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Capital Power reports third quarter 2014 results

EDMONTON, Alberta – Capital Power Corporation (Capital Power, or the Company) (TSX: CPX) today released its financial results for the third quarter and nine months ended September 30, 2014.

Normalized earnings attributable to common shareholders in the third quarter of 2014, after adjusting for one-time items and fair value adjustments, were $10 million, or $0.12 per share, compared with $51 million, or $0.72 per share, in the comparable period of 2013.

As reported on October 17, 2014, the Company incurred a $73 million non-cash write-down of deferred tax assets in the third quarter of 2014. This charge, in conjunction with the timing of both unplanned outages and the extension of a planned outage, resulted in a net loss attributable to shareholders in the third quarter of 2014 was $45 million, or $0.62 per share, compared with net income attributable to shareholders of $44 million, or $0.55 per share, in the comparable period of 2013. Funds from operations were $83 million in the third quarter of 2014, down 34 per cent from $125 million in the third quarter of 2013 reflecting the impact of the timing of the outages and lower average power prices.

For the nine months ended September 30, 2014, normalized earnings attributable to common shareholders were $42 million, or $0.51 per share, compared with $95 million, or $1.35 per share, in the first nine months of 2013. Funds from operations totaled $260 million compared with $316 million in the comparable nine-month period last year.

“Financial results in the third quarter were below our expectations, primarily due to an extended planned outage and unplanned outages at the acquired Sundance PPA units and other plant derates,” said Brian Vaasjo, President and CEO of Capital Power. “These outages occurred primarily in July coinciding with a period of pricing volatility, with Alberta spot power prices in July averaging $122 per megawatt-hour (MWh) compared with $45 per MWh in August and $24 per MWh in September. As a result, with commercial production 100% sold forward in July, we were required to cover a short market position that negatively impacted our portfolio optimization position in the quarter. With the expected output from our commercial plants fully hedged in the high-$50 per MWh for the remainder of the year, we expect funds from operations in 2014 to be at the low end of our annual financial target range of $360 to $400 million.”

“Capital Power’s owned plants achieved strong availability of 97% in the third quarter, which was consistent with expectations,” continued Mr. Vaasjo. “However, due to lower plant availability at the acquired Sundance PPA units, other plant derates and lower Alberta wind generation, overall electricity generation production was below expectations.”

“In the third quarter, net income was impacted by the non-cash $73 million write-down of deferred tax assets relating to U.S. income tax loss carryforwards that can no longer be recognized for accounting purposes based on our current long term forecast for U.S. taxable income,” said Mr. Vaasjo. “For income tax purposes, these U.S. net operating losses do not expire until the 2027 to 2033 period. Accordingly, they retain economic value and as we continue to pursue U.S. contracted power opportunities, the Company could record deferred tax assets in the future. Importantly, the write-down is a non-cash item and has no impact on our operations or other key performance measures.”

Operational and Financial Highlights [1] (unaudited)	**Three months ended September 30**		**Nine months ended June 30**	
(millions of dollars except per share and operational amounts)	**2014**	**2013**	**2014**	**2013**
Electricity generation (excluding acquired Sundance PPA) (GWh)	3,220	4,317	9,174	12,205
Generation plant availability (excluding acquired Sundance PPA) (%)	97	97	95	93
Revenues	$ 248	$ 380	$ 796	$ 1,066
Adjusted EBITDA [2]	$ 91	$ 151	$ 282	$ 390
Net (loss) income	$ (57)	$ 59	$ 2	$ 130
Net (loss) income attributable to shareholders of the Company	$ (45)	$ 44	$ 7	$ 98
Normalized earnings attributable to common shareholders [2]	$ 10	$ 51	$ 42	$ 95
Basic (loss) earnings per share	$ (0.62)	$ 0.55	$ (0.12)	$ 1.19
Diluted (loss) earnings per share	$ (0.62)	$ 0.51	$ (0.12)	$ 1.14
Normalized earnings per share [2]	$ 0.12	$ 0.72	$ 0.51	$ 1.35
Funds from operations [2]	$ 83	$ 125	$ 260	$ 316
Purchase of property, plant and equipment and other assets	$ 25	$ 422	$ 163	$ 884
Dividends per common share, declared	$ 0.3400	$ 0.3150	$ 0.9700	$ 0.9450

The operational and financial highlights in this press release should be read in conjunction with Management's Discussion and Analysis and the audited Consolidated Financial Statements for the nine months ended September 30, 2014.

Earnings before finance expense, income tax expense, depreciation and amortization, impairments, foreign exchange losses, and gains on disposals (adjusted EBITDA), normalized earnings attributable to common shareholders, normalized earnings per share, and funds from operations are non-GAAP financial measures and do not have standardized meanings under GAAP and are, therefore, unlikely to be comparable to similar measures used by other enterprises. See Non-GAAP Financial Measures.

Significant Events

Write-down of deferred tax assets

Capital Power's third quarter 2014 net income was negatively impacted by a non-cash write-down of deferred tax assets of $73 million. The write-down related to the accounting impact of U.S. income tax loss carryforwards that can no longer be recognized for accounting purposes based on the Company's current long-term forecast for U.S. taxable income. The forecast showed a decline in taxable income over the latter years of the forecast period. For income tax purposes, these U.S net operating losses do not expire until the 2027 to 2033 period. Accordingly, they retain economic value and could result in the Company recording deferred tax assets in the future. The Company continues to pursue U.S. contracted power opportunities and the U.S. business development pipeline is active. Importantly, the write-down is a non-cash item and has no impact on operations or other key performance measures.

Dividend increase

On July 25, 2014, the Company announced that its Board of Directors approved a 7.9% increase in the annual dividend for holders of its common shares, from $1.26 per common share to $1.36 per common share. This increased common dividend will commence with the third quarter 2014 quarterly dividend payment payable on October 31, 2014 to shareholders of record at the close of business on September 30, 2014.

Genesee coal mine

Capital Power is a party to various agreements with Prairie Mines & Minerals Royalty Ltd. (PMRL) in relation to the operations of the Genesee coal mine (Genesee Coal Mine Agreements). Pursuant to the Genesee Coal Mine Agreements, PMRL operates the Genesee coal mine. In connection with the acquisition by Westmoreland Coal Company (Westmoreland) of PMRL and the acquisition by Altius Minerals Corporation (Altius) of the royalty assets of PMRL, the Genesee Coal Mine Agreements and certain related agreements have, among other things, been amended to: (a) confirm the acquisitions by Westmoreland and Altius; (b) provide for certain amendments to the Genesee Coal Mine Agreements; and (c) provide for a payment to Capital Power of $20 million on completion of the acquisitions; the payment was received in the second quarter of 2014.

Genesee 4 and 5

On April 24, 2014, Capital Power and ENMAX Corporation (ENMAX) executed a purchase and sale agreement in support of a joint arrangement agreement to jointly develop, construct, and operate the Genesee 4 and 5 power project. The joint arrangement agreement provides for, among other things, an agreement for ENMAX to purchase approximately 225 megawatts (MW) from Capital Power for eight years. The joint arrangement agreement closing occurred in July 2014.

Construction of K2 Wind Power Project commences

On March 24, 2014, construction of the K2 Wind Power Project (K2 Wind) commenced following the successful completion of an $850 million financing in the form of a construction loan that will convert to long-term project debt once K2 Wind starts commercial operations. K2 Wind is a 270 MW wind power project located in Goderich, Ontario that is under joint development by Samsung Renewable Energy, Inc., Pattern Energy Group LP and Capital Power with operations expected to commence in the second half of 2015. The total estimated project cost has been revised upward to $930 million from the previous upper end of range of $900 million primarily due to foreign exchange changes on U.S. contract deliverables. Capital Power's share is $310 million. As a higher portion of the project is expected to be financed with project debt than originally forecast, Capital Power expects higher equity returns on the project.

Analyst Conference Call and Webcast

Capital Power will be hosting a conference call and live webcast with analysts on October 27, 2014 at 11:00 AM (Eastern Time) to discuss the third quarter results. The conference call dial-in numbers are:

(604) 681-8564 (Vancouver)
(403) 532-5601 (Calgary)
(416) 623-0333 (Toronto)
(514) 687-4017 (Montreal)
(855) 353-9183 (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: (855) 201-2300 (toll-free) and entering conference reference number 1165968# followed by participant code 21543#. The replay will be available until midnight on January 27, 2015.

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-GAAP Financial Measures

The Company uses (i) adjusted EBITDA, (ii) funds from operations, (iii) normalized earnings attributable to common shareholders, and (iv) normalized earnings per share as financial performance measures. These terms are not defined financial measures according to GAAP and do not have standardized meanings prescribed by GAAP, and are, therefore, unlikely to be comparable to similar measures used by other enterprises. These measures should not be considered alternatives to net income, net income attributable of shareholders of the Company, net cash flows from operating activities or other measures of financial performance calculated in accordance with GAAP. Rather, these measures are provided to complement GAAP measures in the analysis of the Company's results of operations from management's perspective. Reconciliations of adjusted EBITDA to net income, funds from operations to net cash flows from operating activities and normalized earnings attributable to common shareholders to net income attributable to shareholders of the Company are contained in the Company's Management's Discussion and Analysis dated October 24, 2014 for the nine months ended September 30, 2014, which is available under the Company's profile on SEDAR at www.SEDAR.com.

Forward-looking Information

Forward-looking information or statements included in this press release are provided to inform the Company's shareholders and potential investors about management's assessment of Capital Power's future plans and operations. This information may not be appropriate for other purposes. The forward-looking information in this press release is generally identified by words such as will, anticipate, believe, plan, intend, target and expect or similar words that suggest future outcomes.

Material forward-looking information in this press release includes information with respect to expectations regarding: (i) future cash flows based on expected output of commercial plants and hedged position, and (ii) completion of K2 Wind.

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 relate to: (i) electricity and other energy prices, (ii) performance, (iii) business prospects and opportunities including expected growth and capital projects, (iv) status and impact of policy, legislation and regulation, and (v) effective tax rates.

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 material risks and uncertainties are: (i) changes in electricity prices in markets in which the Company operates, (ii) changes in energy commodity market prices and use of derivatives, (iii) regulatory and political environments including changes to environmental, financial reporting and tax legislation, (iv) power plant availability and performance including maintenance expenditures, (v) ability to fund current and future capital and working capital needs, (vi) acquisitions and developments including timing and costs of regulatory approvals and construction, (vii) changes in market prices and availability of fuel, and (viii) changes in general economic and competitive conditions. See Risks and Risk Management in the Company's December 31, 2013 annual Management's Discussion and Analysis for further discussion of these and other risks.

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CAPITAL POWER CORPORATION

Management's Discussion and Analysis

This management's discussion and analysis (MD&A), dated October 24, 2014, 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, 2014, the audited consolidated financial statements and MD&A of Capital Power Corporation for the year ended December 31, 2013, the annual information form of Capital Power Corporation dated March 14, 2014, and the cautionary statements regarding forward-looking information, which begin on page 2. 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, 2014 and the nine months ended September 30, 2013 is based on the unaudited condensed interim consolidated financial statements of the Company for such periods, which were prepared in accordance with Canadian generally accepted accounting principles (GAAP) and are presented in Canadian dollars unless otherwise specified. In accordance with its terms of reference, the Audit Committee of the Company's Board of Directors reviews the contents of the MD&A and recommends its approval by the Board of Directors. The Board of Directors approved this MD&A as of October 24, 2014.

Contents

Forward-looking Information

Forward-looking information or statements included in this MD&A are provided to inform the Company's shareholders and potential investors about management's assessment of Capital Power's future plans and operations. This information may not be appropriate for other purposes. The forward-looking information in this MD&A is generally identified by words such as will, anticipate, believe, plan, intend, target and expect or similar words that suggest future outcomes.

Material forward-looking information in this MD&A includes information with respect to: (i) expectations related to future revenues, expenses, earnings and funds from operations, (ii) expectations regarding the future pricing of electricity and market fundamentals in existing and target markets, (iii) expectations related to the Company's future cash requirements including interest and principal repayments, capital expenditures, dividends and distributions, (iv) expectations regarding the Company's sources of funding, adequacy and availability of committed bank credit facilities and future borrowings, (v) expectations regarding future growth and emerging opportunities in the Company's target markets including the focus on certain technologies, (vi) expectations regarding the timing of, funding of, and costs for existing, planned and potential development projects and acquisitions, (vii) expectations regarding plant availability, and (viii) expectations regarding capital expenditures for plant maintenance and other.

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 relate to: (i) electricity and other energy prices, (ii) performance, (iii) business prospects and opportunities including expected growth and capital projects, (iv) status of and impact of policy, legislation and regulations, (v) effective tax rates, and (vi) other matters discussed under the Performance Overview and Outlook sections.

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 material risks and uncertainties are: (i) changes in electricity prices in markets in which the Company operates, (ii) changes in energy commodity market prices and use of derivatives, (iii) regulatory and political environments including changes to environmental, financial reporting and tax legislation, (iv) power plant availability and performance including maintenance expenditures, (v) ability to fund current and future capital and working capital needs, (vi) acquisitions and developments including timing and costs of regulatory approvals and construction, (vii) changes in market prices and availability of fuel, and (viii) changes in general economic and competitive conditions. See Risks and Risk Management in the Company's December 31, 2013 annual MD&A for further discussion of these and other risks.

Readers are cautioned not to place undue reliance on any such forward-looking statements, which speak only as of the date made. 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.

Overview of Business and Corporate Structure

Capital Power is a growth-oriented North American power producer headquartered in Edmonton, Alberta. The Company develops, acquires, operates and optimizes power generation from a variety of energy sources. Capital Power owns more than 2,600 megawatts (MW) of power generation capacity at 14 facilities across North America and owns 371 MW of capacity through its interest in the acquired Sundance power purchase arrangement (acquired Sundance PPA). An additional 490 MW of owned generation capacity is under construction in Alberta and Ontario.

The Company's power generation operations and assets are owned by Capital Power L.P. (CPLP), a subsidiary of the Company. As at September 30, 2014, the Company held 21.750 million general partnership units and 56.299 million common limited partnership units of CPLP, which represented approximately 81% of CPLP's total partnership units. EPCOR (in this MD&A, EPCOR refers to EPCOR Utilities Inc. collectively with its subsidiaries) held 18.841 million exchangeable common limited partnership units of CPLP, which represented approximately 19% of CPLP. CPLP's exchangeable common limited partnership units are exchangeable for common shares of Capital Power Corporation on a one-for-one basis.

Corporate Strategy

The Company's corporate strategy remains unchanged from that disclosed in its 2013 annual MD&A. During the nine months ended September 30, 2014, the Company commenced construction of K2 Wind (see Significant Events) and executed agreements with ENMAX Corporation (ENMAX) to jointly develop, construct and operate the Genesee 4 and 5 power project (Genesee 4 and 5).

Performance Overview

The Company measures its performance in relation to its corporate strategy through financial and non-financial targets that are approved by the Board of Directors. The measurement categories include corporate measures and measures specific to certain groups within the Company. The corporate measures are company-wide and include funds from operations and safety. The group-specific measures include plant operating margin and other operations measures, committed capital, construction and maintenance capital on budget and on schedule, and plant site safety.

Operational excellence

Performance measure	2014 full year target	Actual results for the nine months ended September 30, 2014
Plant availability average [1]	95% or greater	95%
Capital expenditures for plant maintenance, Genesee mine extension and other (sustaining capital expenditures)	$85 million	$42 million
Plant operating and maintenance expenses	$165 million to $185 million	$140 million

1 All plants excluding acquired Sundance PPA.

The Company's plant availability averaged 95%, which reflected the second quarter planned outage at Genesee 2 and several unplanned maintenance and forced outages of short-term duration. The most significant unplanned outage was at Genesee 1, which experienced a 10-day maintenance outage in the first quarter to perform valve repairs.

Capital expenditures for maintenance of the plants and other for the nine months ended September 30, 2014 were less than target for the three quarters primarily due to the deferred timing of certain sustaining capital projects. Also, there was lower spending on Genesee mine land purchases for the current quarter and the lower spending is forecast to continue for the balance of the year.

The plant operating and maintenance expenses target includes other raw materials and operating charges, staff costs and employee benefits expense and other administrative expenses for the Company's plants. The actual results for the nine months ended September 30, 2014 were consistent with the target range for full year 2014.

Disciplined growth

Performance measure	2014 full year target	Status at September 30, 2014
K2 Wind	Commence construction and complete project financing	Construction commenced and project financing completed first quarter 2014 (see Significant Events)
Shepard Energy Centre	Complete construction with commercial operation date in early 2015	On track with target
Genesee 4 and 5	Continue on track for first quarter 2015 permitting approval	On track with target

The first fire of the Shepard Energy Centre occurred in September 2014, which was delayed by one month from the previously expected timing. The plant is still expected to be completed on time and on budget with commercial operation commencing in early 2015.

Financial stability and strength

Performance measure	2014 full year target	Actual results for the nine months ended September 30, 2014
Funds from operations [1]	$360 million to $400 million	$260 million

1 Funds from operations is a non-GAAP measure. See Non-GAAP Financial Measures.

Actual funds from operations for the nine months ended September 30, 2014 reflected lower than expected cash flows from plant operations. This was largely due to an extended planned outage and unplanned outages at the acquired Sundance PPA units and other Alberta plant derates, primarily in July 2014, when the Company had sold forward its Alberta power position and power prices for the month averaged $122 per megawatt-hour (MWh). The actual results for the nine months ended September 30, 2014, including the $20 million arising from the amendment of the Genesee Coal Mine Agreements (see Significant Events), are consistent with full year's funds from operations being at the low end of the target range.

Outlook

The following discussion should be read in conjunction with the Forward-looking Information section of this MD&A, which identifies the material factors and assumptions used to develop forward-looking information and their material associated risk factors.

The Company's forecast for average Alberta power prices in 2014 is lower than the average of $80 per MWh experienced in 2013. Based on the actual results for the first three quarters of 2014 and the Company's forecast for the last quarter, it is expected that funds from operations for the full year, including the $20 million arising from the amendment of the Genesee Coal Mine Agreements (see Significant Events), will be at the low end of the target range of $360 million to $400 million. This is primarily driven by lower Alberta electricity prices for the first three quarters of the year. Alberta electricity prices for the last quarter of the year are expected to be in the high-$50 per MWh range.

Portfolio positions for the balance of 2014 and full year 2015 and 2016 and contracted prices, as at September 30, 2014, were:

Alberta commercial portfolio positions and power prices	**October to December 2014**	**Full year 2015**	**Full year 2016**
Percentage of baseload generation sold forward [1]	100%	92%	49%
Contracted price [2]	High-$50 per MWh	Mid-$50 per MWh	Mid-$50 per MWh

1 Based on the Alberta baseload plants and the acquired Sundance PPA plus a portion of Joffre and the uncontracted portion of Shepard Energy Centre baseload.

2 The forecast average contracted prices may differ significantly from the future average realized prices as the hedged and unhedged positions have a varying mix of differently priced blocks of power. This impact is accentuated in 2014, which includes one contract-for-differences for 300 MW for the full year that is sold forward for peak periods only.

The 2014 results will include a full year of operations from Port Dover and Nanticoke, which commenced operations in the fourth quarter of 2013.

The plant availability target for 2014 of 95% reflected scheduled maintenance outages at Genesee 2, Genesee 3 and Joffre. The outage at Genesee 2 occurred in the second quarter of 2014 while the Genesee 3 and Joffre outages are both scheduled for the fourth quarter of 2014. Since several unplanned forced and maintenance outages of short duration have occurred in the year-to-date, the Company expects that the full year 2014 availability will be slightly under the target of 95%.

The Company's estimated 2014 full year growth capital expenditures remain approximately $192 million (see Liquidity and Capital Resources – Investing activities).

Based on the actual expenditures for the nine months ended September 30, 2014 and the current forecast for the last quarter of 2014, estimated sustaining capital expenditures are expected to be moderately less than the annual target of $85 million.

The 2014 targets and forecasts are based on numerous assumptions including power and natural gas price forecasts. However, they do not include the effects of potential future acquisitions or development activities, or potential market and operational impacts relating to unplanned plant outages including outages at facilities of other market participants, and the related impacts on market power prices.

See Liquidity and Capital Resources for discussion of future cash requirements and expected sources of funding.

Non-GAAP Financial Measures

The Company uses (i) earnings before finance expense, income tax expense, depreciation and amortization, impairments, foreign exchange gains or losses, and gains on disposals (adjusted EBITDA), (ii) funds from operations, (iii) normalized earnings attributable to common shareholders, and (iv) normalized earnings per share as financial performance measures.

These terms are not defined financial measures according to GAAP and do not have standardized meanings prescribed by GAAP and are, therefore, unlikely to be comparable to similar measures used by other enterprises. These measures should not be considered alternatives to net income, net income attributable to shareholders of the Company, net cash flows from operating activities or other measures of financial performance calculated in accordance with GAAP. Rather, these measures are provided to complement GAAP measures in the analysis of the Company's results of operations from management's perspective.

Adjusted EBITDA

Capital Power uses adjusted EBITDA to measure the operating performance of plants and categories of plants from period to period. Management believes that a measure of plant operating performance is more meaningful if results not related to plant operations such as impairments, foreign exchange gains or losses and gains on disposals are excluded from the adjusted EBITDA measure.

A reconciliation of adjusted EBITDA to net income is as follows:

(unaudited, $ millions)	Three months ended							
	Sep 30 2014	**Jun 30 2014**	**Mar 31 2014**	**Dec 31 2013**	**Sep 30 2013**	**Jun 30 2013**	**Mar 31 2013**	**Dec 31 2012**
Revenues	248	240	308	327	380	321	365	288
Energy purchases and fuel, other raw materials and operating charges, staff costs and employee benefits expense, and other administrative expense	(157)	(162)	(195)	(208)	(229)	(217)	(230)	(215)
Adjusted EBITDA	**91**	**78**	**113**	**119**	**151**	**104**	**135**	**73**
Depreciation and amortization	(47)	(47)	(46)	(52)	(54)	(58)	(58)	(62)
Impairments	-	-	-	-	(6)	-	-	-
Foreign exchange gain (loss)	(5)	3	(4)	(5)	(1)	-	-	-
Gains on disposals of subsidiaries	-	-	-	76	-	-	-	15
Finance expense	(15)	(11)	(13)	(18)	(18)	(20)	(22)	(21)
Income tax (expense) recovery	(81)	(2)	(12)	(22)	(13)	(3)	(7)	14
Net income (loss)	**(57)**	**21**	**38**	**98**	**59**	**23**	**48**	**19**
Net income attributable to:								
Non-controlling interests	(12)	1	6	21	15	3	14	4
Shareholders of the Company	(45)	20	32	77	44	20	34	15
Net income (loss)	**(57)**	**21**	**38**	**98**	**59**	**23**	**48**	**19**

Funds from operations

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, dividends to the Company's shareholders and distributions to non-controlling interests. Funds from operations are net cash flows from operating activities, adjusted to include finance and current income tax expenses and exclude changes in working capital. The Company includes interest and current income tax expenses recorded during the period rather than interest and income taxes paid. The timing of cash receipts and payments of interest and income taxes and the resulting cash basis amounts are not comparable from period to period. The timing of cash receipts and payments also affects the period-to-period comparability of changes in operating working capital, which are also excluded from funds from operations.

Commencing with the Company's June 30, 2014 quarter-end, the reported funds from operations measure was changed consistent with the reclassification of Part VI.1 income taxes from operating activities to financing activities in the Company's statement of cash flows. All comparative funds from operations amounts for quarters prior to those ended on June 30, 2014 were revised.

A reconciliation of net cash flows from operating activities to funds from operations is as follows:

(unaudited, $ millions)	**Three months ended September 30**		**Nine months ended September 30**	
	2014	**2013**	**2014**	**2013**
Net cash flows from operating activities per Consolidated Statements of Cash Flows	**102**	**84**	**284**	**342**
Add (deduct) items included in calculation of net cash flows from operating activities per Consolidated Statements of Cash Flows:				
Interest paid	5	15	29	49
Realized loss (gain) on the settlement of interest rate derivatives	1	-	(1)	-
Miscellaneous financing charges paid and included in other items of non-cash adjustments to reconcile net income to net cash flows from operating activities	3	1	5	4
Income taxes (recovered) paid	(8)	2	(7)	3
Change in non-cash operating working capital	(4)	32	(10)	(35)
	(3)	50	16	21
Finance expense excluding unrealized changes on interest rate derivative contracts and amortization and accretion charges	(16)	(18)	(39)	(57)
Current income tax recovery (expense)	-	9	(1)	10
Funds from operations	**83**	**125**	**260**	**316**

Normalized earnings attributable to common shareholders 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 per share is based on earnings used in the calculation of earnings per share according to GAAP adjusted for items that are not reflective of performance in the period such as unrealized fair value changes, impairment charges, unusual tax adjustments, gains and losses on disposal of assets or unusual contracts, and foreign exchange gain or loss on the revaluation of U.S. dollar denominated debt. The adjustments consist of unrealized fair value changes on financial instruments that are not necessarily indicative of future actual realized gains or losses, non-recurring gains or losses, or gains or losses reflecting corporate structure decisions.

(unaudited, $ millions except per share amounts and number of common shares)	Three months ended							
	Sep 30 2014	**Jun 30 2014**	**Mar 31 2014**	**Dec 31 2013**	**Sep 30 2013**	**Jun 30 2013**	**Mar 31 2013**	**Dec 31 2012**
Basic (loss) earnings per share ($)	**(0.62)**	**0.17**	**0.33**	**0.89**	**0.55**	**0.20**	**0.44**	**0.19**
Net (loss) income attributable to shareholders of the Company per Consolidated Statements of Income	**(45)**	**20**	**32**	**77**	**44**	**20**	**34**	**15**
Preferred share dividends	(6)	(6)	(5)	(6)	(5)	(6)	(3)	(2)
(Loss) earnings attributable to common shareholders	(51)	14	27	71	39	14	31	13
Write-down of U.S. deferred tax assets	59	-	-	-	-	-	-	-
Unrealized foreign exchange (gain) loss on revaluation of U.S. dollar denominated debt	5	(3)	3	4	-	-	-	-
Unrealized changes in fair value of derivatives	(3)	8	(5)	(9)	(1)	3	(6)	12
Amount received on amendment of the Genesee Coal Mine Agreements	-	(14)	-	-	-	-	-	-
Genesee flood damage repair costs	-	1	1	-	-	-	-	-
Gain on sale of North East U.S. assets	-	-	-	(34)	-	-	-	-
Reduction of amount receivable related to Sundance force majeure claim	-	-	-	6	-	-	-	-
Income tax (recovery)expense related to change in income tax rate applicable to North East U.S.	-	-	-	(6)	6	-	-	-
Restructuring charges	-	-	-	1	4	2	-	-
Obligation to EPCOR for Rossdale plant	-	-	-	(1)	-	-	-	-
Impairment loss on North East U.S. assets	-	-	-	-	3	-	-	-
Gain on sale of hydro facilities	-	-	-	-	-	-	-	(9)
Normalized earnings attributable to common shareholders	**10**	**6**	**26**	**32**	**51**	**19**	**25**	**16**
Weighted average number of common shares outstanding (millions)	82.79	81.94	81.18	79.73	70.83	70.48	70.15	69.84
Normalized earnings per share ($)	**0.12**	**0.07**	**0.32**	**0.40**	**0.72**	**0.27**	**0.36**	**0.23**

Normalized earnings per share reflects the period-over-period change in normalized earnings attributable to common shareholders and the changes from period to period as the weighted average number of common shares outstanding increases and the net income attributable to non-controlling interests decreases.

Financial Highlights

(unaudited, $ millions, except per share amounts)	Three months ended September 30		Nine months ended September 30	
	2014	2013	2014	2013
Revenues	248	380	796	1,066
Adjusted EBITDA [1]	91	151	282	390
Net (loss) income	(57)	59	2	130
Net (loss) income attributable to shareholders of the Company	(45)	44	7	98
Normalized earnings attributable to common shareholders [1]	10	51	42	95
Basic (loss) earnings per share ($)	(0.62)	0.55	(0.12)	1.19
Diluted (loss) earnings per share ($) [2]	(0.62)	0.51	(0.12)	1.14
Normalized earnings per share ($) [1]	0.12	0.72	0.51	1.35
Funds from operations [1]	83	125	260	316
Purchase of property, plant and equipment and other assets	25	422	163	884
Dividends per common share, declared ($)	0.3400	0.3150	0.9700	0.9450
Dividends per Series 1 preferred share, declared ($)	0.2875	0.2875	0.8625	0.8625
Dividends per Series 3 preferred share, declared ($)	0.2875	0.2875	0.8625	0.8901
Dividends per Series 5 preferred share, declared ($)	0.2813	0.2813	0.8439	0.6142

	As at	
	September 30, 2014	December 31, 2013
Loans and borrowings including current portion	1,534	1,527
Total assets	5,193	5,219

1 The consolidated financial highlights, except for adjusted EBITDA, normalized earnings attributable to common shareholders, normalized earnings per share and funds from operations were prepared in accordance with GAAP. See Non-GAAP Financial Measures.

2 Diluted earnings per share was calculated after giving effect to outstanding share purchase options and the potential exchange of common limited partnership units of CPLP held by EPCOR, which are exchangeable for common shares of Capital Power on a one-for-one basis.

Normalized earnings attributable to common shareholders and normalized earnings per share

Normalized earnings attributable to common shareholders were lower in 2014 compared with 2013 for the periods ended September 30. This decrease coupled with the increased number of common shares outstanding resulted in a decrease in normalized earnings per share from 2013 to 2014. See Consolidated Net Income and Results of Operations for discussion of the results for the quarter and year-to-date on a comparative basis.

Funds from operations

Funds from operations for the nine months ended September 30, 2014 decreased in comparison to funds from operations for the nine months ended September 30, 2013 consistent with the lower adjusted EBITDA in year-to-date 2014 compared with the same period in 2013.

Significant Events

Write-down of deferred tax assets

Capital Power's third quarter 2014 net income was negatively impacted by a non-cash write-down of deferred tax assets of $73 million. The write-down related to the accounting impact of U.S. income tax loss carryforwards that can no longer be recognized for accounting purposes based on the Company's current long-term forecast for U.S. taxable income. The forecast showed a decline in taxable income over the latter years of the forecast period. For income tax purposes, these U.S net operating losses do not expire until the 2027 to 2033 period. Accordingly, they retain economic value and could result in the Company recording deferred tax assets in the future. The Company continues to pursue U.S. contracted power opportunities and the U.S. business development pipeline is active. Importantly, the write-down is a non-cash item and has no impact on operations or other key performance measures.

Dividend increase

On July 25, 2014, the Company announced that its Board of Directors approved a 7.9% increase in the annual dividend for holders of its common shares, from $1.26 per common share to $1.36 per common share. This increased common dividend will commence with the third quarter 2014 quarterly dividend payment payable on October 31, 2014 to shareholders of record at the close of business on September 30, 2014.

Genesee coal mine

Capital Power is a party to various agreements with Prairie Mines & Minerals Royalty Ltd. (PMRL) in relation to the operations of the Genesee coal mine (Genesee Coal Mine Agreements). Pursuant to the Genesee Coal Mine Agreements, PMRL operates the Genesee coal mine. In connection with the acquisition by Westmoreland Coal Company (Westmoreland) of PMRL and the acquisition by Altius Minerals Corporation (Altius) of the royalty assets of PMRL, the Genesee Coal Mine Agreements and certain related agreements have, among other things, been amended to: (a) confirm the acquisitions by Westmoreland and Altius; (b) provide for certain amendments to the Genesee Coal Mine Agreements; and (c) provide for a payment to Capital Power of $20 million on completion of the acquisitions; the payment was received in the second quarter of 2014.

Genesee 4 and 5

On April 24, 2014, Capital Power and ENMAX executed a purchase and sale agreement in support of a joint arrangement agreement to jointly develop, construct and operate Genesee 4 and 5. The joint arrangement agreement provides for, among other things, an agreement for ENMAX to purchase approximately 225 MW from Capital Power for eight years. The joint arrangement agreement closing occurred in July 2014.

Construction of K2 Wind Power Project commences

On March 24, 2014, construction of the K2 Wind Power Project (K2 Wind) commenced following the successful completion of an $850 million financing in the form of a construction loan that will convert to long-term project debt once K2 Wind starts commercial operations. K2 Wind is a 270 MW wind power project located in Goderich, Ontario that is under joint development by Samsung Renewable Energy, Inc., Pattern Energy Group LP and Capital Power with operations expected to commence in the second half of 2015. The total estimated project cost has been revised upward to $930 million from the previous upper end of range of $900 million primarily due to foreign exchange changes on U.S. contract deliverables. Capital Power's share is $310 million. As a higher portion of the project is expected to be financed with project debt than originally forecast, Capital Power expects higher equity returns on the project.

Consolidated Net Income and Results of Operations

The primary factors contributing to the change in net income for the three and nine months ended September 30, 2014 compared with the three and nine months ended September 30, 2013 are presented below followed by detailed analysis of these items.

(unaudited, $ millions)	Three months	Nine months
Consolidated net income for the periods ended September 30, 2013	**59**	**130**
Decrease in adjusted EBITDA for Alberta commercial plants and portfolio optimization	(55)	(144)
Decrease in adjusted EBITDA for North East U.S. commercial plants and portfolio optimization	(11)	(22)
(Decrease) increase in adjusted EBITDA for Alberta contracted plants	(11)	14
Decrease in depreciation and amortization expense	7	30
Increase in adjusted EBITDA for Ontario and British Columbia contracted plants	6	22
Increase in adjusted EBITDA for Corporate	6	30
Decrease in impairment expense	6	6
Change in unrealized net gains or losses related to the fair value of commodity derivatives and emission credits	4	(10)
Increase in foreign exchange loss	(4)	(5)
Decrease in finance expense including change in unrealized net gains or losses related to the fair value of interest rate derivatives	3	21
Other	1	2
Decrease in income before tax	(48)	(56)
Increase in income tax expense	(68)	(72)
Decrease in net income	**(116)**	**(128)**
Consolidated net income for the periods ended September 30, 2014	**(57)**	**2**

Results by Plant Category and Other

	Three months ended September 30							
	2014	2013	2014	2013	2014	2013	2014	2013
	Electricity generation (GWh) [1]		**Plant availability** (%) [2]		**Revenues** (unaudited, $ millions)		**Adjusted EBITDA** (unaudited, $ millions) [3]	
Total electricity generation, average plant availability and plant revenues excluding acquired Sundance PPA	3,220	4,317	97	97	215	296		
Alberta commercial plants and acquired Sundance PPA								
Genesee 3	473	480	97	99	30	38		
Keephills 3	461	483	100	100	27	40		
Clover Bar Energy Centre 1, 2 and 3	77	45	97	93	19	16		
Joffre	77	109	95	100	13	19		
Halkirk	86	76	91	89	7	8		
Clover Bar Landfill Gas	3	4	58	66	-	1		
Alberta commercial plants – owned	1,177	1,197	96	96	96	122		
Acquired Sundance PPA	673	659	85	83	32	59		
Portfolio optimization [4]					(9)	21		
	1,850	1,856	91	90	119	202	49	104
Alberta contracted plants								
Genesee 1	854	819	100	98				
Genesee 2	841	840	99	100				
	1,695	1,659	99	99	76	80	44	55
Ontario and British Columbia contracted plants								
Island Generation	6	14	99	100	9	9		
Kingsbridge 1	14	12	93	95	-	-		
Port Dover and Nanticoke [5]	51	n/a	98	n/a	6	n/a		
Quality Wind	71	68	93	100	6	7		
	142	94	97	99	21	16	15	9
North East U.S. commercial plants [6]								
Bridgeport	n/a	690	n/a	93	n/a	30		
Rumford	n/a	57	n/a	100	n/a	7		
Tiverton	n/a	434	n/a	96	n/a	21		
Portfolio optimization					n/a	5		
	n/a	1,181	n/a	95	n/a	63	n/a	11
North Carolina U.S. contracted plants								
Roxboro	73	69	100	97	7	7		
Southport	133	117	85	99	15	13		
	206	186	90	98	22	20	3	2
Corporate [7]					2	(4)	(25)	(31)
Unrealized changes in fair value of commodity derivatives and emission credits					8	3	5	1
Consolidated revenues and adjusted EBITDA					**248**	**380**	**91**	**151**

	Nine months ended September 30							
	2014	2013	2014	2013	2014	2013	2014	2013
	Electricity generation (GWh) [1]		Plant availability (%) [2]		Revenues (unaudited, $ millions)		Adjusted EBITDA (unaudited, $ millions) [3]	
Total electricity generation, average plant availability and plant revenues excluding acquired Sundance PPA	9,174	12,205	95	93	586	893		
Alberta commercial plants and acquired Sundance PPA								
Genesee 3	1,378	1,454	96	99	75	127		
Keephills 3	1,241	1,236	100	88	68	112		
Clover Bar Energy Centre 1, 2 and 3	251	287	97	97	42	77		
Joffre	266	319	97	99	34	57		
Halkirk	316	329	96	95	25	35		
Clover Bar Landfill Gas	11	11	75	84	1	2		
Alberta commercial plants – owned	3,463	3,636	97	96	245	410		
Acquired Sundance PPA	1,944	2,062	80	91	89	176		
Portfolio optimization [4]					103	(17)		
	5,407	5,698	90	94	437	569	151	295
Alberta contracted plants								
Genesee 1	2,304	2,108	93	85				
Genesee 2	2,219	2,332	88	93				
	4,523	4,440	91	89	197	176	120	106
Ontario and British Columbia contracted plants								
Island Generation	121	14	100	100	29	29		
Kingsbridge 1	70	71	95	96	4	4		
Port Dover and Nanticoke [5]	209	n/a	97	n/a	25	n/a		
Quality Wind	249	264	96	99	25	26		
	649	349	98	99	83	59	63	41
North East U.S. commercial plants [6]								
Bridgeport	n/a	2,281	n/a	91	n/a	131		
Rumford	n/a	114	n/a	91	n/a	16		
Tiverton	n/a	898	n/a	80	n/a	49		
Portfolio optimization					n/a	8		
	n/a	3,293	n/a	88	n/a	204	n/a	22
North Carolina U.S. contracted plants								
Roxboro	170	179	96	93	17	17		
Southport	369	308	92	98	44	35		
	539	487	93	96	61	52	6	4
Corporate [7]					22	(4)	(57)	(87)
Unrealized changes in fair value of commodity derivatives and emission credits					(4)	10	(1)	9
Consolidated revenues and adjusted EBITDA					**796**	**1,066**	**282**	**390**

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

2 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.

3 The financial results by plant category, except for adjusted EBITDA, were prepared in accordance with GAAP. See Non-GAAP Financial Measures.

4 The results of the previously reported other portfolio optimization category were included in the Alberta commercial plants and acquired Sundance PPA category effective January 1, 2014. The results for the comparative period have also been reclassified.

[5] Port Dover and Nanticoke includes pre-commissioning output until its commissioning date of November 7, 2013. Revenues and expenses related to commissioning activities were capitalized as part of the cost of the facility in property, plant and equipment.

[6] The North East U.S. commercial plants were disposed of effective November 19, 2013.

[7] Corporate revenues were offset by interplant category eliminations.

Energy prices and hedged positions

		Three months ended September 30		Nine months ended September 30		Year ended December
Alberta	**Unit**	**2014**	**2013**	**2014**	**2013**	**31, 2013**
Hedged position [1]	Percentage sold forward at beginning of period (%)	100	63	100	49	45
Spot power price average	$ per MWh	64	84	56	90	80
Realized power price [2]	$ per MWh	56	94	57	85	78
Natural gas price (AECO) [3]	$ per gigajoule (Gj)	3.81	2.32	4.86	2.87	3.01

[1] Hedged position is for the Alberta baseload plants and acquired Sundance PPA plus a portion of Joffre and the uncontracted portion of Shepard Energy Centre baseload.

[2] Realized power price is the average price realized on the Company's commercial contracted sales and portfolio optimization activities.

[3] AECO means a historical virtual trading hub located in Alberta and known as the Nova Inventory Transfer system operated by TransCanada Pipelines Limited.

Alberta commercial plants, acquired Sundance PPA and portfolio optimization

For the three months ended September 30, 2014, production and availability for the Alberta commercial plants were approximately the same levels as the same period in 2013 but below expected levels primarily due to derates at the Keephills 3 plant and wind generation at Halkirk. Production from the Joffre plant decreased because a planned outage commenced at the end of the third quarter of 2014 but this was offset by increased production at Clover Bar Energy Centre as this plant was dispatched more often. For the nine months ended September 30, 2014, production and availability decreased compared with the corresponding period of 2013 primarily due to unplanned outages at the acquired Sundance PPA units and Genesee 3 in the first two quarters of 2014.

The average Alberta spot prices of $64 per MWh and $56 per MWh for the three and nine months ended September 30, 2014, respectively, were significantly lower than the corresponding periods of 2013, which had average spot prices of $84 per MWh and $90 per MWh, respectively. Power prices in the third quarter of 2014 were volatile, averaging $122 per MWh in July, $45 per MWh in August and $24 per MWh in September. The lower year-to-date 2014 average price reflected greater supply driven by fewer unplanned outages, the return to market of two large coal units in the last quarter of 2013, stronger wind production, and greater imports. In the corresponding periods of 2013, significantly higher prices were driven by high market volatility reflecting tighter supply due to several planned and unplanned outages in the Alberta market, lower imports, and lower than historical wind generation.

During the three months ended September 30, 2014, adjusted EBITDA for the Alberta commercial plants was significantly below the same quarter last year primarily due to an extended planned outage and unplanned outages at the acquired Sundance PPA units and derates at the Keephills 3 plant. The outages occurred primarily in July 2014 coinciding with pricing volatility as described above. As a result, with commercial production 100% sold forward in July 2014, the Company was required to cover a short market position, which negatively impacted its portfolio optimization position in the quarter. Lower spot prices for the balance of the quarter also contributed to the lower financial results of the Alberta commercial plants compared with the same period in 2013. While overall availability of 96% for the Alberta commercial plants (excluding the acquired Sundance PPA) was strong, that did not translate to high generation output primarily owing to the derates. When unplanned or extended planned outages occur, the Company can have short positions at times of high prices. Accordingly, actual results may be different than the results that would be expected based solely on generation output.

The lower results were partly offset by decreased coal costs for Genesee 3 following a reallocation of coal costs between Genesee 1 and 2 and Genesee 3. This reallocation resulted from the third quarter 2014 internal review of the components of coal costs by plant with the resulting adjustment reflecting revised coal costs by plant. Portfolio optimization results for the three months ended September 30, 2014 were significantly lower than the same period in 2013 primarily due to forward sales that settled out of the money due to the factors discussed above. The Company also wrote down its investment in an emissions credit project by $3 million before income taxes based on the counterparty's filing for creditor protection and the low likelihood of recovery.

For the nine months ended September 30, 2014, the Alberta commercial plants had lower financial results compared with the same period in 2013 as a result of the weaker average spot prices and lower production. This was partly offset by forward sales that settled in the money. Portfolio optimization results for the nine months ended September 30, 2014 also reflected the write-down of the investment in an emissions credit project and net losses on North East U.S. natural gas and electricity trades that were wound down due to the 2013 strategic refocus partly offset by gains on Alberta natural gas trades.

Early in 2014, the Company elected to meet its 2013 Specified Gas Emitters Regulation (SGER) compliance requirements by paying the statutory rate of $15 per metric tonne of carbon dioxide (CO_2) emissions above specified limits compared with using its lower cost inventory of CO_2 credits. The decision resulted in an additional cash payment of $4 million for the nine months ended September 30, 2014.

Alberta contracted plants

Production and availability results for the three months ended September 30, 2014 were consistent with the same period in 2013. For the nine months ended September 30, 2014, increased generation and availability reflected fewer unplanned outages compared with the corresponding period in 2013. For the three months ended September 30, 2014, revenues decreased compared with the same period in 2013 primarily due to lower rolling average power prices partly offset by higher capacity payment revenues. Adjusted EBITDA was additionally impacted by increased coal costs following the reallocation of coal costs between Genesee 1 and 2 and Genesee 3 as described above. For the nine months ended September 30, 2014, revenues and adjusted EBITDA were higher compared with the same period in 2013 as a result of the lower availability penalties based on significantly lower rolling average prices in 2014. These improved results were partly offset by costs of approximately $3 million incurred for flood damage repairs to the Genesee river water pumphouse and related infrastructure.

Ontario and British Columbia contracted plants

Increased generation, revenues and adjusted EBITDA for the three months and six months ended September 30, 2014 compared with the same periods in 2013 reflected the addition of the Port Dover and Nanticoke wind project, which commenced commercial operations in the fourth quarter of 2013.

Island Generation’s year-to-date increased generation had little impact on revenues and adjusted EBITDA because, under the terms of the Island Generation agreement, revenues are based on deemed generation, which is determined based on the plant’s availability. Deemed generation for the three and nine months ended September 30, 2014 was consistent with the corresponding periods in 2013.

North East U.S. commercial plants and portfolio optimization

The North East U.S. commercial plants were sold effective November 19, 2013. For the three and nine months ended September 30, 2013, the three North East U.S. plants and related portfolio optimization contributed $11 million and $22 million, respectively, to the Company’s adjusted EBITDA.

North Carolina U.S. contracted plants

For the three months ended September 30, 2014, the performance results for the North Carolina U.S. contracted plants were relatively consistent with the results for the comparable period of 2013. For the nine months ended September 30, 2014, production was higher compared with the same period in 2013 as a result of Southport’s increased off-peak production. Revenues and adjusted EBITDA were higher compared with the same periods in 2013 due primarily to Southport’s increased off-peak production and sale of off-peak renewable emission certificates.

Corporate

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

The Corporate category’s increased adjusted EBITDA for the three and nine months ended September 30, 2014 compared with the same periods in 2013 was primarily due to lower net expenditures as staffing levels were reduced following the restructuring undertaken in the latter part of 2013. In addition, revenues and adjusted EBITDA for the nine months ended September 20, 2014 included the $20 million of revenues arising from the amendment of the Genesee Coal Mine Agreements (see Significant Events).

Unrealized changes in fair value of commodity derivatives and emission credits

(unaudited, $ millions)	Three months ended September 30			
Unrealized changes in fair value of commodity derivatives and emission credits	**2014**	**2013**	**2014**	**2013**
	Revenues		**Adjusted EBITDA**	
Unrealized gains (losses) on Alberta energy derivatives	9	(1)	4	(2)
Unrealized gains on Bridgeport heat rate option	-	1	-	1
Unrealized gains on natural gas derivatives	-	3	-	3
Unrealized gains on emission credits held for trading	-	-	1	-
Unrealized gains on emission portfolio activities	-	-	-	-
Other	(1)	-	-	(1)
	8	3	5	1

(unaudited, $ millions)	Nine months ended September 30			
Unrealized changes in fair value of commodity derivatives and emission credits	**2014**	**2013**	**2014**	**2013**
	Revenues		**Adjusted EBITDA**	
Unrealized (losses) on Alberta energy derivatives	(14)	(11)	(11)	(11)
Unrealized gains on Bridgeport heat rate option	-	13	-	14
Unrealized (losses) gains on natural gas derivatives	(1)	9	(1)	10
Unrealized gains on emission credits held for trading	-	-	1	-
Unrealized gains on emission portfolio activities	9	-	9	-
Other	2	(1)	1	(4)
	(4)	10	(1)	9

1 The financial results, except for adjusted EBITDA, were prepared in accordance with GAAP. See Non-GAAP Financial Measures.

The Company's financial results relating to its Alberta commercial plants and portfolio optimization, and North East U.S. commercial plants and portfolio optimization (until the disposal of these plants in the fourth quarter of 2013) include unrealized changes in the fair value of commodity and other derivatives.

When a derivative instrument settles, the unrealized fair value changes recorded in prior periods for that instrument are reversed and included in this category. The gain or loss realized on settlement is reflected in adjusted EBITDA for the applicable plant or Corporate category.

Alberta desk electricity portfolio activities for the three and nine months ended September 30, 2014 accounted for unrealized net gains of $4 million and unrealized net losses of $11 million, respectively. The gains primarily reflected the reversal of prior periods' unrealized net losses on contracts that settled during the applicable period. The 2014 year-to-date net unrealized losses included the impact of increasing Alberta forward power prices combined with the portfolio's net forward sales contracts. Unrealized net losses of $2 million and $11 million were recognized for the three and nine months ended September 30, 2013, respectively. The unrealized net losses reflected the reversal of prior periods' unrealized net gains on contracts that settled during the applicable period. Additionally, the 2013 third quarter and year-to-date net unrealized losses included the impact of increased forward Alberta power prices combined with the portfolio's net forward sales contracts.

On acquisition of the New England plants in the second quarter of 2011, the Company acquired heat rate options related to the Bridgeport facility. For the three and nine months ended September 30, 2013, the Company recognized unrealized net gains of $1 million and $14 million, respectively, on the Bridgeport heat rate options. The unrealized net gains reflected the reversal of prior periods' unrealized net losses.

Natural gas portfolio activities for the nine months ended September 30, 2014 accounted for unrealized net losses of $1 million. These net losses reflected the reversal of prior periods' unrealized net gains on contracts that settled during the period. Unrealized net gains of $3 million and $10 million were recognized for the three and nine months ended September 30, 2013, respectively. The unrealized net gains largely reflected the reversal of prior periods' unrealized net losses on settlement.

During the three months and nine months ended September 30, 2014, the Company recognized unrealized net gains of $1 million on its emission credits inventory held for trading. The unrealized net gains reflected the impact of valuing inventory at market prices higher than the initial cost.

Emission credits derivatives accounted for unrealized net gains of $9 million for the nine months ended September 30, 2014. The unrealized net gains were primarily driven by trades valued at decreased forward prices.

Consolidated Other Expenses and Non-controlling Interests

(unaudited, $ millions)	Three months ended September 30		Nine months ended September 30	
	2014	2013	2014	2013
Interest on borrowings less capitalized interest	(11)	(17)	(34)	(53)
Realized (loss) gain on settlement of interest rate derivatives	(1)	-	1	-
Other finance expense – sundry interest and guarantee and other fees	(2)	(1)	(4)	(4)
	(14)	(18)	(37)	(57)
Unrealized (losses) gains representing changes in the fair value of interest rate derivatives	1	1	2	1
Other finance expense – amortization and accretion charges	(2)	(1)	(4)	(4)
Total finance expense	(15)	(18)	(39)	(60)
Depreciation and amortization	(47)	(54)	(140)	(170)
Impairments	-	(6)	-	(6)
Foreign exchange loss	(5)	(1)	(6)	(1)
Income tax expense	(81)	(13)	(95)	(23)
Net loss (income) attributable to non-controlling interests	12	(15)	5	(32)

Finance expense

Lower finance expense for the three months and nine months ended September 30, 2014 compared with the three months and nine months ended September 30, 2013 was primarily due to decreased borrowings related to capital projects and increased capitalized interest.

Depreciation and amortization

Depreciation and amortization for the three months and nine months ended September 30, 2014 decreased $7 million and $30 million, respectively, compared with the same periods in the prior year primarily due to the disposal of the North East U.S. assets in the fourth quarter of 2013.

Foreign exchange loss

As at September 30, 2014, the Company had outstanding U.S. dollar denominated debt payable totalling US$295 million. Approximately US$200 million is hedged for accounting purposes using foreign currency swaps. Foreign exchange loss for the three months ended September 30, 2014 consisted of the loss incurred on the revaluation of U.S. dollar denominated debt not hedged for accounting purposes based on the decrease in the exchange rate of the Canadian dollar relative to the U.S. dollar during that period. For the nine month period ended September 30, 2014, the exchange rate of the Canadian dollar relative to the U.S. dollar decreased resulting in an unrealized loss of $6 million.

Income tax expense

In the third quarter of 2014, Capital Power recorded a write-down of its deferred tax assets in the amount of $73 million. This non-cash write-down related to the impact of U.S. income tax loss carryforwards that can no longer be recognized for accounting purposes based on the Company's latest long-term forecast for U.S. taxable income. These loss carryforwards expire between 2027 and 2033 and, thus, retain economic value that could result in the future recording of deferred tax assets depending on future U.S. taxable income projections.

Non-controlling interests

For the three and nine months ended September 30, 2014, approximately 19% (three and nine months ended September 30, 2013 – 29%) of CPLP's net income was attributable to EPCOR, which is reported as net income attributable to non-controlling interests. EPCOR's October 10, 2013 exchange of exchangeable common limited partnership units for common shares of Capital Power reduced its interest in CPLP from 29% to 19%, which reduces the proportion of net income attributable to non-controlling interests in periods subsequent to the exchange. Net income attributable to non-controlling interests also included the Genesee coal mine partner's share of the consolidated depreciation of the coal mine assets.

Comprehensive Income

(unaudited, $ millions)	Three months ended September 30		Nine months ended September 30	
	2014	**2013**	**2014**	**2013**
Net (loss) income	(57)	59	2	130
Other comprehensive income (loss):				
Net unrealized losses on commodity derivatives designated as cash flow hedges	(1)	-	(17)	(65)
Net realized losses and ineffective portion of unrealized losses on commodity derivatives designated as cash flow hedges reclassified to revenues and/or energy purchases and fuel	5	2	-	41
Unrealized foreign exchange (losses) gains on the translation of foreign operations	9	(9)	10	14
	13	(7)	(7)	(10)
Comprehensive (loss) income	**(44)**	**52**	**(5)**	**120**

Other comprehensive (loss) income includes fair value adjustments on financial instruments held by the Company to hedge market risks and which meet the requirements of hedges for accounting purposes. To the extent that such hedges are ineffective, any related gains or losses are recognized in net income. Other unrealized fair value changes on derivatives designated as cash flow hedges and foreign currency translation gains or losses are subsequently recognized in net income when the hedged transactions are completed and the foreign operations are disposed of or otherwise terminated.

Financial Position

(unaudited, $ millions)	**September 30, 2014**	**December 31, 2013**	**Increase (decrease)**	**Primary reason for increase (decrease)**
Trade and other receivables	167	218	(51)	Lower trade receivables related to Alberta operations resulting from lower power prices and receipt of Sundance amount receivable.
Inventories	104	92	12	Increase in coal fuel inventory and emission credits held for trading.
Net derivative financial instruments assets	27	26	1	Impact of increased Alberta forward power prices on the fair value of derivative sell contracts.
Other financial assets	19	36	(17)	Collection of long-term accounts receivable and reclassification of loan to trade and other receivables.
Deferred tax assets	30	95	(65)	Write-down of deferred tax assets (see Significant Events).
Equity-accounted investment	30	15	15	Payment of K2 Wind cash call.
Intangible assets	315	310	5	Purchase of emission credits held for compliance.
Property, plant and equipment	3,562	3,525	37	Capital additions (most significantly, Shepard Energy Centre) partly offset by depreciation and amortization.
Trade and other payables	180	198	(18)	Decrease in capital trade payables related to Port Dover and Nanticoke and decrease in income tax payable.
Provisions (including current portion)	193	175	18	Increased decommissioning provisions resulting from discount rate changes offset by settlement of 2013 incentive accruals.
Share capital	2,380	2,328	52	Shares issued under the Dividend Re-investment Plan and share purchase option plan.
Retained (deficit) earnings and other reserves	(7)	89	(96)	Common and preferred share dividends in excess of net income.

Liquidity and Capital Resources

(unaudited, $ millions)	Nine months ended September 30		Increase
Cash inflows (outflows)	**2014**	**2013**	**(decrease)**
Operating activities	284	342	(58)
Investing activities	(154)	(848)	694
Financing activities	(112)	483	(595)

Operating activities

Cash flows from operating activities for year-to-date 2014 decreased compared with year-to-date 2013 primarily due to decreased plant results and operating working capital changes related to trade and other receivables and trade and other payables balances.

Investing activities

The cash flows used in investing activities for the nine months ended September 30, 2014 included $163 million for purchases of property, plant and equipment and other assets.

Capital expenditures and investments

(unaudited, $ millions)	Pre-2014 Actual	Nine months ended September 30, 2014	Balance of 2014 Estimated [1, 2]	Actual or Projected Total [2, 3]	Timing
Port Dover and Nanticoke	276	10	14	300	Completed 4th quarter 2013
K2 Wind [4]	16	28	2	310	Projected completion 2015
Shepard Energy Centre	684	96	34	821	Projected commercial operation 2015
Subtotal growth projects		**134**			
Sustaining – plant maintenance excluding Genesee mine		30			
Sustaining – Genesee mine maintenance and lands [5]		6			
Sustaining – other		6			
Total capital expenditures [6]		**176**			
Emission credits held for compliance		16			
Capitalized interest		(29)			
Purchase of property, plant and equipment and other assets		**163**			

1 The Company's 2014 estimated capital expenditures include only expenditures for previously identified growth projects and exclude the cost of Genesee 4 and 5 and other potential new development projects.

2 Costs for projects completed in 2013 include certain costs that were or are expected to be incurred subsequent to the date of commercial operations such as site remediation, vendor optimization, project clean-up and project close-out costs.

3 Projected capital expenditures to be incurred over the life of the project are based on management's estimates.

4 Capital Power entered into a partnership agreement to develop K2 Wind, which is expected to be in operation by 2015. The actual and 2014 estimated expenditures for K2 Wind primarily consist of the Company's estimated equity contribution to the K2 Wind partnership. The projected total of $310 million is Capital Power's share of the K2 Wind partnership's expected capital expenditures.

5 Capital expenditures for Genesee mine maintenance represent only those capital expenditures funded by the Company for the Genesee mine operation.

6 Capital expenditures include capitalized interest. Capital expenditures excluding capitalized interest are presented on the Statement of Cash Flows as purchase of property, plant and equipment and other assets.

Financing activities

The cash flows from financing activities during the nine months ended September 30, 2014 primarily reflected the sum of distributions to non-controlling interests, common share dividends, and preferred share dividends paid of $83 million and interest paid and capitalized of $29 million.

The Company's credit facilities consisted of:

(unaudited, $ millions)		As at September 30, 2014			As at December 31, 2013		
	Maturity timing	**Total facilities**	**Credit facility utilization**	**Available**	**Total facilities**	**Credit facility utilization**	**Available**
CPLP committed credit facility	2018	1,200			1,200		
Letters of credit outstanding			131			160	
U.S. dollar bank loans outstanding			-			-	
		1,200	131	1,069	1,200	160	1,040
CPLP demand facility	n/a	20	-	20	20	-	20
Capital Power Corporation demand facility	n/a	5	-	5	5	-	5
		1,225	**131**	**1,094**	**1,225**	**160**	**1,065**

As at September 30, 2014, the committed credit facility utilization decreased $29 million compared with the utilization as at December 31, 2013 primarily due to decreased letters of credit outstanding. The committed credit facility includes an accordion feature that permits an increase to the facility size by $300 million in the future, subject to certain conditions including lender approval. The maturity date of CPLP's credit agreements is July 9, 2018.

The available credit facilities provide the Company with adequate funding for ongoing development projects.

CPLP has a corporate credit rating of BBB- with a stable outlook from Standard & Poor's (S&P). The BBB- rating assigned by S&P is an investment grade credit rating. 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.

CPLP has a long-term debt credit rating of BBB from DBRS Limited (DBRS). 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. The capacity of the payment of financial obligations is considered acceptable but the entity is vulnerable to future events.

The above credit ratings from S&P and DBRS are investment grade credit ratings, which enhance CPLP's ability to re-finance existing debt as it matures and to access cost competitive capital for future growth.

Future cash requirements

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 2014 are expected to include approximately $226 million for capital expenditures excluding capitalized interest and emission credits held for compliance, approximately $24 million for CPLP distributions to EPCOR (subject to approval by the Board of Directors of CPLP's general partner), approximately $104 million for Capital Power's common share dividends (subject to approval by Capital Power Corporation's Board of Directors), and approximately $22 million for preferred share dividends (subject to approval by Capital Power Corporation's Board of Directors). Capital Power Corporation has a Dividend Re-investment Plan (DRIP) where shareholders may elect to reinvest their quarterly cash dividends for additional shares of Capital Power Corporation as an alternative to receiving cash dividends. The participation rate in the DRIP was approximately 31% for 2013. Depending on the participation rate for 2014, cash requirements for common share dividends may differ from the above expectations.

The current portion of loans and borrowings on the September 30, 2014 statement of financial position of $339 million primarily consists of $333 million senior debt payable to EPCOR that was classified as current since the debt is callable and, therefore, potentially repayable in 2015 (see Transactions with Related Parties).

The Company expects to fund the construction of the Shepard Energy Centre and K2 Wind projects using existing bank credit facilities, cash flows from operating activities, and a portion of the proceeds from the sale of the North East U.S. assets. K2 Wind will be financed by non-recourse project debt issued by the K2 Wind limited partnership. The Company's other cash requirements identified above are expected to be funded with cash on hand, cash flows from operating activities, and use of existing bank credit facilities.

The Company's uses short form base shelf prospectuses to provide, market conditions permitting, the Company with the ability to obtain new debt and equity capital from external markets when required. When the short form base shelf prospectuses were both active, Capital Power could raise up to $2 billion by issuing common shares, preferred 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. The equity prospectus expired March 2014 and the debt prospectus expired July 2014. Both prospectuses are expected to be renewed in the fourth quarter of 2014.

Financial market stability remains an issue. If instability reoccurs in the Canadian and U.S. financial markets, CPLP's ability to raise new capital, to meet its financial requirements, and to refinance indebtedness under existing credit facilities and debt agreements may be adversely affected. CPLP has credit exposure relating to various agreements, particularly with respect to its PPA, trading and supplier counterparties. While CPLP continues to monitor its exposure to its significant counterparties, there can be no assurance that all counterparties will be able to meet their commitments.

Off-statement of financial position arrangements

The Company has off-statement of financial position arrangements including operating leases and, as at September 30, 2014, $131 million of outstanding letters of credit for collateral support for trading operations, conditions of certain service agreements and to satisfy legislated reclamation requirements. If the Company were to terminate these off-statement of financial position arrangements, the penalties or obligations would not have a material impact on the Company's financial condition, results of operations, liquidity, capital expenditures or resources.

Capital resources

(unaudited, $ millions)	As at	
	September 30, 2014	**December 31, 2013**
Loans and borrowings	1,534	1,527
Less cash and cash equivalents	119	100
Net debt	1,415	1,427
Share capital	2,380	2,328
Retained (deficit) earnings and other reserves	(7)	89
Non-controlling interests	564	587
Total equity	2,937	3,004
Total capital	**4,352**	**4,431**

Contractual Obligations and Contingent Liabilities

There were no changes to the Company's purchase obligations and commitments since December 31, 2013 that would be material to the Company's business or financial position. For further information on contractual obligations, refer to the Company's December 31, 2013 MD&A.

Contingent liabilities

Capital Power is participating in a proceeding underway before the Alberta Utilities Commission (AUC) regarding factors that form the basis for certain transmission charges paid by Alberta generators including Capital Power. On April 16, 2012, the AUC issued its decision that the factors used from 2006 forward were non-compliant with the applicable legislation and regulations. Capital Power and other Alberta generators subsequently submitted applications to review and vary that decision. On April 23, 2013, the AUC issued its subsequent decision that there is substantial doubt regarding the correctness of the previous decision. The AUC conducted a review proceeding to determine whether the initial decision should be varied. On April 16, 2014, the AUC issued its decision, which upheld its 2012 finding.

After further considering the April 2014 AUC decision, the Company withdrew its separate application for Leave to Appeal before the Alberta Court of Appeal.

In July 2014, the AUC announced that it will conduct a further hearing on this transmission matter in three modules with the first module commencing in April 2015. The hearing modules could extend to the end of 2015 or beyond and are anticipated to address what alternative factors should be applied and the potential application of alternative factors on a prospective or retrospective basis. Capital Power may incur additional payments for transmission charges on a retrospective and go-forward basis but a provision has not been recorded in the Company's financial statements since the outcome of the proceeding is not known. The Company believes that any revised factors that arise from these hearing modules will be applied prospectively.

The Company and its subsidiaries are subject to various legal claims that arise in the normal course of business. Management believes that the aggregate contingent liability of the Company arising from these claims is immaterial and therefore no provision has been made.

Transactions with Related Parties

(unaudited, $ millions)		Three months ended September 30		Nine months ended September 30	
	Note	2014	2013	2014	2013
EPCOR (shareholder)					
CPLP distributions paid	(a)	6	9	18	27
Purchase of distribution and transmission services	(b)	-	4	2	13
Purchase of other services	(b)	2	1	6	5
Power sales	(b)	3	2	7	4
Interest incurred on unsecured senior debt payable and expensed	(c)	3	3	10	14
Interest incurred on unsecured senior debt payable and capitalized	(c)	2	3	6	3
Repayment of unsecured senior debt payable	(c)	-	15	8	15
The City of Edmonton (sole shareholder of EPCOR)					
Power sales	(b)	-	9	2	28

		As at	
	Note	September 30, 2014	December 31, 2013
EPCOR (shareholder)			
Trade and other receivables	(b)	2	1
Trade and other payables	(b)	10	14
Provision for future maintenance costs associated with EPCOR's Rossdale plant	(d)	3	3
Loans and borrowings	(c)	333	341
The City of Edmonton (sole shareholder of EPCOR)			
Trade and other receivables	(b)	-	5

(a) As at September 30, 2014 and December 31, 2013, EPCOR owned 18.841 million exchangeable common limited partnership units of CPLP (representing approximately 19% of CPLP), and 18.841 million accompanying special voting shares and one special limited voting share of Capital Power Corporation. In connection with EPCOR's unitholdings, CPLP paid distributions to EPCOR for the nine months ended September 30, 2014 and 2013.

(b) The power sales and purchase of other services transactions with EPCOR and the City of Edmonton were in the normal course of operations and were recorded at exchange amounts based on normal commercial rates. The Company has a lease agreement with EPCOR for office space that requires payment to EPCOR of $5 million per year through 2031.

(c) The Company's unsecured senior debt payable to EPCOR, at interest rates ranging from 5.80% to 9.00% per annum, matures between 2014 and 2018. As at September 30, 2014, since EPCOR owns less than 20% of the outstanding limited partnership units of CPLP, EPCOR may, by written notice, require repayment of all or any portion of the outstanding principal amount of this debt and accrued interest thereon. If the principal amount specified in such repayment is less than $200 million, then it and the accrued interest thereon shall be payable on or before 180 days after delivery of notice, and if it is $200 million or more, then it and the accrued interest thereon shall be payable on or before 365 days after delivery of notice.

(d) The Rossdale plant, which is owned by EPCOR, was taken out of service in January 2009 and was decommissioned. Certain structures at the plant site were designated as Provincial Historical Resources by the Province of Alberta and are thereby legally protected from demolition. These structures, and additional structures at the plant site, are also on the City of Edmonton's Register of Historic Resources. CPLP has an obligation to EPCOR to share in some of the costs for ongoing operations and maintenance of the Rossdale plant and related assets until 2019.

Risks and Risk Management

There have been no material changes in the nine months ended September 30, 2014 to the Company's business and operational risks as described in the Company's December 31, 2013 MD&A.

Environmental Matters

The Company recorded decommissioning provisions of $145 million as at September 30, 2014 ($120 million as at December 31, 2013) for its generation plants and the Genesee coal mine as it is obliged to remove the facilities at the end of their useful lives and restore the plant and mine sites to their original condition. Decommissioning provisions for the coal mine are incurred over time as new areas are mined, and a portion of the liability is settled over time as areas are reclaimed prior to final pit reclamation.

The Company is obligated to purchase environmental credits totalling $60 million in the current and future years, including purchases in the first nine months of 2014, and expects to use these credits to comply with applicable environmental regulations.

Critical Accounting Estimates and Accounting Judgments

In preparing the consolidated financial statements, management necessarily made estimates in determining transaction amounts and financial statement balances. There have been no significant changes to the Company's critical accounting estimates and accounting judgments as described in the Company's December 31, 2013 MD&A.

Accounting Changes

Effective January 1, 2014

The Company adopted a number of new accounting standards, together with the consequential amendments to other standards, as issued by the International Accounting Standards Board (IASB). The changes that are significant to Capital Power are:

Standard	Description	Impact to Capital Power
Recoverable amount disclosures for non-financial assets – amendments to IAS 36 Impairment of assets	In May 2013, the IASB issued amendments to IAS 36, which require disclosure of the recoverable amount of impaired assets and additional disclosures about the measurement of the impaired assets when the recoverable amount is based on fair value less costs of disposal, including the discount rate when a present value technique is used to measure the recoverable amount.	The amendments are effective for annual periods beginning on or after January 1, 2014. However, the Company early adopted the amendments, on a retrospective basis, with insignificant impact to the Company's financial statement note disclosures.

Future

The IASB issued the following new standards and amendments to existing standards that were not yet effective as of September 30, 2014 and which may significantly impact Capital Power:

Standard	Description	Impact to Capital Power	Effective Date
Acquisition of an interest in a joint operations (amendments to IFRS 11)	The objective of the proposed amendment is to improve comparability of reported financial information by providing guidance on how a joint operator accounts for the acquisition of an interest in a joint operation, in which the activity of the joint operation constitutes a business. It would require a joint operator to account for such an acquisition by applying IRFS 3 Business Combinations and other standards, and disclosing the relevant information specified in those IFRSs for business combinations.	No immediate impact but would affect applicable future transactions	Effective for annual periods beginning on or after January 1, 2016 with early adoption permitted.
IFRS 15 Revenue from contracts with customers	Joint IASB and Financial Accounting Standards Board project to develop a new standard on revenue recognition to ensure consistent treatment for all transactions in all industries and capital markets.	May change the timing of revenue recognized from any contracts with a number of discrete performance obligations (multiple-element arrangements), require separate line disclosure of credit losses, and require more extensive disclosures on annual and interim basis.	Effective for annual periods beginning on or after January 1, 2017 with early adoption permitted.
IFRS 9 (2014) Financial instruments	Completion of final stage to replace standard on financial instruments. Final standard incorporating amendments from all stages includes guidance on the classification and measurement of financial assets, adds requirements for the classification and measurement of financial liabilities, adds guidance on general hedge accounting, and adds requirements for the new expected credit loss model for impairment,	Most significant is the potential application of hedge accounting to more hedging strategies based on new general hedge accounting model. The Company continues to evaluate the impact of these amendments while the IASB continues to work on its macro hedge accounting project.	Effective for annual periods beginning on or after January 1, 2018; available for early adoption.

Financial Instruments

The classification, carrying amounts and fair values of financial instruments held at September 30, 2014 and December 31, 2013 were as follows:

(unaudited, $ millions)			As at			
			September 30, 2014		December 31, 2013	
	Classification	Fair value hierarchy level	Carrying amount	Fair value	Carrying amount	Fair value
Financial assets:						
Cash and cash equivalents	Loans and receivables	n/a	119	119	100	100
Trade and other receivables	Loans and receivables	n/a	167	167	218	218
Derivative financial instruments assets – current and non-current	Financial assets designated at fair value through income or loss	See below	86	86	67	67
Finance lease receivables	Loans and receivables	Level 2	712	703	711	647
Other financial assets	Loans and receivables	Level 2	17	17	34	34
Financial liabilities:						
Trade and other payables	Other financial liabilities	n/a	180	180	198	198
Derivative financial instruments liabilities – current and non-current	Financial liabilities designated at fair value through income or loss	See below	59	59	41	41
Loans and borrowings (including current portion)	Other financial liabilities	Level 2	1,534	1,615	1,527	1,561

Risk management and hedging activities

There have been no material changes in the three months ended September 30, 2014 to the Company's risk management and hedging activities as described in the Company's December 31, 2013 MD&A.

The derivative financial instruments assets and liabilities held at September 30, 2014 compared with December 31, 2013 and used for risk management purposes were measured at fair value and consisted of the following:

(unaudited, $ millions)		As at September 30, 2014				
	Fair value hierarchy level	**Commodity cash flow hedges**	**Commodity non-hedges**	**Foreign exchange hedges**	**Interest rate non-hedges**	**Total**
Derivative financial instruments assets	Level 1	-	-	-	-	-
	Level 2	26	47	11	2	86
	Level 3	-	-	-	-	-
		26	47	11	2	86
Derivative financial instruments liabilities	Level 1	-	-	-	-	-
	Level 2	(18)	(40)	-	(1)	(59)
	Level 3	-	-	-	-	-
		(18)	(40)	-	(1)	(59)
Net derivative financial instruments assets		**8**	**7**	**11**	**1**	**27**

(unaudited, $ millions)		As at December 31, 2013				
	Fair value hierarchy level	**Commodity cash flow hedges**	**Commodity non-hedges**	**Foreign exchange hedges**	**Interest rate non-hedges**	**Total**
Derivative financial instruments assets	Level 1	-	-	-	-	-
	Level 2	29	37	1	-	67
	Level 3	-	-	-	-	-
		29	37	1	-	67
Derivative financial instruments liabilities	Level 1	-	-	-	-	-
	Level 2	(11)	(28)	(1)	(1)	(41)
	Level 3	-	-	-	-	-
		(11)	(28)	(1)	(1)	(41)
Net derivative financial instruments assets (liabilities)		**18**	**9**	**-**	**(1)**	**26**

Commodity and foreign exchange derivatives designated as accounting hedges

Unrealized gains and losses for fair value changes on commodity and foreign exchange derivatives that qualify for hedge accounting are recorded in other comprehensive income and, when realized, are reclassified to net income as revenues, energy purchases and fuel or foreign exchange gains and losses.

Commodity and interest rate derivatives not designated as accounting hedges

The change in fair values of commodity derivatives not designated as hedges is primarily due to changes in forward Alberta power prices and their impact on the Alberta power portfolio. Unrealized and realized gains and losses for fair value changes on commodity derivatives that do not qualify for hedge accounting are recorded in net income as revenues or energy purchases and fuel.

Unrealized and realized losses on interest rate derivatives that are not designated as hedges for accounting purposes are recorded in net income as finance expense.

Fair value measurement

Fair values for Level 1 financial assets and liabilities are based on unadjusted quoted prices in active markets for identical instruments while fair values for Level 2 financial assets and liabilities are generally based on indirectly observable prices. The determination of fair values for Level 3 financial assets and liabilities is performed by the Company's commodity risk group and reviewed by management. These fair values are based partly on the key unobservable inputs of volatilities and correlations of the relative price changes in underlying prices. These volatilities and correlations are estimated using an exponentially-weighted moving average based on historical forward prices. When required, sensitivity analysis for significant Level 3 financial instruments is performed.

Disclosure Controls and Procedures and Internal Control over Financial Reporting

There were no significant changes in the Company's disclosure controls and procedures and internal controls over financial reporting that occurred during the nine months ended September 30, 2014 that have materially affected or are reasonably likely to materially affect the Company's disclosures of required information and internal control over financial reporting.

Summary of Quarterly Results

(GWh)	Three months ended							
Electricity generation	**Sep 30 2014**	**Jun 30 2014**	**Mar 31 2014**	**Dec 31 2013**	**Sep 30 2013**	**Jun 30 2013**	**Mar 31 2013**	**Dec 31 2012**
Total generation excluding acquired Sundance PPA	3,220	2,711	3,241	3,925	4,317	3,746	4,142	4,159
Alberta commercial plants and acquired Sundance PPA								
Genesee 3	473	438	466	463	480	493	481	272
Keephills 3	461	381	399	418	483	296	457	484
Clover Bar Energy Centre 1, 2 and 3	77	66	108	60	45	157	85	174
Joffre	77	71	118	95	109	109	101	65
Halkirk	86	92	138	137	76	118	135	44
Clover Bar Landfill Gas	3	5	3	5	4	4	3	7
Alberta commercial plants – owned	1,177	1,053	1,232	1,178	1,197	1,177	1,262	1,046
Acquired Sundance PPA	673	521	750	710	659	712	691	517
	1,850	1,574	1,982	1,888	1,856	1,889	1,953	1,563
Alberta contracted plants								
Genesee 1	854	771	678	842	819	482	807	830
Genesee 2	841	546	832	802	840	704	788	767
	1,695	1,317	1,510	1,644	1,659	1,186	1,595	1,597
Ontario and British Columbia contracted plants								
Island Generation	6	-	115	210	14	-	-	3
Kingsbridge 1	14	22	34	37	12	22	37	35
Port Dover and Nanticoke	51	66	93	54	n/a	n/a	n/a	n/a
Quality Wind	71	80	97	113	68	88	108	70
Brown Lake	n/a	n/a	n/a	n/a	n/a	n/a	n/a	2
Miller Creek	n/a	n/a	n/a	n/a	n/a	n/a	n/a	1
	142	168	339	414	94	110	145	111
North East U.S. commercial plants								
Bridgeport	n/a	n/a	n/a	326	690	678	913	863
Rumford	n/a	n/a	n/a	10	57	32	25	15
Tiverton	n/a	n/a	n/a	155	434	409	55	389
	n/a	n/a	n/a	491	1,181	1,119	993	1,267
North Carolina U.S. contracted plants								
Roxboro	73	58	39	70	69	57	53	50
Southport	133	115	121	128	117	97	94	88
	206	173	160	198	186	154	147	138

(%)	Three months ended							
Plant availability	**Sep 30 2014**	**Jun 30 2014**	**Mar 31 2014**	**Dec 31 2013**	**Sep 30 2013**	**Jun 30 2013**	**Mar 31 2013**	**Dec 31 2012**
Total average plant availability excluding acquired Sundance PPA	97	92	94	93	97	86	94	89
Alberta commercial plants and acquired Sundance PPA								
Genesee 3	97	96	96	98	100	100	98	56
Keephills 3	100	100	100	99	100	65	98	100
Clover Bar Energy Centre 1, 2 and 3	97	98	97	91	93	99	99	98
Joffre	95	95	100	85	95	94	92	65
Halkirk	91	98	96	99	89	99	98	95
Clover Bar Landfill Gas	58	83	75	98	66	91	97	92
Alberta commercial plants – owned	96	97	98	94	96	91	97	81
Acquired Sundance PPA	85	67	89	89	83	93	97	74
	91	84	94	92	90	92	97	79
Alberta contracted plants								
Genesee 1	100	96	83	100	98	61	96	98
Genesee 2	99	66	93	95	100	86	94	94
	99	81	88	98	99	74	95	96
Ontario and British Columbia contracted plants								
Island Generation	99	100	100	99	100	100	100	100
Kingsbridge 1	93	97	95	94	95	96	99	100
Port Dover and Nanticoke	98	94	98	95	n/a	n/a	n/a	n/a
Quality Wind	93	99	95	98	100	98	99	99
Brown Lake	n/a	n/a	n/a	n/a	n/a	n/a	n/a	100
Miller Creek	n/a	n/a	n/a	n/a	n/a	n/a	n/a	85
	97	98	98	98	99	99	99	100
North East U.S. commercial plants								
Bridgeport	n/a	n/a	n/a	72	93	83	97	85
Rumford	n/a	n/a	n/a	91	100	77	97	84
Tiverton	n/a	n/a	n/a	83	96	93	51	89
	n/a	n/a	n/a	79	95	84	86	86
North Carolina U.S. contracted plants								
Roxboro	100	96	90	98	97	88	94	89
Southport	85	93	99	91	99	94	96	90
	90	94	96	93	98	92	96	90

Financial results

(unaudited, $ millions)	Three months ended							
	Sep 30 2014	Jun 30 2014	Mar 31 2014	Dec 31 2013	Sep 30 2013	Jun 30 2013	Mar 31 2013	Dec 31 2012
Revenues								
Alberta commercial plants, acquired Sundance PPA and portfolio optimization	119	130	188	173	202	198	169	148
Alberta contracted plants	76	58	63	70	80	27	69	75
Ontario and British Columbia contracted plants	21	25	37	33	16	18	25	18
North East U.S. commercial plants and portfolio optimization	-	-	-	23	63	63	78	65
North Carolina U.S. contracted plants	22	22	17	19	20	17	15	16
Corporate [1]	2	18	2	(9)	(4)	2	(2)	-
Unrealized changes in fair value of commodity derivatives and emission credits	8	(13)	1	18	3	(4)	11	(34)
	248	**240**	**308**	**327**	**380**	**321**	**365**	**288**
Adjusted EBITDA								
Alberta commercial plants, acquired Sundance PPA and portfolio optimization	49	43	59	57	104	112	79	63
Alberta contracted plants	44	34	42	53	55	7	44	51
Ontario and British Columbia contracted plants	15	18	30	26	9	12	20	15
North East U.S. commercial plants and portfolio optimization	-	-	-	(1)	11	7	4	(1)
North Carolina U.S. contracted plant	3	3	-	1	2	1	1	2
Corporate	(25)	(7)	(25)	(34)	(31)	(30)	(26)	(30)
Unrealized changes in fair value of commodity derivatives and emission credits	5	(13)	7	17	1	(5)	13	(27)
	91	**78**	**113**	**119**	**151**	**104**	**135**	**73**

[1] Revenues are offset by interplant category revenue eliminations.

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, and planned and unplanned plant outages and items outside the normal course of operations. Net income is also affected by changes in the fair value of the Company’s power, natural gas, foreign exchange and interest rate derivative contracts, and natural gas held for trading.

Financial highlights

(unaudited, $ millions except per share amounts)	Three months ended							
	Sep 30 2014	**Jun 30 2014**	**Mar 31 2014**	**Dec 31 2013**	**Sep 30 2013**	**Jun 30 2013**	**Mar 31 2013**	**Dec 31 2012**
Revenues	248	240	308	327	380	321	365	288
Adjusted EBITDA [1]	91	78	113	119	151	104	135	73
Net (loss) income	(57)	21	38	98	59	23	48	19
Net income (loss) attributable to shareholders of the Company	(45)	20	32	77	44	20	34	15
Basic (loss) earnings per share ($)	(0.62)	0.17	0.33	0.89	0.55	0.20	0.44	0.19
Normalized earnings per share ($) [1]	0.12	0.07	0.31	0.35	0.72	0.27	0.36	0.23

[1] The consolidated financial highlights, except for adjusted EBITDA and normalized earnings per share, were prepared in accordance with GAAP. See Non-GAAP Financial Measures.

	Three months ended							
Spot price averages	**Sep 30 2014**	**Jun 30 2014**	**Mar 31 2014**	**Dec 31 2013**	**Sep 30 2013**	**Jun 30 2013**	**Mar 31 2013**	**Dec 31 2012**
Alberta power ($ per MWh)	64	42	61	49	84	123	65	79
Alberta natural gas (AECO) ($ per Gj)	3.81	4.46	5.45	3.33	2.32	3.36	3.03	2.16
Capital Power's Alberta portfolio average realized power price ($ per MWh)	56	57	58	64	85	93	69	65

Factors impacting results for the previous quarters

Significant events and items that affected results for the previous quarters were as follows:

In the second quarter of 2014, the results for the Alberta commercial plants reflected seasonally low Alberta power prices, lower generation from the acquired Sundance PPA units, and lower generation at Genesee 3 caused by transmission constraints. However, the results for the Alberta contracted plants were positively impacted by lower rolling average pool prices, which caused lower availability penalties on outages in the second quarter of 2014 compared with the same quarter in 2013. Capital Power recorded revenues of $20 million arising from the amendment of the Genesee Coal Mine Agreements. The Company announced a 7.9% increase in the annual dividend for holders of its common shares commencing with the third quarter 2014 quarterly dividend payment.

The 2014 first quarter included the first full quarter of operations and results for Capital Power's Port Dover and Nanticoke wind facility. The Alberta commercial plants' results were impacted by lower pricing experienced in this quarter compared with first quarter 2013. The impact of lower pricing on the significantly hedged portfolio also reduced portfolio optimization results. Additionally, the Company experienced higher costs of emissions compliance. The Genesee 1 unit, within the Alberta contracted plants category, experienced a 10-day unplanned outage, which dampened results. Depreciation and amortization expense was reduced from prior quarters due to the disposal of the North East U.S. assets.

During the quarter ended December 31, 2013, commercial operations of the Port Dover and Nanticoke wind facility commenced while the sale of the North East U.S. assets was completed resulting in a net capacity decrease of 984 MW. The Company recognized a pre-tax gain of $76 million on the sale of the North East U.S. assets. The results for this quarter also included significant unrealized net gains related to the fair value of commodity derivatives and the impact of improved operating results for the Alberta commercial plants and the Ontario and British Columbia contracted plants.

Results of operations for the third quarter of 2013 were influenced by the Alberta spot power average price of $84 per MWh and unplanned plant maintenance outages in the Alberta market. In particular, the high Alberta power prices favourably impacted the Alberta contracted plants' results. The Company announced its agreement with Emera Inc. to sell its North East U.S. plants. This decision to exit North East U.S. market was accompanied by the Company's decision to refocus its merchant power business in Alberta. As a result, the Company recognized a pre-tax impairment loss of $6 million and incurred pre-tax restructuring costs of $9 million in the third quarter of 2013. The purchase of the second tranche of the Company's interest in Shepard Energy Centre was completed during the quarter.

In the second quarter of 2013, Alberta commercial plants had strong results as power prices were driven higher when the Alberta market experienced several planned and unplanned outages. These positive results were partly offset by the results for Alberta contracted plants since Genesee 1 experienced a planned outage and both Genesee 1 and 2 experienced unplanned outages. These outages decreased production and the significant availability penalties incurred reflected the quarter's higher Alberta power prices.

The 2013 first quarter included the first full quarter of operations and results for Capital Power's Quality Wind and Halkirk wind projects. All plants, with the exception of Tiverton in the North East U.S., had relatively strong performance and financial results. Tiverton experienced an outage during the quarter when the maintenance work that was originally scheduled to be performed in the last half of 2013 was completed. The purchase of the first tranche in the Company's interest in Shepard Energy Centre was completed during the quarter.

In the fourth quarter of 2012, commercial operations of the Quality Wind and Halkirk wind projects commenced adding total capacity of 292 MW to the Company's generation portfolio. A pre-tax gain of $15 million was recorded on the sale of the Brown Lake and Miller Creek facilities. Results were negatively impacted by realized losses on the Bridgeport heat rate option and the pricing of physical gas purchases for the Bridgeport plant. These losses were partly offset by gains realized on a financial hedge executed to reduce the natural gas locational basis risk associated with the heat rate option. The net impact of these transactions was a pre-tax loss of $10 million. Planned outages occurred at Genesee 3 and Sundance. Adjusted EBITDA was positively impacted by approximately $9 million due to a change in the estimate of coal inventory for Genesee 1, 2 and 3.

Share and Partnership Unit Information

Quarterly common share trading information

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

	Three months ended							
	Sep 30 2014	Jun 30 2014	March 31 2014	Dec 31 2013	Sep 30 2013	Jun 30 2013	Mar 31 2013	Dec 31 2012
Share price ($/common share)								
High	28.71	26.49	25.81	21.95	22.22	22.55	23.53	23.20
Low	25.75	24.07	20.51	20.30	19.80	19.76	21.02	20.88
Close	26.75	26.36	25.72	21.30	21.26	20.58	21.20	22.73
Volume of shares traded (millions)	19.6	21.6	27.0	23.5	13.2	12.2	14.7	15.3

Outstanding share and partnership unit data

As at October 21, 2014, the Company had 83.043 million common shares outstanding, 18.841 million special voting shares outstanding, 5 million Cumulative Rate Reset Preference Shares, Series 1 outstanding, 6 million Cumulative Rate Reset Preference Shares, Series 3, 8 million Cumulative Rate Reset Preference Shares, Series 5, and one special limited voting share outstanding. Assuming full conversion of the outstanding and issuable share purchase options to common shares and the redemption of all outstanding special voting shares in relation to the conversion of all outstanding exchangeable common limited partnership units of CPLP to common shares and ignoring exercise prices, the outstanding and issuable common shares as at October 21, 2014 were 105.696 million. All of the outstanding special voting shares and the outstanding special limited voting share are held by EPCOR.

As at October 21, 2014, CPLP had 21.750 million general partnership units outstanding, 56.299 million common limited partnership units outstanding and 18.841 million exchangeable common limited partnership units outstanding, which are exchangeable for 18.841 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 common limited partnership units are held by EPCOR.

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.

Condensed Interim Consolidated Financial Statements of

CAPITAL POWER CORPORATION

(Unaudited, in millions of Canadian dollars)
Nine months ended September 30, 2014 and 2013

Condensed Interim Consolidated Financial Statements:

CAPITAL POWER CORPORATION

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

	Three months ended September 30, 2014	Three months ended September 30, 2013	Nine months ended September 30, 2014	Nine months ended September 30, 2013
Revenues (note 3)	$ 248	$ 380	$ 796	$ 1,066
Energy purchases and fuel	(79)	(149)	(285)	(440)
Gross margin	169	231	511	626
Other raw materials and operating charges	(25)	(22)	(71)	(62)
Staff costs and employee benefits expense	(29)	(37)	(92)	(114)
Depreciation and amortization	(47)	(54)	(140)	(170)
Impairments (note 4)	-	(6)	-	(6)
Other administrative expense	(24)	(21)	(66)	(60)
Foreign exchange loss	(5)	(1)	(6)	(1)
Operating income	39	90	136	213
Finance expense	(15)	(18)	(39)	(60)
Income before tax	24	72	97	153
Income tax expense (note 5)	(81)	(13)	(95)	(23)
Net (loss) income	$ (57)	$ 59	$ 2	$ 130
Attributable to:				
Non-controlling interests	$ (12)	$ 15	$ (5)	$ 32
Shareholders of the Company	$ (45)	$ 44	$ 7	$ 98
(Loss) earnings per share (attributable to common shareholders of the Company):				
Basic (note 6)	$ (0.62)	$ 0.55	$ (0.12)	$ 1.19
Diluted (note 6)	$ (0.62)	$ 0.51	$ (0.12)	$ 1.14

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

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

	Three months ended September 30, 2014	Three months ended September 30, 2013	Nine months ended September 30, 2014	Nine months ended September 30, 2013
Net (loss) income	$ (57)	$ 59	$ 2	$ 130
Other comprehensive income (loss):				
Items that are or may be reclassified subsequently to net income:				
Cash flow hedges:				
Unrealized gains (losses) on derivative instruments[1]	1	-	(8)	(65)
Unrealized losses on derivative instruments – joint venture[2]	(2)	-	(9)	-
Reclassification of losses on derivative instruments to income for the period[3]	5	2	-	41
Net investment in foreign subsidiaries:				
Unrealized gains (losses)[4]	9	(9)	10	14
Total items that are or may be reclassified subsequently to net (loss) income, net of tax	13	(7)	(7)	(10)
Total other comprehensive income (loss), net of tax	13	(7)	(7)	(10)
Total comprehensive (loss) income	$ (44)	$ 52	$ (5)	$ 120
Attributable to:				
Non-controlling interests	$ (9)	$ 13	$ (7)	$ 28
Shareholders of the Company	$ (35)	$ 39	$ 2	$ 92

[1] For the three and nine months ended September 30, 2014, net of income tax recoveries of nil and $2 respectively. For the three and nine months ended September 30, 2013, net of income tax recoveries of nil and $14 respectively.

[2] For the three and nine months ended September 30, 2014, net of income tax recoveries of $1 and $3 respectively. For the three and nine months ended September 30, 2013, net of income tax recoveries of nil.

[3] For the three and nine months ended September 30, 2014, net of reclassification of income tax recoveries of $2 and nil respectively. For the three and nine months ended September 30, 2013, net of reclassification of income tax recoveries of $1 and $9 respectively.

[4] For the three and nine months ended September 30, 2014, net of income tax expenses of nil. For the three and nine months ended September 30, 2013, net of income tax expenses of nil.

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

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

	September 30, 2014	December 31, 2013
Assets		
Current assets:		
Cash and cash equivalents	$ 119	$ 100
Trade and other receivables	167	218
Inventories	104	92
Derivative financial instruments assets (note 7)	55	31
	445	441
Non-current assets:		
Other assets	26	27
Derivative financial instruments assets (note 7)	31	36
Finance lease receivables	712	711
Other financial assets	19	36
Deferred tax assets	30	95
Equity-accounted investment	30	15
Intangible assets	315	310
Property, plant and equipment	3,562	3,525
Goodwill	23	23
Total assets	$ 5,193	$ 5,219
Liabilities and equity		
Current liabilities:		
Trade and other payables	$ 180	$ 198
Derivative financial instruments liabilities (note 7)	50	31
Loans and borrowings	339	346
Deferred revenue and other liabilities	6	5
Provisions	19	27
	594	607
Non-current liabilities:		
Derivative financial instruments liabilities (note 7)	9	10
Loans and borrowings	1,195	1,181
Deferred revenue and other liabilities	88	89
Deferred tax liabilities	196	180
Provisions	174	148
	1,662	1,608
Equity:		
Equity attributable to shareholders of the Company		
Share capital (note 8)	2,380	2,328
(Deficit) retained earnings	(7)	83
Other reserves	-	6
(Deficit) retained earnings and other reserves	(7)	89
	2,373	2,417
Non-controlling interests	564	587
Total equity	2,937	3,004
Total liabilities and equity	$ 5,193	$ 5,219

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	Cash flow hedges[1]	Cumulative translation account[1]	Defined benefit plan actuarial losses[1]	Employee benefits reserve	Retained earnings (deficit)	Equity attributable to shareholders of the Company	Non-controlling interests	Total
Equity as at January 1, 2014	$ 2,328	$ 21	$ (14)	$ (11)	$ 10	$ 83	$ 2,417	$ 587	$ 3,004
Net income (loss)	-	-	-	-	-	7	7	(5)	2
Other comprehensive (loss) income :									
Cash flow derivative hedge losses	-	(10)	-	-	-	-	(10)	-	(10)
Cash flow derivative hedge losses – joint venture	-	(12)	-	-	-	-	(12)	-	(12)
Reclassification of losses to income	-	-	-	-	-	-	-	-	-
Unrealized gains on foreign currency translation	-	-	10	-	-	-	10	-	10
Tax on items recognized directly in equity	-	5	-	-	-	-	5	-	5
Attributed to non-controlling interests	-	2	-	-	-	-	2	(2)	-
Other comprehensive (loss) income	$ -	$ (15)	$ 10	$ -	$ -	$ -	$ (5)	$ (2)	$ (7)
Total comprehensive (loss) income	-	(15)	10	-	-	7	2	(7)	(5)
Distributions to non-controlling interests	-	-	-	-	-	-	-	(18)	(18)
Net additional investment by non-controlling interests	-	-	-	-	-	-	-	2	2
Common share dividends (note 8)	-	-	-	-	-	(80)	(80)	-	(80)
Preferred share dividends	-	-	-	-	-	(17)	(17)	-	(17)
Dividends reinvested (note 8)	28	-	-	-	-	-	28	-	28
Share options exercised	24	-	-	-	(2)	-	22	-	22
Share-based compensation	-	-	-	-	1	-	1	-	1
Equity as at September 30, 2014	$ 2,380	$ 6	$ (4)	$ (11)	$ 9	$ (7)	$ 2,373	$ 564	$ 2,937

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

CAPITAL POWER CORPORATION

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

	Share capital	Cash flow hedges[1]	Cumulative translation account[1]	Defined benefit plan actuarial losses[1]	Employee benefits reserve	Retained earnings (deficit)	Equity attributable to shareholders of the Company	Non-controlling interests	Total
Equity as at January 1, 2013	$ 1,903	$ 15	$ 10	$ (13)	$ 9	$ (1)	$ 1,923	$ 829	$ 2,752
Net income	-	-	-	-	-	98	98	32	130
Other comprehensive (loss) income :									
Cash flow derivative hedge losses	-	(79)	-	-	-	-	(79)	-	(79)
Reclassification of losses to income	-	50	-	-	-	-	50	-	50
Unrealized gains on foreign currency translation	-	-	14	-	-	-	14	-	14
Tax on items recognized directly in equity	-	5	-	-	-	-	5	-	5
Attributed to non-controlling interests	-	8	(4)	-	-	-	4	(4)	-
Other comprehensive (loss) income	$ -	$ (16)	$ 10	$ -	$ -	$ -	$ (6)	$ (4)	$ (10)
Total comprehensive (loss) income	-	(16)	10	-	-	98	92	28	120
Issue of share capital	200	-	-	-	-	-	200	-	200
Share issue costs	(6)	-	-	-	-	-	(6)	-	(6)
Deferred taxes	2	-	-	-	-	-	2	-	2
Distributions to non-controlling interests	-	-	-	-	-	-	-	(27)	(27)
Net additional investment by non-controlling interests	-	-	-	-	-	-	-	6	6
Common share dividends (note 8)	-	-	-	-	-	(67)	(67)	-	(67)
Preferred share dividends	-	-	-	-	-	(14)	(14)	-	(14)
Dividends reinvested (note 8)	20	-	-	-	-	-	20	-	20
Share-based compensation	-	-	-	-	1	-	1	-	1
Equity as at September 30, 2013	$ 2,119	$ (1)	$ 20	$ (13)	$ 10	$ 16	$ 2,151	$ 836	$ 2,987

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

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

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

	Nine months ended September 30, 2014	2013
Cash flows from operating activities:		
Net income	$ 2	$ 130
Non-cash adjustments to reconcile net income to net cash flows from operating activities:		
Depreciation and amortization	140	170
Impairments (note 4)	-	6
Finance expense	39	60
Fair value changes on commodity derivative instruments and emission credits held for trading	1	(9)
Foreign exchange loss	6	-
Income tax expense	95	23
Other items	13	(21)
Interest paid[1]	(29)	(49)
Income taxes recovered (paid)[2]	7	(3)
Change in non-cash operating working capital	10	35
Net cash flows from operating activities	284	342
Cash flows used in investing activities:		
Purchase of property, plant and equipment and other assets	(163)	(884)
Other cash flows from investing activities	9	36
Net cash flows used in investing activities	(154)	(848)
Cash flows (used in) from financing activities:		
Proceeds from issue of loans and borrowings	-	410
Repayment of loans and borrowings	(10)	(18)
Issue costs on loans and borrowings	-	(1)
Proceeds from exercise of share options	22	-
Proceeds from issue of preferred shares	-	200
Share issue costs	-	(6)
Distributions paid to non-controlling interests	(18)	(27)
Common share dividends paid (note 8)	(49)	(46)
Preferred share dividends paid (note 8)	(16)	(14)
Interest paid[1]	(29)	(13)
Income taxes paid[2]	(12)	(2)
Net cash flows (used in) from financing activities	(112)	483
Foreign exchange gain on cash held in a foreign currency	1	1
Net increase (decrease) in cash and cash equivalents	19	(22)
Cash and cash equivalents at beginning of period	100	53
Cash and cash equivalents at end of period	$ 119	$ 31

[1] Total interest paid.

[2] Total income taxes paid.

See accompanying notes to the condensed interim consolidated financial statements

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:

These condensed interim consolidated financial statements have been prepared by management in accordance with International Accounting Standards (IAS) 34, Interim Financial Reporting. The condensed interim consolidated financial statements do not include all of the information required for full annual financial statements and should be read in conjunction with the Company’s 2013 annual financial statements prepared in accordance with International Financial Reporting Standards (IFRS).

These condensed interim consolidated financial statements have been prepared following the same accounting policies and methods as those used in preparing the most recent consolidated financial statements for the year ended December 31, 2013, and have been prepared under the historical cost basis, except for the Company’s derivative instruments, emission credits held for trading, defined benefit pension assets and cash-settled share based payments, which are stated at fair value.

These condensed interim consolidated financial statements were approved and authorized for issue by the Board of Directors on October 24, 2014.

3. Revenues:

Capital Power is a party to various agreements with Prairie Mines & Minerals Royalty Ltd. (PMRL) in relation to the operations of the Genesee Coal Mine (Genesee Coal Mine Agreements). Pursuant to the Genesee Coal Mine Agreements, PMRL operates the Genesee Coal Mine. In connection with the acquisition by Westmoreland Coal Company (Westmoreland) of PMRL and the acquisition by Altius Minerals Corporation (Altius) of the royalty assets of PMRL, the Genesee Coal Mine Agreements and certain related agreements have, among other things, been amended to: (a) confirm the acquisitions by Westmoreland and Altius; (b) provide for certain amendments to the Genesee Coal Mine Agreements; and (c) provide for a payment to Capital Power of $20 million upon completion of the acquisitions, which was received in the second quarter of 2014 and recorded within revenues during the nine months ended September 30, 2014 (nine months ended September 30, 2013 – nil).

4. Impairment testing:

The Company reviews its cash generating units (CGUs) that contain goodwill on an annual basis, generally in the third quarter, to determine whether any impairment should be recognized. As a result, the Company’s Southport CGU was tested for impairment during the third quarter of 2014. The carrying amount of the Southport CGU was within the range of its estimated recoverable amount and as such, no impairment was required.

Key assumptions used in calculating recoverable amounts

The recoverable amount of the Southport CGU was determined based on its fair value less costs to sell, estimated using discounted cash flows. The fair value measurement of the Southport CGU is categorized in Level 3 of the fair value hierarchy based on the inputs used in the valuation model. The calculation of the recoverable amount for the Southport CGU is sensitive to several key assumptions as described below.

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

4. Impairment testing, continued:

Discount rates and growth rates

The after-tax discount rates used for the Southport CGU ranged between the period for which the facility is currently contracted and the period following the expiry of the current contract, and reflect the market weighted average cost of capital (WACC) using a capital asset pricing model approach, giving consideration to the risks specific to the Southport CGU. The method and assumptions used to calculate the WACC rate are consistent with the Company's past experience and previous valuations performed by the Company.

The Company has projected cash flows for a period of ten years and used a growth rate to extrapolate the cash flow projections beyond the ten year period through to the end of the useful life of the CGU. The growth rate reflects past experience and is consistent with industry practice. The discount and growth rates used by the Company in the calculation of the recoverable amount for the Southport CGU were as follows:

	2014	2013
Discount rate – currently contracted period	7.9%	7.9%
Discount rate – post current contract period	9.9%	9.9%
Growth rate	2.0%	2.0%

Other key cash flow assumptions

The Company's cash flow projections incorporate estimates of annual plant revenues, expenses and capital expenditures. These estimates incorporate past experience and the Company's current view of future generating capacity, fuel mix, fuel pricing and expected contract renewal, including contracted rates, for the Southport facility.

The Company has assumed the Southport power purchase agreement will be extended for 10 years following the expiry of the current agreement at rates consistent with current pricing, adjusted for 1% inflation. The Company has also assumed that the Southport facility will optimize its fuel mix at 50% wood waste and 50% tire-derived fuel (TDF), and will execute long-term contracts with wood waste and TDF suppliers at prices consistent with current rates, adjusted for inflation.

Consideration is given to externally available information related to future electricity contract rates and fuel inputs when developing assumptions and such external information is used to validate the Company's current view of future rates and costs. These external sources of information include information from third party advisory and research firms serving the industry.

In addition to the annual impairment testing noted above, the Company tested its North East U.S. CGU for impairment immediately prior to classifying those assets as held for sale as at September 30, 2013. As a result, the Company recorded pre-tax impairments of $6 million during the three and nine months ended September 30, 2013.

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

5. Income tax:

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

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	2014	2013
Income before tax	$ 24	$ 72	$ 97	$ 153
Income tax at the statutory rates of 25.0%	6	18	24	38
Increase (decrease) resulting from:				
Amounts attributable to non-controlling interests	-	(4)	(1)	(8)
Change in unrecognized tax benefits	74	3	74	3
Non-taxable amounts	-	(1)	(1)	(4)
Statutory and other rate differences	1	(3)	(1)	(6)
Income tax expense	$ 81	$ 13	$ 95	$ 23

The Company regularly assesses the need to reduce its deferred tax assets to the extent that it is no longer probable that they can be utilized. The Company's cash flow projections, which include estimates described in Note 4, are used to determine the recognition of deferred tax assets. During the three and nine months ended September 30, 2014, the Company reversed $74 million related to deferred tax assets previously recognized, This amount included $73 million related to U.S. income tax loss carryforwards that will expire between 2027 and 2033. The accounting treatment has no effect on the Company's actual ability to utilize the loss carryforwards to reduce future cash tax payments.

6. (Loss) earnings per share:

Basic (loss) earnings per share

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

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	2014	2013
(Loss) income for the period attributable to shareholders of the Company	$ (45)	$ 44	$ 7	$ 98
Preferred share dividends of the Company [1]	(6)	(5)	(17)	(14)
(Loss) earnings used in the calculation of basic (loss) earnings per share	$ (51)	$ 39	$ (10)	$ 84

[1] Includes preferred share dividends in respect of the three and nine months ended September 30, 2014 and 2013 respectively.

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	2014	2013
Weighted average number of common shares used in the calculation of basic (loss) earnings per share	82,788,601	70,828,245	81,974,376	70,488,590

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

6. (Loss) earnings per share, continued:

Diluted (loss) earnings per share

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

	Three months ended September 30, 2014	Three months ended September 30, 2013	Nine months ended September 30, 2014	Nine months ended September 30, 2013
(Loss) earnings used in the calculation of basic (loss) earnings per share	$ (51)	$ 39	$ (10)	$ 84
Effect of exchangeable limited partnership units issued to EPCOR for common shares [1]	(12)	12	-	29
(Loss) earnings used in the calculation of diluted (loss) earnings per share	$ (63)	$ 51	$ (10)	$ 113

[1] The exchangeable limited partnership units issued to EPCOR Utilities Inc. (EPCOR) may be exchanged for common shares of Capital Power on a one-for-one basis. For the three months ended September 30, 2014, the potential exchange of such units for common shares of the Company was included in the calculation of diluted loss per share. The potential exchange would remove the attribution of net loss to non-controlling interests related to Capital Power L.P (CPLP) of $10 million and related income taxes of $2 million. The effect of this adjustment was neutral to basic loss per share. For the nine months ended September 30, 2014, the potential exchange of such units for common shares of the Company was not included in the calculation of diluted loss per share as it was anti-dilutive. For the three and nine months ended September 30, 2013, the potential exchange of such units for common shares of the Company had a dilutive impact as the potential exchange would remove the attribution of net income to non-controlling interests related to CPLP of $17 million and $41 million for the three and nine months ended September 30, 2013 respectively. 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 $5 million and $12 million for the three and nine months ended September 30, 2013 respectively.

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

	Three months ended September 30, 2014	Three months ended September 30, 2013	Nine months ended September 30, 2014	Nine months ended September 30, 2013
Weighted average number of common shares used in the calculation of basic (loss) earnings per share	82,788,601	70,828,245	81,974,376	70,488,590
Effect of dilutive share purchase options [2]	-	-	-	-
Effect of exchangeable limited partnership units issued to EPCOR for common shares	18,841,000	28,441,000	-	28,441,000
Weighted average number of common shares used in the calculation of diluted (loss) earnings per share	101,629,601	99,269,245	81,974,376	98,929,590

[2] For the three and nine months ended September 30, 2014, the average market price of the Company's common shares exceeded the exercise price of all granted share purchase options, but since the assumed exercise of the stock options decreased the basic loss per share, the options did not have a dilutive effect. For the three and nine months ended September 30, 2013, 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 per share.

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

7. 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, 2014				
	Energy and emission credits		Foreign exchange	Interest rate	
	cash flow hedges	non-hedges	cash flow hedges	non-hedges	Total
Derivative instruments assets:					
Current	$ 9	$ 33	$ 11	$ 2	$ 55
Non-current	17	14	-	-	31
Derivative instruments liabilities:					
Current	(15)	(34)	-	(1)	(50)
Non-current	(3)	(6)	-	-	(9)
Net fair value	$ 8	$ 7	$ 11	$ 1	$ 27
Net notional buys (sells):					
Megawatt hours of electricity (millions)	(9)	(6)			
Gigajoules of natural gas (millions)		22			
Metric tons of emission allowances (millions)		-			
Megawatt hours of renewable energy credits (millions)		(2)			
Cross currency swaps and interest rate swaps (millions of U.S. dollars)			$ 195	$ 100	
Interest rate swaps (millions of Canadian dollars)				$ 100	
Range of remaining contract terms in years	0.1 to 4.3	0.1 to 6.5	6.7 to 11.7	6.7 to 11.2	

	December 31, 2013				
	Energy		Foreign exchange	Interest rate	
	cash flow hedges	non-hedges	cash flow hedges	non-hedges	Total
Derivative instruments assets:					
Current	$ 7	$ 24	$ -	$ -	$ 31
Non-current	22	13	1	-	36
Derivative instruments liabilities:					
Current	(6)	(23)	(1)	(1)	(31)
Non-current	(5)	(5)	-	-	(10)
Net fair value	$ 18	$ 9	$ -	$ (1)	$ 26
Net notional buys (sells):					
Megawatt hours of electricity (millions)	(10)	(4)			
Gigajoules of natural gas (millions)	-	1			
Cross currency swaps and interest rate swaps (millions of U.S. dollars)			$ 195	$ 100	
Range of remaining contract terms in years	0.1 to 5.0	0.1 to 5.0	7.5 to 12.5	7.5	

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

7. 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 dependent on which is most representative of fair value in the circumstances, in the principal 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 inputs, no inception gains or losses are recognized, until inputs become 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, 2014		Three months ended September 30, 2013	
	Unrealized gains	Realized losses	Unrealized gains (losses)	Realized (losses) gains
Energy cash flow hedges	$ 8	$ (7)	$ 3	$ (3)
Energy and emission credits non-hedges	5	(5)	1	47
Foreign exchange cash flow hedges[1]	-	-	-	-
Foreign exchange non-hedges	-	-	(1)	
Interest rate non-hedges	1	(1)	1	-

[1] For the three months ended September 30, 2014, unrealized gains of $10 million (three months ended September 30, 2013 – nil) related to foreign exchange cash flow hedges were reclassified from other comprehensive income to net loss to offset the impact to unrealized foreign exchange loss from the revaluation of U.S. dollar denominated loans and borrowings.

	Nine months ended September 30, 2014		Nine months ended September 30, 2013	
	Unrealized (losses) gains	Realized gains	Unrealized (losses) gains	Realized (losses) gains
Energy cash flow hedges	$ (10)	$ -	$ (29)	$ (50)
Energy and emission credits non-hedges	(1)	9	9	114
Foreign exchange cash flow hedges[2]	-	-	-	-
Foreign exchange non-hedges	-	-	(1)	-
Interest rate non-hedges	2	1	1	-

[2] For the nine months ended September 30, 2014, unrealized gains of $11 million (nine months ended September 30, 2013 – nil) related to foreign exchange cash flow hedges were reclassified from other comprehensive loss to net income to offset the impact to unrealized foreign exchange loss from the revaluation of U.S. dollar denominated loans and borrowings.

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

7. Derivative financial instruments and hedge accounting, continued:

Realized and unrealized gains and losses relate only to financial derivative instruments. The following gains and losses are included in the Company's statements of income for the three and nine months ended September 30, 2014 and 2013:

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	2014	2013
Revenues	$ 5	$ 62	$ 85	$ 123
Energy purchases and fuel	(12)	(17)	(77)	(50)
Foreign exchange gain (loss)	10	(1)	11	(1)
Finance expense	-	1	3	1

The Company has elected to apply hedge accounting on certain derivatives it uses to manage commodity price risk relating to electricity prices and currency risk relating to U.S. dollar denominated loans and borrowings. For the three and nine months ended September 30, 2014, the changes in the fair value of the ineffective portion of hedging derivatives required to be recognized in the statement of income was nil (three and nine months ended September 30, 2013 – nil). Net after tax gains and 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, 2014
Within one year	$ (5)
Between 1 – 5 years	10
After more than 5 years	-
	$ 5

The Company's cash flow hedges extend to 2018 for energy cash flow hedges and to 2026 for foreign exchange cash flow hedges.

8. Share capital:

The common and preferred share dividends declared and paid by the Company for the three and nine months ended September 30, 2014 and 2013 are summarized as follows:

	Dividends declared							
	For the three months ended September 30,				For the nine months ended September 30,			
	2014		2013		2014		2013	
	Per share	Total	Per share	Total	Per share	Total	Per share	Total
Common	$ 0.3400	$ 28	$ 0.3150	$ 23	$ 0.9700	$ 80	$ 0.9450	$ 67
Preference, Series 1	0.2875	1	0.2875	1	0.8625	4	0.8625	4
Preference, Series 3	0.2875	2	0.2875	2	0.8625	6	0.8901	6
Preference, Series 5	0.2813	2	0.2813	2	0.8439	6	0.6142	4

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

8. Share capital, continued:

	Dividends paid							
	For the three months ended September 30,				For the nine months ended September 30,			
	2014		2013		2014		2013	
	Per share	Total[1]	Per share	Total[1]	Per share	Total[1]	Per share	Total[1]
Common	$ 0.3150	$ 26	$ 0.3150	$ 22	$ 0.9450	$ 77	$ 0.9450	$ 66
Preference, Series 1	0.2875	1	0.2875	1	0.8625	4	0.8625	4
Preference, Series 3	0.2875	2	0.2875	2	0.8625	6	0.8901	6
Preference, Series 5	0.2813	2	0.2813	2	0.8439	6	0.6142	4

[1] For the three and nine months ended September 30, 2014, dividends paid on common shares consist of $16 million and $49 million paid in cash and $10 million and $28 million paid through the Company's dividend reinvestment plan as common shares issued, respectively. For the three and nine months ended September 30, 2013, dividends paid on common shares consist of $15 million and $46 million paid in cash and $7 million and $20 million paid through the Company's dividend reinvestment plan as common shares issued, respectively.

9. Financial instruments:

Fair values

Details of the fair values of the Company's derivative instruments are described in note 7.

The Company classifies its cash and cash equivalents as loans and receivables and measures them at amortized cost which approximates their fair values.

Trade and other receivables are classified as loans and receivables; trade and other payables are classified as other financial liabilities; all of which are measured at amortized cost and their fair values are not materially different from their carrying amounts due to their short-term nature.

The classification, carrying amount and fair value of the Company's other financial instruments are summarized as follows:

		September 30, 2014		December 31, 2013	
	Fair value hierarchy level	Carrying amount	Fair value	Carrying amount	Fair value
Other financial assets					
Loans and receivables	Level 2	$ 17	$ 17	$ 34	$ 34
Finance lease receivables					
Loans and receivables	Level 2	712	703	711	647
Loans and borrowings					
Other financial liabilities (includes current portion)	Level 2	1,534	1,615	1,527	1,561

Loans and receivables

The fair values of the Company's finance lease receivables and other loans and receivables are estimated by discounting the expected future cash flows of these instruments at current market interest rates for comparable instruments with similar terms, plus an estimated credit spread based on the counterparty credit risk as at September 30, 2014 and December 31, 2013.

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

9. Financial instruments, continued:

Fair values, continued:

Loans and borrowings

The fair value of the Company's loans and borrowings is based on determining a current yield for the Company's loans and borrowings as at September 30, 2014 and December 31, 2013. This yield is based on an estimated credit spread for the Company over the yields of long-term Government of Canada and U.S. Government bonds that have similar maturities to the Company's loans and borrowings. The estimated credit spread is based on the Company's indicative spread as published by independent financial institutions.

Fair value hierarchy

Fair value represents the Company's estimate of the price at which a financial instrument could be exchanged between knowledgeable and willing parties in an orderly arm's length transaction under no compulsion to act. Fair value measurements recognized in the consolidated statements of financial position are categorized into levels within a fair value hierarchy based on the nature of the valuation inputs and precedence is given to those fair value measurements calculated using observable inputs over those using unobservable inputs. The determination of fair value requires judgment and is based on market information where available and appropriate. The valuation techniques used by the Company in determining the fair value of its financial instruments are the same as those used as at December 31, 2013.

The fair value measurement of a financial instrument is included in only one of the three levels of the fair value hierarchy, the determination of which is based upon the lowest level input that is significant to the derivation of the fair value. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment which will affect the placement within the fair value hierarchy levels. As at September 30, 2014 and December 31, 2013, the Company did not classify any financial instruments in Level 3 of the hierarchy.

The following tables present the Company's financial instruments measured at fair value on a recurring basis in the consolidated statements of financial position, classified using the fair value hierarchy described above:

	September 30, 2014			
	Level 1	Level 2	Level 3	Total
Derivative financial instruments assets				
Commodity derivatives	$ -	$ 73	$ -	$ 73
Foreign exchange derivatives	-	11	-	11
Interest rate derivatives	-	2		2
	$ -	$ 86	$ -	$ 86
Derivative financial instruments liabilities				
Commodity derivatives	-	(58)	-	(58)
Interest rate derivatives	-	(1)	-	(1)
	$ -	$ (59)	$ -	$ (59)

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

9. Financial instruments, continued:

Fair value hierarchy, continued:

	December 31, 2013			
	Level 1	Level 2	Level 3	Total
Derivative financial instruments assets				
Commodity derivatives	$ -	$ 66	$ -	$ 66
Foreign exchange derivatives	-	1	-	1
	$ -	$ 67	$ -	$ 67
Derivative financial instruments liabilities				
Commodity derivatives	-	(39)	-	(39)
Foreign exchange derivatives	-	(1)	-	(1)
Interest rate derivatives	-	(1)	-	(1)
	$ -	$ (41)	$ -	$ (41)

The Company's policy is to recognize transfers between levels as of the date of the event of change in circumstances that caused the transfer. There were no significant transfers between levels in the fair value hierarchy for the three and nine months ended September 30, 2014 and the year ended December 31, 2013.

10. Segment information:

The Company operates in one reportable business segment involved in the operation of electrical generation plants within Canada (Alberta, British Columbia and Ontario), and in the U.S. (North Carolina) as this is how management assesses performance and determines resource allocations. The Company had operations in Connecticut, Maine and Rhode Island within the U.S. up until the fourth quarter of 2013 when the Company disposed of its North East U.S. assets.

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

	Three months ended September 30, 2014				Three months ended September 30, 2013			
	Canada	U.S.	Inter-area eliminations	Total	Canada	U.S.	Inter-area eliminations	Total
Revenues - external	$ 227	$ 21	$ -	$ 248	$ 289	$ 91	$ -	$ 380
Revenues - inter-area	1	-	(1)	-	11	-	(11)	-
Total revenues	$ 228	$ 21	$ (1)	$ 248	$ 300	$ 91	$ (11)	$ 380

	Nine months ended September 30, 2014				Nine months ended September 30, 2013			
	Canada	U.S.	Inter-area eliminations	Total	Canada	U.S.	Inter-area eliminations	Total
Revenues - external	$ 710	$ 86	$ -	$ 796	$ 777	$ 289	$ -	$1,066
Revenues - inter-area	12	-	(12)	-	29	(5)	(24)	-
Total revenues	$ 722	$ 86	$ (12)	$ 796	$ 806	$ 284	$ (24)	$1,066

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

10. Segment information, continued:

	September 30, 2014			December 31, 2013		
	Canada	U.S.	Total	Canada	U.S.	Total
Property, plant and equipment	$ 3,477	$ 85	$ 3,562	$ 3,441	$ 84	$ 3,525
Intangible assets	314	1	315	309	1	310
Goodwill	-	23	23	-	23	23
Other assets	26	-	26	27	-	27
	$ 3,817	$ 109	$ 3,926	$ 3,777	$ 108	$ 3,885

11. Comparative figures:

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