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For release: October 26, 2015

Capital Power reports third quarter 2015 results

EDMONTON, Alberta – Capital Power Corporation (Capital Power, or the Company) (TSX: CPX) today released financial results for the third quarter ended September 30, 2015.

Net income attributable to shareholders in the third quarter of 2015 was $49 million and basic earnings per share attributable to common shareholders was $0.44 per share compared with a net loss of $45 million and basic loss per share of $0.62 in the comparable period of 2014. Net cash flows from operating activities were $184 million in the third quarter of 2015 compared with $102 million in the third quarter of 2014.

Normalized earnings attributable to common shareholders in the third quarter of 2015, after adjusting for one-time items and fair value adjustments, were $33 million or $0.33 per share compared with $10 million or $0.12 per share in the third quarter of 2014. Funds from operations were $97 million in the third quarter of 2015, up 17 per cent from $83 million in the third quarter of 2014.

For the nine months ended September 30, 2015, net income attributable to shareholders was $55 million and basic earnings per share attributable to common shareholders was $0.40 per share compared with net income of $7 million and basic loss per share of $0.12 for the nine months ended September 30, 2014. Net cash flows from operating activities were $303 million for the nine months ended September 30, 2015 compared with $284 million for the nine months ended September 30, 2014.

For the nine months ended September 30, 2015, normalized earnings attributable to common shareholders were $70 million, or $0.73 per share, compared with $42 million, or $0.51 per share, in the first nine months of 2014. Funds from operations totaled $275 million compared with $260 million in the comparable nine-month period last year.

"The third quarter was highlighted by a 95 per cent average plant availability and financial results that exceeded management's expectations," said Brian Vaasjo, President and CEO of Capital Power. "We continue to see the benefits of strong portfolio optimization activities that captured an average realized Alberta power price of $61 per megawatt hour (MWh) in the third quarter, well above the average spot price of $26 per MWh that reflected excess supply from minimal plant outages and lower market volatility."

"With $275 million in funds from operations generated in the first nine months of the year and based on our outlook for the balance of the year, we are now increasing our expectation from the low end of our $365 to $415 million funds from operations annual target range to the mid-point of the range," said Mr. Vaasjo.

Operational and Financial Highlights [1] (unaudited)	**Three months ended September 30**		**Nine months ended September 30**	
(millions of dollars except per share and operational amounts)	**2015**	**2014**	**2015**	**2014**
Electricity generation (excluding Sundance power purchase arrangement (PPA)) (GWh)	3,687	3,220	10,638	9,174
Generation plant availability (excluding Sundance PPA) (%)	95%	97%	94%	95%
Revenues	$ 469	$ 248	$ 910	$ 796
Adjusted EBITDA [2]	$ 148	$ 91	$ 340	$ 282
Net income (loss)	$ 50	$ (57)	$ 52	$ 2
Net income (loss) attributable to shareholders of the Company	$ 49	$ (45)	$ 55	$ 7
Basic and diluted earnings (loss) per share	$ 0.44	$ (0.62)	$ 0.40	$ (0.12)
Normalized earnings attributable to common shareholders [2]	$ 33	$ 10	$ 70	$ 42
Normalized earnings per share [2]	$ 0.33	$ 0.12	$ 0.73	$ 0.51
Net cash flows from operating activities	$ 184	$ 102	$ 305	$ 284
Funds from operations [2]	$ 97	$ 83	$ 275	$ 260
Purchase of property, plant and equipment and other assets	$ 36	$ 25	$ 123	$ 163
Dividends per common share, declared	$ 0.3650	$ 0.3400	$ 1.0450	$ 0.9700

[1] The operational and financial highlights in this press release should be read in conjunction with Management's Discussion and Analysis and the unaudited condensed interim consolidated financial statements for the nine months ended September 30, 2015.

[2] 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.

Executive appointment

The Company appointed Mark Zimmerman to the position of Senior Vice President, Corporate Development and Commercial Services, effective November 2, 2015.

Mr. Zimmerman has more than 25 years of experience in the energy infrastructure and petroleum industries, with leadership roles focusing on finance, valuation, corporate strategy, business development, and mergers and acquisitions. He served as President of TC Pipelines LP from 2007 to 2010, and has worked for TransCanada Pipelines Ltd. from 1997 to 2015, most recently as Vice President Corporate Development & Strategy.

Mr. Zimmerman is a Chartered Accountant, Chartered Business Valuator and a member of the Institute of Corporate Directors. He holds a Bachelor of Commerce (1989) from the University of Alberta.

Analyst Conference Call and Webcast

Capital Power will be hosting a conference call and live webcast with analysts on October 26, 2015 at 11:00 AM (ET) to discuss its third quarter financial 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 1186355# followed by participant code 21543#. The replay will be available until January 24, 2016.Interested parties may also access the live webcast at www.capitalpower.com with an archive of the webcast available following the conclusion of the 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, therefore, are 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. 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, prepared as of October 23, 2015, for the nine months ended September 30, 2015 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 expectations regarding: (i) funds from operations, (ii) consistent growth of dividends, and (iii) the impact of environmental regulations including emissions compliance costs.

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, 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 of equipment, (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 Management's Discussion and Analysis, prepared as of February 20, 2015, for further discussion of these and other risks.

For more information, please contact:

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CAPITAL POWER CORPORATION

Management's Discussion and Analysis

This management's discussion and analysis (MD&A), prepared as of October 23, 2015, 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, 2015, the audited consolidated financial statements and MD&A of Capital Power Corporation for the year ended December 31, 2014, the annual information form of Capital Power Corporation dated March 4, 2015, and the cautionary statements regarding forward-looking information which begin on page 5. 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, 2015 and September 30, 2014 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 23, 2015.

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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 expectations regarding:

- future revenues, expenses, earnings and funds from operations,
- the future pricing of electricity and market fundamentals in existing and target markets,
- the Company's future cash requirements including interest and principal repayments, capital expenditures, dividends and distributions,
- the Company's sources of funding, adequacy and availability of committed bank credit facilities and future borrowings,
- future growth and emerging opportunities in the Company's target markets including the focus on certain technologies,
- the timing of, funding of, and costs for existing, planned and potential development projects and acquisitions
- plant availability and planned outages,
- capital expenditures for plant maintenance and other, and,
- future income taxes payable.

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, expected future developments, and other factors it believes are appropriate. The material factors and assumptions used to develop these forward-looking statements relate to:

- electricity and other energy prices,
- performance,
- business prospects and opportunities including expected growth and capital projects,
- status of and impact of policy, legislation and regulations,
- effective tax rates, and
- other matters discussed under the Performance Overview and Outlook and Targets for 2015 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:

- changes in electricity prices in markets in which the Company operates,
- changes in energy commodity market prices and use of derivatives,
- regulatory and political environments including changes to environmental, financial reporting and tax legislation,
- power plant availability and performance including maintenance of equipment,
- ability to fund current and future capital and working capital needs,
- acquisitions and developments including timing and costs of regulatory approvals and construction,
- changes in market prices and availability of fuel, and
- changes in general economic and competitive conditions.

See Risks and Risk Management in the Company's December 31, 2014 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 3,200 megawatts (MW) of power generation capacity at 17 facilities across North America and owns 371 MW of capacity through its interest in the acquired Sundance power purchase arrangement (Sundance PPA). An additional 545 MW of owned generation capacity is under construction or in advanced development in Alberta and North Carolina.

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, 2015, the Company held 21.750 million general partnership units and 80.953 million common limited partnership units of CPLP which represented 100% of CPLP's total partnership units. Effective April 2, 2015, EPCOR Utilities Inc. (EPCOR) exchanged 18.841 million exchangeable common limited partnership units of CPLP for common shares of Capital Power Corporation (see Significant Events).

CORPORATE STRATEGY

The Company's corporate strategy remains unchanged from that disclosed in its 2014 annual MD&A. During the nine months ended September 30, 2015, the Company commenced commercial operation of Shepard Energy Centre (Shepard) and K2 Wind, continued its site development for Genesee 4 and 5, and commenced construction of the Beaufort Solar project located in North Carolina.

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	2015 target	Actual results for the nine months ended September 30, 2015
Plant availability average [1]	94% or greater	94%
Capital expenditures for plant maintenance, Genesee mine extension and other (sustaining capital expenditures)	$65 million	$50 million
Plant operating and maintenance expenses	$180 million to $200 million	$143 million

1 All plants excluding Sundance PPA.

The Company's plant availability averaged 94% which reflected the second quarter planned outages for Genesee 1 and Joffre, the third quarter planned outage for Keephills 3, and unplanned outages for Shepard in the second quarter. These outages were partly offset by higher availability at the Genesee units due to lower than expected unplanned outage hours.

Capital expenditures for maintenance of the plants, Genesee mine extension and other for the nine months ended September 30, 2015 were consistent with the target for 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, 2015 were consistent with the full year target range.

Disciplined growth

Performance measure	2015 target	Status as at September 30, 2015
K2 Wind	Complete construction with commercial operation date in mid-2015	Commercial operation commenced May 2015
Genesee 4 and 5	Transition from development to construction	On track with target

See Outlook for discussion of updated timing of completion of the Genesee 4 and 5 project.

Financial stability and strength

Performance measure	2015 target	Actual results for the nine months ended September 30, 2015
Funds from operations [1]	$365 million to $415 million	$275 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, 2015 were in line with expected funds from operations for the full year.

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.

At its 2014 Investor Day held in December 2014, the Company provided financial guidance for 2015 funds from operations in the range of $365 million to $415 million. This was based on a forecasted 2015 Alberta spot power price average of $44 per megawatt hour (MWh) which was lower than market forward pricing at the time. Since then, Alberta power forward pricing for 2015 has declined. This is due to a combination of events including lower forward natural gas prices for 2015, lower economic growth in Alberta and its expected impact on Alberta power demand growth, and market reaction to the low overall average prices during the first nine months of the year, which averaged $37 per MWh. Spot prices and forward prices rebounded somewhat in May and June 2015 and the Company was able to lock in a number of forward contracts at the higher prices. However, spot prices have since softened. As such, the Company is still forecasting lower prices than the Company's spot price forecast coming into the year. Lower expected growth in the Alberta economy is largely the result of the significant decline in global oil prices.

While the Company anticipated lower power prices in 2015 and accordingly hedged almost all of its baseload power position, the lower price environment has had and is expected to have multiple impacts. Those impacts include: reduced availability incentive revenue from the Alberta contracted facilities, reduced dispatch and earnings from the Alberta commercial gas peaking facilities, and reduced earnings from the Halkirk wind facility. In addition, lower power prices are consistent with lower volatility in the Alberta market which reduces the opportunity to capture earnings from power trading activities.

Shepard commenced commercial operation in March 2015 and K2 Wind commenced commercial operation in May 2015. Power generation from these facilities is expected to continue to have a positive impact on earnings and funds from operations. This additional contribution is muted by an unplanned outage at Shepard during the second quarter and lower forecast average Alberta power prices. The Company was able to lock in higher prices in June forward contracts to partially offset low spot prices and expects 2015 funds from operations to be at the mid-point of its 2015 target range.

The impact of low Alberta power prices may be greater than expected and may be amplified by the supply and demand dynamics in the Alberta electricity market should demand decrease as a result of general economic conditions.

In 2015, Capital Power's availability target of 94% reflects major scheduled maintenance outages for Genesee 1 (completed in the second quarter) and Keephills 3 (completed in the third quarter) compared with the 2014 major scheduled maintenance outages for Genesee 2, Genesee 3, and Joffre.

Portfolio position and contracted prices for 2016 and 2017, as at September 30, 2015, were:

Alberta commercial portfolio positions and power prices	Full year 2016	Full year 2017
Percentage of baseload generation sold forward [1]	95%	32%
Contracted price [2]	High-$40 per MWh	Mid-$50 per MWh

[1] Based on the Alberta baseload plants and the Sundance PPA plus a portion of Joffre and the uncontracted portion of Shepard 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.

The Company's estimated full year growth capital expenditures are expected to increase to $96 million from the late 2014 estimate of $38 million due primarily to the addition of the Beaufort Solar project and additional costs incurred for Shepard, partly offset by the deferral of certain Genesee 4 activities into future periods. The Shepard additional costs include a contractual bonus due to the turbine manufacturer based on final facility performance measurements related to electrical output and heat rate. This bonus is payable in U.S. dollars and thus included significant foreign exchange due to the movement of exchange rates during the construction period. These final facility performance measurements are expected to improve the overall economics of the project and more than offset the additional capital costs incurred because of the bonus. The additional capital costs were partly offset by a contribution from ENMAX Corporation (ENMAX) of $5 million recognized as deferred revenues which will be recognized in revenues over the term of the Energy Supply Agreement between Capital Power and ENMAX. Shepard's final expected capital expenditures also increased as a result of higher capitalized interest due to the delay in the commercial operation date from February 2015 to March 2015. The capital costs accrued for Shepard to September 30, 2015 are subject to normal course discussion and negotiation which could result in lower final capital costs.

Based on the actual expenditures for the nine months ended September 30, 2015 and the current forecast for the last three months of 2015, sustaining capital expenditures are expected to be consistent with the target of $65 million.

The 2015 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 owned by 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.

The expected timing of Genesee 4 is the end of 2019. The targeted completion date reflects current market conditions, including the downturn in oil prices and slower expected economic growth in Alberta. Completion of the first unit at the end of 2019 will coincide with the need for additional generation to meet growing demand and to replace generation from the retirement of some existing coal generating units in Alberta.

Due to the Alberta government's changes to emissions regulations announced in June 2015 (see Significant Events), Capital Power expects that, between 2016 and 2020, the increase in the Company's emissions compliance costs will be partly mitigated by higher wholesale electricity prices directly caused by the new regulations while its inventory of low-cost carbon offset credits are expected to offset the balance of its compliance costs through 2020. The projected impact after 2020 is a $10 million to $15 million reduction in adjusted EBITDA (see Non-GAAP Financial Measures) once its existing carbon offset credits inventory is fully utilized and assuming no actions to further reduce carbon dioxide emissions at existing thermal generating facilities.

The Alberta government introduced changes that increased the provincial corporate income tax rate from 10% to 12% effective July 1, 2015. The increased rate increases the Company's non-cash income tax expense from the second quarter of 2015 onwards.

Governance updates

Following the previously announced appointments of Ms. Jill Gardiner and Ms. Kelly Huntington to the Capital Power Board of Directors, the Board of Directors made the following changes to the membership of its standing committees: Ms. Gardiner and Ms. Huntington joined the Audit Committee; Ms. Gardiner and Mr. Philip Lachambre joined the Corporate Governance, Compensation and Nominating Committee; Ms. Huntington and Mr. Patrick Daniel joined the Health, Safety and Environment Committee, and Mr. Lachambre stepped down from that committee.

Effective April 24, 2015, the position of Chair of the non-EPCOR elect directors was eliminated as a consequence of EPCOR's secondary offering and conversion of all remaining exchangeable common limited partnership units of CPLP on April 2, 2015. Mr. Donald Lowry and Mr. Allister McPherson will continue to recuse themselves from all business involving a conflict of interest with EPCOR. As Mr. Lowry is no longer a nominee of EPCOR, his cooling-off period will expire on April 2, 2016, as previously disclosed in Capital Power's management proxy circular dated April 24, 2015.

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, therefore, are 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 (loss) is as follows:

(unaudited, $ millions)	**Three months ended**							
	Sep 30 2015	**Jun 30 2015**	**Mar 31 2015**	**Dec 31 2014**	**Sep 30 2014**	**Jun 30 2014**	**Mar 31 2014**	**Dec 31 2013**
Revenues	469	83	358	432	248	240	308	327
Energy purchases and fuel, other raw materials and operating charges, staff costs and employee benefits expense, and other administrative expense	(321)	(38)	(211)	(291)	(157)	(162)	(195)	(208)
Adjusted EBITDA	**148**	**45**	**147**	**141**	**91**	**78**	**113**	**119**
Depreciation and amortization	(53)	(55)	(51)	(49)	(47)	(47)	(46)	(52)
Foreign exchange (loss) gain	(8)	1	(8)	(4)	(5)	3	(4)	(5)
Gains on disposals of subsidiaries	-	-	-	-	-	-	-	76
Finance expense	(25)	(24)	(18)	(16)	(15)	(11)	(13)	(18)
Income from joint venture	4	1	-	-	-	-	-	-
Income tax expense	(16)	(16)	(20)	(24)	(81)	(2)	(12)	(22)
Net income (loss)	**50**	**(48)**	**50**	**48**	**(57)**	**21**	**38**	**98**
Net income (loss) attributable to:								
Non-controlling interests	1	(14)	10	9	(12)	1	6	21
Shareholders of the Company	49	(34)	40	39	(45)	20	32	77
Net income (loss)	**50**	**(48)**	**50**	**48**	**(57)**	**21**	**38**	**98**

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 operating working capital. The Company includes interest and current income tax expenses excluding Part VI.1 tax 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 tax from operating activities to financing activities in the Company's Condensed Interim Consolidated Statements of Cash Flows. All comparative funds from operations amounts for quarters prior to those ended on June 30, 2014 were revised.

Commencing with the Company's December 31, 2014 quarter-end, the reported funds from operations measure was changed to remove the impact of fair value changes in certain unsettled derivative financial instruments that are charged or credited to the Company's bank margin account held with a specific exchange counterparty. As part of its collateral requirements, the exchange counterparty updates its bank margin accounts daily, by recording fair value changes on unsettled derivative financial instruments outstanding with its customers, including the Company. Consistent with the exchange counterparty, such changes are recorded as cash transactions on the Company's Condensed Interim Consolidated Statements of Financial Position and net cash flows from operating activities. However, the underlying derivative transactions have not settled. Accordingly, the Company removes the effect of such fair value changes in its determination of funds from operations. The impact of the fair value changes in derivatives reflected as cash settlement was immaterial for quarters prior to the fourth quarter of 2014.

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**	
	2015	**2014**	**2015**	**2014**
Net cash flows from operating activities per Condensed Interim Consolidated Statements of Cash Flows	**184**	**102**	**305**	**284**
Add (deduct) items included in calculation of net cash flows from operating activities per Condensed Interim Consolidated Statements of Cash Flows:				
Interest paid	18	5	52	29
Change in fair value of derivatives reflected as cash settlement	(27)	-	(5)	-
Realized gains (losses) on the settlement of interest rate derivatives	-	1	(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	1	3	3	5
Income taxes paid (recovered)	-	(8)	1	(7)
Change in non-cash operating working capital	(53)	(4)	(19)	(10)
	(61)	(3)	31	16
Finance expense excluding unrealized changes on interest rate derivative contracts and amortization and accretion charges	(25)	(16)	(60)	(39)
Current income tax expense excluding Part VI.1 tax	(1)	-	(1)	(1)
Funds from operations	**97**	**83**	**275**	**260**

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, shown net of tax, 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 2015	**Jun 30 2015**	**Mar 31 2015**	**Dec 31 2014**	**Sep 30 2014**	**Jun 30 2014**	**Mar 31 2014**	**Dec 31 2013**
Basic earnings (loss) per share ($)	**0.44**	**(0.39)**	**0.41**	**0.40**	**(0.62)**	**0.17**	**0.33**	**0.89**
Net income (loss) attributable to shareholders of the Company per Condensed Interim Consolidated Statements of Income (Loss)	**49**	**(34)**	**40**	**39**	**(45)**	**20**	**32**	**77**
Preferred share dividends including Part VI.1 tax	(5)	(6)	(6)	(6)	(6)	(6)	(5)	(6)
Earnings (loss) attributable to common shareholders	44	(40)	34	33	(51)	14	27	71
Unrealized changes in fair value of derivatives	(19)	33	(17)	(21)	(3)	8	(5)	(9)
Unrealized foreign exchange loss (gain) on revaluation of U.S. dollar denominated debt	6	(2)	10	4	5	(3)	3	4
Restructuring charges	2	-	-	-	-	-	-	1
Income tax expense related to increase in deferred tax liabilities caused by change in Alberta statutory corporate income tax rate	-	19	-	-	-	-	-	-
Impact of change in non-controlling interests percentage on adjustments of previous quarters	-	(1)	-	1	-	-	-	-
Recognition of tax liability on foreign domiciled investment	-	1	-	-	-	-	-	-
Write-down of U.S. deferred tax assets	-	-	-	-	59	-	-	-
Amount received upon amendment of the Genesee Coal Mine Agreements	-	-	-	-	-	(14)	-	-
Genesee flood damage repair costs	-	-	-	-	-	1	1	-
Gain on sale of North East U.S. assets	-	-	-	-	-	-	-	(34)
Reduction of amount receivable related to Sundance force majeure claim	-	-	-	-	-	-	-	6
Income tax recovery related to change in income tax rate applicable to North East U.S.	-	-	-	-	-	-	-	(6)
Obligation to EPCOR for Rossdale plant	-	-	-	-	-	-	-	(1)
Normalized earnings attributable to common shareholders	**33**	**10**	**27**	**17**	**10**	**6**	**26**	**32**
Weighted average number of common shares outstanding (millions)	100.91	102.05	83.74	83.31	82.79	81.94	81.18	79.73
Normalized earnings per share ($)	**0.33**	**0.10**	**0.32**	**0.20**	**0.12**	**0.07**	**0.32**	**0.40**

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 or decreases 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	
	2015	**2014**	**2015**	**2014**
Revenues	469	248	910	796
Adjusted EBITDA [1]	148	91	340	282
Net income (loss)	50	(57)	52	2
Net income (loss) attributable to shareholders of the Company	49	(45)	55	7
Normalized earnings attributable to common shareholders [1]	33	10	70	42
Basic and diluted earnings (loss) per share ($) [2]	0.44	(0.62)	0.40	(0.12)
Normalized earnings per share ($) [1]	0.33	0.12	0.73	0.51
Funds from operations [1,3]	97	83	275	260
Purchase of property, plant and equipment and other assets	36	25	123	163
Dividends per common share, declared ($)	0.3650	0.3400	1.0450	0.9700
Dividends per Series 1 preferred share, declared ($)	0.2875	0.2875	0.8625	0.8625
Dividends per Series 3 preferred share, declared ($)	0.2875	0.2875	0.8625	0.8625
Dividends per Series 5 preferred share, declared ($)	0.2813	0.2813	0.8439	0.8439

	As at	
	September 30, 2015	**December 31, 2014**
Loans and borrowings including current portion	1,606	1,586
Total assets	5,406	5,420

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 exchange of common limited partnership units of CPLP held by EPCOR for common shares of Capital Power on a one-for-one basis. See Significant Events.

3 The reported funds from operations measure was changed consistent with the reclassification of Part VI.1 tax from operating activities to financing activities in the Company's Condensed Interim Consolidated Statements of Cash Flows. All comparative funds from operations amounts for 2014 were revised.

Normalized earnings attributable to common shareholders and normalized earnings per share

Normalized earnings attributable to common shareholders and normalized earnings per share were higher for the three months ended September 30, 2015 compared with the three months ended September 30, 2014. The number of common shares outstanding increased as a result of the common shares issued to EPCOR following the exchange transactions (see Significant Events). Normalized earnings attributable to common shareholders and normalized earnings per share for the first nine months of 2015 increased from the first nine months of 2014 consistent with increased adjusted EBITDA.

Funds from operations

Funds from operations for the three and nine months ended September 30, 2015 in comparison to the three and nine months ended September 30, 2014 were consistent with the changes in adjusted EBITDA for those periods.

SIGNIFICANT EVENTS

Dividend increase

On July 27, 2015, the Company announced that its Board of Directors approved a 7.4% increase in the annual dividend for holders of its common shares, from $1.36 per common share to $1.46 per common share. This increased common dividend will commence with the third quarter 2015 quarterly dividend payment payable on October 30, 2015 to shareholders of record at the close of business on September 30, 2015.

Changes to Alberta's emissions regulations and review of climate change policy

On June 25, 2015, the Alberta government announced changes to Alberta's regulations governing carbon emissions and a comprehensive review of Alberta's climate change policy. The changes to the Specified Gas Emitters Regulation will increase the required reduction in emissions intensity from 12% to 15% in 2016 and 20% in 2017, and increase the cost of contributions to the Climate Change and Emissions Management Fund from $15 per tonne of greenhouse gases to $20 per tonne in 2016 and $30 per tonne in 2017.

Capital Power expects that, between 2016 and 2020, the increase in the Company's emissions compliance costs will be partly mitigated by higher wholesale power prices directly caused by the new regulations while its inventory of low-cost carbon offset credits are expected to offset the balance of its increased compliance costs through 2020. The projected impact post 2020 is a $10 million to $15 million reduction in adjusted EBITDA once its existing carbon offset credits inventory is fully utilized and assuming no actions by Capital Power to further reduce carbon dioxide emissions.

On August 14, 2015, a five member panel, appointed by the Alberta Minister of Environment and Parks, was announced and will provide recommendations to the Alberta government on how to address climate change. These recommendations are expected in the fourth quarter. Capital Power continues to actively participate in the consultation process that is expected to lead to a provincial climate change strategy to be announced in the fourth quarter of 2015.

K2 Wind begins commercial operation

On May 29, 2015, Capital Power, Samsung Renewable Energy Inc. and Pattern Energy Group LP announced that K2 Wind is fully operational and capable of generating 270 MW of electricity for the province of Ontario and operates under a 20-year power purchase agreement with the Independent Electricity System Operator. Capital Power owns 90 MW or 33.3% of the capacity of this facility. Capital Power's share of final construction costs are expected to be $310 million.

Secondary offering of Capital Power shares by EPCOR

On April 2, 2015, EPCOR exchanged all of its exchangeable common limited partnership units in CPLP for common shares of Capital Power on a one-for-one basis and sold 9.450 million of such common shares to the public pursuant to a secondary offering at $23.85 per common share. Capital Power did not receive any of the proceeds from EPCOR's sale of common shares. After giving effect to the exchange and the secondary offering, EPCOR owns approximately 9.1% of the common shares of Capital Power and no special voting shares of Capital Power or limited partnership units of CPLP. EPCOR has advised that it plans to eventually sell all or a substantial portion of its remaining interest in Capital Power, subject to market conditions, based on its requirements for capital and other circumstances that may arise in the future. In connection with the offering, the Registration Rights Agreement between Capital Power and EPCOR was terminated. Thus, the Company will no longer be obligated to assist EPCOR in making a secondary offering and any future sales of common shares by EPCOR will be completed by other means. As a result of EPCOR ceasing to hold special voting shares and EPCOR's ownership interest in Capital Power decreasing to below 10%, EPCOR no longer has the right, separately as a holder of special voting shares, to nominate and appoint any directors to Capital Power's Board of Directors.

The Company intends to review the structure of CPLP with the goals of simplifying the organization structure and reporting, and reducing costs associated with CPLP, including audit, legal, board, management and filing expenses.

Approval of normal course issuer bid and suspension of Dividend Re-investment Plan

On March 25, 2015, Capital Power's normal course issuer bid to purchase and cancel up to 5 million of its outstanding common shares during the one-year period from April 7, 2015 to April 6, 2016 was approved by the Toronto Stock Exchange. Up to September 30, 2015, the Company purchased and cancelled 3.582 million common shares totalling $79 million. Effective with the June 30, 2015 dividend, Capital Power also announced that its Dividend Re-investment Plan (DRIP) for its common shares will be suspended until further notice. Shareholders who participated in the DRIP began receiving cash dividends as of the July 31, 2015 payment date.

Shepard begins commercial operation

On March 11, 2015, Capital Power and ENMAX announced that Shepard is now fully operational and capable of generating over 800 MW of electricity to the Alberta grid. Capital Power became a 50% owner of this natural gas facility in 2012 and its final construction costs are expected to be $854 million which includes an accrued performance bonus due to the turbine manufacturer. Final construction costs are less than Capital Power's original budget estimated for the project.

Executive appointments

Capital Power and the Board of Directors announced the appointments of Bryan DeNeve to the executive position of Senior Vice President, Finance and Chief Financial Officer and Stuart Lee to the executive position of Senior Vice President, Corporate Development and Commercial Services effective May 1, 2015. Mr. DeNeve and Mr. Lee formerly held the positions of Senior Vice President, Corporate Development and Commercial Services and Senior Vice President, Finance and Chief Financial Officer, respectively.

The Company announced the appointment of Mark Zimmerman to the position of Senior Vice President, Corporate Development and Commercial Services effective November 2, 2015, to replace Mr. Lee who resigned from Capital Power effective August 31, 2015 to take the position of President and Chief Executive Officer at EPCOR.

CONSOLIDATED NET INCOME (LOSS) AND RESULTS OF OPERATIONS

The primary factors contributing to the change in consolidated net income for the three and nine months ended September 30, 2015 compared with the three and nine months ended September 30, 2014 are presented below followed by further discussion of these items.

(unaudited, $ millions)	**Three months**		**Nine months**	
Consolidated net (loss) income for the periods ended September 30, 2014		**(57)**		**2**
Increase (decrease) in adjusted EBITDA:				
Alberta commercial plants and portfolio optimization	23		33	
Alberta contracted plants	8		19	
Ontario and British Columbia contracted plants	1		2	
U.S. contracted plants	3		11	
Corporate	-		(19)	
Change in unrealized net gains or losses related to the fair value of commodity derivatives and emission credits	22	57	12	58
Increase in depreciation and amortization expense		(6)		(19)
Increase in foreign exchange loss		(3)		(9)
Increase in finance expense including change in unrealized net gains or losses related to the fair value of interest rate derivatives		(10)		(28)
Income from joint venture		4		5
Increase in income before tax		42		7
Decrease in income tax expense		65		43
Increase in net income		**107**		**50**
Consolidated net income for the periods ended September 30, 2015		**50**		**52**

Results by Plant Category and Other

	Three months ended September 30							
	2015	2014	2015	2014	2015	2014	2015	2014
	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 Sundance PPA	3,687	3,220	95	97	179	215		
Alberta commercial plants and Sundance PPA								
Genesee 3	498	473	100	97	12	30		
Keephills 3	258	461	63	100	6	27		
Clover Bar Energy Centre 1, 2 and 3	39	77	88	97	3	19		
Joffre	62	77	100	95	7	13		
Shepard	572	N/A	100	N/A	21	N/A		
Halkirk	88	86	97	91	6	7		
Clover Bar Landfill Gas	2	3	81	58	-	-		
Alberta commercial plants – owned	1,519	1,177	92	96	55	96		
Sundance PPA	688	673	91	85	19	32		
Portfolio optimization [4]	N/A	N/A	N/A	N/A	163	(9)		
	2,207	1,850	92	91	237	119	72	49
Alberta contracted plants								
Genesee 1	865	854	100	100				
Genesee 2	843	841	98	99				
	1,708	1,695	99	99	72	76	52	44
Ontario and British Columbia contracted plants								
Island Generation	37	6	100	99	9	9		
K2 Wind [5]	46	N/A	98	N/A	N/A	N/A		
Kingsbridge 1	13	14	94	93	-	-		
Port Dover and Nanticoke	44	51	95	98	5	6		
Quality Wind	97	71	94	93	9	6		
	237	142	97	97	23	21	16	15
U.S. contracted plants								
Macho Springs, New Mexico [6]	19	N/A	96	N/A	2	N/A		
Roxboro, North Carolina	76	73	94	100	9	7		
Southport, North Carolina	128	133	94	85	18	15		
	223	206	95	90	29	22	6	3
Corporate [7]					2	2	(25)	(25)
Unrealized changes in fair value of commodity derivatives and emission credits					106	8	27	5
Consolidated revenues and adjusted EBITDA					**469**	**248**	**148**	**91**

	Nine months ended September 30							
	2015	2014	2015	2014	2015	2014	2015	2014
	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 Sundance PPA	10,638	9,174	94	95	586	586		
Alberta commercial plants and Sundance PPA								
Genesee 3	1,482	1,378	100	96	53	75		
Keephills 3	1,151	1,241	89	100	41	68		
Clover Bar Energy Centre 1, 2 and 3	207	251	93	97	24	42		
Joffre	224	266	96	97	25	34		
Shepard	1,075	N/A	86	N/A	45	N/A		
Halkirk	331	316	98	96	25	25		
Clover Bar Landfill Gas	7	11	91	75	-	1		
Alberta commercial plants – owned	4,477	3,463	93	97	213	245		
Sundance PPA	1,944	1,944	87	80	66	89		
Portfolio optimization [4]	N/A	N/A	N/A	N/A	304	106		
	6,421	5,407	91	90	583	440	184	151
Alberta contracted plants								
Genesee 1	2,288	2,304	90	93				
Genesee 2	2,517	2,219	99	88				
	4,805	4,523	95	91	205	197	139	120
Ontario and British Columbia contracted plants								
Island Generation	74	121	100	100	28	29		
K2 Wind [5]	65	N/A	98	N/A	N/A	N/A		
Kingsbridge 1	65	70	95	95	4	4		
Port Dover and Nanticoke	204	209	97	97	24	25		
Quality Wind	287	249	97	96	28	25		
	695	649	98	98	84	83	65	63
U.S. contracted plants								
Macho Springs, New Mexico [6]	81	N/A	98	N/A	9	N/A		
Roxboro, North Carolina	205	170	93	96	23	17		
Southport, North Carolina	375	369	90	92	52	44		
	661	539	93	93	84	61	17	6
Corporate [7]					7	19	(76)	(57)
Unrealized changes in fair value of commodity derivatives and emission credits					(53)	(4)	11	(1)
Consolidated revenues and adjusted EBITDA					**910**	**796**	**340**	**282**

1 Gigawatt hours (GWh) of 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 activities category were included in the Alberta commercial plants and Sundance PPA category effective January 1, 2014.

5 K2 Wind is accounted for under the equity method. Capital Power's share of the plant's net income is included in Income from joint venture on the Company's Condensed Interim Consolidated Statements of Income (Loss). The equivalent of Capital Power's share of the plant's revenue and adjusted EBITDA was $7 million and $6 million, respectively for the three months ended September 30, 2015, and $10 million and $8 million for the nine months ended September 30, 2015.

6 Macho Springs was acquired in December 2014.

7 Corporate revenues were offset by interplant category eliminations.

Energy prices and hedged positions

Alberta	Unit	Three months ended September 30 2015	2014	Nine months ended September 30 2015	2014	Year ended December 31, 2014
Hedged position [1]	Percentage sold forward at beginning of period (%)	100	100	100	100	100
Spot power price average	$/MWh	26	64	37	56	49
Realized power price [2]	$/MWh	61	56	55	57	58
Natural gas price (AECO) [3]	$/gigajoule (Gj)	2.77	3.81	2.64	4.86	4.49

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

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

3 AECO refers to the historical virtual trading hub located in Alberta and known as the Nova Inventory Transfer system operated by TransCanada Pipelines Limited.

Alberta commercial plants, Sundance PPA and portfolio optimization

For the three and nine months ended September 30, 2015, generation increased compared with the same periods in 2014 primarily due to the addition of Shepard and the impact of the unplanned outages of Genesee 3 during the first two quarters of 2014. However, these increases were partly offset by the planned outage of Keephills 3, and, to a lesser extent, the unplanned outage of Clover Bar Energy Centre Unit 2 during the third quarter of 2015.

Alberta spot power price averaged $26 per MWh for the three months ended September 30, 2015 compared with $64 per MWh for the same period in 2014. The Company realized higher power prices by selling forward 100% of its commercial production, a portion of which was secured in June 2015 when forward rates increased temporarily. For the three months ended September 30, 2014, the Company experienced high Alberta power prices and outages at the Sundance PPA and had to cover its short position at the higher power prices.

For the nine months ended September 30, 2015, the lower average spot price reflected minimal market volatility due to generation from Shepard, and fewer unplanned baseload plant outages. Revenues and adjusted EBITDA benefited from the lower average spot price given that the Company had sold forward 100% of its commercial production at higher prices.

Alberta contracted plants

For the nine months ended September 30, 2015 compared with the same period in 2014, increased generation and availability were due to fewer and shorter unplanned outages at Genesee 1 and 2. Generation and availability for the three months ended September 30, 2015 were consistent with the same period in 2014. Revenues and adjusted EBITDA were higher compared with the corresponding periods in 2014 primarily due to increased availability, lower coal costs, and flood damage repairs recognized in 2014, partly offset by the impact of lower power prices in 2015.

Ontario and British Columbia contracted plants

Increased generation for the three and nine months ended September 30, 2015 compared with the same periods in 2014 primarily reflected the addition of K2 Wind in the second quarter of 2015 coupled with increased wind generation experienced at Quality Wind.

Revenues and adjusted EBITDA for the first three and nine months of 2015 were consistent with the same periods in 2014. While Island Generation's dispatch increased during the third quarter of 2015, the impact on revenues and adjusted EBITDA were minimal 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, 2015 was consistent with the corresponding period in 2014. For the nine months ended September 30, 2015, Island Generation was not dispatched as often during the first half of 2015. In addition, revenues and adjusted EBITDA for the periods do not include the operational results of K2 Wind which is accounted for under the equity method.

U.S. contracted plants

For the three and nine months ended September 30, 2015 compared with the same periods in 2014, increased generation reflected the addition of Macho Springs and increased off-peak generation at Roxboro and Southport. Availability was higher compared with the same period in 2014 due to fewer outages.

Revenues and adjusted EBITDA for the three and nine months ended September 30, 2015 increased compared with the same periods in 2014 due to the addition of Macho Springs, increased generation from Roxboro, and increased contracted prices for the sales of renewable energy 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 keeping with Capital Power's ongoing objectives to realize efficiencies, the Company incurred $3 million of restructuring charges, primarily a reduction of headcount, during the third quarter of 2015. This additional charge was mainly offset by reduced performance incentive expenses. The Company also recognized $20 million of revenues in the second quarter of 2014 arising from the amendment of the Genesee Coal Mine Agreements on the acquisition of Prairie Mines & Minerals Royalty Ltd.'s 50% interest in the Genesee Coal Mine by Westmoreland Coal Company. There were no comparable revenues in 2015.

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	**2015**	**2014**	**2015**	**2014**
	Revenues		**Adjusted EBITDA [1]**	
Unrealized gains on Alberta energy derivatives	114	9	26	4
Unrealized losses on natural gas derivatives	(7)	-	-	-
Unrealized losses on emission portfolio activities	(1)	-	(1)	-
Unrealized gains on emission credits held for trading	-	-	2	1
Other	-	(1)	-	-
	106	**8**	**27**	**5**

(unaudited, $ millions)	Nine months ended September 30			
Unrealized changes in fair value of commodity derivatives and emission credits	**2015**	**2014**	**2015**	**2014**
	Revenues		**Adjusted EBITDA [1]**	
Unrealized (losses) gains on Alberta energy derivatives	(6)	(14)	2	(10)
Unrealized (losses) gains on natural gas derivatives	(47)	(1)	8	(1)
Unrealized gains on emission portfolio activities	-	9	-	9
Unrealized gains on emission credits held for trading	-	-	1	1
Other	-	2	-	-
	(53)	**(4)**	**11**	**(1)**

[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 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 upon settlement is reflected in adjusted EBITDA for the applicable plant or Corporate category.

Alberta desk electricity portfolio activity in the three months ended September 30, 2015 accounted for unrealized net gains of $26 million. The gains were attributed to the impact of decreasing Alberta forward power prices on the valuation of the portfolio's net forward sales contracts combined with the reversal of prior periods' unrealized losses that settled during the period. During the same period in 2014, the Company recognized unrealized net gains of $4 million which reflected the reversal of prior periods' net losses on forward sales contracts which settled during the three months ended, partially offset by the impact of increasing Alberta forward power prices on the valuation of net forward sales contracts. During the nine months ended September 30, 2015, the Company recognized unrealized net gains of $2 million which reflected the impact of decreasing Alberta forward power prices on the valuation of net forward sales contracts partially offset by the reversal of prior periods' unrealized net gains on forward sales contracts which settled during the period. During the nine months ended September 30, 2014, the Company recognized unrealized net losses of $10 million primarily due to net forward sales contracts valued based on increasing Alberta forward power prices.

During the nine months ended September 30, 2015, the Company recognized unrealized net gains of $8 million on natural gas derivatives which primarily reflected the reversal of previously recognized unrealized net losses on contracts which settled during the first nine months of 2015.

Emission portfolio activities for the three months ended September 30, 2015 were consistent with the same period in 2014. For the nine months ended September 30, 2015 the unrealized emission portfolio valuation amounts were immaterial compared to the same period in 2014 when the Company recognized unrealized net gains of $9 million, which were primarily driven by the impact of increasing forward prices on the valuation of net forward sales contracts.

Unrealized changes in the fair value of emission credits held for trading were comparable for the three and nine months ended September 30, 2015 compared to the same periods in 2014.

Consolidated Other Expenses and Non-controlling Interests

(unaudited, $ millions)	Three months ended September 30		Nine months ended September 30	
	2015	**2014**	**2015**	**2014**
Interest on borrowings less capitalized interest	(23)	(11)	(58)	(34)
Realized gains (losses) on settlement of interest rate derivatives	-	(1)	1	1
Other finance expense – sundry interest and guarantee and other fees	(1)	(2)	(3)	(4)
	(24)	(14)	(60)	(37)
Unrealized gains (losses) representing changes in the fair value of interest rate derivatives	-	1	(2)	2
Other finance expense – amortization and accretion charges	(1)	(2)	(4)	(4)
Other finance expense – finance charges incurred on repurchase of debt	-	-	(1)	-
Total finance expense	(25)	(15)	(67)	(39)
Depreciation and amortization	(53)	(47)	(159)	(140)
Foreign exchange loss	(8)	(5)	(15)	(6)
Income tax expense	(16)	(81)	(52)	(95)
Net (income) loss attributable to non-controlling interests	(1)	12	3	5

Finance expense

Higher finance expense for the three and nine months ended September 30, 2015 compared with the three and nine months ended September 30, 2014 was primarily due to decreased capitalized interest as Shepard was completed in March 2015 and additional debt incurred as a result of the acquisition of Macho Springs in December 2014.

Depreciation and amortization

Depreciation and amortization for the three and nine months ended September 30, 2015 increased $6 million and $19 million, respectively, compared with the same periods in the prior year primarily due to additional expense recognized for Macho Springs which was acquired in December 2014 and for Shepard which commenced commercial operation in March 2015.

Foreign exchange loss

As at September 30, 2015, the Company had outstanding U.S. dollar denominated debt payable totalling US$295 million. Approximately US$195 million is hedged for accounting purposes using foreign currency swaps. Foreign exchange loss consisted of the loss incurred on the revaluation of U.S. dollar denominated debt not hedged for accounting purposes. The exchange rate of the Canadian dollar relative to the U.S. dollar decreased during the three and nine months ended September 30, 2015 resulting in an unrealized loss of $8 million and $15 million, respectively.

Income tax expense

Income tax expense decreased by $65 million and $43 million for the three and nine months ended September 30, 2015 primarily due to a $73 million write-down of U.S. income tax loss carryforwards in the third quarter of 2014. This decrease was partially offset by an increase in income tax expense of $19 million in the second quarter of 2015 for the impact of the increase in the Alberta statutory corporate income tax rate which increased deferred tax liabilities on the Condensed Interim Consolidated Statements of Financial Position.

Non-controlling interests

For the period from January 1, 2015 to April 2, 2015, 18% of CPLP's net income was attributable to EPCOR (three months and nine months ended September 30, 2014 - 19%) which was reported as net income attributable to non-controlling interests by the Company. Effective April 2, 2015, EPCOR disposed of all its interest in CPLP (see Significant Events). Net income attributable to non-controlling interests also included the Genesee Coal Mine Assets

(Coal Mine) partner's share of the consolidated net income of the Coal Mine. Subsequent to April 2, 2015, non-controlling interests for future periods will consist only of the Coal Mine partner's share of consolidated net income of the Coal Mine.

COMPREHENSIVE INCOME (LOSS)

(unaudited, $ millions)	Three months ended September 30		Nine months ended September 30	
	2015	**2014**	**2015**	**2014**
Net income (loss)	50	(57)	52	2
Other comprehensive income (loss):				
Net unrealized gains (losses) on commodity derivatives designated as cash flow hedges	78	(1)	37	(17)
Net realized (gains) losses and ineffective portion of unrealized (gains) losses on commodity derivatives designated as cash flow hedges reclassified to revenues and/or energy purchases and fuel	(20)	5	(34)	-
Unrealized foreign exchange gains on the translation of foreign operations	12	9	26	10
	70	13	29	(7)
Comprehensive income (loss)	**120**	**(44)**	**81**	**(5)**

Other comprehensive income (loss) 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

The significant changes in the Condensed Interim Consolidated Statements of Financial Position from December 31, 2014 to September 30, 2015 were as follows:

(unaudited, $ millions)	September 30, 2015	December 31, 2014	Increase (decrease)	Primary reason for increase (decrease)
Trade and other receivables	174	185	(11)	Lower trade receivables related to Alberta operations resulting from lower power prices.
Inventories	122	104	18	Increased purchase of emission credits held for trading.
Net derivative financial instruments assets	167	113	54	Impact of decreased Alberta forward power prices on the fair value of forward sales contracts.
Finance lease receivables	694	708	(14)	Payments received.
Property, plant and equipment	3,713	3,701	12	Capital additions (primarily Shepard and Beaufort Solar) partly offset by depreciation and amortization.
Trade and other payables	208	185	23	Increased capital trade payables related to Shepard and Beaufort Solar.
Loans and borrowings (including current portion)	1,606	1,586	20	Increased bankers' acceptances outstanding and increased U.S. dollar denominated debt outstanding including the impact of foreign exchange partly offset by repayment of loans and borrowings.
Net deferred tax liabilities	336	228	108	Impact of increased Alberta statutory income tax rate and increased share of ownership of CPLP.
Provisions (including current portion)	233	220	13	Increased decommissioning provisions resulting from discount rate reductions.
Share capital	2,786	2,391	395	Shares issued to EPCOR and under the Dividend Re-investment Plan.
Retained earnings (deficit)	(62)	25	(87)	Net income offset by common and preferred share dividends.
Other reserves	60	35	25	Unrealized gains on cash flow hedges, partly offset by reclassification of gains to income.
Non-controlling interests	68	552	(484)	EPCOR's exchange of exchangeable common limited partnership units of CPLP for common shares of Capital Power

LIQUIDITY AND CAPITAL RESOURCES

(unaudited, $ millions)	Nine months ended September 30		
Cash inflows (outflows)	**2015**	**2014**	**Increase (decrease)**
Operating activities	305	284	21
Investing activities	(117)	(154)	37
Financing activities	(230)	(112)	(118)

Operating activities

Cash flows from operating activities for the nine months ended September 30, 2015 increased on a year-over-year basis primarily due to the increase in overall plant adjusted EBITDA and higher cash contributions from operating working capital, partly offset by the receipt, in 2014, of $20 million in revenues on the amendment of the Genesee Coal Mine Agreements.

Investing activities

Cash flows used in investing activities for the nine months ended September 30, 2015 totalled $117 million and reflected the sum of purchases of property, plant and equipment and other assets and cash outflows from changes in trade payable balances related to capital expenditures, partly offset by cash proceeds on sale of emission credits and other miscellaneous cash receipts. The year-over-year reduction is due to lower spending on growth projects.

Capital expenditures and investments

(unaudited, $ millions)	Pre-2015 Actual	Nine months ended September 30, 2015 Actual	Balance of 2015 Estimated [1]	Actual or Projected Total [2]	Timing
K2 Wind [3]	44	1	-	310	Commercial operation commenced May 2015
Shepard	811	37	6	854	Commercial operation commenced March 2015
Beaufort Solar	-	29	16	45	Targeted completion in fourth quarter 2015
Genesee 4 and 5 [4]	2	4	3	700	Targeted completion of first unit 2019
Subtotal growth projects		**71**			
Sustaining – plant maintenance excluding Genesee mine		42			
Sustaining – Genesee mine maintenance and lands [5]		4			
Sustaining – other		4			
Total capital expenditures [6]		**121**			
Emission credits held for compliance		10			
Capitalized interest		(8)			
Purchase of property, plant and equipment and other assets		**123**			

1 The Company's 2015 estimated capital expenditures include only expenditures for previously announced growth projects and exclude other potential new development projects.

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

3 The actual 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 including both debt and equity financed components.

4 Excludes interest to fund construction and refundable transmission system contribution payments.

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

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

Financing activities

The cash flows used in financing activities for the nine months ended September 30, 2015 totalled $230 million and primarily reflected the sum of distributions to non-controlling interests, common share dividends, preferred share dividends, common shares buyback, repayment of loans and borrowings and capitalized interest paid.

The Company's credit facilities consisted of:

(unaudited, $ millions)		As at September 30, 2015			As at December 31, 2014		
	Maturity timing	**Total facilities**	**Credit facility utilization**	**Available**	**Total facilities**	**Credit facility utilization**	**Available**
CPLP committed credit facility	2020	1,000			1,200		
Letters of credit outstanding			15			122	
Bankers' acceptances outstanding			13			-	
U.S. dollar bank loans outstanding			8			17	
		1,000	36	964	1,200	139	1,061
CPLP bilateral demand credit facilities	N/A	200					
Letters of credit outstanding			112	88	N/A	N/A	N/A
CPLP demand facility	N/A	20	-	20	20	-	20
Capital Power Corporation demand facility	N/A	5	-	5	5	-	5
		1,225	**148**	**1,077**	**1,225**	**139**	**1,086**

During the third quarter of 2015, the Company entered into $200 million of demand bilateral credit facilities. The total credit facility utilization increased $9 million compared with the utilization as at December 31, 2014 primarily due to increased bankers acceptances 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, 2020. 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 category assigned by S&P is the fourth highest rating of S&P's ten rating categories for long-term debt obligations. 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 expected cash requirements for 2015 include:

(unaudited, $millions)	2015 Expected Cash Requirements
Medium-term note settlement and/or repayment	249
Capital expenditures excluding capitalized interest and emission credits held for compliance	153
Common share purchase and cancellation	101
Common share dividends	127
Preferred share dividends	22
CPLP distributions to EPCOR	13

The current portion of loans and borrowings on the September 30, 2015 Condensed Interim Consolidated Statements of Financial Position included $325 million senior debt payable to EPCOR which 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 development and construction of the Genesee 4 and 5 project using existing bank credit facilities and cash flows from operating activities. The Company's other cash requirements identified above are expected to be funded with cash on hand, cash flows from operating activities, use of existing bank credit facilities, and, if necessary, the issuance of long-term debt.

The Company uses short-form base shelf prospectuses to provide it with the ability, market conditions permitting, to obtain new debt and equity capital from external markets when required. Under the short-form base shelf prospectuses, Capital Power may raise up to $3 billion by issuing common shares, preferred shares, subscription receipts exchangeable for common shares and/or other securities of the Company and/or debt securities, and up to $1 billion by issuing medium-term notes with maturities of not less than one year. These prospectuses expire in January 2017.

If instability reoccurs in the Canadian and U.S. financial markets, Capital Power'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. Capital Power has credit exposure relating to various agreements, particularly with respect to its PPA, trading and supplier counterparties. While Capital Power 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, 2015, $127 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, 2015	December 31, 2014
Loans and borrowings	1,606	1,586
Less cash and cash equivalents	34	71
Net debt	1,572	1,515
Share capital	2,786	2,391
Retained earnings (deficit) and other reserves	(2)	60
Non-controlling interests	68	552
Total equity	2,852	3,003
Total capital	**4,424**	**4,518**

CONTRACTUAL OBLIGATIONS AND CONTINGENT LIABILITIES

As of October 23, 2015, the Company's contractual obligations have increased by approximately $20 million with respect to the Beaufort Solar project which is expected to commence commercial operation by the end of 2015 at an estimated total project cost of $45 million. The Company expects to enter into a sale-leaseback transaction of the Beaufort Solar project with a tax equity partner.

There were no other changes to the Company's purchase obligations and commitments since December 31, 2014 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, 2014 MD&A.

Contingent liabilities

Capital Power is participating in a line loss factor 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. This proceeding intends to address the factors to be applied for the years 2006 forward and is expected to be completed in three modules. In January 2015, the AUC issued its decision in Module A of the line loss factor proceeding that the AUC has the jurisdiction and authority to retrospectively change the line loss rule and related loss factors and that such changes as may be determined will be applied retroactively. Module B will address the replacement line loss factors and rules. Module C will address the compensation to be paid or received by the various parties. It is expected that a Module B decision will be issued in the fourth quarter of 2015 while the timing of a Module C decision is unknown. There are many variables and considerations that must be taken into account in establishing transmission line loss factors and new line loss factors have not been established nor has any mechanism for the sharing of any retrospective adjustments been established. Capital Power may incur material additional 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 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

EPCOR was a related party of Capital Power until April 2, 2015, following the secondary offering and exchange of exchangeable common limited partnership units which decreased EPCOR's interest in the Company to 9.1% (see Significant Events). The City of Edmonton, as the sole shareholder of EPCOR, was also a related party of Capital Power until April 2, 2015.

The following table presents the related party transactions between Capital Power and its related parties for the period from January 1, 2015 to April 2, 2015 compared with the three and nine months ended September 30, 2014.

The power sales and purchase of 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. CPLP paid distributions to EPCOR for the period from January 1, 2015 to April 2, 2015 and the nine months ended September 30, 2014 based on EPCOR's unitholdings during those periods.

(unaudited, $ millions)	**Period from January 1, 2015 to April 2, 2015**	**Three months ended September 30, 2014**	**Nine months ended September 30, 2014**
EPCOR (shareholder)			
CPLP distributions paid [1]	6	6	18
Purchase of distribution and transmission services	-	-	2
Purchase of other services	2	2	6
Power sales	5	3	7
Interest incurred on unsecured senior debt payable	5	5	16
Repayment of unsecured senior debt payable	9	-	8
The City of Edmonton (sole shareholder of EPCOR)			
Power sales	-	-	2

[1] Distributions of $7 million were paid on April 30, 2015 based on EPCOR's unitholdings outstanding as of March 31, 2015.

As at September 30, 2015, Capital Power's loans and borrowings payable to EPCOR were $325 million (December 31, 2014 - $334 million). The Company's unsecured senior debt payable to EPCOR, at interest rates ranging from 5.80% to 9.00% per annum, matures between 2015 and 2018. 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.

Trade and other receivables of $3 million and trade and other payables of $13 million at December 31, 2014 due from or due to EPCOR were subsequently settled.

RISKS AND RISK MANAGEMENT

During the second quarter, as a result of the Alberta provincial election, a new Alberta provincial government was formed, which introduced additional uncertainty to the Company's operations. As noted in Significant Events, the Alberta government introduced changes to Alberta regulations governing carbon emissions and introduced a panel that will recommend further changes in the fourth quarter of 2015. The Alberta government also enacted increases to Alberta corporate income tax rates. Capital Power will actively participate in the Alberta government's climate change consultation process and will continue to seek opportunities to contribute to government strategies that impact the Company's operations.

There have been no other material changes in the nine months ended September 30, 2015 to the Company's business and operational risks as described in the Company's December 31, 2014 MD&A.

ENVIRONMENTAL MATTERS

The Company's recorded decommissioning provisions of $175 million as at September 30, 2015 ($161 million as at December 31, 2014) 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 Genesee 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 totaling approximately $30 million in the current and future years and expects to mostly use these credits to comply with applicable environmental regulations.

USE OF JUDGMENTS AND ESTIMATES

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 use of judgments and estimates as described in the Company's December 31, 2014 MD&A.

ACCOUNTING CHANGES

Effective January 1, 2015

There were no significant changes to accounting standards that were effective January 1, 2015 and that were adopted or applied by the Company.

Future

The IASB issued the following new standards and amendments to existing standards that were not yet effective as of September 30, 2015 and which may significantly impact Capital Power:

Standard	Description	Impact to Capital Power	Effective Date
General hedge accounting (amendments to IFRS 9, IFRS 7, and IAS 39)	Potentially provides that hedge accounting may be applied to more hedge strategies, that some own use contracts may be fair valued, and to remove the bright line assessment of hedge effectiveness.	May be able to apply hedge accounting to more hedge strategies. Capital Power is currently analyzing the requirements to determine how best to apply them, determine system requirements, and develop the required disclosures.	These amendments do not have a mandatory effective date but are available for application under IFRS 9 or IAS 39.
Acquisition of an interest in a joint operation (amendments to IFRS 11)	Provides guidance on how a joint operator accounts for the acquisition of an interest in a joint operation that is a business. It requires a joint operator to account for such an acquisition by applying IFRS 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; early application permitted.
Sale or contribution of assets between an investor and its associate or joint venture (amendments to IFRS 10 and IAS 28)	Provides that a full gain or loss will be recognized on the loss of control of a business (whether it is housed in a subsidiary or not) including cases in which the investor retains joint control of, or significant influence over, the investee.	No immediate impact but would affect applicable future transactions.	Effective for annual periods beginning on or after January 1, 2016; early application permitted.
Revenue from contracts with customers (IFRS 15)	New standard on revenue recognition consisting of a single and comprehensive framework for 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 an annual and interim basis.	Effective for annual periods beginning on or after January 1, 2018; early application permitted and to be applied retrospectively.
Financial instruments (IFRS 9)	New standard, replacing IAS 39, which addresses requirements for classification and measurement, impairment, hedge accounting and derecognition of financial assets and liabilities.	May change the measurement of certain financial instruments and the recording of expected credit losses. Capital Power is currently analyzing the requirements to determine how best to apply them, determine system requirements, and develop the required disclosures.	Effective for annual periods beginning on or after January 1, 2018; early application permitted.

FINANCIAL INSTRUMENTS

The classification, carrying amounts and fair values of financial instruments held at September 30, 2015 and December 31, 2014 were as follows:

(unaudited, $ millions)	Classification	Fair value hierarchy level	September 30, 2015 Carrying amount	September 30, 2015 Fair value	December 31, 2014 Carrying amount	December 31, 2014 Fair value
Financial assets:						
Cash and cash equivalents	Loans and receivables	N/A	34	34	71	71
Trade and other receivables	Loans and receivables	N/A	174	174	185	185
Derivative financial instruments assets – current and non-current	Financial assets designated at fair value through income or loss	Level 2	222	222	187	187
Finance lease receivables	Loans and receivables	Level 2	694	664	708	726
Other financial assets	Loans and receivables	Level 2	13	13	16	17
Financial liabilities:						
Trade and other payables	Other financial liabilities	N/A	208	208	185	185
Derivative financial instruments liabilities – current and non-current	Financial liabilities designated at fair value through income or loss	Level 2	55	55	74	74
Loans and borrowings (including current portion)	Other financial liabilities	Level 2	1,606	1,700	1,586	1,670

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. As at September 30, 2015 and December 31, 2014, the Company did not classify any financial instruments in Level 3 of the fair value hierarchy.

Risk management and hedging activities

There have been no material changes in the nine months ended September 30, 2015 to the Company's risk management and hedging activities as described in the Company's December 31, 2014 MD&A.

The derivative financial instruments assets and liabilities held at September 30, 2015 compared with December 31, 2014 and used for risk management purposes were measured at fair value and consisted of the following:

(unaudited, $ millions)	As at September 30, 2015				
	Commodity cash flow hedges	Commodity non-hedges	Foreign exchange hedges	Interest rate non-hedges	Total
Derivative financial instruments assets	59	93	62	8	222
Derivative financial instruments liabilities	(5)	(39)	-	(11)	(55)
Net derivative financial instruments assets (liabilities)	**54**	**54**	**62**	**(3)**	**167**

(unaudited, $ millions)	As at December 31, 2014				
	Commodity cash flow hedges	Commodity non-hedges	Foreign exchange hedges	Interest rate non-hedges	Total
Derivative financial instruments assets	53	109	21	4	187
Derivative financial instruments liabilities	(3)	(66)	-	(5)	(74)
Net derivative financial instruments assets (liabilities)	**50**	**43**	**21**	**(1)**	**113**

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.

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 during the nine months ended September 30, 2015 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 2015**	**Jun 30 2015**	**Mar 31 2015**	**Dec 31 2014**	**Sep 30 2014**	**Jun 30 2014**	**Mar 31 2014**	**Dec 31 2013**
Total generation excluding Sundance PPA	3,687	3,553	3,398	3,204	3,220	2,711	3,241	3,925
Alberta commercial plants and Sundance PPA								
Genesee 3	498	491	493	369	473	438	466	463
Keephills 3	258	436	457	433	461	381	399	418
Clover Bar Energy Centre 1, 2 and 3	39	98	70	45	77	66	108	60
Joffre	62	76	86	58	77	71	118	95
Shepard	572	443	60	N/A	N/A	N/A	N/A	N/A
Halkirk	88	107	136	146	86	92	138	137
Clover Bar Landfill Gas	2	3	2	3	3	5	3	5
Alberta commercial plants – owned	1,519	1,654	1,304	1,054	1,177	1,053	1,232	1,178
Sundance PPA	688	565	691	819	673	521	750	710
	2,207	2,219	1,995	1,873	1,850	1,574	1,982	1,888
Alberta contracted plants								
Genesee 1	865	608	815	857	854	771	678	842
Genesee 2	843	838	836	856	841	546	832	802
	1,708	1,446	1,651	1,713	1,695	1,317	1,510	1,644
Ontario and British Columbia contracted plants								
Island Generation	37	37	-	9	6	-	115	210
K2 Wind	46	19	N/A	N/A	N/A	N/A	N/A	N/A
Kingsbridge 1	13	21	31	35	14	22	34	37
Port Dover and Nanticoke	44	69	91	91	51	66	93	54
Quality Wind	97	82	108	101	71	80	97	113
	237	228	230	236	142	168	339	414
U.S. contracted plants								
Macho Springs, New Mexico	19	37	25	5	N/A	N/A	N/A	N/A
Roxboro, North Carolina	76	70	59	74	73	58	39	70
Southport, North Carolina	128	118	129	122	133	115	121	128
	223	225	213	201	206	173	160	198
U.S. commercial plants								
Bridgeport, Connecticut	N/A	N/A	N/A	N/A	N/A	N/A	N/A	326
Rumford, Maine	N/A	N/A	N/A	N/A	N/A	N/A	N/A	10
Tiverton, Rhode Island	N/A	N/A	N/A	N/A	N/A	N/A	N/A	155
	N/A	N/A	N/A	N/A	N/A	N/A	N/A	491

(%)	Three months ended							
Plant availability	**Sep 30 2015**	**Jun 30 2015**	**Mar 31 2015**	**Dec 31 2014**	**Sep 30 2014**	**Jun 30 2014**	**Mar 31 2014**	**Dec 31 2013**
Total average plant availability excluding Sundance PPA	95	90	98	94	97	92	94	93
Alberta commercial plants and Sundance PPA								
Genesee 3	100	100	100	74	97	96	96	98
Keephills 3	63	97	100	92	100	100	100	99
Clover Bar Energy Centre 1, 2 and 3	88	95	97	90	97	98	97	91
Joffre	100	87	99	82	95	95	100	85
Shepard	100	73	80	N/A	N/A	N/A	N/A	N/A
Halkirk	97	98	99	98	91	98	96	99
Clover Bar Landfill Gas	81	93	100	87	58	83	75	98
Alberta commercial plants – owned	92	89	97	87	96	97	98	94
Sundance PPA	91	79	92	96	85	67	89	89
	92	86	95	91	91	84	94	92
Alberta contracted plants								
Genesee 1	100	72	98	100	100	96	83	100
Genesee 2	98	100	100	100	99	66	93	95
	99	86	99	100	99	81	88	98
Ontario and British Columbia contracted plants								
Island Generation	100	100	100	100	99	100	100	99
K2 Wind	98	98	N/A	N/A	N/A	N/A	N/A	N/A
Kingsbridge 1	94	95	97	96	93	97	95	94
Port Dover and Nanticoke	95	97	99	97	98	94	98	95
Quality Wind	94	97	98	98	93	99	95	98
	97	98	99	98	97	98	98	98
U.S. contracted plants								
Macho Springs, New Mexico	96	99	99	99	N/A	N/A	N/A	N/A
Roxboro, North Carolina	94	87	97	100	100	96	90	98
Southport, North Carolina	94	88	89	88	85	93	99	91
	95	91	94	92	90	94	96	93
U.S. commercial plants								
Bridgeport, Connecticut	N/A	N/A	N/A	N/A	N/A	N/A	N/A	72
Rumford, Maine	N/A	N/A	N/A	N/A	N/A	N/A	N/A	91
Tiverton, Rhode Island	N/A	N/A	N/A	N/A	N/A	N/A	N/A	83
	N/A	N/A	N/A	N/A	N/A	N/A	N/A	79

Financial results

(unaudited, $ millions)	Three months ended							
	Sep 30 2015	**Jun 30 2015**	**Mar 31 2015**	**Dec 31 2014**	**Sep 30 2014**	**Jun 30 2014**	**Mar 31 2014**	**Dec 31 2013**
Revenues								
Alberta commercial plants, Sundance PPA and portfolio optimization	237	130	216	200	119	133	188	173
Alberta contracted plants	72	67	66	69	76	58	63	70
Ontario and British Columbia contracted plants	23	25	36	36	21	25	37	33
U.S. contracted plants	29	28	27	22	22	22	17	19
U.S. commercial plants and portfolio optimization	-	-	-	-	-	-	-	23
Corporate [1]	2	4	1	(20)	2	15	2	(9)
Unrealized changes in fair value of commodity derivatives and emission credits	106	(171)	12	125	8	(13)	1	18
	469	**83**	**358**	**432**	**248**	**240**	**308**	**327**
Adjusted EBITDA								
Alberta commercial plants, Sundance PPA and portfolio optimization	72	49	63	60	49	43	59	57
Alberta contracted plants	52	45	42	41	44	34	42	53
Ontario and British Columbia contracted plants	16	19	30	29	15	18	30	26
U.S. contracted plants	6	6	5	1	3	3	-	1
U.S. commercial plants and portfolio optimization	-	-	-	-	-	-	-	(1)
Corporate	(25)	(27)	(24)	(27)	(25)	(7)	(25)	(34)
Unrealized changes in fair value of commodity derivatives and emission credits	27	(47)	31	37	5	(13)	7	17
	148	**45**	**147**	**141**	**91**	**78**	**113**	**119**

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

Quarterly revenues, net income and cash flows from 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.

Financial highlights

(unaudited, $ millions except per share amounts)	Three months ended							
	Sep 30 2015	**Jun 30 2015**	**Mar 31 2015**	**Dec 31 2014**	**Sep 30 2014**	**Jun 30 2014**	**Mar 31 2014**	**Dec 31 2013**
Revenues	469	83	358	432	248	240	308	327
Adjusted EBITDA [1]	148	45	147	141	91	78	113	119
Net income (loss)	50	(48)	50	48	(57)	21	38	98
Net income (loss) attributable to shareholders of the Company	49	(34)	40	39	(45)	20	32	77
Basic earnings (loss) per share ($)	0.44	(0.39)	0.41	0.40	(0.62)	0.17	0.33	0.89
Normalized earnings per share ($) [1]	0.33	0.10	0.32	0.20	0.12	0.07	0.32	0.40
Funds from operations [1]	97	70	108	102	83	85	92	110
Purchase of property, plant and equipment and other assets	36	35	52	57	25	63	75	59

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

	Three months ended							
Spot price averages	**Sep 30 2015**	**Jun 30 2015**	**Mar 31 2015**	**Dec 31 2014**	**Sep 30 2014**	**Jun 30 2014**	**Mar 31 2014**	**Dec 31 2013**
Alberta power ($ per MWh)	26	57	29	30	64	42	61	49
Alberta natural gas (AECO) ($ per Gj)	2.77	2.52	2.63	3.43	3.81	4.46	5.45	3.33
Capital Power's Alberta portfolio average realized power price ($ per MWh)	61	46	59	58	56	57	58	64

Factors impacting results for the previous quarters

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

The results for the second quarter of 2015 reflected volatility in Alberta power prices where spot prices averaged $97 per MWh in June due to warmer weather compared with $21 per MWh in April 2015 and $54 per MWh in May 2015. The positive EBITDA realized by the Alberta plants was partly offset by portfolio optimization results. With commercial production sold forward at 100% in the quarter, the Company was required to cover a short market position at higher prices. Capital Power's second quarter 2015 results were also negatively impacted by the announcement of an increase to the Alberta statutory income tax rate, which resulted in $19 million of additional income tax expense for the quarter. The Alberta government also announced changes to Alberta's regulations governing carbon emissions with increases to the required reduction in emissions intensity and cost of compliance. Capital Power announced a 7.4% increase in the annual dividend for holders of its common shares which will commence with the third quarter 2015 quarterly dividend payment payable on October 30, 2015.

The results for the quarter ended March 31, 2015 reflected the impact of low Alberta power pricing averaging $29 per MWh. Alberta commercial plant results reflected the commencement of operations at Shepard. Portfolio optimization results were strong since the Company was fully hedged at an average realized price of $59 per MWh. The Alberta electricity portfolio accounted for unrealized net gains of $21 million due to decreasing Alberta forward prices combined with the portfolio's net forward sales contracts.

The results for the quarter ended December 31, 2014 reflected the Genesee 3 major planned outage and the impact of low Alberta power pricing averaging $30 per MWh. Portfolio optimization revenues were strong since the Company hedged a greater portion of its baseload generation by entering into more contracts. Captured prices realized through portfolio optimization were greater than spot prices during the fourth quarter of 2014. Alberta commercial plant results included an $8 million recovery on settlement of a claim with a turbine supplier relating to a component failure at Genesee 3 in 2008. Adjusted EBITDA for the Alberta contracted plants was negatively impacted by costs associated with the wind-up of the Genesee coal mine's defined benefit pension plan. Significant events during the quarter were the acquisition of renewable development sites and the receipt of all major regulatory approvals for Genesee 4 and 5.

Financial results for the third quarter of 2014 reflected the impact of an extended planned outage and other unplanned outages at the Sundance PPA units and derates at the Keephills 3 plant. The outages occurred primarily in July 2014 coinciding with a period of pricing volatility with Alberta spot power prices in July averaging $122 per MWh compared with $45 per MWh in August 2014 and $24 per MWh in September 2014. With commercial production 100% sold forward in July 2014, the resulting short position was covered at the higher prices. Capital Power's third quarter 2014 net income was also 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 could no longer be recognized for accounting purposes based on the Company's long-term forecast for U.S. taxable income.

In the second quarter of 2014, the results for the Alberta commercial plants reflected seasonally low Alberta power prices, lower generation from the 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 operation 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.

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 2015	**Jun 30 2015**	**Mar 31 2015**	**Dec 31 2014**	**Sep 30 2014**	**Jun 30 2014**	**Mar 31 2014**	**Dec 31 2013**
Share price ($/common share)								
High	22.42	25.58	27.12	28.14	28.71	26.49	25.81	21.95
Low	18.28	21.53	23.77	24.50	25.75	24.07	20.51	20.30
Close	18.88	21.54	24.51	26.00	26.75	26.37	25.72	21.30
Volume of shares traded (millions)	19.4	21.1	18.8	13.9	12.5	13.9	18.2	16.6

Outstanding share and partnership unit data

As at October 20, 2015, the Company had 99.214 million common 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 ignoring exercise prices, the outstanding and issuable common shares as at October 20, 2015 were 102.987 million. The outstanding special limited voting share is held by EPCOR.

As at October 20, 2015, CPLP had 21.750 million general partnership units outstanding and 80.953 million common limited partnership units outstanding. All of the outstanding general partnership units and the outstanding common limited partnership units are held by the Company.

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, 2015 and 2014

CAPITAL POWER CORPORATION

Condensed Interim Consolidated Financial Statements
Nine months ended September 30, 2015 and 2014

Condensed Interim Consolidated Financial Statements:

CAPITAL POWER CORPORATION

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

	Three months ended September 30, 2015	Three months ended September 30, 2014	Nine months ended September 30, 2015	Nine months ended September 30, 2014
Revenues	$ 469	$ 248	$ 910	$ 796
Energy purchases and fuel	(243)	(79)	(343)	(285)
Gross margin	226	169	567	511
Other raw materials and operating charges	(26)	(25)	(73)	(71)
Staff costs and employee benefits expense	(33)	(29)	(95)	(92)
Depreciation and amortization	(53)	(47)	(159)	(140)
Other administrative expense	(19)	(24)	(59)	(66)
Foreign exchange loss	(8)	(5)	(15)	(6)
Operating income	87	39	166	136
Finance expense	(25)	(15)	(67)	(39)
Income from joint venture	4	-	5	-
Income before tax	66	24	104	97
Income tax expense (note 5)	(16)	(81)	(52)	(95)
Net income (loss)	$ 50	$ (57)	$ 52	$ 2
Attributable to:				
Non-controlling interests	$ 1	$ (12)	$ (3)	$ (5)
Shareholders of the Company	$ 49	$ (45)	$ 55	$ 7
Earnings (loss) per share (attributable to common shareholders of the Company):				
Basic (note 6)	$ 0.44	$ (0.62)	$ 0.40	$ (0.12)
Diluted (note 6)	$ 0.44	$ (0.62)	$ 0.40	$ (0.12)

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

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

	Three months ended September 30, 2015	Three months ended September 30, 2014	Nine months ended September 30, 2015	Nine months ended September 30, 2014
Net income (loss)	$ 50	$ (57)	$ 52	$ 2
Other comprehensive income (loss):				
Items that are or may be reclassified subsequently to net income (loss):				
Cash flow hedges:				
Unrealized gains (losses) on derivative instruments[1]	83	1	45	(8)
Unrealized losses on derivative instruments – joint venture[2]	(5)	(2)	(8)	(9)
Reclassification of (gains) losses on derivative instruments to income for the period[3]	(20)	5	(34)	-
Net investment in foreign subsidiaries:				
Unrealized gain[4]	12	9	26	10
Total items that are or may be reclassified subsequently to net income (loss), net of tax	70	13	29	(7)
Total other comprehensive income (loss), net of tax	70	13	29	(7)
Total comprehensive income (loss)	$ 120	$ (44)	$ 81	$ (5)
Attributable to:				
Non-controlling interests	$ 4	$ (9)	$ (2)	$ (7)
Shareholders of the Company	$ 116	$ (35)	$ 83	$ 2

[1] For the three and nine months ended September 30, 2015, net of income tax expense of $30 and $18 respectively. For the three and nine months ended September 30, 2014, net of income tax recovery of nil and $2 respectively.

[2] For the three and nine months ended September 30, 2015, net of income tax recovery of $2 and $3 respectively. For the three and nine months ended September 30, 2014, net of income tax recovery of $1 and $3 respectively.

[3] For the three and nine months ended September 30, 2015, net of reclassification of income tax expense of $7 and $13 respectively. For the three and nine months ended September 30, 2014, net of reclassification of income tax recovery of $2 and nil respectively.

[4] For the three and nine months ended September 30, 2015, net of income tax expense of nil. For the three and nine months ended September 30, 2014, net of income tax expense 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, 2015	December 31, 2014
Assets		
Current assets:		
Cash and cash equivalents	$ 34	$ 71
Trade and other receivables	174	185
Inventories	122	104
Derivative financial instruments assets (note 7)	157	132
	487	492
Non-current assets:		
Other assets	25	28
Derivative financial instruments assets (note 7)	65	55
Finance lease receivables	694	708
Other financial assets	14	18
Deferred tax assets	23	21
Equity-accounted investment	15	22
Intangible assets	341	350
Property, plant and equipment	3,713	3,701
Goodwill	29	25
Total assets	$ 5,406	$ 5,420
Liabilities and equity		
Current liabilities:		
Trade and other payables	$ 208	$ 185
Derivative financial instruments liabilities (note 7)	40	64
Loans and borrowings	565	599
Deferred revenue and other liabilities	2	5
Provisions	21	22
	836	875
Non-current liabilities:		
Derivative financial instruments liabilities (note 7)	15	10
Loans and borrowings	1,041	987
Deferred revenue and other liabilities	91	98
Deferred tax liabilities	359	249
Provisions	212	198
	1,718	1,542
Equity:		
Equity attributable to shareholders of the Company		
Share capital (note 8)	2,786	2,391
Retained earnings (deficit)	(62)	25
Other reserves	60	35
Retained earnings (deficit) and other reserves	(2)	60
	2,784	2,451
Non-controlling interests (note 8)	68	552
Total equity	2,852	3,003
Total liabilities and equity	$ 5,406	$ 5,420

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, 2015	$ 2,391	$ 40	$ (1)	$ (13)	$ 9	$ 25	$ 2,451	$ 552	$ 3,003
Net income (loss)	-	-	-	-	-	55	55	(3)	52
Other comprehensive income :									
Cash flow derivative hedge gains	-	63	-	-	-	-	63	-	63
Cash flow derivative hedge losses – joint venture	-	(11)	-	-	-	-	(11)	-	(11)
Reclassification of gains to income	-	(47)	-	-	-	-	(47)	-	(47)
Unrealized gain on foreign currency translation	-	-	26	-	-	-	26	-	26
Tax on items recognized directly in equity	-	(2)	-	-	-	-	(2)	-	(2)
Attributed to non-controlling interests	-	-	(1)	-	-	-	(1)	1	-
Other comprehensive income	$ -	$ 3	$ 25	$ -	$ -	$ -	$ 28	$ 1	$ 29
Total comprehensive income (loss)	-	3	25	-	-	55	83	(2)	81
Issue of share capital (note 8)	449	-	-	-	-	-	449	-	449
Deferred taxes on share issue costs (note 8)	1	-	-	-	-	-	1	-	1
Distributions to non-controlling interests	-	-	-	-	-	-	-	(6)	(6)
Net additional investment by non-controlling interests	-	-	-	-	-	-	-	4	4
Change in non-controlling interests ownership	-	(1)	-	-	-	30	29	(480)	(451)
Tax on change in non-controlling interests ownership	-	(3)	-	-	-	(56)	(59)	-	(59)
Common share dividends (note 8)	-	-	-	-	-	(99)	(99)	-	(99)
Preferred share dividends (note 8)	-	-	-	-	-	(16)	(16)	-	(16)
Tax on preferred share dividends	-	-	-	-	-	(1)	(1)	-	(1)
Dividends reinvested (note 8)	22	-	-	-	-	-	22	-	22
Common shares buyback (note 8)	(79)	-	-	-	-	-	(79)	-	(79)
Share-based payment	-	-	-	-	1	-	1	-	1
Share options exercised (note 8)	2	-	-	-	-	-	2	-	2
Equity as at September 30, 2015	$ 2,786	$ 39	$ 24	$ (13)	$ 10	$ (62)	$ 2,784	$ 68	$ 2,852

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

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

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

	Share capital	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)
Unrealized gain 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 (note 8)	-	-	-	-	-	(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 (loss). Other reserves on the statements of financial position are the aggregate of accumulated other comprehensive income (loss) and the employee benefits reserve.

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

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

	Nine months ended September 30, 2015	2014
Cash flows from operating activities:		
Net income	$ 52	$ 2
Non-cash adjustments to reconcile net income to net cash flows from operating activities:		
Depreciation and amortization	159	140
Finance expense	67	39
Fair value changes on commodity derivative instruments and emission credits held for trading	(11)	1
Unrealized foreign exchange loss	16	6
Income tax expense	52	95
Other items	(16)	1
Change in fair value of derivative instruments reflected as cash settlement	5	-
Finance lease receivable collected	15	12
Interest paid[1]	(52)	(29)
Income taxes (paid) recovered[2]	(1)	7
Change in non-cash operating working capital	19	10
Net cash flows from operating activities	305	284
Cash flows used in investing activities:		
Purchase of property, plant and equipment and other assets	(123)	(163)
Other cash flows from investing activities	12	19
Change in non-cash investing working capital	(6)	(10)
Net cash flows used in investing activities	(117)	(154)
Cash flows used in financing activities:		
Proceeds from issue of loans and borrowings	3	-
Repayment of loans and borrowings	(41)	(10)
Issue costs on loans and borrowings	(1)	-
Proceeds from exercise of share options	1	22
Common shares buyback (note 8)	(79)	-
Distributions paid to non-controlling interests	(12)	(18)
Common share dividends paid (note 8)	(70)	(49)
Preferred share dividends paid (note 8)	(16)	(16)
Capitalized interest paid[1]	(8)	(29)
Income taxes paid[2]	(7)	(12)
Net cash flows used in financing activities	(230)	(112)
Foreign exchange gain on cash held in a foreign currency	5	1
Net (decrease) increase in cash and cash equivalents	(37)	19
Cash and cash equivalents at beginning of period	71	100
Cash and cash equivalents at end of period	$ 34	$ 119

[1] Total interest paid.

[2] Total income taxes paid.

See accompanying notes to the condensed interim consolidated financial statements

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

1. Reporting entity:

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

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

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

2. Basis of presentation:

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 2014 annual consolidated 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, 2014, 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 23, 2015.

3. Business combination:

The purchase price allocation of the Company's acquisition of Element Power U.S. LLC was finalized during the third quarter of 2015. The adjustments from the amounts recorded and disclosed at December 31, 2014 resulted from the receipt of final information related to balances as of the acquisition date, and minor changes in assumptions related to the replacement cost of property, plant and equipment. The adjustments are as follows:

	December 31, 2014	Adjustments	September 30, 2015
Cash	$ 3	$ -	$ 3
Other assets	3	-	3
Intangibles	36	-	36
Property, plant and equipment	103	(7)	96
Loans and borrowings	(76)	4	(72)
Provisions	(3)	-	(3)
Deferred tax liabilities	(29)	3	(26)
Fair value of net assets acquired	$ 37	$ -	$ 37

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 2015. 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:

	2015	2014
Discount rate – currently contracted period	6.8%	7.9%
Discount rate – post current contract period	8.8%	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 in 2021 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, 45% tire-derived fuel (TDF), and 5% coal, and that long-term contracts will be executed 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.

5. Income tax:

Income tax differs 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,	
	2015	2014	2015	2014
Income before tax	$ 66	$ 24	$ 104	$ 97
Income tax at the statutory rates of 26.0% (2014 – 25.0%)	17	6	27	24
Increase (decrease) resulting from:				
Amounts attributable to non-controlling interests	-	-	2	(1)
Change in unrecognized tax benefits	(4)	74	-	74
Non-taxable amounts	-	-	-	(1)
Statutory and other rate differences	2	1	20	(1)
Other	1	-	3	-
Income tax expense	$ 16	$ 81	$ 52	$ 95

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

6. Earnings (loss) per share:

Basic earnings (loss) per share

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

	Three months ended September 30, 2015	Three months ended September 30, 2014	Nine months ended September 30, 2015	Nine months ended September 30, 2014
Income (loss) for the period attributable to shareholders of the Company	$ 49	$ (45)	$ 55	$ 7
Preferred share dividends of the Company [1]	(5)	(6)	(17)	(17)
Earnings (loss) used in the calculation of basic earnings (loss) per share	$ 44	$ (51)	$ 38	$ (10)

[1] Includes preferred share dividends and related taxes in respect of the three and nine months ended September 30, 2015 and 2014 respectively.

	Three months ended September 30, 2015	Three months ended September 30, 2014	Nine months ended September 30, 2015	Nine months ended September 30, 2014
Weighted average number of common shares used in the calculation of basic earnings (loss) per share	100,909,850	82,788,601	95,629,854	81,974,376

Diluted earnings (loss) per share

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

	Three months ended September 30, 2015	Three months ended September 30, 2014	Nine months ended September 30, 2015	Nine months ended September 30, 2014
Earnings (loss) used in the calculation of basic earnings (loss) per share	$ 44	$ (51)	$ 38	$ (10)
Effect of exchangeable limited partnership units issued to EPCOR for common shares [2]	-	(12)	-	-
Earnings (loss) used in the calculation of diluted earnings per share	$ 44	$ (63)	$ 38	$ (10)

[2] The exchangeable limited partnership units issued to EPCOR Utilities Inc. (EPCOR) were exchangeable for common shares of Capital Power on a one-for-one basis. On April 2, 2015, EPCOR exchanged all of its outstanding exchangeable limited partnership units for common shares of Capital Power. As such, the units exchanged were included in the calculation of the Company's basic earnings (loss) per share effective for the second quarter of 2015. For the nine months ended September 30, 2015, the potential exchange of such units was not included in the calculation as it was anti-dilutive during the first quarter of 2015. 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.

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

6. Earnings (loss) per share, continued:

Diluted earnings (loss) per share, continued:

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

	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
Weighted average number of common shares used in the calculation of basic earnings (loss) per share	100,909,850	82,788,601	95,629,854	81,974,376
Effect of dilutive share purchase options[3]	-	-	13,867	-
Effect of exchangeable limited partnership units issued to EPCOR for common shares	-	18,841,000	-	-
Weighted average number of common shares used in the calculation of diluted earnings (loss) per share	100,909,850	101,629,601	95,643,721	81,974,376

[3] For the nine months ended September 30, 2015, the average market price of the Company's common shares exceeded the exercise price of certain granted share purchase options but had a neutral effect on earnings per share. For the three months ended September 30, 2015 and for the three and nine months ended September 30, 2014, 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, 2015				
	Energy and emission allowances		Foreign exchange	Interest rate	
	cash flow hedges	non-hedges	cash flow hedges	non-hedges	Total
Derivative instruments assets:					
Current	$ 32	$ 55	$ 62	$ 8	$ 157
Non-current	27	38	-	-	65
Derivative instruments liabilities:					
Current	(2)	(27)	-	(11)	(40)
Non-current	(3)	(12)	-	-	(15)
Net fair value	$ 54	$ 54	$ 62	$ (3)	$ 167
Net notional buys (sells) (millions):					
Megawatt hours of electricity	(9)	(4)			
Gigajoules of natural gas		6			
Metric tons of emission allowances		(4)			
Megawatt hours of renewable energy credits		(2)			
Cross currency swaps and interest rate swaps (U.S. dollars)			$ 195	$ 100	
Interest rate swaps (Canadian dollars)				$ 100	
Range of remaining contract terms in years[1]	0.1 to 3.3	0.1 to 5.5	5.7 to 10.7	5.7 to 10.2	

[1] Terms of certain foreign exchange cash flow hedge contracts and interest rate non-hedge contracts require settlement in 2.7 years and 0.2 years respectively. The remaining years of the underlying derivatives of these contracts are reflected in the table above.

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

7. Derivative financial instruments and hedge accounting, continued:

	December 31, 2014				
	Energy and emission allowances		Foreign exchange	Interest rate	
	cash flow hedges	non-hedges	cash flow hedges	non-hedges	Total
Derivative instruments assets:					
Current	$ 27	$ 80	$ 21	$ 4	$ 132
Non-current	26	29	-	-	55
Derivative instruments liabilities:					
Current	(1)	(58)	-	(5)	(64)
Non-current	(2)	(8)	-	-	(10)
Net fair value	$ 50	$ 43	$ 21	$ (1)	$ 113
Net notional buys (sells) (millions):					
Megawatt hours of electricity	(8)	(6)			
Gigajoules of natural gas		5			
Metric tons of emission allowances		(2)			
Megawatt hours of renewable energy credits		(2)			
Cross currency swaps and interest rate swaps (U.S. dollars)			$ 195	$ 100	
Interest rate swaps (Canadian dollars)				$ 100	
Range of remaining contract terms in years[2]	0.1 to 4.0	0.1 to 6.3	6.5 to 11.5	6.5 to 10.9	

[2] Terms of certain foreign exchange cash flow hedge contracts and interest rate non-hedge contracts require settlement in 2.0 years and 0.9 years respectively. The remaining years of the underlying derivatives of these contracts are reflected in the table above.

Fair values of derivative instruments are determined using valuation techniques, inputs, and assumptions as described in the Company's 2014 annual consolidated financial statements. 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. As at September 30, 2015 and December 31, 2014, the Company classified all financial instruments under Level 2 of the fair value hierarchy described in note 9.

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

	Three months ended September 30, 2015		Three months ended September 30, 2014	
	Unrealized gains	Realized gains	Unrealized gains	Realized losses
Energy cash flow hedges	$ 78	$ 27	$ 8	$ (7)
Energy and emission allowances non-hedges	25	49	5	(5)
Foreign exchange cash flow hedges[3]	8	-	-	-
Interest rate non-hedges	-	-	1	(1)

[3] For the three months ended September 30, 2015, unrealized gains of $17 million (three months ended September 30, 2014 – unrealized gains of $10 million) related to foreign exchange cash flow hedges were reclassified from other comprehensive income (loss) to net income (loss) to offset the impact to unrealized foreign exchange losses 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:

	Nine months ended September 30, 2015		Nine months ended September 30, 2014	
	Unrealized gains (losses)	Realized gains	Unrealized (losses) gains	Realized gains
Energy cash flow hedges	$ 9	$ 47	$ (10)	$ -
Energy and emission allowances non-hedges	10	64	(1)	9
Foreign exchange cash flow hedges[4]	7	-	-	-
Interest rate non-hedges	(2)	1	2	1

[4] For the nine months ended September 30, 2015, unrealized gains of $34 million (nine months ended September 30, 2014 – unrealized gains of $11 million) related to foreign exchange cash flow hedges were reclassified from other comprehensive income (loss) to net income (loss) to offset the impact to unrealized foreign exchange losses from the revaluation of U.S. dollar denominated loans and borrowings.

Realized and unrealized gains and losses relate only to derivative financial instruments. The following realized and unrealized gains and losses are included in the Company's statements of income (loss) for the three and nine months ended September 30, 2015 and 2014:

	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
Revenues	$ 207	$ 5	$ 173	$ 85
Energy purchases and fuel	(106)	(12)	(52)	(77)
Foreign exchange gain	17	10	34	11
Finance expense	-	-	(1)	3

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, 2015, the changes in the fair value of the ineffective portion of hedging derivatives required to be recognized in the statement of income (loss) were nil (three and nine months ended September 30, 2014 – nil).

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

	September 30, 2015
Within one year	$ 32
Between 1 – 5 years	24
After more than 5 years	-
	$ 56

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

8. Share capital:

	Common shares		Preference shares		Special voting shares	
	Number of shares	Amount	Number of shares	Amount	Number of shares	Amount
As at January 1, 2014	80,889,878	$ 1,864	19,000,000	$ 464	18,841,000	$ -
Share purchase options exercised	1,028,778	26	-	-	-	-
Dividend reinvestment plan	1,542,240	37	-	-	-	-
As at December 31, 2014	83,460,896	$ 1,927	19,000,000	$ 464	18,841,000	$ -
Shares exchanged [1]	18,841,000	449	-	-	(18,841,000)	-
Deferred taxes on share issue costs	-	1	-	-	-	-
Share purchase options exercised	76,580	2	-	-	-	-
Dividend reinvestment plan[2]	882,103	22	-	-	-	-
Common shares buyback[3]	(3,581,941)	(79)	-	-	-	-
As at September 30, 2015	99,678,638	$ 2,322	19,000,000	$ 464	-	$ -

[1] On April 2, 2015, EPCOR exchanged 9,450,000 of its exchangeable limited partnership units of CPLP on a one-for-one basis for common shares of Capital Power and subsequently completed its sale of the 9,450,000 common shares at an offering price of $23.85 per common share for aggregate gross proceeds of $225 million. In connection with the offering, EPCOR exchanged its remaining 9,391,000 outstanding exchangeable limited partnership units in CPLP for common shares of Capital Power in accordance with the terms of the exchangeable common limited partnership units. As a result of the unit exchange and share offering, EPCOR's ownership interest in CPLP was reduced to nil (December 31, 2014 – 18%) and Capital Power's interest in CPLP increased to 100% (December 31, 2014 – 82%); therefore EPCOR ceased to be a related party of the Company.

[2] Effective for the June 30, 2015 dividend, Capital Power suspended its dividend reinvestment plan for its common shares until further notice.

[3] On March 25, 2015, the Toronto Stock Exchange approved Capital Power's normal course issuer bid to purchase and cancel up to 5,000,000 of its outstanding common shares during the one-year period from April 7, 2015 to April 6, 2016. During the three and nine months ended September 30, 2015, the Company repurchased and canceled 1,983,805 and 3,581,941 of its outstanding common shares, respectively (three and nine months ended September 30, 2014 – nil).

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

8. Share capital, continued:

The common and preferred share dividends declared and paid by the Company for the three and nine months ended September 30, 2015 and 2014 are summarized as follows:

	Dividends declared							
	For the three months ended September 30,				For the nine months ended September 30,			
	2015		2014		2015		2014	
	Per share	Total	Per share	Total	Per share	Total	Per share	Total
Common[4]	$ 0.3650	$ 36	$ 0.3400	$ 28	$ 1.0450	$ 99	$ 0.9700	$ 80
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	0.8625	6
Preference, Series 5	0.2813	2	0.2813	2	0.8439	6	0.8439	6

[4] On July 27, 2015, the Company's Board of Directors approved an increase of 7.4% in the quarterly dividend to $0.365 per common share effective for the third quarter of 2015.

	Dividends paid							
	For the three months ended September 30,				For the nine months ended September 30,			
	2015		2014		2015		2014	
	Per share	Total[5]	Per share	Total[5]	Per share	Total[5]	Per share	Total[5]
Common[5]	$ 0.3400	$ 35	$ 0.3150	$ 26	$ 1.0200	$92	$ 0.9450	$ 77
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	0.8625	6
Preference, Series 5	0.2813	2	0.2813	2	0.8439	6	0.8439	6

[5] For the three and nine months ended September 30, 2015, dividends paid on common shares consist of $35 million and $70 million paid in cash and nil and $22 million paid through the Company's dividend reinvestment plan as common shares issued, respectively. 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.

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

9. Financial instruments:

Fair values

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

The classification and measurement of the Company's other short-term financial instruments are consistent with the methodologies described in the Company's 2014 annual consolidated financial statements. Due to the short-term nature of the financial instruments, the fair values are not materially different from their carrying amounts.

The fair values of the Company's other long-term financial instruments are determined using the same valuation techniques, inputs, and assumptions as described in the Company's 2014 annual consolidated financial statements. The classification, carrying amount and fair value of the Company's other financial instruments are summarized as follows:

		September 30, 2015		December 31, 2014	
	Fair value hierarchy level	Carrying amount	Fair value	Carrying amount	Fair value
Other financial assets					
Loans and receivables	Level 2	$ 13	$ 13	$ 16	$ 17
Finance lease receivables					
Loans and receivables	Level 2	694	664	708	726
Loans and borrowings					
Other financial liabilities (includes current portion)	Level 2	1,606	1,700	1,586	1,670

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, 2014. 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, 2015 and December 31, 2014, the Company did not classify any financial instruments in Level 3 of the hierarchy.

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, 2015 and the year ended December 31, 2014.

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10. Segment information:

The Company operates in one reportable business segment involved in the operation of electrical generation facilities within Canada (Alberta, British Columbia and Ontario) and in the U.S. (North Carolina and New Mexico), as this is how management assesses performance and determines resource allocations. The Company also holds a portfolio of wind and solar development sites in the U.S.

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

	Three months ended September 30, 2015				Three months ended September 30, 2014			
	Canada	U.S.	Inter-area eliminations	Total	Canada	U.S.	Inter-area eliminations	Total
Revenues - external	$ 435	$ 34	$ -	$ 469	$ 227	$ 21	$ -	$ 248
Revenues - inter-area	5	3	(8)	-	1	-	(1)	-
Total revenues	$ 440	$ 37	$ (8)	$ 469	$ 228	$ 21	$ (1)	$ 248

	Nine months ended September 30, 2015				Nine months ended September 30, 2014			
	Canada	U.S.	Inter-area eliminations	Total	Canada	U.S.	Inter-area eliminations	Total
Revenues - external	$ 815	$ 95	$ -	$ 910	$ 710	$ 86	$ -	$ 796
Revenues - inter-area	8	5	(13)	-	12	-	(12)	-
Total revenues	$ 823	$ 100	$ (13)	$ 910	$ 722	$ 86	$ (12)	$ 796

	As at September 30, 2015			As at December 31, 2014		
	Canada	U.S.	Total	Canada	U.S.	Total
Property, plant and equipment	$ 3,486	$ 227	$ 3,713	$ 3,511	$ 190	$ 3,701
Intangible assets	299	42	341	313	37	350
Goodwill	-	29	29	-	25	25
Other assets	22	3	25	25	3	28
	$ 3,807	$ 301	$ 4,108	$ 3,849	$ 255	$ 4,104

11. Comparative figures:

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