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For release: October 29, 2018

Capital Power reports strong third quarter 2018 results

Results are highlighted by strong cash flow generation in the quarter

EDMONTON, Alberta – Capital Power Corporation (TSX: CPX) today released financial results for the quarter ended September 30, 2018.

Third Quarter Highlights

- Announced the acquisition of Arlington Valley, a 580 megawatt contracted natural gas facility in Arizona
- Achieved excellent operating performance with 98% facility availability
- Generated net cash flows from operating activities of $65 million and adjusted funds from operations of $156 million
- Purchased and cancelled 0.5 million common shares under the Normal Course Issuer Bid

"One of the highlights in the quarter was the announced acquisition of Arlington Valley, a contracted natural gas facility operating in the attractive Desert Southwest (DSW) power market", said Brian Vaasjo, President and CEO of Capital Power. "As I stated at the time, this transaction contributes immediately to our adjusted funds from operations and earnings and provides geographic diversification outside of Alberta while providing a platform for potential further growth in the DSW market. Arlington Valley is a low risk, cash generating investment that provides stable contracted cash flows until 2025 and has a high probability of re-contracting as confirmed by third-party market assessments."

Net cash flows from operating activities were $65 million in the third quarter of 2018 compared with $120 million in the third quarter of 2017. Adjusted funds from operations (AFFO) were $156 million in the third quarter of 2018, compared to $135 million in the third quarter of 2017.

Net income attributable to shareholders in the third quarter of 2018 was $20 million and basic earnings per share was $0.10 per share, compared with net loss attributable to shareholders of $5 million, and basic loss per share of $0.13, in the comparable period of 2017. Normalized earnings attributable to common shareholders in the third quarter of 2018, after adjusting for non-recurring items and fair value adjustments, were $36 million or $0.35 per share compared with $29 million or $0.28 per share in the third quarter of 2017.

Net cash flows from operating activities were $317 million for the nine months ended September 30, 2018 compared with $297 million for the nine months ended September 30, 2017. Adjusted funds from operations were $317 million for the nine months of 2018, compared to $267 million in the comparable nine month period last year.

For the nine months ended September 30, 2018, net income attributable to shareholders was $133 million and basic earnings per share was $0.99 per share compared with $154 million and $1.30 per share for the nine months ended September 30, 2017. For the nine months ended September 30, 2018, normalized earnings attributable to common shareholders were $90 million, or $0.87 per share, compared with $88 million, or $0.88 per share, in the first nine months of 2017.

"Capital Power's financial results for the third quarter of 2018 exceeded management's expectations," said Mr. Vaasjo. “Our third quarter results benefitted from strong operating performance with average facility availability of 98 per cent and higher Alberta power prices that averaged $55 per megawatt hour (MWh) compared to $25 per MWh a year ago. The Company generated a strong quarter of adjusted funds from operations of $156 million in the third quarter and $317 million in the first nine months of 2018. Based on our outlook for the fourth quarter of the year, we continue to be on track to achieve AFFO above the midpoint of the $360 million to $400 million target range for 2018.”

The Company continued to be active with its Normal Course Issuer Bid (NCIB) by purchasing and cancelling 0.5 million common shares at an average exercise price of $25.34 per share for a total cost of $13 million in the third quarter. In the first nine months of 2018, the Company purchased and cancelled 2.2 million common shares at an average exercise price of $24.77 per share for a total cost of $55 million. Under its TSX approved NCIB, the Company can purchase and cancel up to 9.3 million common shares during the one-year period ending February 20, 2019.

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)	**2018**	**2017**	**2018**	**2017**
Electricity generation (Gigawatt hours)	5,213	4,720	14,823	12,356
Generation facility availability	98%	97%	96%	96%
Revenues and other income	$ 389	$ 346	$ 1,059	$ 885
Adjusted EBITDA [2]	$ 138	$ 158	$ 533	$ 397
Net income (loss)	$ 19	$ (7)	$ 128	$ 147
Net income (loss) attributable to shareholders of the Company	$ 20	$ (5)	$ 133	$ 154
Basic earnings (loss) per share	$ 0.10	$ (0.13)	$ 0.99	$ 1.30
Diluted earnings (loss) per share	$ 0.10	$ (0.13)	$ 0.99	$ 1.29
Normalized earnings attributable to common shareholders [2]	$ 36	$ 29	$ 90	$ 88
Normalized earnings per share [2]	$ 0.35	$ 0.28	$ 0.87	$ 0.88
Net cash flows from operating activities	$ 65	$ 120	$ 317	$ 297
Adjusted funds from operations [2, 3]	$ 156	$ 135	$ 317	$ 267
Adjusted funds from operations per share [2]	$ 1.52	$ 1.30	$ 3.07	$ 2.68
Purchase of property, plant and equipment and other assets	$ 135	$ 28	$ 241	$ 176
Dividends per common share, declared	$ 0.4475	$ 0.4175	$ 1.2825	$ 1.1975

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, 2018.

2 Earnings before net finance expense, income tax expense, depreciation and amortization, impairments, foreign exchange gains or losses, finance expense and depreciation expense from its joint venture interests, and gains or losses on disposals (adjusted EBITDA), normalized earnings attributable to common shareholders, normalized earnings per share, adjusted funds from operations and adjusted funds from operations per share 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.

3 Commencing with the Company’s March 31, 2018 quarter-end, the reported adjusted funds from operations measure was refined to better reflect the purpose of the measure (see Non-GAAP Financial Measures). The applicable comparable periods have been adjusted to conform to the current period’s presentation.

Significant Events

Acquisition of Arlington Valley

On September 6, 2018, the Company announced it has entered into an agreement to acquire 100% of the ownership interests in Arlington Valley, LLC, which owns the Arlington Valley facility (Arlington facility), a 580 megawatt (MW) combined cycle natural gas generation facility, from funds managed by Oaktree Capital Management, L.P. and its co-investors for a total of $396 million (US$300 million), subject to working capital and other closing adjustments. Capital Power will finance the transaction using its credit facilities followed by permanent debt financing. The transaction is expected to close in the fourth quarter of 2018, subject to regulatory approvals and other customary closing conditions.

The Arlington facility sells capacity and electricity to an investment grade load serving utility (credit ratings of A2/A- from Moody's and S&P, respectively) under tolling agreements through 2025. The Arlington facility is adjacent to the Palo Verde hub allowing for additional capacity and energy to be sold into the DSW or the California Independent System Operator (CAISO) wholesale markets during the months outside the summer tolling months.

The acquisition of the Arlington facility supports the Company's US growth strategy and fully meets the Company's investment criteria. Arlington facility is a well-positioned asset in the attractive DSW power market with growing demand and a low investment risk environment. In addition to meeting the Company's expected return criteria, the investment contributes to the Company's dividend growth strategy through immediate AFFO accretion supported by contracted cash flows to the end of 2025 with a high probability of re-contracting as confirmed through third-party market assessments.

The Arlington facility is expected to generate approximately US$62 million of adjusted EBITDA and US$44 million of AFFO in 2019 during the last year of its current toll. Subsequently, adjusted EBITDA averages US$35 million per year (ranging from US$32 million to US$38 million) and US$16 million of AFFO during the 6-year period from 2020 to 2025. Based on the expected financing, the 5-year average accretion for AFFO is expected to be $0.22 per share reflecting a 6% increase. The average accretion to earnings is expected to be $0.03 per share in the first 5 years, representing a 2% increase.

Dividend increase

On July 27, 2018, the Company's Board of Directors approved an increase of 7% in the annual dividend for holders of its common shares, from $1.67 per common share to $1.79 per common share. This increased common dividend will commence with the third quarter 2018 quarterly dividend payment on October 31, 2018 to shareholders of record at the close of business on September 28, 2018.

Genesee contracted physical natural gas capacity

During the second quarter, Capital Power secured additional physical natural gas delivery capacity for the Genesee site. This capacity is expected to enable increased natural gas co-firing as early as 2020 and allows for full conversion to natural gas as early as 2020.

Genesee royalty rate agreement

During the second quarter, Capital Power entered into an agreement with Genesee Royalty Limited Partnership establishing a fixed royalty rate structure in place of the previous structure which was based on coal regulations from the 1980's. The new structure provides improved royalty cost certainty in the future.

Investment in C2CNT

In May 2018, Capital Power acquired a 5% equity interest in C2CNT, a company that developed and is now testing at scale an innovative technology that captures and transforms carbon dioxide (CO2) into a useful and high-value product called carbon nanotubes, for total consideration of $3.2 million (US$2.5 million). This technology will take CO2 from many sources including emissions from thermal power generation and other industrial processes and convert it into a carbon-based product that can be used in various industries. This investment in C2CNT supports Capital Power's pursuit of innovative and leading-edge technology and approaches that have the potential to reduce greenhouse gases. Included with the acquisition is an option that may be elected prior to March 1, 2020 to increase the Company's equity interest in C2CNT by an additional 20%.

Bloom Wind tax equity agreement amendment

As part of the enactment of the U.S. Tax Cuts and Jobs Act of 2017 in the fourth quarter of 2017, and the resulting reduction in the U.S. Federal corporate tax rate (effective January 1, 2018), a change in tax law provision was triggered in the tax equity agreement for Bloom Wind. As a result, in May of 2018, the Company re-negotiated certain commercial terms within the tax equity agreement for Bloom Wind. The re-negotiated terms of the Bloom Wind tax equity agreement resulted in an interest rate increase on the tax equity financing balance. As well, a one-time reduction to the tax equity financing balance by $44 million (US $33 million) was recorded relating to additional tax benefits used by the tax equity partner. The overall impact of the re-negotiated terms of the tax-equity agreement resulted in a one-time, non-cash increase in net income after tax of $15 million (US $11 million). Under the re-negotiated tax equity agreement and considering the reduction in the U.S. Federal corporate tax rate, the Company has maintained its original expected returns for the project.

Completion of contracts for Cardinal Point Wind

On April 30, 2018, Capital Power announced that the construction of Cardinal Point Wind will proceed once all applicable regulatory approvals are received. Cardinal Point Wind is a 150 MW facility to be constructed in the McDonough and Warren Counties, Illinois, and is anticipated to cost between $289 million and $301 million (US$236 million to US$246 million). Commercial operation of the facility is expected in March of 2020. Capital Power will operate Cardinal Point Wind under a 12-year fixed price contract with an investment grade U.S. financial institution covering 85% of the facility's output. Under the contract, Capital Power will swap the market revenue of the facility's generation for a fixed price payment over a 12-year term. In addition, the Cardinal Point Wind project has secured 15-year, fixed-price Renewable Energy Credit (REC) contracts with three Illinois utilities. The REC and output contracts will secure long-term predictable revenues, allowing Cardinal Point Wind to secure renewable energy tax equity financing and provide Capital Power the opportunity to complete its third wind development project in the growing U.S. renewables market.

Executive appointment

Consistent with the Company's ongoing commitment to sustainability, during the second quarter of 2018, the Company named Senior Vice President, Kate Chisholm, its Chief Legal and Sustainability Officer, and sustainability was added to the Board of Directors' mandate.

Analyst conference call and webcast

Capital Power will be hosting a conference call and live webcast with analysts on October 29, 2018 at 9:00 am (MDT) to discuss the third quarter financial results. The conference call dial-in numbers are:

(604) 638-5340 (Vancouver)
(403) 351-0324 (Calgary)
(416) 915-3239 (Toronto)
(514) 375-0364 (Montreal)
(800) 319-4610 (toll-free from Canada and USA)

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

Non-GAAP Financial Measures

The Company uses (i) earnings before net finance expense, income tax expense, depreciation and amortization, impairments, foreign exchange gains or losses, finance expense and depreciation expense from its joint venture interests, and gains or losses on disposals (adjusted EBITDA), (ii) adjusted funds from operations, (iii) adjusted funds from operations per share (iv) normalized earnings attributable to common shareholders, and (v) 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 facilities and categories of facilities from period to period. Management believes that a measure of facility operating performance is more meaningful if results not related to facility operations such as impairments, foreign exchange gains or losses and gains or losses on disposals are excluded from the adjusted EBITDA measure.

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

(unaudited, $ millions)	Three months ended							
	Sep 30 2018	**Jun 30 2018**	**Mar 31 2018**	**Dec 31 2017**	**Sep 30 2017**	**Jun 30 2017**	**Mar 31 2017**	**Dec 31 2016**
Revenues and other income	389	363	307	261	346	201	338	280
Energy purchases and fuel, other raw materials and operating charges, staff costs and employee benefits expense, and other administrative expense	(261)	(152)	(153)	(125)	(198)	(119)	(208)	(148)
Adjusted EBITDA from joint ventures [1]	10	12	18	18	10	14	13	12
Adjusted EBITDA	**138**	**223**	**172**	**154**	**158**	**96**	**143**	**144**
Depreciation and amortization	(74)	(74)	(75)	(72)	(74)	(65)	(60)	(53)
Impairment	-	-	-	-	(83)	-	-	-
Losses on termination of power purchase arrangement	-	-	-	-	-	-	-	(20)
Foreign exchange (loss) gain	(2)	3	3	(4)	21	9	2	(4)
Net finance expense	(28)	(29)	(33)	(32)	(31)	(25)	(20)	(24)
Finance expense and depreciation expense from joint ventures [1]	(7)	(8)	(7)	(13)	(6)	(2)	(3)	(3)
Income tax (expense) recovery	(8)	(47)	(19)	(46)	8	94	(15)	(14)
Net income (loss)	**19**	**68**	**41**	**(13)**	**(7)**	**107**	**47**	**26**
Net income (loss) attributable to:								
Non-controlling interest	(1)	(2)	(2)	(3)	(2)	(2)	(3)	(2)
Shareholders of the Company	20	70	43	(10)	(5)	109	50	28
Net income (loss)	**19**	**68**	**41**	**(13)**	**(7)**	**107**	**47**	**26**

[1] Total income from joint ventures as per the Company's consolidated statements of income (loss).

Adjusted funds from operations and adjusted funds from operations per share

The Company uses adjusted funds from operations as a measure of the Company's ability to generate cash from its current operating activities to fund growth capital expenditures, debt repayments and common share dividends to the Company's shareholders. Commencing with the Company's March 31, 2018 quarter-end, the Company made several adjustments to its adjusted funds from operations measure to better reflect the purpose of the measure. These changes included the following:

- The reduction for sustaining capital expenditures historically included costs associated with the Company's Genesee performance standard project. These costs have been considered further and given that the intent of this project is to improve efficiency of the facility, management considers these costs to be growth in nature, and hence they should not be considered sustaining capital expenditures that would be deducted in the adjusted funds from operations measure.
- In prior periods, there has been an addback included for Part VI.1 preferred dividend tax impacts which effectively contemplated the associated tax deduction related to preferred share dividends that reduced current tax payable. Upon further consideration, since that deduction offsets the cash tax payable related to Part VI.1 preferred dividend taxes, the cash effects of the preferred dividend tax impacts should offset. The remaining impact to adjusted funds from operations should therefore be the current income tax expense without any adjustment pertaining to preferred dividend tax impacts.
- Historically, the impacts of tax equity financing structures on adjusted funds from operations have been insignificant. With the commencement of commercial operations of Bloom Wind in 2017, management has revisited the flow of these operations through the adjusted funds from operations metric. Similar to the treatment of joint venture interests, the treatment of assets under tax equity financing structures has been adjusted to reflect the Company's share of the adjusted funds from operations of these assets within consolidated adjusted funds from operations. To give effect to this change, the deduction for net finance expense now excludes non-cash implicit interest expense pertaining to tax equity financing structures. However, a deduction is made to remove the tax equity project investors' respective shares of the adjusted funds from operations of the assets under tax equity financing structures, as determined by their shares of the distributable cash of the respective operations.

Comparative figures have been restated to reflect the above refinements to the adjusted funds from operations metric.

Adjusted funds from operations represents net cash flows from operating activities adjusted to include net finance expense and current income tax expense and exclude changes in operating working capital and distributions received from the Company's joint venture interests. Net finance expense and current income tax expense are included as 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. Changes in operating working capital are excluded from adjusted funds from operations as the timing of cash receipts and payments also affects the period-to-period comparability. Distributions received from the Company's joint venture interests are excluded as the distributions are calculated after the effect of joint venture debt payments, which are not considered operating activities. Adjusted funds from operations is reduced by the tax equity financing project investors' shares of adjusted funds from operations associated with assets under tax equity financing structures to ensure that only the Company's share is reflected in the overall metric. Adjusted funds from operations also excludes 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. Adjusted funds from operations is reduced by sustaining capital expenditures and preferred share dividends and adjusted to include the Company's share of the adjusted funds from operations of its joint venture interests and cash from coal compensation that will be received annually.

Commencing with the quarter ended March 31, 2018, the Company began presenting adjusted funds from operations per share. This metric is determined by applying adjusted funds from operations to the weighted average number of common shares used in the calculation of basic, diluted and normalized earnings per share.

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

(unaudited, $ millions)	Three months ended September 30		Nine months ended September 30	
	2018	**2017**	**2018**	**2017**
Net cash flows from operating activities per condensed interim consolidated statements of cash flows	**65**	**120**	**317**	**297**
Add (deduct) items included in calculation of net cash flows from operating activities per condensed interim consolidated statements of cash flows:				
Interest paid	20	18	70	55
Change in fair value of derivatives reflected as cash settlement	4	6	(16)	6
Distributions received from joint ventures	(5)	(8)	(24)	(22)
Miscellaneous financing charges paid [1]	1	2	4	4
Income taxes paid	1	2	2	2
Change in non-cash operating working capital	68	(10)	62	-
	89	10	98	45
Net finance expense [2]	(23)	(26)	(72)	(65)
Current income tax expense	(6)	(4)	(15)	(11)
Sustaining capital expenditures [3]	(13)	(12)	(54)	(46)
Preferred share dividends paid	(10)	(9)	(30)	(25)
Cash received from coal compensation	50	50	50	50
Remove tax equity interests' respective shares of adjusted funds from operations	(1)	-	(5)	(4)
Adjusted funds from operations from joint ventures	5	6	28	26
Adjusted funds from operations	**156**	**135**	**317**	**267**
Weighted average number of common shares outstanding (millions)	**102.4**	**104.1**	**103.2**	**99.5**
Adjusted funds from operations per share ($)	**1.52**	**1.30**	**3.07**	**2.68**

1 Included in other cash items on the condensed interim consolidated statements of cash flows to reconcile net income to net cash flows from operating activities.

2 Excludes unrealized changes on interest rate derivative contracts, amortization, accretion charges and non-cash implicit interest on tax equity investment structures.

3 Includes sustaining capital expenditures net of partner contributions of $1 million and $6 million for the three and nine months ended September 30, 2018, respectively, compared with $3 million and $7 million for the three and nine months ended September 30, 2017, respectively.

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 (loss) used in the calculation of basic earnings (loss) per share according to GAAP and 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 2018	**Jun 30 2018**	**Mar 31 2018**	**Dec 31 2017**	**Sep 30 2017**	**Jun 30 2017**	**Mar 31 2017**	**Dec 31 2016**
Basic earnings (loss) per share ($)	**0.10**	**0.57**	**0.32**	**(0.20)**	**(0.13)**	**1.03**	**0.44**	**0.21**
Net income (loss) attributable to shareholders of the Company per condensed interim consolidated statements of income (loss)	**20**	**70**	**43**	**(10)**	**(5)**	**109**	**50**	**28**
Preferred share dividends including Part VI.1 tax	(10)	(11)	(10)	(11)	(9)	(8)	(8)	(8)
Earnings (loss) attributable to common shareholders	10	59	33	(21)	(14)	101	42	20
Unrealized changes in fair value of derivatives [1]	26	(19)	25	14	(31)	23	(7)	(8)
Non-cash tax equity adjustment (see Significant Events)	-	(15)	-	-	-	-	-	-
Income tax adjustment	-	(2)	2	-	-	-	-	-
Realized foreign exchange loss (gain) on settlement of foreign currency derivative instruments	-	-	(29)	-	12	-	-	-
Impairment losses	-	-	-	-	53	-	-	-
Unrealized foreign exchange (gain) loss on revaluation of U.S. dollar denominated debt	-	-	-	(1)	44	(12)	(1)	3
Realized foreign exchange gain on revaluation of U.S. dollar denominated debt	-	-	-	(1)	(35)	-	-	-
Recognition of U.S. deferred tax assets related to non-capital losses	-	-	-	-	-	(86)	-	-
Losses on termination of the Sundance power purchase arrangement	-	-	-	-	-	-	-	15
Provision for Line Loss Rule Proceeding	-	-	-	7	-	-	-	-
U.S. tax reform rate decrease	-	-	-	31	-	-	-	-
Deferred income tax reduction related to temporary difference on investment in subsidiary	-	-	-	-	-	-	-	(1)
Success fee received related to development project	-	-	-	(3)	-	-	-	(3)
Release of tax liability on foreign domiciled investment	-	-	-	(1)	-	-	(1)	-
Normalized earnings attributable to common shareholders	**36**	**23**	**31**	**25**	**29**	**26**	**33**	**26**
Weighted average number of common shares outstanding (millions)	102.4	103.1	104.2	104.3	104.1	98.1	96.3	96.1
Normalized earnings per share ($)	**0.35**	**0.22**	**0.30**	**0.24**	**0.28**	**0.27**	**0.34**	**0.27**

1 Includes impacts of the interest rate non-hedge held by one of the Company's joint ventures and recorded within income from joint ventures on the Company's statements of income.

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 disclosures regarding the expected results in relation to the 2018 AFFO guidance range, expectations pertaining to the construction cost and commercial operations date for Cardinal Point Wind and expectations pertaining to the acquisition of Arlington Valley (see Significant Events). Such expectations around the Arlington Valley acquisition include: (i) impacts of the acquisition on adjusted funds from operations, adjusted funds from operations per share and adjusted EBITDA, (ii) financing plans for the acquisition, (iii) timing of close for the acquisition, and (iv) re-contracting of the Arlington Valley facility.

These statements are based on certain assumptions and analyses made by the Company in light of its experience and perception of historical trends, current conditions, 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, other energy and carbon prices, (ii) anticipated facility performance, (iii) business prospects (including potential re-contracting opportunities) and opportunities including expected growth and capital projects, (iv) status of and impact of policy, legislation and regulations, 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, market structure and tax legislation, (iv) facility availability and performance including maintenance of equipment, (v) ability to fund current and future capital and working capital needs, (vi) developments including timing and costs of regulatory approvals and construction, (vii) changes in market prices and availability of fuel, (viii) ability to realize the anticipated benefits of the Arlington Valley acquisition, (ix) limitations inherent in the Company's review of acquired assets and (x) changes in general economic and competitive conditions. See Risks and Risk Management in the Company's Management's Discussion and Analysis for the year ended December 31, 2017, prepared as of February 15, 2018, 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 specified approval date. 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.

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CAPITAL POWER CORPORATION

Management's Discussion and Analysis

This management's discussion and analysis (MD&A), prepared as of October 26, 2018, 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, 2018, the audited consolidated financial statements and MD&A of Capital Power Corporation for the year ended December 31, 2017, the annual information form of Capital Power Corporation dated February 23, 2018, and the cautionary statements regarding forward-looking information which begin on page 12. 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, 2018 and the nine months ended September 30, 2017 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 26, 2018.

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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 adjusted funds from operations,
- the future pricing of electricity and market fundamentals in existing and target markets,
- future dividend growth,
- 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 (including the New Frontier Wind project, phase 1 of the Whitla Wind project and the Cardinal Point Wind project),
- facility availability and planned outages,
- capital expenditures for facility maintenance and other (sustaining capital, future growth projects),
- the impact of the transition to a capacity market on the Company's future growth projects including the Genesee 4 and 5 projects,
- expectations pertaining to the financial impacts of the acquisition of Arlington Valley (see Significant Events), including the impacts to adjusted funds from operations, adjusted funds from operations per share and adjusted EBITDA,
- the financing plans for and the timing of the close of the acquisition of Arlington Valley,
- re-contracting of the Arlington Valley facility,
- expectations around the Line Loss Rule Proceeding including timing of retrospective loss factors being finalized, participation in applicable appeal processes, and potential impacts to the Company, and
- impacts of future IFRS standards and amendments.

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 and carbon prices,
- performance,
- business prospects (including potential re-contracting of facilities) 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 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, market structure and tax legislation,
- generation facility 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,
- ability to realize the anticipated benefits of the Arlington Valley acquisition,
- limitations inherent in the Company's review of acquired assets, and
- changes in general economic and competitive conditions.

See Risks and Risk Management in the Company's December 31, 2017 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 specified approval date. 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, owns and operates power generation facilities from a variety of energy sources. Capital Power owns approximately 4,500 megawatts (MW) of power generation capacity at 24 facilities across North America. Approximately 1,000 MW of owned generation capacity is in advanced development in Alberta, North Dakota, and Illinois. An additional 580 MW of owned generation capacity will be added upon close of the acquisition of Arlington Valley (see Significant Events).

The Company's power generation operations and assets are owned by Capital Power L.P. (CPLP) and Capital Power (US Holdings) Inc., both wholly owned subsidiaries of the Company.

CORPORATE STRATEGY

The Company's corporate strategy remains unchanged from that disclosed in its 2017 annual MD&A.

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 of Capital Power. The measurement categories include corporate measures and measures specific to certain groups within the Company. The corporate measures are company-wide and include adjusted funds from operations and safety. The group-specific measures include facility operating margin and other operations measures, committed capital, construction and maintenance capital on budget and on schedule, and facility site safety.

Operational excellence

Performance measure	2018 target	Actual results for the nine months ended September 30, 2018
Facility availability average	95% or greater	96%
Sustaining capital expenditures	$85 million	$54 million [1]
Genesee performance standard [2]	$15 million	$8 million
Facility operating and maintenance expenses	$230 million to $250 million	$177 million

1 Includes sustaining capital expenditures net of joint venture contributions of $6 million.

2 This project is designed to reduce CO_2 emissions and improve the efficiency of the Company's coal-fired facilities in response to the Alberta Climate Leadership Plan (CLP).

The Company's facility availability averaged 96% which reflected planned outages at York Energy, Shepard, Joffre, Clover Bar Energy Centre, Roxboro, Southport, Decatur Energy and Genesee. Unplanned outages also occurred at Keephills 3, Decatur Energy, Southport and Clover Bar Energy Centre.

Sustaining capital expenditures for the nine months ended September 30, 2018 were lower than target for the year to date. Full year expenditures are expected to be above the target driven by higher than anticipated Keephills 3 mine capital expenditures. Expenditures for the Genesee performance standard for the nine months ended September 30, 2018 were lower than target for the year to date, and the full year expenditures are expected to be above the target driven by higher Keephills 3 mine costs.

The facility operating and maintenance expenses target includes other raw materials and operating charges, staff costs and employee benefits expense and other administrative expense for the Company's facilities. The actual results for the nine months ended September 30, 2018 were consistent with the target for the year to date and the full year expenditures are expected to be consistent with the target.

Disciplined growth

Performance measure	2018 target	Status as at September 30, 2018
New Frontier Wind	Complete New Frontier Wind on time and on budget.	Construction expected to be complete and on budget by December of 2018.
Whitla Wind	Progress on the development of Whitla Wind to be on track with budget and the 2019 completion date.	Turbine supply agreement signed during the second quarter of 2018, Alberta Utilities Commission approval has been received and construction has commenced. Construction is expected to be complete and on budget in the fourth quarter of 2019.
New development	Execute contracts for the output of one to three new wind developments.	On track with target and are progressing with the Company's development sites including the completion of contracts for Cardinal Point Wind (see Significant Events).

Financial stability and strength

Performance measure	2018 target	Actual results for the nine months ended September 30, 2018
Adjusted funds from operations [1]	$360 million to $400 million	$317 million

[1] Adjusted funds from operations is a non-GAAP measure. See Non-GAAP Financial Measures.

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 Investor Day held in December 2017, the Company provided financial guidance for 2018 adjusted funds from operations (see Non-GAAP Financial Measures) in the range of $360 million to $400 million. The 2018 guidance was based on a price of $49 per megawatt hour (MWh) for 2018 for the Alberta baseload assets which were 87% sold forward at the beginning of 2018. The 2018 Alberta forward power price increased in the latter part of 2017 to an average of $54 per MWh largely due to the announcement of retirements and long-term coal supply outages, beginning in 2018, on certain coal assets not owned by the Company. Based on the actual results for the first nine months of 2018 and the Company's forecast for the remainder of 2018, which considers current Alberta forward power prices, the Company expects adjusted funds from operations for 2018 to be above the midpoint of the guidance range.

Priorities for the Company in 2018 include continuing to work with the Government of Alberta concerning the transition away from an energy-only market to a capacity market. The Company is also working to manage its carbon costs by utilizing its credit inventory and pursuing generation facility modifications with its carbon reduction program (Genesee Performance Standard). The Company continues to develop its wind facilities with New Frontier Wind and Whitla Wind expected to commence commercial operation in the fourth quarters of 2018 and 2019, respectively. During the second quarter of 2018, the Company executed a contract for the output of the Cardinal Point Wind project (see Significant Events) and is well positioned to be competitive in securing additional contracted wind developments during the remainder of 2018.

In 2018, Capital Power's availability target of 95% reflects major scheduled maintenance outages for Genesee 2, Genesee 3, Clover Bar Energy Centre, Joffre, Shepard, and Decatur Energy compared to those scheduled for Genesee 1, Keephills 3, and Clover Bar Energy Centre in 2017.

The Alberta portfolio position, contracted prices and forward Alberta pool prices for 2019, 2020, and 2021 as at September 30, 2018, were:

Alberta commercial portfolio positions and power prices	Full year 2019	Full year 2020	Full year 2021
Percentage of baseload generation sold forward [1]	55%	22%	4%
Contracted price [2]	Low-$50	Low-$50	Mid-$50
Forward Alberta pool prices	$55	$48	$47

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

[2] Forecasted average contracted prices may differ significantly from future average realized prices as future realized prices are driven by a combination of previously contracted prices and settled prices.

The 2018 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 facility outages including outages at facilities of other market participants, and the related impacts on market power prices.

At its Investor Day held in December 2017, the Company reaffirmed 7% annual dividend growth guidance through 2020. Each annual increase is subject to changing circumstances and approval by the Board of Directors of Capital Power at the time of the increase.

See Liquidity and Capital Resources for discussion of future cash requirements and expected sources of funding. It is expected that, outside of new growth opportunities, no additional common share equity will be required in 2018.

NON-GAAP FINANCIAL MEASURES

The Company uses (i) earnings before net finance expense, income tax expense, depreciation and amortization, impairments, foreign exchange gains or losses, finance expense and depreciation expense from its joint venture interests, and gains or losses on disposals (adjusted EBITDA), (ii) adjusted funds from operations, (iii) adjusted funds from operations per share, (iv) normalized earnings attributable to common shareholders, and (v) 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 facilities and categories of facilities from period to period. Management believes that a measure of facility operating performance is more meaningful if results not related to facility operations such as impairments, foreign exchange gains or losses and gains or losses on disposals are excluded from the adjusted EBITDA measure.

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

(unaudited, $ millions)	Three months ended							
	Sep 30 2018	**Jun 30 2018**	**Mar 31 2018**	**Dec 31 2017**	**Sep 30 2017**	**Jun 30 2017**	**Mar 31 2017**	**Dec 31 2016**
Revenues and other income	389	363	307	261	346	201	338	280
Energy purchases and fuel, other raw materials and operating charges, staff costs and employee benefits expense, and other administrative expense	(261)	(152)	(153)	(125)	(198)	(119)	(208)	(148)
Adjusted EBITDA from joint ventures [1]	10	12	18	18	10	14	13	12
Adjusted EBITDA	**138**	**223**	**172**	**154**	**158**	**96**	**143**	**144**
Depreciation and amortization	(74)	(74)	(75)	(72)	(74)	(65)	(60)	(53)
Impairment	-	-	-	-	(83)	-	-	-
Losses on termination of power purchase arrangement	-	-	-	-	-	-	-	(20)
Foreign exchange (loss) gain	(2)	3	3	(4)	21	9	2	(4)
Net finance expense	(28)	(29)	(33)	(32)	(31)	(25)	(20)	(24)
Finance expense and depreciation expense from joint ventures [1]	(7)	(8)	(7)	(13)	(6)	(2)	(3)	(3)
Income tax (expense) recovery	(8)	(47)	(19)	(46)	8	94	(15)	(14)
Net income (loss)	**19**	**68**	**41**	**(13)**	**(7)**	**107**	**47**	**26**
Net income (loss) attributable to:								
Non-controlling interest	(1)	(2)	(2)	(3)	(2)	(2)	(3)	(2)
Shareholders of the Company	20	70	43	(10)	(5)	109	50	28
Net income (loss)	**19**	**68**	**41**	**(13)**	**(7)**	**107**	**47**	**26**

[1] Total income from joint ventures as per the Company's consolidated statements of income (loss).

Adjusted funds from operations and adjusted funds from operations per share

The Company uses adjusted funds from operations as a measure of the Company's ability to generate cash from its current operating activities to fund growth capital expenditures, debt repayments and common share dividends to the Company's shareholders. Commencing with the Company's March 31, 2018 quarter-end, the Company made several adjustments to its adjusted funds from operations measure to better reflect the purpose of the measure. These changes included the following:

- The reduction for sustaining capital expenditures historically included costs associated with the Company's Genesee performance standard project. These costs have been considered further and given that the intent of this project is to improve efficiency of the facility, management considers these costs to be growth in nature, and hence they should not be considered sustaining capital expenditures that would be deducted in the adjusted funds from operations measure.
- In prior periods, there has been an addback included for Part VI.1 preferred dividend tax impacts which effectively contemplated the associated tax deduction related to preferred share dividends that reduced current tax payable. Upon further consideration, since that deduction offsets the cash tax payable related to Part VI.1 preferred dividend taxes, the cash effects of the preferred dividend tax impacts should offset. The remaining impact to adjusted funds from operations should therefore be the current income tax expense without any adjustment pertaining to preferred dividend tax impacts.
- Historically, the impacts of tax equity financing structures on adjusted funds from operations have been insignificant. With the commencement of commercial operations of Bloom Wind in 2017, management has revisited the flow of these operations through the adjusted funds from operations metric. Similar to the treatment of joint venture interests, the treatment of assets under tax equity financing structures has been adjusted to reflect

the Company's share of the adjusted funds from operations of these assets within consolidated adjusted funds from operations. To give effect to this change, the deduction for net finance expense now excludes non-cash implicit interest expense pertaining to tax equity financing structures. However, a deduction is made to remove the tax equity project investors' respective shares of the adjusted funds from operations of the assets under tax equity financing structures, as determined by their shares of the distributable cash of the respective operations.

Comparative figures have been restated to reflect the above refinements to the adjusted funds from operations metric.

Adjusted funds from operations represents net cash flows from operating activities adjusted to include net finance expense and current income tax expense and exclude changes in operating working capital and distributions received from the Company's joint venture interests. Net finance expense and current income tax expense are included as 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. Changes in operating working capital are excluded from adjusted funds from operations as the timing of cash receipts and payments also affects the period-to-period comparability. Distributions received from the Company's joint venture interests are excluded as the distributions are calculated after the effect of joint venture debt payments, which are not considered operating activities. Adjusted funds from operations is reduced by the tax equity financing project investors' shares of adjusted funds from operations associated with assets under tax equity financing structures to ensure that only the Company's share is reflected in the overall metric. Adjusted funds from operations also excludes 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. Adjusted funds from operations is reduced by sustaining capital expenditures and preferred share dividends and adjusted to include the Company's share of the adjusted funds from operations of its joint venture interests and cash from coal compensation that will be received annually.

Commencing with the quarter ended March 31, 2018, the Company began presenting adjusted funds from operations per share. This metric is determined by applying adjusted funds from operations to the weighted average number of common shares used in the calculation of basic, diluted and normalized earnings per share.

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

(unaudited, $ millions)	Three months ended September 30		Nine months ended September 30	
	2018	**2017**	**2018**	**2017**
Net cash flows from operating activities per condensed interim consolidated statements of cash flows	**65**	**120**	**317**	**297**
Add (deduct) items included in calculation of net cash flows from operating activities per condensed interim consolidated statements of cash flows:				
Interest paid	20	18	70	55
Change in fair value of derivatives reflected as cash settlement	4	6	(16)	6
Distributions received from joint ventures	(5)	(8)	(24)	(22)
Miscellaneous financing charges paid [1]	1	2	4	4
Income taxes paid	1	2	2	2
Change in non-cash operating working capital	68	(10)	62	-
	89	10	98	45
Net finance expense [2]	(23)	(26)	(72)	(65)
Current income tax expense	(6)	(4)	(15)	(11)
Sustaining capital expenditures [3]	(13)	(12)	(54)	(46)
Preferred share dividends paid	(10)	(9)	(30)	(25)
Cash received from coal compensation	50	50	50	50
Remove tax equity interests' respective shares of adjusted funds from operations	(1)	-	(5)	(4)
Adjusted funds from operations from joint ventures	5	6	28	26
Adjusted funds from operations	**156**	**135**	**317**	**267**
Weighted average number of common shares outstanding (millions)	**102.4**	**104.1**	**103.2**	**99.5**
Adjusted funds from operations per share ($)	**1.52**	**1.30**	**3.07**	**2.68**

1 Included in other cash items on the condensed interim consolidated statements of cash flows to reconcile net income to net cash flows from operating activities.

2 Excludes unrealized changes on interest rate derivative contracts, amortization, accretion charges and non-cash implicit interest on tax equity investment structures.

[3] Includes sustaining capital expenditures net of partner contributions of $1 million and $6 million for the three and nine months ended September 30, 2018, respectively, compared with $3 million and $7 million for the three and nine months ended September 30, 2017, respectively.

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 (loss) used in the calculation of basic earnings (loss) per share according to GAAP and 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 2018	**Jun 30 2018**	**Mar 31 2018**	**Dec 31 2017**	**Sep 30 2017**	**Jun 30 2017**	**Mar 31 2017**	**Dec 31 2016**
Basic earnings (loss) per share ($)	**0.10**	**0.57**	**0.32**	**(0.20)**	**(0.13)**	**1.03**	**0.44**	**0.21**
Net income (loss) attributable to shareholders of the Company per condensed interim consolidated statements of income (loss)	**20**	**70**	**43**	**(10)**	**(5)**	**109**	**50**	**28**
Preferred share dividends including Part VI.1 tax	(10)	(11)	(10)	(11)	(9)	(8)	(8)	(8)
Earnings (loss) attributable to common shareholders	10	59	33	(21)	(14)	101	42	20
Unrealized changes in fair value of derivatives [1]	26	(19)	25	14	(31)	23	(7)	(8)
Non-cash tax equity adjustment (see Significant Events)	-	(15)	-	-	-	-	-	-
Income tax adjustment	-	(2)	2	-	-	-	-	-
Realized foreign exchange loss (gain) on settlement of foreign currency derivative instruments	-	-	(29)	-	12	-	-	-
Impairment losses	-	-	-	-	53	-	-	-
Unrealized foreign exchange (gain) loss on revaluation of U.S. dollar denominated debt	-	-	-	(1)	44	(12)	(1)	3
Realized foreign exchange gain on revaluation of U.S. dollar denominated debt	-	-	-	(1)	(35)	-	-	-
Recognition of U.S. deferred tax assets related to non-capital losses	-	-	-	-	-	(86)	-	-
Losses on termination of the Sundance power purchase arrangement	-	-	-	-	-	-	-	15
Provision for Line Loss Rule Proceeding	-	-	-	7	-	-	-	-
U.S. tax reform rate decrease	-	-	-	31	-	-	-	-
Deferred income tax reduction related to temporary difference on investment in subsidiary	-	-	-	-	-	-	-	(1)
Success fee received related to development project	-	-	-	(3)	-	-	-	(3)
Release of tax liability on foreign domiciled investment	-	-	-	(1)	-	-	(1)	-
Normalized earnings attributable to common shareholders	**36**	**23**	**31**	**25**	**29**	**26**	**33**	**26**
Weighted average number of common shares outstanding (millions)	102.4	103.1	104.2	104.3	104.1	98.1	96.3	96.1
Normalized earnings per share ($)	**0.35**	**0.22**	**0.30**	**0.24**	**0.28**	**0.27**	**0.34**	**0.27**

[1] Includes impacts of the interest rate non-hedge held by one of the Company's joint ventures and recorded within income from joint ventures on the Company's statements of income.

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

FINANCIAL HIGHLIGHTS

(unaudited, $ millions, except per share amounts)	**Three months ended September 30**		**Nine months ended September 30**	
	2018	**2017**	**2018**	**2017**
Revenues and other income	389	346	1,059	885
Adjusted EBITDA [1]	138	158	533	397
Net income (loss)	19	(7)	128	147
Net income (loss) attributable to shareholders of the Company	20	(5)	133	154
Normalized earnings attributable to common shareholders [1]	36	29	90	88
Basic earnings (loss) per share ($)	0.10	(0.13)	0.99	1.30
Diluted earnings (loss) per share ($) [2]	0.10	(0.13)	0.99	1.29
Normalized earnings per share ($) [1]	0.35	0.28	0.87	0.88
Net cash flows from operating activities	65	120	317	297
Adjusted funds from operations [1]	156	135	317	267
Adjusted funds from operations per share ($) [1]	1.52	1.30	3.07	2.68
Purchase of property, plant and equipment and other assets	135	28	241	176
Dividends per common share, declared ($)	0.4475	0.4175	1.2825	1.1975
Dividends per Series 1 preferred share, declared ($)	0.1913	0.1913	0.5739	0.5739
Dividends per Series 3 preferred share, declared ($)	0.2875	0.2875	0.8625	0.8625
Dividends per Series 5 preferred share, declared ($)	0.3274	0.2813	0.8900	0.8439
Dividends per Series 7 preferred share, declared ($)	0.3750	0.3750	1.1250	1.1250
Dividends per Series 9 preferred share, declared ($)	0.3594	0.2048	1.0782	0.2048

	As at	
	September 30, 2018	**December 31, 2017**
Loans and borrowings including current portion	2,139	2,146
Total assets	6,893	6,898

[1] The consolidated financial highlights, except for adjusted EBITDA, normalized earnings attributable to common shareholders, normalized earnings per share, adjusted funds from operations and adjusted funds from operations per share 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.

See Consolidated Net Income and Results of Operations for discussion of the key drivers of the changes in revenues and other income, adjusted EBITDA, net income and net income attributable to shareholders of the Company.

The changes in basic and diluted earnings per share were driven by the same factors as net income which are discussed in Consolidated Net Income and Results of Operations. The changes in normalized earnings per share and normalized earnings attributable to common shareholders were affected by the same drivers as basic earnings per share, but also the adjustments between earnings per share and normalized earnings per share described under Non-GAAP Financial Measures.

See Liquidity and Capital Resources for discussion of the key drivers of the changes in net cash flows from operating activities. Adjusted funds from operations for the three months ended September 30, 2018 was higher than adjusted funds from operations for the same period in 2017 as a result of increases from the Alberta facilities driven by the adjusted EBITDA increases described in Consolidated Net Income and Results of Operations and lower finance expense than in the comparable period. Higher adjusted funds from operations for the nine months ended September 30, 2018 reflects higher adjusted funds from operations from the new facilities acquired in June 2017 and higher adjusted funds from operations from the Alberta contracted facilities driven by the adjusted EBITDA increase described in Consolidated Net Income and Results of Operations, offset partly by higher finance expense, higher preferred share dividends and higher sustaining capital expenditures.

The increase in purchases of property, plant and equipment and other assets is discussed in Liquidity and Capital Resources.

SIGNIFICANT EVENTS

Acquisition of Arlington Valley

On September 6, 2018, the Company announced it has entered into an agreement to acquire 100% of the ownership interests in Arlington Valley, LLC, which owns the Arlington Valley facility (Arlington facility), a 580 megawatt (MW) combined cycle natural gas generation facility, from funds managed by Oaktree Capital Management, L.P. and its co-investors for a total of $396 million (US$300 million), subject to working capital and other closing adjustments. Capital Power will finance the transaction using its credit facilities followed by permanent debt financing. The transaction is expected to close in the fourth quarter of 2018, subject to regulatory approvals and other customary closing conditions.

The Arlington facility sells capacity and electricity to an investment grade load serving utility (credit ratings of A2/A- from Moody's and S&P, respectively) under tolling agreements through 2025. The Arlington facility is adjacent to the Palo Verde hub allowing for additional capacity and energy to be sold into the Desert Southwest (DSW) or the California Independent System Operator (CAISO) wholesale markets during the months outside the summer tolling months.

The acquisition of the Arlington facility supports the Company's US growth strategy and fully meets the Company's investment criteria. Arlington facility is a well-positioned asset in the attractive DSW power market with growing demand and a low investment risk environment. In addition to meeting the Company's expected return criteria, the investment contributes to the Company's dividend growth strategy through immediate adjusted funds from operations (AFFO) accretion supported by contracted cash flows to the end of 2025 with a high probability of re-contracting as confirmed through third-party market assessments.

The Arlington facility is expected to generate approximately US$62 million of adjusted EBITDA and US$44 million of AFFO in 2019 during the last year of its current toll. Subsequently, adjusted EBITDA averages US$35 million per year (ranging from US$32 million to US$38 million) and US$16 million of AFFO during the 6-year period from 2020 to 2025. Based on the expected financing, the 5-year average accretion for AFFO is expected to be $0.22 per share reflecting a 6% increase. The average accretion to earnings is expected to be $0.03 per share in the first 5 years, representing a 2% increase.

Dividend increase

On July 27, 2018, the Company's Board of Directors approved an increase of 7% in the annual dividend for holders of its common shares, from $1.67 per common share to $1.79 per common share. This increased common dividend will commence with the third quarter 2018 quarterly dividend payment on October 31, 2018 to shareholders of record at the close of business on September 28, 2018.

Genesee contracted physical natural gas capacity

During the second quarter, Capital Power secured additional physical natural gas delivery capacity for the Genesee site. This capacity is expected to enable increased natural gas co-firing as early as 2020 and allows for full conversion to natural gas as early as 2020.

Genesee royalty rate agreement

During the second quarter, Capital Power entered into an agreement with Genesee Royalty Limited Partnership establishing a fixed royalty rate structure in place of the previous structure which was based on coal regulations from the 1980's. The new structure provides improved royalty cost certainty in the future.

Investment in C2CNT

In May 2018, Capital Power acquired a 5% equity interest in C2CNT, a company that developed and is now testing at scale an innovative technology that captures and transforms carbon dioxide (CO_2) into a useful and high-value product called carbon nanotubes, for total consideration of $3.2 million (US$2.5 million). This technology will take CO_2 from many sources including emissions from thermal power generation and other industrial processes and convert it into a carbon-based product that can be used in various industries. This investment in C2CNT supports Capital Power's pursuit of innovative and leading-edge technology and approaches that have the potential to reduce greenhouse gases. Included with the acquisition is an option that may be elected prior to March 1, 2020 to increase the Company's equity interest in C2CNT by an additional 20%.

Bloom Wind tax equity agreement amendment

As part of the enactment of the U.S. Tax Cuts and Jobs Act of 2017 in the fourth quarter of 2017, and the resulting reduction in the U.S. Federal corporate tax rate (effective January 1, 2018), a change in tax law provision was triggered in the tax equity agreement for Bloom Wind. As a result, in May of 2018, the Company re-negotiated certain commercial terms within the tax equity agreement for Bloom Wind. The re-negotiated terms of the Bloom Wind tax equity agreement resulted in an interest rate increase on the tax equity financing balance. As well, a one-time reduction to the tax equity financing balance by $44 million (US$33 million) was recorded relating to additional tax benefits used by the tax equity partner. The overall impact of the re-negotiated terms of the tax-equity agreement resulted in a one-time, non-cash increase in net income after tax of $15 million (US$11 million). Under the re-negotiated tax equity agreement and considering the reduction in the U.S. Federal corporate tax rate, the Company has maintained its original expected returns for the project.

Completion of contracts for Cardinal Point Wind

On April 30, 2018, Capital Power announced that the construction of Cardinal Point Wind will proceed once all applicable regulatory approvals are received. Cardinal Point Wind is a 150 MW facility to be constructed in the McDonough and Warren Counties, Illinois, and is anticipated to cost between $289 million and $301 million (US$236 million to US$246 million). Commercial operation of the facility is expected in March of 2020. Capital Power will operate Cardinal Point Wind under a 12-year fixed price contract with an investment grade U.S. financial institution covering 85% of the facility's output. Under the contract, Capital Power will swap the market revenue of the facility's generation for a fixed price payment over a 12-year term. In addition, the Cardinal Point Wind project has secured 15-year, fixed-price Renewable Energy Credit (REC) contracts with three Illinois utilities. The REC and output contracts will secure long-term predictable revenues, allowing Cardinal Point Wind to secure renewable energy tax equity financing and provide Capital Power the opportunity to complete its third wind development project in the growing U.S. renewables market.

Executive appointment

Consistent with the Company's ongoing commitment to sustainability, during the second quarter of 2018, the Company named Senior Vice President, Kate Chisholm, its Chief Legal and Sustainability Officer, and sustainability was added to the Board of Directors' mandate.

CONSOLIDATED NET INCOME AND RESULTS OF OPERATIONS

The primary factors contributing to the change in consolidated net income for the three and nine months ended September 30, 2018 compared with the three and nine months ended September 30, 2017 are presented below followed by further discussion of these items.

(unaudited, $ millions)	Three months		Nine months	
Consolidated net income for the periods ended September 30, 2017		**(7)**		**147**
(Decrease) Increase in adjusted EBITDA:				
Alberta commercial facilities and portfolio optimization	5		(2)	
Alberta contracted facilities	13		27	
Ontario and British Columbia contracted facilities	-		12	
U.S. contracted facilities	(2)		89	
Corporate	(4)		1	
Change in unrealized net gains or losses related to the fair value of commodity derivatives and emission credits	(32)	(20)	9	136
Impairments		83		83
Increase in depreciation and amortization expense		-		(24)
Increase in net unrealized gains on interest rate derivatives included in finance expense		2		2
Decrease in foreign exchange gain		(23)		(28)
Decrease in finance expense and depreciation expense from joint ventures		(1)		(11)
Decrease (increase) in net finance expense		1		(16)
Increase in income before tax		42		142
Change in income tax expense or recovery		(16)		(161)
Increase (decrease) in net income		**26**		**(19)**
Consolidated net income for the periods ended September 30, 2018		**19**		**128**

Results by facility category and other

	Three months ended September 30							
	2018	2017	2018	2017	2018	2017	2018	2017
	Electricity generation (GWh) [1]		**Facility availability** (%) [2]		**Revenues and other income** (unaudited, $ millions)		**Adjusted EBITDA** (unaudited, $ millions) [3]	
Total electricity generation, average facility availability and facility revenues	5,213	4,720	98	97	302	233		
Alberta commercial facilities [4]								
Genesee 3	495	509	98	100	27	12		
Keephills 3	494	380	100	83	27	9		
Clover Bar Energy Centre 1, 2 and 3	217	140	88	93	15	5		
Joffre	154	101	97	100	15	6		
Shepard Energy Centre	789	730	100	99	36	25		
Halkirk	85	95	95	88	7	6		
Clover Bar Landfill Gas	-	6	7	94	-	1		
Alberta commercial facilities	2,234	1,961	96	95	127	64		
Portfolio optimization	N/A	N/A	N/A	N/A	21	96		
	2,234	1,961	96	95	148	160	60	55
Alberta contracted facilities [4]								
Genesee 1	829	830	99	97				
Genesee 2	799	823	100	96				
	1,628	1,653	99	96	70	61	54	41
Ontario and British Columbia contracted facilities								
Island Generation	17	12	100	100	10	10		
York Energy [5]	3	5	100	100	N/A	N/A		
East Windsor [7]	4	2	99	99	8	8		
K2 Wind [6]	35	28	98	99	N/A	N/A		
Kingsbridge 1	14	11	98	98	-	-		
Port Dover and Nanticoke	43	39	94	93	5	4		
Quality Wind	74	85	94	91	7	8		
EnPower [8]	10	7	100	95	1	1		
	200	189	98	98	31	31	31	31
U.S. contracted facilities								
Roxboro, North Carolina	87	80	100	99	10	9		
Southport, North Carolina	104	124	100	97	15	17		
Decatur Energy, Alabama [9]	784	542	100	100	35	31		
Beaufort Solar, North Carolina	8	7	100	97	1	1		
Bloom Wind, Kansas [10]	152	145	97	97	11	17		
Macho Springs, New Mexico	16	19	97	98	2	2		
	1,151	917	99	99	74	77	44	46
Corporate [11]					15	14	(16)	(12)
Unrealized changes in fair value of commodity derivatives and emission credits					51	3	(35)	(3)
Consolidated revenues and other income and adjusted EBITDA					**389**	**346**	**138**	**158**

	Nine months ended September 30							
	2018	2017	2018	2017	2018	2017	2018	2017
	Electricity generation (GWh) [1]		**Facility availability** (%) [2]		**Revenues and other income** (unaudited, $ millions)		**Adjusted EBITDA** (unaudited, $ millions) [3]	
Total electricity generation, average facility availability and facility revenues	14,823	12,356	96	96	893	594		
Alberta commercial facilities [4]								
Genesee 3	1,442	1,482	98	99	70	31		
Keephills 3	1,348	1,244	97	89	66	27		
Clover Bar Energy Centre 1, 2 and 3	596	200	90	94	44	7		
Joffre	397	206	93	96	38	14		
Shepard Energy Centre	2,169	1.939	89	98	98	72		
Halkirk	320	336	97	94	29	23		
Clover Bar Landfill Gas	-	17	29	94	-	2		
Alberta commercial facilities	6,272	5,424	93	96	345	176		
Portfolio optimization	N/A	N/A	N/A	N/A	92	291		
	6,272	5,424	93	96	437	467	166	168
Alberta contracted facilities [4]								
Genesee 1	2,391	2,252	100	89				
Genesee 2	2,109	2,459	92	98				
	4,500	4,711	96	93	197	177	150	123
Ontario and British Columbia contracted facilities								
Island Generation	27	12	100	100	29	29		
York Energy [5]	8	8	98	100	N/A	N/A		
East Windsor [7]	8	3	99	99	26	16		
K2 Wind [6]	152	136	99	99	N/A	N/A		
Kingsbridge 1	70	72	98	97	3	3		
Port Dover and Nanticoke	221	203	97	97	27	25		
Quality Wind	250	263	96	95	22	24		
EnPower [8]	35	9	95	96	3	1		
	771	706	98	98	110	98	123	111
U.S. contracted facilities								
Roxboro, North Carolina	253	247	96	97	28	28		
Southport, North Carolina	333	308	94	91	46	45		
Decatur Energy, Alabama [9]	2,029	649	98	100	74	35		
Beaufort Solar, North Carolina	22	21	96	95	2	2		
Bloom Wind, Kansas[10]	547	190	97	98	80	21		
Macho Springs, New Mexico	96	100	98	97	11	12		
	3,280	1,515	97	98	241	143	151	62
Corporate [11]					45	44	(43)	(44)
Unrealized changes in fair value of commodity derivatives and emission credits					29	(44)	(14)	(23)
Consolidated revenues and other income and adjusted EBITDA					**1,059**	**885**	**533**	**397**

1 Gigawatt hours (GWh) of electricity generation reflects the Company's share of facility output.

2 Facility availability represents the percentage of time in the period that the facility 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 facility category, except for adjusted EBITDA, were prepared in accordance with GAAP. See Non-GAAP Financial Measures.

4 During the fourth quarter of 2016, management determined, based on a review of the nature of future cash flows, that its Alberta assets should be combined as one CGU for impairment testing purposes. Since the cash flows of Genesee 1 and 2 will remain contracted through 2020, management will continue to present facility results based on the Alberta Commercial and Alberta Contracted groupings through 2020.

5 York Energy was acquired on April 13, 2017. York Energy is accounted for under the equity method. Capital Power's share of the facility's net income is included in income from joint ventures on the Company's condensed interim consolidated statements of income. Capital Power's share of the facility's adjusted EBITDA is included in adjusted EBITDA above. The equivalent of Capital Power's share of the facility's revenue was $7 million and $22 million for three and nine months ended September 30, 2018, respectively, compared with $7 million and $13 million for the three and nine months ended September 30, 2017, respectively. The facility's revenues are not included in the above results.

6 K2 Wind is accounted for under the equity method. Capital Power's share of the facility's net income is included in income from joint ventures on the Company's condensed interim consolidated statements of income. Capital Power's share of the facility's adjusted EBITDA is included in adjusted EBITDA above. The equivalent of Capital Power's share of the facility's revenue was $6 million and $28 million for the three and nine months ended September 30, 2018, respectively, compared with $6 million and $31 million for the three and nine months ended September 30, 2017, respectively. The facility's revenues are not included in the above results.

7 East Windsor was acquired on April 13, 2017.

8 EnPower was acquired on June 1, 2017.

9 Decatur Energy was acquired on June 13, 2017.

10 Bloom Wind was commissioned on June 1, 2017.

11 Corporate revenues were offset by interplant category eliminations.

Energy prices and hedged positions

		Three months ended September 30		Nine months ended September 30		Year ended December
Alberta	**Unit**	**2018**	**2017**	**2018**	**2017**	**31, 2017**
Hedged position [1]	Percentage sold forward at beginning of period (%)	100	100	90	100	100
Spot power price average	$/MWh	55	25	49	22	22
Realized power price [2]	$/MWh	54	49	50	52	51
Natural gas price (AECO) [3]	$/gigajoule (Gj)	1.15	1.34	1.42	2.14	2.03

1 Hedged position is for the Alberta baseload facilities as well as a portion of Joffre and the uncontracted portion of Shepard.

2 Realized power price is the average price realized as a result of 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 facilities and portfolio optimization

The Alberta spot price averaged $55 per MWh and $49 per MWh for the three and nine months ended September 30, 2018, respectively which were higher than the corresponding periods in 2017 due to the impact of higher carbon costs as well as retirements and long-term coal supply outages which occurred at baseload facilities not owned by the Company. Spot power price average for 2017 reflected minimal market volatility combined with conservative offer strategies from market participants, stable baseload supply, strong imports and low natural gas prices.

For the three and nine months ended September 30, 2018, generation was higher than the comparable periods in 2017 primarily due to higher dispatch at Shepard, Joffre and Clover Bar Energy Centre. Higher availability for the three months ended September 30, 2018 was primarily due to a planned outage at Keephills 3 during the third quarter of 2017, compared with no planned outage during the same quarter in 2018. Lower availability for the nine months ended September 30, 2018 was mainly due to a planned outage at Shepard that occurred in the second quarter of 2018, as well as maintenance outages for the Clover Bar Energy Centre and Joffre facilities in the third quarter of 2018.

Revenues and other income for the three and nine months ended September 30, 2018 decreased compared with the corresponding periods in 2017 primarily due to lower realized revenues on portfolio optimization activities. This was partially offset by higher revenues earned at Alberta Commercial facilities from both increased generation as well as higher spot prices.

Adjusted EBITDA for the three months ending September 30, 2018 increased over the comparable period in 2017 as a result of lower realized expenses on portfolio optimization activities as well as lower natural gas commodity costs. Adjusted EBITDA for the nine months ending September 30, 2018 decreased over the comparable period in 2017, due to lower realized power prices for the portfolio and increased carbon costs. This was partially offset by lower natural gas commodity costs and higher ancillary services revenues earned in 2018.

Alberta contracted facilities

Availability for the three and nine months ended September 30, 2018 was higher compared with the corresponding periods in 2017 primarily due to fewer outages in 2018. Lower generation for the three and nine months ended September 30, 2018 as compared with the corresponding periods in 2017 was due to lower dispatch by the power purchase arrangement (PPA, refers to both power purchase arrangements and power purchase agreements) Buyer during 2018 as compared to 2017. Higher revenues and other income for the three and nine months ended September 30, 2018 compared with the corresponding periods in 2017 reflected the impact of higher Alberta power prices, including higher net availability incentive and excess energy payments received, and higher capacity revenues primarily due to higher PPA input rates.

Adjusted EBITDA increased for the three and nine months ended September 30, 2018 compared with the corresponding periods in 2017, primarily due to the noted favourable revenues and other income variances. EBITDA for the three and nine months ended September 30, 2018 as compared with the corresponding periods in 2017 also reflected favourable variances for environmental compliance incentive recoveries and net savings due to increased natural gas supplementing.

Ontario and British Columbia contracted facilities

Generation for the three and nine months ended September 30, 2018 was higher than the comparable period in 2017 primarily due to higher wind capacity and generation at Port Dover and Nanticoke and K2 Wind, partially offset by lower wind capacity and generation at Quality Wind. Generation was also higher driven by the acquisitions in the second quarter of 2017. Revenues and other income and adjusted EBITDA for the three months ended September 30, 2018 were consistent with the corresponding period in 2017. Revenues and other income were higher for the nine months ended September 30, 2018 compared with the corresponding period in 2017 primarily due to the acquisitions of facilities in the second quarter of 2017. Adjusted EBITDA for the nine months ended September 30, 2018 was higher than the comparable period in 2017 primarily due to EBITDA from the acquired facilities and higher wind capacity at Port Dover and Nanticoke, offset partly by the impact of lower wind capacity at Quality Wind and K2 Wind. Revenues and other income does not include K2 Wind and York Energy, which are accounted for under the equity method.

U.S. contracted facilities

Generation for the three months ended September 30, 2018 was higher than the comparable period in 2017 primarily due to higher dispatch at Decatur Energy, partially offset by lower generation at Southport due to a 13-day force majeure caused by Hurricane Florence. Revenues and other income and adjusted EBITDA for the three months ended September 30, 2018 were lower than the comparable period in 2017 primarily due to the impact of lower than budgeted tax rates on Bloom Wind revenues and the impacts of the force majeure at Southport. These impacts were partially offset by higher revenue at Decatur Energy due to increased dispatch. Generation, revenues and other income, and adjusted EBITDA for the nine months ended September 30, 2018 were higher than the comparable periods of 2017 primarily due to the addition of Decatur Energy in April 2017 and the commencement of commercial operations of Bloom Wind in June 2017. Revenues and other income and adjusted EBITDA for the nine months ended September 30, 2018 were also higher than the comparable period in 2017 due to the re-negotiation of the Bloom Wind tax equity agreement in the second quarter of 2018. Availability for the three and nine months ended September 30, 2018 was in line with the comparable periods in 2017

Corporate

Corporate results include (i) revenues for cost recoveries and other income related to coal compensation from the Province of Alberta, (ii) costs 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. Note that cost recovery revenues are primarily intercompany revenues that are offset by interplant category transactions.

Net corporate expenditures for the three months ended September 30, 2018 were higher than the corresponding period in 2017 mainly due to higher performance incentive expenses due to the increase in the Company’s share price during the third quarter of 2018. Net corporate expenditures for the nine months ended September 30, 2018 were lower than the corresponding period in 2017 mainly due to higher business development expenses resulting from the Veresen thermal facilities and Decatur Energy acquisitions in the second quarter of 2017, partially offset by the increased performance incentive expenses in the third quarter of 2018.

Unrealized changes in fair value of commodity derivatives and emission credits

(unaudited, $ millions)	Three months ended September 30			
	2018	**2017**	**2018**	**2017**
Unrealized changes in fair value of commodity derivatives and emission credits	**Revenues and other income**		**Adjusted EBITDA**	
Unrealized gains (losses) on Alberta energy derivatives	95	(2)	-	(6)
Unrealized losses on U.S. energy derivatives	(42)	-	(42)	-
Unrealized (losses) gains on natural gas derivatives	(3)	4	7	3
Unrealized gains on emission derivatives	1	1	1	1
Unrealized losses on emission credits held for trading	-	-	(1)	(1)
	51	**3**	**(35)**	**(3)**

(unaudited, $ millions)	Nine months ended September 30			
	2018	**2017**	**2018**	**2017**
Unrealized changes in fair value of commodity derivatives and emission credits	**Revenues and other income**		**Adjusted EBITDA**	
Unrealized gains (losses) on Alberta energy derivatives	51	(62)	(3)	(16)
Unrealized losses on U.S. energy derivatives	(18)	-	(18)	-
Unrealized (losses) gains on natural gas derivatives	(13)	15	4	(10)
Unrealized gains on emission derivatives	9	3	9	3
Unrealized losses on emission credits held for trading	-	-	(6)	-
	29	**(44)**	**(14)**	**(23)**

The Company's financial results relating to its Alberta commercial facilities 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 facility category.

During the three months ended September 30, 2017 the Alberta energy portfolio recognized unrealized losses of $6 million, mainly due to the reversal of prior period unrealized net gains on forward sales contracts that settled during the quarter. During the nine months ended September 30, 2018 and 2017, the Alberta energy portfolio recognized unrealized losses of $3 million and $16 million, respectively. Unrealized losses recognized in both 2018 and 2017 were the result of the reversal of prior period unrealized net gains on positions that settled in the respective periods.

During the three and nine months ended September 30, 2018, the Company recorded unrealized losses of $42 million and $18 million respectively, on U.S. energy derivatives, as a result of increasing forward prices on forward sales contracts.

Unrealized gains on natural gas derivatives reported by the Company in 2018 were attributable to net forward purchase contracts valued against increasing forward natural gas prices, as well as the reversal of prior period unrealized losses on purchase contracts that settled in the respective periods. During the three months ended September 30, 2017, unrealized gains on natural gas derivatives reported by the Company reflected the reversal of prior period unrealized losses on purchase contracts that settled during the quarter. Unrealized losses on natural gas derivatives recognized during the nine months ending September 30, 2017 reflected net forward purchase contracts which were valued against decreasing forward natural gas prices and the reversal of prior periods unrealized gains which settled during the period.

Unrealized gains on emission derivatives reported by the Company in 2018 and 2017 were primarily due to forward purchase contracts on emissions allowances and renewable energy credits which were valued against increasing forward prices and the impact of the reversal of previously unrealized gains and losses on positions that settled during the respective periods.

During the nine months ended September 30, 2018, the Company recorded unrealized losses on emission credits held for trading, primarily due to the reversal of prior period unrealized gains on emission credits sold in 2018.

Consolidated other expenses and non-controlling interest

(unaudited, $ millions)	Three months ended September 30		Nine months ended September 30	
	2018	2017	2018	2017
Interest on borrowings less capitalized interest	(26)	(29)	(82)	(69)
Other net finance expense – interest on coal compensation from the Province of Alberta, sundry interest, guarantee and other fees	3	3	8	10
	(23)	(26)	(74)	(59)
Unrealized gains representing changes in the fair value of interest rate derivatives	2	-	2	-
Other net finance expense – amortization and accretion charges, including accretion of deferred revenue pertaining to coal compensation from the Province of Alberta	(7)	(5)	(18)	(17)
Total net finance expense	(28)	(31)	(90)	(76)
Impairments	-	(83)	-	(83)
Depreciation and amortization	(74)	(74)	(223)	(199)
Foreign exchange (loss) gain	(2)	21	4	32
Finance expense and depreciation expense from joint ventures	(7)	(6)	(22)	(11)
Income tax (expense) recovery	(8)	8	(74)	87
Net loss attributable to non-controlling interest	1	2	5	7

Net finance expense

Lower finance expense for the three months ended September 30, 2018 compared to the same period in the prior year was primarily due to the reduced tax equity financing balance resulting from the Bloom Wind tax equity agreement amendment in the second quarter of 2018 (see Significant Events) and lower short-term debt interest in 2018 due to the Decatur Energy acquisition financing in the comparable 2017 period. Higher net finance expense for the nine months ended September 30, 2018 compared with the same periods in the prior year was primarily due to additional loans and borrowings as a result of the acquisition of the Veresen thermal facilities and Decatur Energy and the receipt of Bloom Wind Project Investor financing in the second quarter of 2017.

Impairments

During the third quarter of 2018, no impairment losses were recorded. In the prior year comparable periods, the Company recognized pre-tax impairment losses on the Southport, Roxboro and Decatur Energy cash generating units of $32 million, $14 million and $37 million, respectively.

Depreciation and amortization

Depreciation and amortization for the three months ended September 30, 2018 was consistent with the same period in the prior year. Depreciation and amortization for the nine months ended September 30, 2018 increased compared with the same period in the prior year primarily due to the facilities acquired in the second quarter of 2017.

Foreign exchange (loss) gain

As at September 30, 2018, the Company had outstanding foreign currency purchase contracts totalling US$117 million. For the three months ended September 30, 2018, the exchange rate of the Canadian dollar relative to the U.S. dollar strengthened resulting in an unrealized loss in the period. For the nine months ended September 30, 2018, the exchange rate of the Canadian dollar relative to the U.S. dollar weakened resulting in an unrealized gain.

As at September 30, 2017 the Company had outstanding U.S. dollar denominated debt payable totalling US$595 million. Approximately US$300 million was hedged using foreign currency derivative instruments. In September 2017, the Company issued $450 million of medium-term notes which were primarily used to repay the increased committed credit facilities. The foreign exchange gain consisted primarily of the gain incurred on the revaluation of U.S. dollar denominated debt not hedged for accounting purposes. For the three and nine months ended September 30, 2017, the exchange rate of the Canadian dollar relative to the U.S. dollar strengthened, resulting in an unrealized gain in both periods.

Finance expense and depreciation expense from joint ventures

Finance expense and depreciation expense from joint ventures includes Capital Power's share of finance expense and depreciation expense of K2 Wind and York Energy, which are accounted for under the equity method.

Income tax (expense) recovery

For the three and nine months ended September 30, 2018 income tax expense increased $16 million and $161 million, respectively, compared with the corresponding period in 2017 primarily due to amounts attributable to tax-equity interests and higher consolidated income before tax. Furthermore, in the second quarter of 2017, there was a reversal of a previous non-cash write-down related to U.S. income tax losses that resulted in a tax recovery, of which no comparable tax recovery was recognized in 2018.

Non-controlling interest

Non-controlling interest consists only of the Coal Mine partner's share of the consolidated depreciation expense of the Coal Mine.

COMPREHENSIVE INCOME (LOSS)

(unaudited, $ millions)	Three months ended September 30		Nine months ended September 30	
	2018	**2017**	**2018**	**2017**
Net income (loss)	19	(7)	128	147
Other comprehensive income (loss):				
Net unrealized gains on derivative instruments	32	13	13	9
Net unrealized gains on derivative instruments – joint ventures	2	3	3	3
Net realized losses (gains) on derivative instruments reclassified to net income	7	(13)	8	(48)
Net realized losses on derivative instruments reclassified to net income – joint ventures	1	1	2	3
Unrealized foreign exchange (loss) gain on the translation of foreign operations	(8)	(35)	12	(56)
Actuarial gain related to the Company's defined benefit pension plan	-	-	-	2
	34	(31)	38	(87)
Comprehensive income (loss)	**53**	**(38)**	**166**	**60**

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 consolidated statements of financial position from December 31, 2017 to September 30, 2018 were as follows:

(unaudited, $ millions)	September 30, 2018	December 31, 2017	Increase (decrease)	Primary reason for increase (decrease)
Trade and other receivables	349	278	71	Primarily due to higher receivables at various facilities due to higher pool prices and receivables from counterparties relating to facility emissions compliance obligations.
Inventories	169	120	49	Increase in emission credits held for trading and higher coal inventory.
Net derivative financial instruments	6	29	(23)	Decrease mainly due to unrealized losses recorded in Q3 on the New Frontier Wind and Cardinal Point Wind swaps.
Intangible assets	364	401	(37)	Decrease primarily due to emission credits returned and used for compliance, partially offset by increase in capital costs on project under development.
Deferred revenue and other liabilities (including current portion)	659	639	20	Increase due to the cumulative impact of adopting IFRS 15 (see Accounting Changes) resulting in an adjustment to the opening balance of deferred revenue at January 1, 2018 primarily due to the timing of revenue recognition for capacity revenue related to the Company's interest in the Joffre joint operation.
Net deferred tax liabilities	358	300	58	Increase primarily attributable to tax-equity interests (see Significant Events).
Share Capital	3,216	3,262	(46)	Decrease primarily due to common shares purchased.

LIQUIDITY AND CAPITAL RESOURCES

(unaudited, $ millions)	Nine months ended September 30		
Cash inflows (outflows)	**2018**	**2017**	**Change**
Operating activities	317	297	20
Investing activities	(168)	(1,079)	911
Financing activities	(161)	749	(910)

Operating activities

Cash flows from operating activities for the nine months ended September 30, 2018 increased compared with the same period in 2017 primarily due to higher adjusted EBITDA (before unrealized changes in fair value of commodity derivatives and emission credits and non-cash tax equity attributes), partially offset by higher interest paid due to additional loans and borrowings as a result of the acquisition of the Veresen thermal facilities and the receipt of Bloom Wind Project financing in the second quarter of 2017 and non-cash operating working capital outflows in 2018. Cash inflows in 2018 were also higher compared with 2017 due to positive 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.

Investing activities

Cash flows used in investing activities for the nine months ended September 30, 2018 decreased compared with the same period in 2017 primarily due to the acquisition of the thermal facilities and Decatur Energy in the second quarter of 2017, lower year-to-date spending on wind development projects in 2018 compared to Bloom Wind spending in 2017 and the 2017 prepayment related to the amended Genesee Mine Joint Venture Agreement.

Capital expenditures and investments

(unaudited, $ millions)	**Pre-2018 Actual**	**Nine months ended September 30, 2018 Actual**	**Balance of 2018 Estimated [1, 2]**	**Actual or Projected Total [2]**	**Timing**
Genesee 4 and 5 [3,4]	18	-	-	700	Targeted completion as early as 2021 and 2022, respectively
New Frontier Wind [5]	20	104	58	182	Targeted completion in December 2018
Whitla Wind [6]	3	52	15	320	Targeted completion in the fourth quarter of 2019
Cardinal Point Wind [7]	2	7	21	295	Targeted completion in Q1 2020
Development sites	9	5	2		
Subtotal growth projects		**168**	**96**		
Sustaining – plant maintenance excluding Genesee mine		58			
Sustaining – Genesee mine maintenance and lands		10			
Total capital expenditures [8]		**236**			
Emission credits held for compliance		5			
Investment in C2CNT [9] (see Significant Events)		3			
Capitalized interest		(3)			
Purchase of property, plant and equipment and other assets		**241**			

1 The Company's 2018 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 projects for Genesee 4 and 5, New Frontier Wind, Whitla Wind and Cardinal Point Wind are based on management's estimates. Projected capital expenditures for development sites, are not reflected beyond the current period until specific projects reach the advanced development stages.

[3] Excludes interest to fund construction and refundable transmission system contribution payments.

[4] Continuation and timing of the Genesee 4 and 5 project will be considered once sufficient Alberta market certainty exists and new generation is required in Alberta to balance supply and demand.

[5] Projected total cost excludes a $19 million (US$15 million) developer fee paid to a subsidiary of the Company.

[6] The projected total cost for Whitla Wind reflects the midpoint of the expected range of construction costs of $315 million to $325 million.

[7] The projected total cost for Cardinal Point Wind reflects the midpoint of the expected range of construction costs of $289 million to $301 million (US$236 million to US$246 million).

[8] Capital expenditures include capitalized interest. Capital expenditures excluding capitalized interest are presented on the consolidated statements of cash flows as purchase of property, plant and equipment and other assets.

[9] In the second quarter of 2018, the Company acquired a 5% equity interest in C2CNT (see Significant Events) for total consideration of $3.2 million (US$2.5 million) to be paid over a two-year period. The initial payment of $1.3 million (US$1.0 million) was paid in the second quarter of 2018 and the balance of consideration will be paid by January 1, 2020.

Financing activities

The cash flows from financing activities for the nine months ended September 30, 2018 primarily reflected the repayment of loans and borrowings, payment of common and preferred share dividends, and common shares purchased under the Company's normal course issuer bid, partially offset by the net issuance of loans and borrowings and a realized foreign exchange gain on the settlement of foreign currency derivative instruments pertaining to U.S. dollar borrowings. Cash flows from financing activities were higher in the comparative period most notably due to higher issuances of loans and borrowings and shares driven by the acquisitions in 2017 as well as the receipt of Project Investor financing for Bloom Wind in 2017.

The Company's credit facilities consisted of:

(unaudited, $ millions)		**As at September 30, 2018**			**As at December 31, 2017**		
	Maturity timing	**Total facilities**	**Credit facility utilization**	**Available**	**Total facilities**	**Credit facility utilization**	**Available**
Committed credit facilities	2023	1,000			1,055		
Letters of credit outstanding			74			30	
Bankers' acceptance outstanding			100			-	
Bank loans outstanding [1]			153			28	
		1,000	327	673	1,055	58	997
Bilateral demand credit facilities	N/A	200			200		
Letters of credit outstanding			145			139	
		200	145	55	200	139	61
Demand credit facilities	N/A	25	-	25	25	-	25
		1,225	**472**	**753**	**1,280**	**197**	**1,083**

[1] U.S. dollar denominated bank loans outstanding totaling US$119 million (December 31, 2017 – US$23 million).

As at September 30, 2018, the committed credit facility utilization increased $269 million compared with the utilization as at December 31, 2017, due to the issuance of bankers' acceptance, increased U.S. dollar bank loans, and increased letters of credit outstanding. In the second quarter of 2018, the maturity of the existing credit facilities of $1 billion were extended to July 2023. The available credit facilities provide the Company with adequate funding for ongoing development projects.

The Company 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.

The Company has a corporate credit rating of BBB (low) with a stable outlook from DBRS Limited (DBRS). The BBB rating category 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 and 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 Capital Power'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 2018 include:

(unaudited, $ millions)	Nine months ended September 30, 2018 Actual	Balance of 2018 estimated	Total 2018 expected cash requirements
Repayment of debt payable	192	4	196
Capital expenditures – sustaining	54	36	90
Capital expenditures – ongoing growth projects	168	96	264
Capital expenditures – Genesee performance standard	8	2	10
Common share dividends [1]	130	45	175
Preferred share dividends	30	10	40
	582	**193**	**775**

[1] Includes 7% annual dividend growth (see Significant Events).

The Company uses a short-form base shelf prospectus 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 prospectus, 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. This prospectus expires in June 2020.

If the Canadian and U.S. financial markets become unstable, 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, 2018, $219 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, 2018	**December 31, 2017**
Loans and borrowings	2,139	2,146
Finance lease obligation [1]	18	18
Less cash and cash equivalents	(41)	(52)
Net debt	2,116	2,112
Share capital	3,216	3,262
Deficit and other reserves	(272)	(248)
Non-controlling interest	43	48
Total equity	2,987	3,062
Total capital	**5,103**	**5,174**

[1] Includes the current portion disclosed within trade and other payables.

CONTINGENT LIABILITIES, OTHER LEGAL MATTERS AND PROVISIONS

Contingent liabilities

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.

Other legal matters

In each of 2017 and 2018, the Government of Alberta (GoA) withheld approximately $2.7 million from the Company's annual off-coal payment, on the basis of an alleged "implied term" of the Off-Coal Agreement. Capital Power believes there was no such implied term and has therefore sued the GoA for recovery of the withheld amount and specific performance for future payments. Similarly, the GoA amended its Linear Property Assessment Guidelines in 2017 to eliminate the anticipated cessation of coal emissions (and related business closures) from being considered in property tax assessments, which erroneously suggests that the off-coal payments were intended to compensate the Company for non-net book value related costs. Capital Power has also commenced litigation on the basis that this provision discriminatorily applies only to three coal generators.

Line Loss Rule Proceeding provision

Capital Power participated in the Line Loss Rule (LLR) Proceeding before the Alberta Utilities Commission (AUC) regarding loss factors that form the basis for certain transmission charges paid by Alberta generators, including Capital Power. The LLR Proceeding addressed the replacement of the non-compliant LLR as well as the possible correction of line loss charges and credits for the years 2006 to 2017.

The Company is participating in appeal processes rendering the final outcome of the LLR Proceeding still unknown. However, based on the current decision, Capital Power would incur additional charges related to transmission amounts of historical periods and as such recorded a current provision of $9 million during the fourth quarter of 2017 pertaining to its currently held Alberta assets.

RISKS AND RISK MANAGEMENT

There have been no material changes in the nine months ended September 30, 2018 to the Company's business and operational risks as described in the Company's December 31, 2017 MD&A.

ENVIRONMENTAL MATTERS

The Company recorded decommissioning provisions of $232 million as at September 30, 2018 ($228 million as at December 31, 2017) for its generation facilities and the Coal Mine as it is obliged to remove the facilities at the end of their useful lives and restore the facility and mine sites to their original condition. Decommissioning provisions for the Coal Mine are incurred over time as new areas are mined, and a portion of the liability is settled over time as areas are reclaimed prior to final pit reclamation. The timing of reclamation activities could vary and the amount of decommissioning provisions could change depending on potential future changes in environmental regulations and the timing of any facility fuel conversions.

The Company is obligated to purchase environmental credits totaling $331 million in future years and expects to mostly use these credits to comply with applicable environmental regulations.

REGULATORY MATTERS

The Ontario Independent Electricity System Operator (IESO) is in the preliminary stages of a Market Renewal Program (MRP), which is a series of coordinated initiatives expected to result in a fundamental redesign of Ontario's electricity market. The IESO's stated goal for the MRP is to improve how electricity is priced, scheduled and procured to meet Ontario's electricity system needs. The Company is actively participating in the MRP stakeholder process and collaborating with the IESO. The PPAs for the York Energy, East Windsor, K2 Wind, Port Dover and Nanticoke and Kingsbridge 1 facilities contain provisions for renegotiation should there be a change in market rules. The intent of these provisions is to preserve the underlying supplier economics within the respective PPAs. Accordingly, the Company does not believe that implementation of the MRP will have a material adverse effect on its financial condition and results of operations.

On July 25, 2018, the Government of Ontario introduced Bill 4, the *Cap and Trade Cancellation Act, 2018*. If passed, Bill 4 will repeal the *Climate Change Mitigation and Low-carbon Economy Act, 2016*, and set out the legal framework for a wind-down of the Cap and Trade program. The Federal Government has proposed legislation that will impose a carbon pricing system on provinces that do not have an equivalent system in place to meet targeted GHG reduction levels, that if implemented is proposed to be in place effective January 1, 2019. The PPAs for York Energy and East Windsor both have a provision that triggers a contractual amendment, the effect of which will enable recovery of any imposed federal carbon compliance costs. Accordingly, the Company does not believe the implementation of a federal carbon pricing system will have a material adverse effect on its financial condition and results of operations.

USE OF JUDGMENTS AND ESTIMATES

In preparing the condensed interim consolidated financial statements, management made judgments, estimates and assumptions that affect the application of the Company's accounting policies and the reported amount of assets, liabilities, income and expenses. Actual results may differ from these estimates. There have been no significant changes to the Company's use of judgments and estimates as described in the Company's December 31, 2017 MD&A, other than those judgments made as a part of the adoption of new accounting standards in the first quarter of 2018, as described under Accounting Changes.

ACCOUNTING CHANGES

Effective January 1, 2018

The Company adopted new accounting standards as issued by the International Accounting Standards Board (IASB). The standards and impact to Capital Power are:

Standard	Description	Impact to Capital Power and current implementation status	Effective Date
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.	The Company applied IFRS 15 using the cumulative effect method recognizing the cumulative impact of initially apply IFRS 15 as an adjustment to the opening balance of equity at January 1, 2018. The adoption of this standard has resulted in a pre-tax increase to the opening deficit of $44 million which consists of: • Increase to opening deficit of $3 million ($2 million post tax) and a decrease to emission revenue receivables due to the timing of revenue recognition of RECs. Prior to the adoption of IFRS 15, the Company recognized revenue on the sale of RECs at the time of generation. Under IFRS 15, the Company satisfies its performance obligation when RECs are delivered to the customer which occurs subsequent to the period of REC generation. • Increase to opening deficit of $41 million ($31 million post tax) and increased deferred revenue and other liabilities for a contract liability due to the timing of revenue recognition for capacity revenue related to the Company's interest in the Joffre joint operation. Prior to the adoption of IFRS 15, revenue was recognized when the Company had the right to bill. Capacity payments are based on a declining rate base capacity payment schedule. Under IFRS 15, the performance obligation is satisfied as the facility provides the availability of the contracted power generation and as such, revenue is recognized over the term of the contract. The Company applied the "right to invoice" practical expedient on energy revenues where the Company has a right to consideration from a buyer that corresponds directly with the value to the buyer of the Company's performance obligation completed to date. A number of the Company's revenue contracts are accounted for under IAS 17 – Leases and IFRS 9 – Financial Instruments and therefore are excluded from the scope of IFRS 15. Additional disclosures included in the interim financial statements include disaggregated revenues by major types and current operational groupings of revenues.	Effective for annual periods beginning on or after January 1, 2018.
Financial instruments (IFRS 9)	New standard, replacing IAS 39, which addresses requirements for classification and measurement, impairment, hedge accounting and de-recognition of financial assets and liabilities.	The change in accounting policy has been applied retrospectively and did not result in a change in the carrying amount of any financial instruments at the transition date. Additionally, the Company adopted consequential amendments to IFRS 7: Financial Instruments: Disclosures that have been applied commencing January 1, 2018. The Company completed an assessment of its financial assets and liabilities classification as at January 1, 2018 under IFRS 9. While the categories are different under the new standard, there were no changes to the accounting methods applied as compared to the previous classification under IAS 39. The Company has identified no financial instruments for which credit risk has increased significantly since initial recognition nor financial assets that are impaired as at September 30, 2018. Derivative instruments continue to be measured at fair value through income or loss unless cash flow hedge accounting is used, in which case they are measured at fair value through other comprehensive income. The Company has applied the new general hedge accounting model prospectively and determined no changes to its hedging relationships previously designated under IAS 39.	Effective for annual periods beginning on or after January 1, 2018.

Future

The IASB issued the following new standard that was not yet effective as of September 30, 2018 and is relevant to Capital Power:

Standard	Description	Impact to Capital Power and current implementation status	Effective Date
Leases (IFRS 16)	New standard which replaces IAS 17 and addresses the recognition, measurement, presentation and disclosure of leases and provides a new approach to lessee accounting, requiring lessees to recognize assets and liabilities for all leases.	The standard will require the Company to recognize lease assets and lease obligations with respect to leases previously classified as operating leases which include office space leases and land leases. Management has determined that certain PPAs and energy supply contracts that are currently considered to be finance leases with the Company as the lessor will no longer be considered leases upon adoption of this new standard, but rather will be accounted for under IFRS 15 – *Revenue from Contracts with Customers*. Management has assessed the transition options for the adoption of IFRS 16 and will not grandfather lease assessments under the previous standard to IFRS 16. For contracts determined to contain leases, with the Company as the lessee under IFRS 16, the Company will elect to apply the modified retrospective approach (cumulative catch-up), recognizing a right-of-use asset of the underlying asset and a lease liability for future lease payments. The Company will continue to recognize finance leases on the balance sheet and will recognize right-of-use assets and lease liabilities relating to the respective operating leases. For contracts determined to contain a lease, with the Company as the lessor under IFRS 16 that continue to meet the lease requirements to be classified as a lease, no adjustments are required on transition. Certain PPAs that no longer meet the requirements to be classified as leases under IFRS 16 will be accounted for under IFRS 15 – *Revenue from Contracts with Customers* and the transition impact will be accounted for retrospectively in accordance with IAS 8 - *Accounting Policies, Changes in Accounting Estimates and Errors* and treated as a change in accounting policy.	Effective for annual periods beginning on or after January 1, 2019.

FINANCIAL INSTRUMENTS

The classification, carrying amounts and fair values of financial instruments held at September 30, 2018 and December 31, 2017 were as follows:

(unaudited, $ millions)		September 30, 2018		December 31, 2017	
	Fair value hierarchy level [1]	Carrying amount	Fair value	Carrying amount	Fair value
Financial assets:					
Amortized cost					
Cash and cash equivalents	N/A	41	41	52	52
Trade and other receivables [2]	N/A	272	272	200	200
Government grant receivable [3]	Level 2	507	507	544	544
Finance lease receivables [3]	Level 2	650	714	667	757
Other financial assets [4]	Level 2	4	4	4	4
Fair value through income or loss					
Derivative financial instruments assets – current and non-current	See Below	149	149	157	157
Fair value through other comprehensive income					
Derivative financial instruments assets – current and non-current	See Below	16	16	14	14
Financial liabilities:					
Other financial liabilities					
Trade and other payables [5]	N/A	220	220	215	215
Finance lease obligation [3]	Level 2	18	20	18	20
Loans and borrowings [3]	Level 2	2,139	2,157	2,146	2,203
Designated at fair value through income or loss					
Derivative financial instruments liabilities – current and non-current	See Below				
Fair value through other comprehensive income		133	133	112	112
Derivative financial instruments liabilities – current and non-current	See Below	26	26	30	30

1 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 prepared by appropriate subject matter experts and reviewed by the Company's commodity risk group and by management.

2 Excludes current portion of government grant receivable, finance lease receivables and other financial assets.

3 Includes current portion.

4 Included in trade and other receivables and non-current other assets, as appropriate, within the statements of financial position.

5 Excludes current portion of finance lease obligation.

Risk management and hedging activities

There have been no material changes in the nine months ended September 30, 2018 to the Company's risk management and hedging activities as described in the Company's December 31, 2017 MD&A.

The derivative financial instruments assets and liabilities held at September 30, 2018 compared with December 31, 2017 and used for risk management purposes were measured at fair value and consisted of the following:

(unaudited, $ millions)		As at September 30, 2018						
	Fair value hierarchy level	**Commodity cash flow hedges**	**Commodity non-hedges**	**Interest rate cash flow hedges**	**Interest rate non-hedges**	**Foreign exchange cash flow hedges**	**Foreign exchange non-hedges**	**Total**
Derivative financial instruments assets	Level 2	6	106	10	2	-	2	126
	Level 3	-	39	-	-	-	-	39
		6	145	10	2	-	2	165
Derivative financial instruments liabilities	Level 2	(17)	(111)	-	-	(9)	-	(137)
	Level 3	-	(22)	-	-	-	-	(22)
		(17)	(133)	-	-	(9)	-	(159)
Net derivative financial instruments (liabilities) assets		**(11)**	**12**	**10**	**2**	**(9)**	**2**	**6**

(unaudited, $ millions)		As at December 31, 2017			
	Fair value hierarchy level	**Commodity cash flow hedges**	**Commodity non-hedges**	**Foreign exchange non-hedges**	**Total**
Derivative financial instruments assets	Level 2	14	84	41	139
	Level 3	-	32	-	32
		14	116	41	171
Derivative financial instruments liabilities	Level 2	(30)	(101)	(9)	(140)
	Level 3	-	(2)	-	(2)
		(30)	(103)	(9)	(142)
Net derivative financial instruments (liabilities) assets		**(16)**	**13**	**32**	**29**

Commodity and foreign exchange derivatives designated as accounting hedges

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

As a result of the addition of Decatur Energy and the repayment of certain U.S. dollar denominated loans and borrowings during the third quarter of 2017, the foreign currency exposure that the cross-currency interest rate swap was hedging no longer existed. As a result, the Company de-designated the cross-currency interest rate swap as a foreign exchange cash flow hedge during the third quarter of 2017. Unrealized gains associated with this de-designated foreign exchange cash flow hedge began to flow directly through net income as foreign exchange gains starting in the third quarter of 2017. Prior to the time of de-designation of the foreign exchange cash flow hedge, the unrealized gains or losses were reclassified to net income, within foreign exchange gains or losses, each period to offset the impact to unrealized foreign exchange gains and losses from the revaluation of the U.S. dollar loans and borrowings that were being hedged.

The Company previously elected to apply hedge accounting on certain derivative financial instruments whereby the Company entered into swap agreements with third parties in order to swap the market revenues earned on Bloom Wind and New Frontier Wind generation for a fixed annual payment on Bloom Wind and a fixed price per MWh on New Frontier Wind. Since Bloom Wind's commercial operation date in June 2017, actual captured basis exceeded the expected basis differential and changes to the Bloom Wind Node price have not been as closely aligned to changes in the SPP North Hub price as previously expected. With this additional information, management revised the forward price methodology resulting in the Bloom Wind swap no longer meeting the hedge effectiveness criteria. Based on the revised methodology for Bloom Wind, management expects New Frontier Wind to function in a similar manner to Bloom Wind post commercial operation date. As a result, effective October 30, 2017, the Company de-designated the swap agreements relating to both Bloom Wind and New Frontier Wind as cash flow hedges. Since the forecasted transactions are still expected to occur, the fair value recognized in accumulated other comprehensive loss will remain and fair value adjustments subsequent to ineffectiveness will be recognized in net income. The balance in accumulated other comprehensive loss will be reclassified to net income in future periods as generation occurs at the respective facilities.

Commodity, foreign exchange 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 and natural gas prices and their impact on the Alberta portfolio as well as the change in pricing on U.S. trading relating to the swap arrangements on the Company's U.S. wind generation. 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 gains and losses on foreign exchange and interest rate derivatives that are not designated as hedges for accounting purposes are recorded in net income as foreign exchange gains or losses and finance expense, respectively.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

There were no significant changes in the Company's disclosure controls and procedures and internal controls over financial reporting that occurred during the nine months ended September 30, 2018 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 2018**	**Jun 30 2018**	**Mar 31 2018**	**Dec 31 2017**	**Sep 30 2017**	**Jun 30 2017**	**Mar 31 2017**	**Dec 31 2016**
Total generation	5,213	4,584	5,026	4,839	4,720	3,673	3,962	3,793
Alberta commercial facilities [1]								
Genesee 3	495	468	479	511	509	480	493	341
Keephills 3	494	434	420	362	380	419	445	478
Clover Bar Energy Centre 1, 2 and 3	217	204	175	92	140	24	36	94
Joffre	154	115	128	119	101	70	35	66
Shepard Energy Centre	789	585	795	694	730	560	649	410
Halkirk	85	103	132	168	95	119	122	121
Clover Bar Landfill Gas	-	-	-	2	6	6	5	3
	2,234	1,909	2,129	1,948	1,961	1,678	1,785	1,513
Alberta contracted facilities [1]								
Genesee 1	829	751	811	860	830	576	846	863
Genesee 2	799	647	663	864	823	825	811	860
	1,628	1,398	1,474	1,724	1,653	1,401	1,657	1,723
Ontario and British Columbia contracted facilities								
Island Generation	17	-	10	3	12	-	-	37
York Energy	3	3	2	2	5	1	N/A	N/A
East Windsor	4	2	2	1	2	1	N/A	N/A
K2 Wind	35	41	76	57	28	29	79	77
Kingsbridge 1	14	20	36	37	11	25	36	37
Port Dover and Nanticoke	43	70	108	84	39	71	93	92
Quality Wind	74	98	78	117	85	84	94	85
EnPower	10	11	14	13	7	2	N/A	N/A
	200	245	326	314	189	213	302	328
U.S. contracted facilities								
Roxboro, North Carolina	87	90	76	86	80	88	79	84
Southport, North Carolina	104	118	111	120	124	92	92	107
Decatur Energy, Alabama	784	576	669	425	542	107	N/A	N/A
Beaufort Solar, North Carolina	8	8	6	6	7	8	6	6
Bloom Wind, Kansas	152	197	198	190	145	46	N/A	N/A
Macho Springs, New Mexico	16	43	37	26	19	40	41	32
	1,151	1,032	1,097	853	917	381	218	229

[1] During the fourth quarter of 2016, management determined, based on a review of the nature of future cash flows, that its Alberta assets should be combined as one CGU for impairment testing purposes. Since the cash flows of Genesee 1 and 2 will remain contracted through 2020, management will continue to present facility results based on the Alberta Commercial and Alberta Contracted groupings through 2020.

(%)	Three months ended							
Facility availability	**Sep 30 2018**	**Jun 30 2018**	**Mar 31 2018**	**Dec 31 2017**	**Sep 30 2017**	**Jun 30 2017**	**Mar 31 2017**	**Dec 31 2016**
Total average facility availability	98	93	96	95	97	94	97	94
Alberta commercial facilities [1]								
Genesee 3	98	98	97	100	100	97	99	68
Keephills 3	100	100	92	75	83	92	93	99
Clover Bar Energy Centre 1, 2 and 3	88	90	93	97	93	89	99	99
Joffre	97	90	93	100	100	96	92	98
Shepard Energy Centre	100	68	100	94	99	97	99	76
Halkirk	95	98	98	97	88	99	96	98
Clover Bar Landfill Gas	7	78	-	45	94	95	95	92
	96	87	96	93	95	95	97	87
Alberta contracted facilities [1]								
Genesee 1	99	100	100	100	97	70	100	100
Genesee 2	100	93	83	100	96	100	97	100
	99	97	92	100	96	85	98	100
Ontario and British Columbia contracted facilities								
Island Generation	100	100	100	100	100	100	100	100
York Energy	100	94	100	100	100	100	N/A	N/A
East Windsor	99	99	99	97	99	99	N/A	N/A
K2 Wind	98	100	98	98	99	100	99	100
Kingsbridge 1	98	98	98	98	98	95	98	97
Port Dover and Nanticoke	94	99	100	96	93	100	98	99
Quality Wind	94	97	97	96	91	99	97	97
EnPower	100	86	97	96	95	98	N/A	N/A
	98	98	99	98	98	99	99	99
U.S. contracted facilities								
Roxboro, North Carolina	100	99	88	100	99	100	93	94
Southport, North Carolina	100	95	89	99	97	86	92	98
Decatur Energy, Alabama	100	94	100	89	100	100	N/A	N/A
Beaufort Solar, North Carolina	100	98	93	97	97	90	97	92
Bloom Wind, Kansas	97	96	98	98	97	98	N/A	N/A
Macho Springs, New Mexico	97	98	97	98	98	96	98	97
	99	95	98	92	99	96	94	96

[1] During the fourth quarter of 2016, management determined, based on a review of the nature of future cash flows, that its Alberta assets should be combined as one CGU for impairment testing purposes. Since the cash flows of Genesee 1 and 2 will remain contracted through 2020, management will continue to present facility results based on the Alberta Commercial and Alberta Contracted groupings through 2020.

Financial results

(unaudited, $ millions)	Three months ended							
	Sep 30 2018	**Jun 30 2018**	**Mar 31 2018**	**Dec 31 2017**	**Sep 30 2017**	**Jun 30 2017**	**Mar 31 2017**	**Dec 31 2016**
Revenues and other income								
Alberta commercial facilities, and portfolio optimization [1]	148	116	173	190	160	153	154	172
Alberta contracted facilities [1]	70	66	61	64	61	55	61	65
Ontario and British Columbia contracted facilities	31	35	44	48	31	32	35	33
U.S. contracted facilities	74	102	65	58	77	37	29	29
Corporate [2]	15	15	15	19	14	16	14	11
Unrealized changes in fair value of commodity derivatives and emission credits	51	29	(51)	(118)	3	(92)	45	(30)
	389	**363**	**307**	**261**	**346**	**201**	**338**	**280**
Adjusted EBITDA								
Alberta commercial facilities, and portfolio optimization [1]	60	51	55	60	55	55	58	70
Alberta contracted facilities [1]	54	51	45	47	41	37	45	40
Ontario and British Columbia contracted facilities [3]	31	39	53	54	31	40	40	40
U.S. contracted facilities	44	72	35	30	46	10	6	8
Corporate	(16)	(12)	(15)	(19)	(12)	(17)	(15)	(20)
Unrealized changes in fair value of commodity derivatives and emission credits	(35)	22	(1)	(18)	(3)	(29)	9	6
	138	**223**	**172**	**154**	**158**	**96**	**143**	**144**

1 During the fourth quarter of 2016, management determined, based on a review of the nature of future cash flows, that its Alberta assets should be combined as one CGU for impairment testing purposes. Since the cash flows of Genesee 1 and 2 will remain contracted through 2020, management will continue to present facility results based on the Alberta Commercial and Alberta Contracted groupings through 2020.

2 Revenues are offset by interplant category revenue eliminations.

3 The reported Ontario and British Columbia contracted facilities' adjusted EBITDA includes the adjusted EBITDA from the K2 Wind and York Energy joint ventures

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 facility 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, interest rate and foreign exchange derivative contracts.

Financial highlights

(unaudited, $ millions except per share amounts)	Three months ended							
	Sep 30 2018	**Jun 30 2018**	**Mar 31 2018**	**Dec 31 2017**	**Sep 30 2017**	**Jun 30 2017**	**Mar 31 2017**	**Dec 31 2016**
Revenues and other income	389	363	307	261	346	201	338	280
Adjusted EBITDA [1,2]	138	223	172	154	158	96	143	144
Net income (loss)	19	68	41	(13)	(7)	107	47	26
Net income (loss) attributable to shareholders of the Company	20	70	43	(10)	(5)	109	50	28
Basic earnings (loss) per share ($)	0.10	0.57	0.32	(0.20)	(0.13)	1.03	0.44	0.21
Normalized earnings per share ($) [1]	0.35	0.22	0.30	0.24	0.28	0.27	0.34	0.27
Net cash flows from operating activities	65	109	143	75	120	78	99	69
Adjusted funds from operations [1, 3]	156	76	85	94	135	44	88	53
Adjusted funds from operations per share ($) [1]	1.52	0.74	0.82	0.90	1.30	0.45	0.91	0.55
Purchase of property, plant and equipment and other assets	135	66	40	42	28	63	85	174

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

2 The reported Ontario and British Columbia contracted facilities adjusted EBTIDA includes the adjusted EBITDA from the K2 Wind and York Energy joint ventures.

3 Commencing with the Company's March 31, 2018 quarter-end, the reported adjusted funds from operations measure was refined to better reflect the purpose of the measure (see Non-GAAP Financial Measures). The applicable comparable periods have been adjusted to conform to the current period's presentation.

	Three months ended							
Spot price averages	**Sep 30 2018**	**Jun 30 2018**	**Mar 31 2018**	**Dec 31 2017**	**Sep 30 2017**	**Jun 30 2017**	**Mar 31 2017**	**Dec 31 2016**
Alberta power ($ per MWh)	55	56	35	22	25	19	22	22
Alberta natural gas (AECO) ($ per Gj)	1.15	1.10	1.99	1.73	1.34	2.62	2.56	2.97
Capital Power's Alberta portfolio average realized power price ($ per MWh)	54	51	47	46	49	52	55	67

Factors impacting results for the previous quarters

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

For the quarter ended June 30, 2018, the Company recorded net income attributed to shareholders of $70 million compared to $109 million for the quarter ended June 30, 2017. Lower net income reflected the reversal of a previous write-down of deferred tax assets related to the tax benefit associated with the Company's U.S. income tax loss carryforwards as a result of the acquisition of Decatur Energy and the commissioning of Bloom Wind in the second quarter of 2017. Further contributing to the decrease was higher financing expenses and depreciation and amortization due to the acquisition of the thermal facilities and Decatur Energy and the receipt of Bloom Wind Project financing in the second quarter of 2017. These variances were partially offset by higher adjusted EBITDA in the second quarter of 2018 compared to the second quarter of 2017 primarily due to the impact of higher Alberta power prices in 2018 compared with 2017 on the Alberta contracted assets, a full quarter of results from the assets acquired in the second quarter of 2017, and higher Bloom Wind revenue due to the renegotiation of the commercial terms within the Bloom Wind tax equity agreement. Non-cash after tax net income related to Bloom Wind increased $15 million driven by tax rate differences while the $44 million increase in adjusted EBITDA was related to timing.

For the quarter ended March 31, 2018, the Company recorded net income attributed to shareholders of $43 million compared to $50 million for the quarter ended March 31, 2017. The financial results reflected higher unrealized gains on Alberta energy derivatives in the first quarter of 2017 that resulted from the impact of decreasing forward Alberta power prices on net forward sales contracts, partially offset by the reversal of prior year unrealized net gains on forward sales contracts that settled during the first quarter of 2017. Further contributing to the decrease was higher financing expenses and depreciation and amortization due to the acquisition of the thermal facilities and Decatur

Energy and the receipt of Bloom Wind Project financing in the second quarter of 2017. Adjusted EBITDA was higher in the first quarter of 2018 compared to the first quarter of 2017 primarily due Bloom Wind commencing operations and acquisition of the thermal facilities and Decatur Energy in the second quarter of 2017.

For the quarter ended December 31, 2017, the Company recorded net loss attributable to shareholders of $10 million compared to net income attributable to shareholders of $28 million for the quarter ended December 31, 2016. The decrease compared to the prior quarter mainly resulted from lower average realized prices on the Alberta portfolio and unrealized losses on the Alberta power portfolio that were primarily due to the reversal of prior period unrealized net gains on forward sales contracts that settled during the period. Adjusted EBITDA was higher quarter over quarter mostly due to the impact of the acquired thermal facilities and Decatur Energy in the second quarter of 2017 and other income related to coal compensation from the Province of Alberta. During the fourth quarter of 2017, the U.S. federal income tax rate decreased as part of the U.S. tax reform and the Company's U.S. deferred tax assets and liabilities were re-measured. As a result of the re-measurement, the Company recognized $31 million in deferred income tax expense. In the fourth quarter of 2017, the Company also recorded a current provision of $9 million related to the LLR proceeding based on current Module C conclusions.

Financial results for the third quarter of 2017 reflected the impact of low Alberta power pricing averaging $25 per MWh. Revenues were lower compared with the corresponding period in 2016 mainly due to lower average realized prices on the Alberta portfolio and unrealized losses on the Alberta power portfolio that were primarily due to the reversal of prior period unrealized net gains on forward sales contracts that settled during the period. Adjusted EBITDA increased quarter over quarter mostly attributable to the acquisition of the thermal facilities and Decatur Energy in the second quarter of 2017 and other income related to coal compensation from the Province of Alberta. The Company recognized non-cash impairment losses in the third quarter of 2017 totalling $83 million (pre-tax) related to the Company's Southport, Roxboro and Decatur Energy facilities.

The results for the second quarter of 2017 reflected low Alberta power pricing and realized power prices. The Company completed the acquisitions of the thermal power business of Veresen Inc. and Decatur Energy. The Company also reversed a previous write-down of deferred tax assets related to the tax benefit associated with the Company's U.S. income tax loss carryforwards as a result of the acquisition of Decatur Energy and the commissioning of Bloom Wind. Despite these acquisitions, adjusted EBITDA was lower in the second quarter of 2017 compared to the second quarter of 2016 primarily due to lower realized power prices in 2017 compared with 2016 and unrealized losses on net forward natural gas purchase contracts valued against decreasing forward natural gas prices in 2017 compared with net forward natural gas purchase contracts valued against increasing forward natural gas prices in 2016.

Financial results for the first quarter of 2017 and 2016 reflected low Alberta power pricing and realized power prices. Adjusted EBITDA increased quarter over quarter mainly due to unrealized gains on net forward power sales contracts valued against decreasing prices and other income related to coal compensation from the Province of Alberta. The Company's normalized earnings per share of $0.34 in the first quarter of 2017 was consistent with the normalized earnings per share of $0.33 in the first quarter of 2016 after adjustment for the $46 million post-tax loss as a result of the de-recognition of the Sundance PPA intangible asset in the first quarter of 2016.

For the quarter ended December 31, 2016, the Company recorded net income attributable to shareholders of $28 million and normalized earnings per share of $0.27, compared to $35 million and $0.42, respectively, for the quarter ended December 31, 2015. Net income attributable to common shareholders was lower for the quarter compared to the same quarter in the prior year primarily due to the payment for the settlement of legal action related to the termination of the Sundance PPA in 2016, partially offset by higher adjusted EBITDA and lower interest costs in the fourth quarter of 2016 compared with the same period in 2015. Normalized earnings per share of $0.27 in the fourth quarter of 2016 was lower than the comparable amount of $0.42 in the fourth quarter of 2015 primarily due to the decrease in adjusted EBITDA after removing the effects of unrealized changes in fair value of derivative contracts and increased preferred share dividends in 2016 compared with 2015.

SHARE AND PARTNERSHIP UNIT INFORMATION

Quarterly common share trading information

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

	Three months ended							
	Sep 30 2018	**Jun 30 2018**	**Mar 31 2018**	**Dec 31 2017**	**Sep 30 2017**	**Jun 30 2017**	**Mar 31 2017**	**Dec 31 2016**
Share price ($/common share)								
High	29.45	26.00	25.14	25.59	26.51	26.14	26.43	24.49
Low	25.12	23.42	22.15	23.26	23.81	24.05	23.15	19.90
Close	28.51	25.23	24.24	24.49	24.67	24.32	26.06	23.23
Volume of shares traded (millions)	14.8	11.1	14.0	16.9	14.1	14.8	17.0	23.2

Outstanding share and partnership unit data

As at October 23, 2018, the Company had 102.507 million common shares, 5 million Cumulative Rate Reset Preference Shares (Series 1), 6 million Cumulative Rate Reset Preference Shares (Series 3), 8 million Cumulative Rate Reset Preference Shares (Series 5), 8 million Cumulative Minimum Rate Reset Preference Shares (Series 7), 6 million Cumulative Minimum Rate Reset Preference Shares (Series 9) 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 23, 2018 were 106.224 million. The outstanding special limited voting share is held by EPCOR.

As at October 23, 2018, CPLP had 24.040 million general partnership units outstanding and 89.473 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, 2018 and 2017

CAPITAL POWER CORPORATION

Condensed Interim Consolidated Financial Statements
Nine months ended September 30, 2018 and 2017

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, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Nine months ended September 30, 2017
Revenues	$ 367	$ 317	$ 943	$ 821
Other income	22	29	116	64
Energy purchases and fuel	(173)	(115)	(300)	(279)
Gross margin	216	231	759	606
Other raw materials and operating charges	(27)	(29)	(91)	(82)
Staff costs and employee benefits expense	(39)	(31)	(107)	(98)
Depreciation and amortization	(74)	(74)	(223)	(199)
Impairments (note 5)	-	(83)	-	(83)
Other administrative expense	(22)	(23)	(68)	(66)
Foreign exchange (loss) gain	(2)	21	4	32
Operating income	52	12	274	110
Net finance expense	(28)	(31)	(90)	(76)
Income from joint ventures	3	4	18	26
Income (loss) before tax	27	(15)	202	60
Income tax (expense) recovery (note 6)	(8)	8	(74)	87
Net income (loss)	$ 19	$ (7)	$ 128	$ 147
Attributable to:				
Non-controlling interest	$ (1)	$ (2)	$ (5)	$ (7)
Shareholders of the Company	$ 20	$ (5)	$ 133	$ 154

Earnings (loss) per share (attributable to common shareholders of the Company):

Basic (note 7)	$ 0.10	$ (0.13)	$ 0.99	$ 1.30
Diluted (note 7)	$ 0.10	$ (0.13)	$ 0.99	$ 1.29

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, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Nine months ended September 30, 2017
Net income (loss)	$ 19	$ (7)	$ 128	$ 147
Other comprehensive income (loss):				
Items that will not be reclassified subsequently to net income (loss):				
Defined benefit plans:				
Actuarial gains[1]	-	-	-	2
Items that are or may be reclassified subsequently to net income (loss):				
Cash flow hedges:				
Unrealized gains on derivative instruments[2]	32	13	13	9
Unrealized gains on derivative instruments – joint ventures[3]	2	3	3	3
Reclassification of losses (gains) on derivative instruments to income for the period[4]	7	(13)	8	(48)
Reclassification of losses on derivative instruments to income for the period – joint ventures[5]	1	1	2	3
Net investment in foreign subsidiaries:				
Unrealized (losses) gains [6]	(8)	(35)	12	(56)
Total items that are or may be reclassified subsequently to net income (loss), net of tax	34	(31)	38	(89)
Total other comprehensive income (loss), net of tax	34	(31)	38	(87)
Total comprehensive income (loss)	$ 53	$ (38)	$ 166	$ 60
Attributable to:				
Non-controlling interest	$ (1)	$ (2)	$ (5)	$ (7)
Shareholders of the Company	$ 54	$ (36)	$ 171	$ 67

[1] For the three and nine months ended September 30, 2018 and September 30, 2017, net of income tax of nil.

[2] For the three and nine months ended September 30, 2018, net of income tax expense of $14 million and $7 million, respectively. For the three and nine months ended September 30, 2017, net of income tax expense of $6 million and $5 million, respectively.

[3] For the three and nine months ended September 30, 2018 and for the three and nine months ended September 30, 2017, net of income tax expense of $1 million.

[4] For the three and nine months ended September 30, 2018, net of reclassification of income tax recovery of $2 million and $3 million, respectively. For the three and nine months ended September 30, 2017, net of reclassification of income tax expense of $4 million and $17 million, respectively.

[5] For the three and nine months ended September 30, 2018, net of reclassification of income tax recovery of $1 million. For the three and nine months ended September 30, 2017, net of reclassification of income tax recovery of nil and $1 million, respectively.

[6] For the three and nine months ended September 30, 2018, net of income tax of nil. For the three and nine months ended September 30, 2017, net of income tax recovery of $1 million and nil, respectively.

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, 2018	December 31, 2017
Assets		
Current assets:		
Cash and cash equivalents	$ 41	$ 52
Trade and other receivables	349	278
Inventories	169	120
Derivative financial instruments assets (note 8)	57	92
	616	542
Non-current assets:		
Other assets	62	68
Derivative financial instruments assets (note 8)	108	79
Finance lease receivables	626	644
Government grant receivable	456	493
Deferred tax assets	42	74
Equity-accounted investments	184	184
Intangible assets	364	401
Property, plant and equipment	4,400	4,378
Goodwill (notes 5)	35	35
Total assets	$ 6,893	$ 6,898
Liabilities and equity		
Current liabilities:		
Trade and other payables	$ 221	$ 216
Derivative financial instruments liabilities (note 8)	70	86
Loans and borrowings	288	239
Deferred revenue and other liabilities	63	58
Provisions	45	37
	687	636
Non-current liabilities:		
Derivative financial instruments liabilities (note 8)	89	56
Loans and borrowings	1,851	1,907
Finance lease obligation	17	17
Deferred revenue and other liabilities	596	581
Deferred tax liabilities	400	374
Provisions	266	265
	3,219	3,200
Equity:		
Equity attributable to shareholders of the Company		
Share capital (note 9)	3,216	3,262
Deficit	(244)	(181)
Other reserves	(28)	(67)
Deficit and other reserves	(272)	(248)
	2,944	3,014
Non-controlling interest	43	48
Total equity	2,987	3,062
Total liabilities and equity	$ 6,893	$ 6,898

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 reserve[1]	Defined benefit plan actuarial losses[1]	Employee benefits reserve	Deficit	Equity attributable to shareholders of the Company	Non-controlling interest	Total
Equity as at January 1, 2018	$ 3,262	$ (39)	$ (27)	$ (11)	$ 10	$ (181)	$ 3,014	$ 48	$ 3,062
Impact of change in accounting policy (note 3)	-	-	-	-	-	(44)	(44)	-	(44)
Tax impact of change in accounting policy (note 3)	-	-	-	-	-	11	11	-	11
Adjusted equity as at January 1, 2018	$ 3,262	$ (39)	$ (27)	$ (11)	$ 10	$ (214)	$ 2,981	$ 48	$ 3,029
Net income	-	-	-	-	-	133	133	(5)	128
Other comprehensive income:									
Cash flow derivative hedge gains	-	20	-	-	-	-	20	-	20
Cash flow derivative hedge gains – joint ventures	-	4	-	-	-	-	4	-	4
Reclassification of losses to net income	-	11	-	-	-	-	11	-	11
Reclassification of losses to net income – joint ventures	-	3	-	-	-	-	3	-	3
Unrealized gain on foreign currency translation	-	-	12	-	-	-	12	-	12
Tax on items recognized directly in equity	-	(12)	-	-	-	-	(12)	-	(12)
Other comprehensive income	$ -	$ 26	$ 12	$ -	$ -	$ -	$ 38	$ -	$ 38
Total comprehensive income	-	26	12	-	-	133	171	(5)	166
Common share dividends (note 9)	-	-	-	-	-	(132)	(132)	-	(132)
Preferred share dividends (note 9)	-	-	-	-	-	(30)	(30)	-	(30)
Tax on preferred share dividends	-	-	-	-	-	(1)	(1)	-	(1)
Common shares purchased (note 9)	(55)	-	-	-	-	-	(55)	-	(55)
Share-based payments	-	-	-	-	1	-	1	-	1
Share options exercised	9	-	-	-	-	-	9	-	9
Equity as at September 30, 2018	$ 3,216	$ (13)	$ (15)	$ (11)	$ 11	$ (244)	$ 2,944	$ 43	$ 2,987

[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 reserve[1]	Defined benefit plan actuarial losses[1]	Employee benefits reserve	Deficit	Equity attributable to shareholders of the Company	Non-controlling interest	Total
Equity as at January 1, 2017	$ 2,918	$ 22	$ 26	$ (10)	$ 11	$ (124)	$ 2,843	$ 58	$ 2,901
Net income (loss)	-	-	-	-	-	154	154	(7)	147
Other comprehensive (loss) income:									
Defined benefit plan actuarial gains	-	-	-	2	-	-	2	-	2
Cash flow derivative hedge gains	-	14	-	-	-	-	14	-	14
Cash flow derivative hedge gains – joint ventures	-	4	-	-	-	-	4	-	4
Reclassification of gains to net income	-	(65)	-	-	-	-	(65)	-	(65)
Reclassification of losses to net income – joint ventures	-	4	-	-	-	-	4	-	4
Unrealized loss on foreign currency translation	-	-	(56)	-	-	-	(56)	-	(56)
Tax on items recognized directly in equity	-	10	-	-	-	-	10	-	10
Other comprehensive (loss) income	$ -	$ (33)	$ (56)	$ 2	$ -	$ -	$ (87)	$ -	$ (87)
Total comprehensive (loss) income	-	(33)	(56)	2	-	154	67	(7)	60
Common share dividends (note 9)	-	-	-	-	-	(122)	(122)	-	(122)
Preferred share dividends (note 9)	-	-	-	-	-	(25)	(25)	-	(25)
Issue of share capital	333	-	-	-	-	-	333	-	333
Share issue costs	(11)	-	-	-	-	-	(11)	-	(11)
Deferred taxes on share issue costs	3	-	-	-	-	-	3	-	3
Share-based payment	-	-	-	-	(1)	-	(1)	-	(1)
Share options exercised	18	-	-	-	-	-	18	-	18
Equity as at September 30, 2017	$ 3,261	$ (11)	$ (30)	$ (8)	$ 10	$ (117)	$ 3,105	$ 51	$ 3,156

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

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

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

	Nine months ended September 30,	
	2018	2017
Cash flows from operating activities:		
Net income	$128	$ 147
Non-cash adjustments to reconcile net income to net cash flows from operating activities:		
Impairments (note 5)	-	83
Depreciation and amortization	223	199
Net finance expense	90	76
Fair value changes on commodity derivative instruments and emission credits held for trading	14	22
Foreign exchange gains	(4)	(31)
Income tax expense (recovery) (note 6)	74	(87)
Income from joint ventures	(18)	(26)
Reduction in finance lease receivables	17	16
Recognition of government grant deferred revenue	(38)	(39)
Tax equity attributes	(70)	(16)
Other items	10	5
Change in fair value of derivative instruments reflected as cash settlement	16	(6)
Distributions received from joint ventures	24	22
Interest paid[1]	(70)	(55)
Other cash items	(17)	(13)
Change in non-cash operating working capital	(62)	-
Net cash flows from operating activities	317	297
Cash flows used in investing activities:		
Purchase of property, plant and equipment and other assets	(241)	(176)
Business acquisitions, net of acquired cash	-	(839)
Government grant received	50	50
Genesee Coal Mine prepayment	-	(70)
Other cash flows from investing activities	6	9
Change in non-cash investing working capital	17	(53)
Net cash flows used in investing activities	(168)	(1,079)
Cash flows (used in) from financing activities:		
Proceeds from issue of loans and borrowings	224	1,098
Repayment of loans and borrowings	(192)	(510)
Issue costs on loans and borrowings	(1)	(9)
Issue of shares	-	333
Share issue costs	-	(11)
Proceeds from exercise of share options	9	17
Common shares purchased (note 9)	(55)	-
Dividends paid (note 9)	(160)	(141)
Realized gains (losses) on settlement of foreign exchange derivatives	33	(13)
Capitalized interest paid[1]	(3)	(6)
Income taxes paid on preferred share dividends	(15)	(8)
Other cash flows (used in) from financing activities	(1)	(1)
Net cash flows (used in) from financing activities	(161)	749
Foreign exchange gain (loss) on cash held in a foreign currency	1	(3)
Net decrease in cash and cash equivalents	(11)	(36)
Cash and cash equivalents at beginning of period	52	98
Cash and cash equivalents at end of period	$ 41	$ 62

[1] Total interest paid.

See accompanying notes to the condensed interim consolidated financial statements

1. Reporting entity:

Capital Power Corporation (the Company or Capital Power) develops, acquires, owns and operates power generating facilities 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 2017 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 annual consolidated financial statements, except as outlined in note 3, 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 26, 2018.

3. Changes in significant accounting policies:

Effective January 1, 2018, the Company adopted the following new accounting standards:

IFRS 15 – Revenue from Contracts with Customers

The objective of this standard is to provide a single and comprehensive framework for revenue recognition that replaces previous revenue standards. The objective of the disclosure requirements is to enable users of the financial statements to understand the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers.

The Company’s revenues from contracts with customers within the scope of IFRS 15 consist mainly of the sale of electricity and natural gas based on energy sales agreements, capacity agreements and emission credit sales. Energy revenues are billed to the customer based on the market price at the time of performance or observable contract prices depending on the terms of the agreement.

The Company’s revenues from contracts with customers are disaggregated by major type of revenues and operational groupings by facility category. Major types of revenues include energy revenues and emission credit revenues. Revenues excluded from the scope of IFRS 15 are disclosed as revenues from other sources and consist of contracts accounted for under IAS 17 – Leases and IFRS 9 – Financial Instruments as described in the following table. Disaggregated revenues are disclosed in note 12.

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

3. Changes in significant accounting policies, continued:

IFRS 15 – Revenue from Contracts with Customers, continued

Contracts with customers by operational groupings are as follows:

Operational grouping	Description
Alberta Commercial	The power generated by the Company's interests in Alberta Commercial facilities is sold into energy markets on a merchant or non-contracted basis. The Company's interests in the majority of these facilities are under contractual arrangements that are considered to be joint operations. The accounting policies of these joint operations are aligned with the accounting policies of the Company and are included within the scope of IFRS 15. Renewable Energy Credits (RECs) sales from Halkirk are also within the scope of IFRS 15 and are described in the contracts with customers table. The Company's portfolio optimization activities and associated revenues are excluded from the scope of IFRS 15.
Alberta Contracted	Power generation revenue from the Alberta Contracted facilities is managed under power purchase arrangements (PPAs) determined to be leases, which are accounted for under IAS 17 – Leases and are therefore excluded from the scope of IFRS 15. Generation in excess of the committed capacity under these PPAs is managed as part of the Company's Alberta electricity portfolio optimization activities accounted for under IFRS 9 – Financial Instruments, and therefore is also excluded from the scope of IFRS 15. By-product energy sales are included in energy revenues within the scope of IFRS 15.
Ontario and British Columbia Contracted	The majority of the power generated by the Ontario and British Columbia Contracted facilities is sold pursuant to long-term contracts that are accounted for under IAS 17 – Leases and is therefore excluded from the scope of IFRS 15. The Company's joint venture interests in K2 Wind and York Energy are accounted for under IFRS 11 – Joint Arrangements under the equity method. The accounting policies of York Energy are aligned with the accounting policies of the Company and the revenue recognition of York Energy follows IFRS 15. K2 Wind's PPA is accounted for under IAS 17 – Leases and therefore is excluded from the scope of IFRS 15. The Company's share of the joint venture facilities' net income is included in income from joint ventures on the condensed interim consolidated statements of income and as a result, these facilities are not subject to the disclosure requirements of IFRS 15. Steam production sales are included in energy revenues within the scope of IFRS 15.
U.S. Contracted	Power generation revenue from the U.S. Contracted facilities, that are managed under PPAs determined to be leases, is accounted for under IAS 17 – Leases and therefore is excluded from the scope of IFRS 15. In addition, certain U.S. renewable facilities contain revenue swap arrangements that are accounted for under IFRS 9 – Financial Instruments which are also excluded from the scope of IFRS 15. Power generation revenues from facilities with long-term sales arrangements that are determined not to contain a lease are included in energy revenues within the scope of IFRS 15.

The Company has applied IFRS 15 using the cumulative effect method recognizing the cumulative effect of initially applying IFRS 15 as an adjustment to the opening deficit balance as at January 1, 2018. Therefore, the comparative information has not been restated and continues to be reported under IAS 18 – Revenue. The adoption of this standard has resulted in the opening deficit adjustments described below as well as additional disclosures regarding revenues as summarized below.

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

3. Changes in significant accounting policies, continued:

IFRS 15 – Revenue from Contracts with Customers, continued

Contracts with customers

Revenue type	Nature, timing of satisfaction of performance obligations and significant payment terms
Energy revenues[1,2]	Electricity and natural gas supply contracts include a single performance obligation that is satisfied over time. Revenues from the sale of electricity and natural gas are recognized under the right to invoice practical expedient. The right to invoice practical expedient allows an entity to recognize revenue when it has the right to invoice the customer, if that amount corresponds directly with the value to the customer of the entity's performance completed to date. This occurs upon delivery or availability for delivery under the respective contracts. Customers are billed in the reporting period subsequent to when the performance obligation was met and settlements are in accordance with the agreed-upon contractual terms. In instances where the right to invoice practical expedient cannot be applied, energy revenues are recognized as the performance obligation is satisfied and measured under the output method which is based on energy generated, or availability, depending on the nature of the contracts with customers.
Emission credit revenues[1,3]	RECs generated by certain of the Company's facilities are sold to the respective customers under the terms of fixed price agreements. REC revenues are recognized when the performance obligations are satisfied at the specified transaction price. This occurs when physical control of RECs is transferred to the customer.

1 The Company's contracts with customers are billed and paid in accordance with agreed-upon contractual terms. The Company has not incurred additional costs to obtain or fulfil the contracts with its customers. The timing of revenue recognition, billing and cash collection does not differ from the Company's previous accounting policies under IAS 18 other than as described in footnotes 2 and 3 to this table. As at September 30, 2018, the Company has not recorded any conditional unbilled receivables (contract assets) or customer advances and deposits (contract liabilities) other than as described in footnote 2 to this table.

2 The Joffre Cogeneration Project (Joffre), a joint operation of the Company accounted for under IFRS 11 – Joint Arrangements, sells power generation capacity under an energy supply agreement. The performance obligation to provide availability of the contracted power generation over the contract term is satisfied over the contract term. The capacity payments are based on a declining rate base capacity payment schedule and were previously recognized under IAS 18 as revenues when the Company had the right to bill. Upon the adoption of IFRS 15, revenues are recognized as the performance obligation is satisfied. The Company recorded a pre-tax increase to the opening deficit at January 1, 2018 of $41 million ($31 million post tax) and increased deferred revenue and other liabilities for a contract liability due to the change in the timing of capacity payment revenue recognition for the cumulative effect of initially applying IFRS 15. The contract liability will be recognized as revenue over the term of the Energy Supply Agreement which continues until the plant is decommissioned at the end of its useful life (2041) or until the agreement is terminated. For the three and nine months ended September 30, 2018, no revenue has been recognized related to the contract liability balance.

3 Prior to the adoption of IFRS 15, the Company recognized revenue on the sale of certain RECs at the time of generation. Under IFRS 15, the Company satisfies its performance obligation when RECs are delivered to the customer which occurs subsequent to the period of REC generation. As such, the Company recorded an adjustment for the change in timing of REC revenue recognition for the cumulative effect of initially applying IFRS 15 resulting in a pre-tax increase to the opening deficit at January 1, 2018 of $3 million ($2 million post tax).

3. Changes in significant accounting policies, continued:

IFRS 9 – Financial Instruments

The objective of this standard is to set out requirements for recognizing and measuring financial assets, financial liabilities and some contracts to buy or sell non-financial items, improve transparency in the disclosure of expected credit losses and to improve the overall usefulness of financial statements for users by revising the current hedge accounting requirements.

As a result of the adoption of IFRS 9 as at January 1, 2018, the Company's accounting policy for financial instruments has been modified with the nature and effects of key changes summarized below. The change in accounting policy has been applied retrospectively and did not result in a change in the carrying amount of any financial instruments at the transition date. Additionally, the Company adopted consequential amendments to IFRS 7: Financial Instruments: Disclosures that have been applied commencing January 1, 2018. The Company has elected not to restate comparative information, and as a result, the prior year continues to be accounted for in accordance with its previous accounting policy.

The following are the modifications to the Company's accounting policy for financial instruments under IFRS 9.

Classification of financial assets and financial liabilities

The Company classifies its financial instruments in the following categories: fair value through income or loss (FVTIL), fair value through other comprehensive income (FVTOCI) or amortized cost. The Company determines the classification of financial assets at initial recognition. Classification of financial assets and liabilities is determined based on the business model by which assets and liabilities are managed and their cash flow characteristics.

A financial asset is measured at FVTIL if it is classified as held for trading or is designated as such upon initial recognition. The Company may designate financial instruments as held at FVTIL when such financial instruments have a reliably determinable fair value and where doing so eliminates or significantly reduces a measurement or recognition inconsistency that would otherwise arise from measuring assets and liabilities or recognizing gains and losses on them on a different basis.

To reduce its exposure to movements in energy commodity prices, interest rate changes, and foreign currency exchange rates, the Company uses various risk management techniques including the use of derivative instruments. All derivative instruments, including embedded derivatives, are measured at FVTIL. If cash flow hedge accounting requirements are met, derivative instruments are measured at FVTOCI.

The Company completed an assessment of its classification of financial assets and liabilities as at January 1, 2018 under IFRS 9. While the categories are different under the new standard, there were no changes to the accounting methods applied as compared to the previous classification under IAS 39.

3. Changes in significant accounting policies, continued:

IFRS 9 – Financial Instruments, continued

Financial assets and liabilities classification:

Financial assets and liabilities	IAS 39	IFRS 9
Financial assets		
Cash and cash equivalents	Loans and receivables measured at amortized cost	Amortized cost
Trade and other receivables	Loans and receivables measured at amortized cost	Amortized cost
Derivative financial instruments assets		
Non-hedges	FVTIL	FVTIL
Cash flow hedges	FVTOCI	FVTOCI
Financial liabilities		
Trade and other payables	Other financial liabilities measured at amortized cost	Amortized cost
Derivative financial instruments liabilities		
Non-hedges	FVTIL	FVTIL
Cash flow hedges	FVTOCI	FVTOCI
Loans and borrowings	Other financial liabilities measured at amortized cost	Amortized cost

Measurement of financial assets and liabilities

Financial assets and liabilities at fair value through income or loss

Financial assets and liabilities classified as held at FVTIL are measured at fair value with the changes in fair value reported in net income. Fair values are determined in the manner described in the use of judgments and estimates note in the Company's annual consolidated financial statements for the year ended December 31, 2017. Gains or losses realized on de-recognition of investments held at fair value through income or loss are recognized into net income.

Financial assets and liabilities at fair value through other comprehensive income

Realized gains and losses on financial energy derivatives classified as FVTOCI are recorded in revenues or energy purchases and fuel, realized gains and losses on interest rate derivatives classified as FVTOCI are recorded in net finance expense and realized gains and losses on foreign exchange derivatives classified as FVTOCI are recorded in revenues or foreign exchange gains or losses, as appropriate. Unrealized gains and losses are recorded in other comprehensive income or loss. Fair values are determined in the manner described in the use of judgments and estimates note in the Company's annual consolidated financial statements for the year ended December 31, 2017.

Financial assets and liabilities at amortized cost

Financial assets and liabilities are recognized initially at fair value plus any directly attributable transaction costs. After initial recognition they are measured at amortized cost using the effective interest method less any impairment losses as described below in the impairment of financial assets section.

Impairment of financial assets

IFRS 9 introduces a forward-looking 'expected loss' impairment model which applies to all financial assets measured at amortized cost or FVTOCI. The Company considers the probability of default upon initial recognition of financial assets and whether there has been a significant increase in credit risk on an ongoing basis throughout each reporting period. The impairment methodology applied depends on whether there has been a significant increase in credit risk. The Company applies judgment to assess whether there is a significant increase in credit risk and considers available and reasonable forward-looking information in supporting this assessment.

3. Changes in significant accounting policies, continued:

IFRS 9 – Financial Instruments, continued

Impairment of financial assets, continued

For financial assets measured at FVTOCI, expected allowances are recognized as 12-month expected credit losses (ECLs) unless the credit risk of a financial asset has increased significantly, in which case lifetime ECL measurement applies. The Company has identified no financial instruments for which credit risk has increased significantly since initial recognition nor financial assets that are impaired as at September 30, 2018. Credit risk management procedures, including risk mitigation practices, are as described in the risk management note in the Company's annual consolidated financial statements for the year ended December 31, 2017.

The Company has applied the simplified approach to providing for ECLs prescribed by IFRS 9, which permits the use of the lifetime expected loss provision for all trade and other receivables, including finance lease receivables. No impairment provision has been recorded by the Company as at September 30, 2018 related to trade and other receivables and finance lease receivables and the Company considers these financial assets to be low risk.

Derivative instruments and hedging activities

Under IFRS 9, all derivative instruments, including embedded derivatives, are recorded at fair value on the statement of financial position as derivative financial instruments assets or derivative financial instruments liabilities except for embedded derivative instruments that are clearly and closely related to their host contract and the combined instrument is not measured at fair value. This accounting policy remains unchanged from IAS 39 and derivative instruments continue to be measured at FVTIL unless cash flow hedge accounting is used, in which case they are measured at FVTOCI. Embedded derivative instruments that are in scope of the standard are never separated from their host contract and are classified and measured as a combined instrument.

The Company has applied the new general hedge accounting model prospectively and determined no changes to its hedging relationships previously designated under IAS 39.

4. Future accounting changes:

IFRS 16 – Leases – The new standard which replaces IAS 17 – Leases addresses the recognition, measurement, presentation and disclosure of leases. IFRS 16 provides a new approach to lessee accounting requiring lessees to recognize right-of-use assets and lease liabilities for all leases previously classified as operating leases, including but not limited to, office space leases and land leases. IFRS 16 is effective for annual periods beginning on or after January 1, 2019.

Management has assessed the transition options for the adoption of IFRS 16 and does not expect to grandfather lease assessments under the previous standard to IFRS 16. Management has determined that certain power purchase agreements (PPAs) and energy supply contracts that are currently considered to be finance leases with the Company as the lessor will no longer be considered leases upon adoption of this new standard, but rather will be accounted for under IFRS 15 – Revenue from Contracts with Customers.

For contracts determined to contain leases, with the Company as the lessee under IFRS 16, the Company will elect to apply the modified retrospective approach (cumulative catch-up), recognizing a right-of-use asset of the underlying asset and a lease liability for future lease payments. The Company will continue to recognize finance leases on the balance sheet and will recognize right-of-use assets and lease liabilities relating to the respective operating leases.

For contracts determined to contain a lease, with the Company as the lessor under IFRS 16 that continue to meet the lease requirements to be classified as a lease, no adjustments are required on transition. Certain PPAs that no longer meet the requirements to be classified as leases under IFRS 16 will be accounted for under IFRS 15 – Revenue from Contracts with Customers and the transition impact will be accounted for retrospectively in accordance with IAS 8 - Accounting Policies, Changes in Accounting Estimates and Errors and treated as a change in accounting policy.

5. Impairment testing:

The Company reviews its CGUs that contain goodwill on an annual basis, in the third quarter, to determine whether any impairments should be recognized. As a result, the Company's East Windsor CGU was tested for impairment during the third quarter of 2018. The carrying amount of the East Windsor CGU was within the range of its estimated recoverable amount and as such, no impairment was required.

Key assumptions – recoverable amount

The recoverable amount of the East Windsor CGU was determined based on its fair value less costs to sell, estimated using discounted cash flows. The fair value measurement of the East Windsor 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 is sensitive to several key assumptions as described below.

Discount rates

The after-tax discount rate used for the East Windsor CGU reflects the market weighted average cost of capital (WACC) using a capital asset pricing model approach, giving consideration to the risks specific to the East Windsor CGU. The method and assumptions used to calculate the WACC rate are generally consistent with the Company's past experience and previous valuations performed by the Company. The calculated WACC rate used for impairment testing was 6.0% which decreased from the rate used in the prior year's impairment testing based on peer market analysis, new market comparable transactions and adjustments pertaining to plant specific risk factors.

Other key cash flow assumptions

The Company's cash flow projections incorporate estimates of annual plant revenues, expenses and capital expenditures to the end of the East Windsor CGU's useful life. These estimates reflect past experience and the Company's current view of future generating capacity and fuel pricing. The Company has assumed the East Windsor PPA with the Ontario Independent Electricity System Operator will be extended for 20 years following the expiry of the current agreement in 2029 and re-contracted cash flow projections are based on the cost of generation for a new build. 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.

Sensitivities for key cash flow assumptions

The recoverable amount for the East Windsor CGU approximates the carrying amount of the CGU, and as such, unfavourable changes to key cash flow assumptions would lead to an impairment of the CGU.

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

6. 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, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Nine months ended September 30, 2017
Income (loss) before tax	$ 27	$ (15)	$ 202	$ 60
Income tax at the statutory rate of 27%	8	(4)	55	16
Increase (decrease) resulting from:				
Non-taxable amounts	(2)	(9)	(10)	(15)
Amounts attributable to non-controlling interest and tax-equity interests[1]	4	4	27	3
Statutory and other rate differences	(1)	(1)	2	(2)
Change in unrecognized tax benefits[2]	-	2	-	(89)
Other	(1)	-	-	-
Income tax expense (recovery)	$ 8	$ (8)	$ 74	$ (87)

[1] During the nine months ended September 30, 2018, the Company recorded a non-taxable, non-cash, one-time amount attributable to tax-equity interests in Bloom Wind of $15 million (US$11 million) relating to the renegotiation of certain commercial terms within the Bloom Wind tax equity agreement. This renegotiation resulted from the reduction of the U.S. Federal corporate tax rate which was effective January 1, 2018. The total amount recorded reflects an increase in other income of $44 million (US$33 million) net of an increase in income tax expense of $29 million (US$22 million).

[2] During the nine months ended September 30, 2017, the Company reversed a previous write-down of deferred tax assets of $86 million related to the tax benefit associated with the Company's U.S. income tax loss carryforwards. As a result of the acquisition of Decatur Energy and the commissioning of Bloom Wind (both during the second quarter of 2017), it became probable that sufficient future taxable income would be available from U.S. operations to utilize the underlying losses.

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

7. Earnings (loss) per share:

Basic earnings (loss) per share

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

	Three months ended September 30,		Nine months ended September 30,	
	2018	2017	2018	2017
Income (loss) for the period attributable to shareholders of the Company	$ 20	$ (5)	$ 133	$ 154
Preferred share dividends of the Company[1]	(10)	(9)	(31)	(25)
Earnings (loss) used in the calculation of basic earnings (loss) per share	$ 10	$ (14)	$ 102	$ 129

[1] Includes preferred share dividends and related taxes in respect of the three and nine months ended September 30, 2018 and 2017 respectively.

	Three months ended September 30,		Nine months ended September 30,	
	2018	2017	2018	2017
Weighted average number of common shares used in the calculation of basic earnings (loss) per share	102,374,301	104,156,318	103,219,849	99,549,463

Diluted earnings (loss) per share

The earnings (loss) used in the calculation of diluted earnings (loss) per share does not differ from the earnings (loss) used in the calculation of basic earnings (loss) per share for the three and nine months ended September 30, 2018 and 2017. 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,	
	2018	2017	2018	2017
Weighted average number of common shares used in the calculation of basic earnings (loss) per share	102,374,301	104,156,318	103,219,849	99,549,463
Effect of dilutive share purchase options[2]	384,161	366,687	297,697	367,801
Weighted average number of common shares used in the calculation of diluted earnings (loss) per share	102,758, 462	104,523,005	103,517,546	99,917,264

[2] For the three and nine months ended September 30, 2018 and the three months ended September 30, 2017, 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 nine months ended September 30, 2017, the average market price of the Company's common shares exceeded the exercise price of certain granted share options and had a dilutive effect on earnings per share.

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

8. Derivative financial instruments and hedge accounting:

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

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

	September 30, 2018						
	Energy and emission allowances		Interest rate		Foreign exchange		
	cash flow hedges	non-hedges	cash flow hedges	non-hedges	cash flow hedges	non-hedges	Total
Derivative instruments assets:							
Current	$ 2	$ 46	$ 5	$ 2	$ -	$ 2	$ 57
Non-current	4	99	5	-	-	-	108
Derivative instruments liabilities:							
Current	(13)	(48)	-	-	(9)	-	(70)
Non-current	(4)	(85)	-	-	-	-	(89)
Net fair value	$ (11)	$ 12	$ 10	$ 2	$ (9)	$ 2	$ 6
Net notional buys (sells) (millions):							
Megawatt hours of electricity	(7)	(15)					
Gigajoules of natural gas		130					
Metric tons of emission allowances		1					
Number of renewable energy credits		(11)					
Bond forwards			$ 200	$ 150			
Interest rate swaps			$ 200				
Forward currency buys[1]					$ 300	$ 117	
Range of remaining contract terms in years	0.1 to 4.3	0.1 to 14.3	0.4 to 1.2	0.2	0.3	0.6 to 1.1	

[1] U.S. dollars

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

8. Derivative financial instruments and hedge accounting, continued:

	December 31, 2017			
	Energy and emission allowances		Foreign exchange	
	cash flow hedges	non-hedges	non-hedges	Total
Derivative instruments assets:				
Current	$ 4	$ 47	$ 41	$ 92
Non-current	10	69	-	79
Derivative instruments liabilities:				
Current	(20)	(59)	(7)	(86)
Non-current	(10)	(44)	(2)	(56)
Net fair value	$ (16)	$ 13	$ 32	$ 29
Net notional buys (sells) (millions):				
Megawatt hours of electricity	(7)	(12)		
Gigajoules of natural gas		15		
Metric tons of emission allowances		1		
Number of renewable energy credits		(6)		
Cross currency interest rate swaps (U.S. dollars) [2]			$ 195	
Forward currency sells (U.S. dollars) [2]			$ (80)	
Range of remaining contract terms in years [3]	0.1 to 4.0	0.1 to 13.2	1.4 to 1.9	

[2] The cross currency interest rate swaps and forward currency sells of US$195 were net settled on January 11, 2018 with a realized gain of $33 million.

[3] The remaining years of foreign exchange cash flow non-hedge contracts reflect US$115 million in forward currency buys.

Fair values of derivative instruments are determined, using valuation techniques, inputs, and assumptions as described in the Company's 2017 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.

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

8. Derivative financial instruments and hedge accounting, continued:

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, 2018		Three months ended September 30, 2017	
	Unrealized gains (losses)	Realized (losses) gains	Unrealized (losses) gains	Realized gains (losses)
Energy cash flow hedges	$ 56	$ (9)	$ -	$ 19
Energy and emission allowances non-hedges	(34)	13	(2)	14
Foreign exchange cash flow hedges [4]	(9)	-	(50)	-
Foreign exchange non-hedges	(2)	-	41	(13)
Interest rate cash flow hedges	8	-	-	-
Interest rate non-hedges	2	(1)	-	-

[4] For the three months ended September 30, 2018, unrealized losses of nil (three months ended September 30, 2017 – unrealized losses of $15 million) related to foreign exchange cash flow hedges were reclassified from other comprehensive income to net income to offset the impact to unrealized foreign exchange gains and losses from the revaluation of U.S. dollar denominated loans and borrowings.

	Nine months ended September 30, 2018		Nine months ended September 30, 2017	
	Unrealized gains (losses)	Realized (losses) gains	Unrealized (losses) gains	Realized gains (losses)
Energy cash flow hedges	$ 30	$ (11)	$ (52)	$ 65
Energy and emission allowances non-hedges	(8)	45	(23)	41
Foreign exchange cash flow hedges [5]	(9)	-	(58)	1
Foreign exchange non-hedges	(29)	33	37	(13)
Interest rate cash flow hedges	10	-	-	-
Interest rate non-hedges	2	(1)	-	-

[5] For the nine months ended September 30, 2018, unrealized losses of nil (nine months ended September 30, 2017 – unrealized losses of $24 million) related to foreign exchange cash flow hedges were reclassified from other comprehensive income to net income to offset the impact to unrealized foreign exchange gains from the revaluation of U.S. dollar denominated loans and borrowings.

Realized and unrealized gains and losses relate only to financial derivative 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, 2018 and 2017:

	Three months ended September 30,		Nine months ended September 30,	
	2018	2017	2018	2017
Revenues	$ 55	$ 72	$ 69	$ 156
Energy purchases and fuel	(85)	(41)	(43)	(73)
Foreign exchange (loss) gain	(2)	(23)	4	(33)
Net finance expense	1	-	1	-

8. Derivative financial instruments and hedge accounting, continued:

The Company has elected to apply hedge accounting on certain derivatives it uses to manage commodity price risk relating to electricity prices. For the three and nine months ended September 30, 2018 there were no changes in the fair value of the ineffective portion of hedging derivatives required to be recognized in the statement of income (three and nine months ended September 30, 2017 – nil and a gain of $2 million, respectively).

Net after tax gains 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, 2018
Within one year	$ (14)
Between 1 – 5 years	6
After more than 5 years	9
	$ 1

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

9. Share capital:

	Dividends declared							
	For the three months ended September 30,				For the nine months ended September 30,			
	2018		2017		2018		2017	
	Per share	Total	Per share	Total	Per share	Total	Per share	Total
Common[1]	$ 0.4475	$ 46	$ 0.4175	$ 44	$ 1.2825	$ 132	$ 1.1975	$122
Preference, Series 1	0.1913	1	0.1913	1	0.5739	3	0.5739	3
Preference, Series 3	0.2875	1	0.2875	2	0.8625	5	0.8625	6
Preference, Series 5	0.3274	3	0.2813	2	0.8900	7	0.8439	6
Preference, Series 7	0.3750	3	0.3750	3	1.1250	9	1.1250	9
Preference, Series 9	0.3594	2	0.2048	1	1.0782	6	0.2048	1

[1] On July 27, 2018, the Company's Board of Directors approved an increase of 7% to $1.79 in the annual dividend per common share effective for the third quarter of 2018.

	Dividends paid							
	For the three months ended September 30,				For the nine months ended September 30,			
	2018		2017		2018		2017	
	Per share	Total	Per share	Total	Per share	Total	Per share	Total
Common	$ 0.4175	$ 43	$ 0.3900	$ 40	$ 1.2525	$ 130	$ 1.1700	$116
Preference, Series 1	0.1913	1	0.1913	1	0.5739	3	0.5739	3
Preference, Series 3	0.2875	1	0.2875	2	0.8625	5	0.8625	6
Preference, Series 5	0.3274	3	0.2813	2	0.8900	7	0.8439	6
Preference, Series 7	0.3750	3	0.3750	3	1.1250	9	1.1250	9
Preference, Series 9	0.3594	2	0.2048	1	1.0782	6	0.2048	1

During the three and nine months ended September 30, 2018, the Company purchased and canceled 504,318 and 2,231,256 of its outstanding common shares at average exercise prices of $25.34 per share and $24.77 per share for $13 million and $55 million, respectively (three and nine months ended September 30, 2017 – nil) under its Toronto Stock Exchange approved normal course issuer bid.

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

10. Financial instruments:

Fair values

Details of the fair values of the Company's derivative instruments are described in note 8.

The Company's other short-term financial instruments are classified and measured at amortized cost, consistent with the methodologies described in the Company's 2017 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 2017 annual consolidated financial statements. The carrying amount and fair value of the Company's other financial instruments, which are all classified and subsequently measured at amortized cost, are summarized as follows:

		September 30, 2018		December 31, 2017	
	Fair value hierarchy level	Carrying amount[1]	Fair value	Carrying amount[1]	Fair value
Other financial assets[2]	Level 2	$ 4	$ 4	$ 4	$ 4
Finance lease receivables	Level 2	650	714	667	757
Government grant receivable	Level 2	507	507	544	544
Loans and borrowings	Level 2	2,139	2,157	2,146	2,203
Finance lease obligation	Level 2	18	20	18	20

[1] Includes current portion.

[2] Included in trade and other receivables and non-current other assets, as appropriate, within the statements of financial position.

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, 2017.

The fair value measurement of a financial instrument is included in only one of the three levels described in the Company's 2017 annual consolidated financial statements, 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.

The Company's policy is to recognize transfers between levels as of the date of the event that caused the transfer. The transfers between levels in the fair value hierarchy for the nine months ended September 30, 2018 and the year ended December 31, 2017 are disclosed below within the continuity of Level 3 balances.

The table below presents the Company's financial instruments measured at fair value on a recurring basis in the consolidated statements of financial position, classified using the fair value hierarchy described in the Company's 2017 annual consolidated financial statements.

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

10. Financial instruments, continued:

Fair value hierarchy, continued

	September 30, 2018			
	Level 1	Level 2	Level 3	Total
Derivative financial instruments assets	$ -	$ 126	$ 39	$ 165
Derivative financial instruments liabilities	-	(137)	(22)	(159)

	December 31, 2017			
	Level 1	Level 2	Level 3	Total
Derivative financial instruments assets	$ -	$ 139	$ 32	$ 171
Derivative financial instruments liabilities	-	(140)	(2)	(142)

Valuation techniques used in determination of fair values within Level 3

The following financial instruments are classified within Level 3 of the hierarchy as forward market prices are not available for the full period of the contracts, as such their fair values are derived using forecasts based on internal modelling.

- On April 30, 2018, the Company entered into a 12-year contract to swap the market price per megawatt hour (MWh) for a fixed price per MWh for 85% of the notional generation of its Cardinal Point Wind project (Cardinal Point Wind). The term of this contract extends beyond a liquid trading period.
- On August 30, 2017, the Company entered into a 12-year contract to swap the market price per MWh for a fixed price per MWh for 87% of the notional generation of its New Frontier Wind project (New Frontier Wind). The term of this contract extends beyond a liquid trading period.
- On April 21, 2016, the Company entered into a 10-year, fixed price contract to swap the market revenue of its Bloom Wind project's generation for a fixed annual payment for a 10-year term, which extends beyond a liquid trading period.

In addition, as at September 30, 2018 and December 31, 2017, the Company holds contracts for the sale of RECs for which pricing beyond two years is not readily observable and are therefore classified in Level 3 of the hierarchy.

The fair values of the Company's commodity derivatives included within Level 3 are determined by applying a mark-to-forecast model. The table below presents ranges for the Company's Level 3 inputs:

	September 30, 2018	December 31, 2017
REC pricing (per certificate) - Thermal	$0.61	$0.80 to $0.86
REC pricing (per certificate) - Solar	$209.66 to $400.09	$200.05 to $348.25
Power pricing (per MWh) – Wind	$12.86 to $62.96	$16.75 to $35.64

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

10. Financial instruments, continued:

Fair value hierarchy, continued

Valuation process applied to Level 3

The valuation models used to calculate the fair values of the derivative financial instruments assets and liabilities within Level 3 are prepared by appropriate subject matter experts and reviewed by the Company's commodity risk group and by management. The valuation technique and the associated inputs are assessed on a regular basis for ongoing reasonability.

The table below presents the impact to fair value of Level 3 derivative instruments based on reasonably possible alternative assumptions:

	September 30, 2018	December 31, 2017
REC pricing – Thermal [3]	$ 1	$ 1
REC pricing – Solar [3]	-	-
Power pricing – Wind [3]	16	12

[3] Increase or decrease to fair value calculated using a $1 per unit change.

Continuity of Level 3 balances

The Company classifies financial instruments in Level 3 of the fair value hierarchy when there is reliance on at least one significant unobservable input to the valuation model used to determine fair value. In addition to these unobservable inputs, the valuation model for Level 3 instruments also relies on a number of inputs that are observable either directly or indirectly. Accordingly, the unrealized gains and losses shown below include changes in the fair value related to both observable and unobservable inputs. The following table summarizes the changes in the fair value of financial instruments classified in Level 3:

	Nine months ended September 30, 2018	Year ended December 31, 2017
As at January 1 [4]	$ 30	$ (10)
Unrealized and realized (losses) gains included in net income [5]	(12)	8
Unrealized and realized gains included in other comprehensive income	-	32
Settlements [6]	-	2
Transfers [7]	(2)	(2)
Foreign exchange gain	1	-
As at end of period	$ 17	$ 30
Total unrealized gains for the period included in other comprehensive income	$ -	$ 32
Total unrealized and realized (losses) gains for the period included in net income[5]	$ (12)	$ 10

[4] The fair value of derivative instruments assets and liabilities are presented on a net basis.

[5] Gains are recorded in revenues.

[6] Relates to settlement of financial derivative instruments.

[7] Relates to transfers between Level 3 and Level 2 when pricing inputs become readily observable.

All instruments classified as Level 3 are derivative type instruments. Gains and losses associated with Level 3 balances may not necessarily reflect the underlying exposures of the Company. As a result, unrealized gains and losses from Level 3 financial instruments are often offset by unrealized gains and losses on financial instruments that are classified in Levels 1 or 2.

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

11. Commitments:

During the third quarter of 2018, the Company entered into an agreement to acquire 100% of the ownership interests in Arlington Valley, LLC, which owns the Arlington Valley facility (Arlington facility), a 580 megawatt (MW) combined cycle natural gas generation facility located in Arizona, from a third party. The transaction is expected to close in the fourth quarter of 2018, subject to regulatory approvals and other customary closing conditions. Capital Power will finance the purchase price of approximately $396 million (US$300 million), plus working capital and other closing adjustments, using its credit facilities followed by permanent debt financing.

12. 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, New Mexico, Kansas and Alabama), 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., including New Frontier Wind and Cardinal Point Wind which are under development in North Dakota and Illinois, respectively.

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

	Three months ended September 30, 2018				Three months ended September 30, 2017			
	Canada	U.S.	Inter-area eliminations	Total	Canada	U.S.	Inter-area eliminations	Total
Revenues - external	$ 334	$ 33	$ -	$ 367	$ 239	$ 78	$ -	$ 317
Revenues - inter-area	5	(1)	(4)	-	11	11	(22)	-
Other income	16	6	-	22	16	13	-	29
Total revenues and other income	$ 355	$ 38	$ (4)	$ 389	$ 266	$ 102	$ (22)	$ 346

	Nine months ended September 30, 2018				Nine months ended September 30, 2017			
	Canada	U.S.	Inter-area eliminations	Total	Canada	U.S.	Inter-area eliminations	Total
Revenues - external	$ 771	$ 172	$ -	$ 943	$ 664	$ 157	$ -	$ 821
Revenues - inter-area	9	8	(17)	-	29	40	(69)	-
Other income	46	70	-	116	48	16	-	64
Total revenues and other income	$ 826	$ 250	$ (17)	$1,059	$ 741	$ 213	$ (69)	$ 885

	As at September 30, 2018			As at December 31, 2017		
	Canada	U.S.	Total	Canada	U.S.	Total
Property, plant and equipment	$ 3,401	$ 999	$ 4,400	$ 3,465	$ 913	$ 4,378
Intangible assets	266	98	364	309	92	401
Goodwill	35	-	35	35	-	35
Other assets	62	-	62	67	1	68
	$ 3,764	$ 1,097	$ 4,861	$ 3,876	$1,006	$ 4,882

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

12. Segment information, continued:

The Company's revenues from contracts with customers are disaggregated by major type of revenues and operational groupings of revenues:

	Three months ended September 30, 2018						
	Alberta Commercial	Alberta Contracted	Ontario and British Columbia Contracted	U.S. Contracted	Total from contracts with customers	Other sources	Total
Energy revenues	$ 140	$ 2	$ 1	$ 19	$ 162	$ 195	$ 357
Emission credit revenues	4	-	-	1	5	5	10
Total revenues [1]	$ 144	$ 2	$ 1	$ 20	$ 167	$ 200	$ 367

	Nine months ended September 30, 2018						
	Alberta Commercial	Alberta Contracted	Ontario and British Columbia Contracted	U.S. Contracted	Total from contracts with customers	Other sources	Total
Energy revenues	$ 384	$ 6	$ 2	$ 61	$ 453	$ 447	$ 900
Emission credit revenues	17	-	-	3	20	23	43
Total revenues [1]	$ 401	$ 6	$ 2	$ 64	$ 473	$ 470	$ 943

[1] Included within trade and other receivables, as at September 30, 2018, were amounts related to contracts with customers of $155 million.

13. Comparative figures:

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