contributions are realized, whereas, previously under GAAP, this was recorded as a reduction of depreciation. The impacts were increases to other income and increases to depreciation expense of \$1 million and \$3 million for the three and nine months ended September 30, 2010 respectively.
- The Company has chosen to present its statement of income by nature of expense. Certain amounts have been reclassified on the statement of income to align expenses with the revised presentation format. The most significant adjustment is to separately disclose staff costs and employee benefits expenses. This reclassification resulted in other raw materials and operating charges and other administrative expenses increasing by \$25 million and \$18 million respectively for the three months ended September 30, 2010 and \$81 million and \$37 million respectively for the nine months ended September 30, 2010.
- In accordance with IAS 37, the unwinding of the discount on provisions should be presented as a finance expense. Under Canadian GAAP, it was presented as part of depreciation and amortization. The impacts of this difference were to reclassify \$1 million and \$5 million for the three and nine months ended September 30, 2010 respectively.

13. Comparative figures:

Certain comparative Canadian GAAP figures have been reclassified to conform to the current period's presentation.