Capital Power Corporation
12th Floor, EPCOR Tower
1200 – 10423 101 Street
Edmonton, AB  T5H 0E9

For release: April 30, 2018

# Capital Power reports solid first quarter 2018 results and announces the commencement of its Cardinal Point Wind development project

## *Company on track to achieve results above the midpoint of the annual financial target range*

**EDMONTON, Alberta** – Capital Power Corporation (Capital Power, or the Company) (TSX: CPX) today released financial results for the quarter ended March 31, 2018.

Net cash flows from operating activities were $143 million in the first quarter of 2018 compared with $99 million in the first quarter of 2017. Adjusted funds from operations were $85 million in the first quarter of 2017, compared to $88 million in the first quarter of 2017.

Net income attributable to shareholders in the first quarter of 2018 was $43 million and basic earnings per share was $0.32 per share, compared with net income attributable to shareholders of $50 million, and basic earnings per share of $0.44, in the comparable period of 2017. Normalized earnings attributable to common shareholders in the first quarter of 2018, after adjusting for one-time items and fair value adjustments, were $31 million or $0.30 per share compared with $33 million or $0.34 per share in the first quarter of 2017.

"Capital Power continued its organic growth in the United States renewables market with the commencement of our third wind development project," said Brian Vaasjo, President and CEO of Capital Power. "The development of the Cardinal Point Wind project is underway now that we have finalized a 12-year fixed price hedge agreement in April 2018 with an investment grade U.S. financial institution for 85 per cent of the facility's output. We continue to leverage our competitive advantages in development and construction to invest in wind projects in the U.S. Cardinal Point Wind is a 150-megawatt wind facility located in Illinois, with commercial operations expected to commence in March of 2020."

"Our first quarter results benefitted from strong operating performance with average facility availability of 96 per cent, and contributions from assets that we acquired and developed in 2017, offset by the timing of planned Genesee outages in 2018 compared to 2017," continued Mr. Vaasjo. "We expect the power prices in Alberta to increase over the next 6-12 months consistent with current forward prices."

"The Alberta power market continues to experience demand growth, and the impact of higher carbon costs combined with coal plants coming off-line, resulting in an average Alberta spot price of $35 per megawatt hour (MWh) in the first quarter of 2018. This was the highest quarterly power price since the second quarter of 2015, and higher than the $22 per MWh average in 2017. With nearly 500 megawatts of peaking natural gas and wind facilities, Capital Power is well-positioned to benefit from expected higher power prices as reflected in average forward prices in the mid-$50/MWh range for the remainder of 2018 and 2019. Management expects adjusted funds from operations in 2018 to be above the mid point of the $360 million to $400 million guidance range," said Mr. Vaasjo.

"By mid-2018, the Alberta Electric System Operator should have finalized its proposed capacity market design for Alberta's electricity market, which will provide clarity on the future of the Alberta power market," said Mr. Vaasjo. "The recent release of Draft 2 of the Comprehensive Market Design by AESO continues to be consistent with our view of a properly designed capacity market for Alberta."

In the first quarter, the Company was active in its Normal Course Issuer Bid (NCIB) by purchasing and cancelling 713,100 common shares for a total cost of $17 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]<br>(unaudited) | **Three months ended March 31** | | | |
|---|---|---|---|---|
| *(millions of dollars except per share and operational amounts)* | | **2018** | | **2017** |
| Electricity generation (Gigawatt hours) | | 5,026 | | 3,962 |
| Generation facility availability | | 96% | | 97% |
| Revenues and other income | $ | 307 | $ | 338 |
| Adjusted EBITDA [2] | $ | 172 | $ | 143 |
| Net income | $ | 41 | $ | 47 |
| Net income attributable to shareholders of the Company | $ | 43 | $ | 50 |
| Basic earnings per share | $ | 0.32 | $ | 0.44 |
| Diluted earnings per share | $ | 0.32 | $ | 0.43 |
| Normalized earnings attributable to common shareholders [2] | $ | 31 | $ | 33 |
| Normalized earnings per share [2] | $ | 0.30 | $ | 0.34 |
| Net cash flows from operating activities | $ | 143 | $ | 99 |
| Adjusted funds from operations [2,3] | $ | 85 | $ | 88 |
| Adjusted funds from operations per share [2] | $ | 0.82 | $ | 0.91 |
| Purchase of property, plant and equipment and other assets | $ | 40 | $ | 85 |
| Dividends per common share, declared | $ | 0.4175 | $ | 0.3900 |

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 three months ended March 31, 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.

## Subsequent Event

### *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.

## Analyst conference call and webcast

Capital Power will be hosting a conference call and live webcast with analysts on April 30, 2018 at 9:00 am (MDT) to discuss the first 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 | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | **Mar 31 2018** | **Dec 31 2017** | **Sep 30 2017** | **Jun 30 2017** | **Mar 31 2017** | **Dec 31 2016** | **Sep 30 2016** | **Jun 30 2016** |
| Revenues and other income | 307 | 261 | 346 | 201 | 338 | 280 | 374 | 226 |
| Energy purchases and fuel, other raw materials and operating charges, staff costs and employee benefits expense, and other administrative expense | (153) | (125) | (198) | (119) | (208) | (148) | (232) | (127) |
| Adjusted EBITDA from joint ventures [1] | 18 | 18 | 10 | 14 | 13 | 12 | 6 | 9 |
| **Adjusted EBITDA** | **172** | **154** | **158** | **96** | **143** | **144** | **148** | **108** |
| Depreciation and amortization | (75) | (72) | (74) | (65) | (60) | (53) | (53) | (54) |
| Impairments | - | - | (83) | - | - | - | (6) | - |
| Losses on termination of power purchase arrangement | - | - | - | - | - | (20) | - | - |
| Foreign exchange gain (loss) | 3 | (4) | 21 | 9 | 2 | (4) | 3 | (1) |
| Net finance expense | (33) | (32) | (31) | (25) | (20) | (24) | (21) | (19) |
| Finance expense and depreciation expense from joint ventures [1] | (7) | (13) | (6) | (2) | (3) | (3) | (3) | (4) |
| Income tax (expense) recovery | (19) | (46) | 8 | 94 | (15) | (14) | (4) | (10) |
| **Net income (loss)** | **41** | **(13)** | **(7)** | **107** | **47** | **26** | **64** | **20** |
| | | | | | | | | |
| **Net income (loss) attributable to:** | | | | | | | | |
| Non-controlling interest | (2) | (3) | (2) | (2) | (3) | (2) | (2) | (3) |
| Shareholders of the Company | 43 | (10) | (5) | 109 | 50 | 28 | 66 | 23 |
| **Net income (loss)** | **41** | **(13)** | **(7)** | **107** | **47** | **26** | **64** | **20** |

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 March 31 | |
|---|---|---|
| | **2018** | **2017** |
| **Net cash flows from operating activities per condensed interim consolidated statements of cash flows** | **143** | **99** |
| Add (deduct) items included in calculation of net cash flows from operating activities per condensed interim consolidated statements of cash flows: | | |
| Interest paid | 25 | 14 |
| Change in fair value of derivatives reflected as cash settlement | (9) | 2 |
| Distributions received from joint ventures | (13) | (8) |
| Miscellaneous financing charges paid [1] | 2 | 2 |
| Income taxes paid | 1 | - |
| Change in non-cash operating working capital | (16) | 2 |
| | (10) | 12 |
| Net finance expense [2] | (25) | (17) |
| Current income tax expense | (4) | (2) |
| Sustaining capital expenditures [3] | (21) | (4) |
| Preferred share dividends paid | (10) | (8) |
| Remove tax equity interests' respective shares of adjusted funds from operations | (2) | (2) |
| Adjusted funds from operations from joint ventures | 14 | 10 |
| **Adjusted funds from operations** | **85** | **88** |
| Weighted average number of common shares outstanding (millions) | 104.2 | 96.3 |
| **Adjusted funds from operations per share ($)** | **0.82** | **0.91** |

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 $2 million for each of the three months ended March 31, 2018 and 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 | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | **Mar 31 2018** | **Dec 31 2017** | **Sep 30 2017** | **Jun 30 2017** | **Mar 31 2017** | **Dec 31 2016** | **Sep 30 2016** | **Jun 30 2016** |
| **Basic earnings (loss) per share ($)** | **0.32** | **(0.20)** | **(0.13)** | **1.03** | **0.44** | **0.21** | **0.63** | **0.19** |
| **Net income (loss) attributable to shareholders of the Company per condensed interim consolidated statements of income (loss)** | **43** | **(10)** | **(5)** | **109** | **50** | **28** | **66** | **23** |
| Preferred share dividends including Part VI.1 tax | (10) | (11) | (9) | (8) | (8) | (8) | (5) | (5) |
| Earnings (loss) attributable to common shareholders | 33 | (21) | (14) | 101 | 42 | 20 | 61 | 18 |
| Realized foreign exchange (gain) loss on settlement of foreign currency derivative instruments | (29) | - | 12 | - | - | - | - | - |
| Unrealized changes in fair value of derivatives [1] | 25 | 14 | (31) | 23 | (7) | (8) | (22) | 10 |
| Income tax adjustment | 2 | - | - | - | - | - | - | - |
| Impairment losses | - | - | 53 | - | - | - | 4 | - |
| Unrealized foreign exchange (gain) loss on revaluation of U.S. dollar denominated debt | - | (1) | 44 | (12) | (1) | 3 | 1 | 1 |
| 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 | - | - |
| Change in unrecognized tax benefits | - | - | - | - | - | - | (27) | - |
| Provision for Line Loss Rule Proceeding | - | 7 | - | - | - | - | - | - |
| U.S. tax reform rate decrease | - | 31 | - | - | - | - | - | - |
| Deferred income tax (reduction) expense related to temporary difference on investment in subsidiary | - | - | - | - | - | (1) | 13 | - |
| 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** | **31** | **25** | **29** | **26** | **33** | **26** | **30** | **29** |
| Weighted average number of common shares outstanding (millions) | 104.2 | 104.3 | 104.1 | 98.1 | 96.3 | 96.1 | 96.1 | 96.1 |
| **Normalized earnings per share ($)** | **0.30** | **0.24** | **0.28** | **0.27** | **0.34** | **0.27** | **0.31** | **0.30** |

[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 expected results in relation to the 2018 AFFO guidance range and expectations pertaining to the construction cost and commercial operations date for Cardinal Point Wind.

These statements are based on certain assumptions and analyses made by the Company in light of its experience and perception of historical trends, current conditions, 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 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, and (viii) 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.

## For more information, please contact:

**Media Relations:**
Michael Sheehan
(780) 392-5222
msheehan@capitalpower.com

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

# CAPITAL POWER CORPORATION

## Management's Discussion and Analysis

This management's discussion and analysis (MD&A), prepared as of April 27, 2018, should be read in conjunction with the unaudited condensed interim consolidated financial statements of Capital Power Corporation and its subsidiaries for the three months ended March 31, 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 10. In this MD&A, any reference to the Company or Capital Power, except where otherwise noted or the context otherwise indicates, means Capital Power Corporation together with its subsidiaries.

In this MD&A, financial information for the three months ended March 31, 2018 and the three months ended March 31, 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 April 27, 2018.

## Contents


Forward-Looking Information ........ 10
Overview of Business and Corporate Structure ........ 11
Corporate Strategy ........ 11
Performance Overview ........ 12
Outlook ........ 13
Non-GAAP Financial Measures ........ 14
Financial Highlights ........ 18
Subsequent Event ........ 19
Consolidated Net Income and Results of Operations ........ 19
Financial Position ........ 24
Liquidity and Capital Resources ........ 25
Contingent Liabilities and Provisions ........ 28
Risks and Risk Management ........ 28
Environmental Matters ........ 28
Regulatory Matters ........ 28
Use of Judgments and Estimates ........ 29
Accounting Changes ........ 30
Financial Instruments ........ 31
Disclosure Controls and Procedures and Internal Control over Financial Reporting ........ 33
Summary of Quarterly Results ........ 34
Share and Partnership Unit Information ........ 39
Additional Information ........ 39

## 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 project,
- 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, other energy and carbon prices,
- performance,
- business prospects and opportunities including expected growth and capital projects,
- status of and impact of policy, legislation and regulations,
- effective tax rates, and
- other matters discussed under the Performance Overview and Outlook 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, 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 using a variety of energy sources. Capital Power owns approximately 4,500 megawatts (MW) of power generation capacity across North America. Approximately 1000 MW of owned generation capacity is in advanced development in Alberta, North Dakota, and Illinois.

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 three months ended March 31, 2018 |
|---|---|---|
| Facility availability average | 95% or greater | 96% |
| Sustaining capital expenditures | $85 million | $21 million [1] |
| Genesee performance standard [2] | $15 million | $1 million |
| Facility operating and maintenance expenses | $230 million to $250 million | $61 million |

1 Includes sustaining capital expenditures net of partner contributions of $2 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 Joffre, Roxboro, Southport, and Genesee. Unplanned outages also occurred at Keephills 3 and Cloverbar Energy Centre.

Sustaining capital expenditures for the three months ended March 31, 2018 were higher than target for the year to date primarily due to the Genesee 2 outage, originally planned to occur in the second quarter, occurring in the first quarter. Full year sustaining capital expenditures are expected to be above the target driven by higher anticipated Keephills 3 mine capital expenditures than targeted. Expenditures for the Genesee performance standard for the three months ended March 31, 2018 were lower than target for the year to date but for the full year, expenditures are expected to be consistent with target.

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 three months ended March 31, 2018 were below the target for the year to date but the full year expenditures are expected to be consistent with the target.

### Disciplined growth

| Performance measure | 2018 target | Status as at March 31, 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. | Construction 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 Subsequent Event). |

### Financial stability and strength

| Performance measure | 2018 target | Actual results to March 31, 2018 |
|---|---|---|
| Adjusted funds from operations [1] | $360 million to $400 million | $85 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, that will begin in 2018, on certain coal assets not owned by the Company. Based on the actual results for the first quarter of 2018 and the Company's forecast for the future three quarters, which considers the increase in the Alberta forward power price, 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. Subsequent to the end of the first quarter of 2018, the Company executed a contract for the output of the Cardinal Point Wind project (see Subsequent Event) 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 March 31, 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] | 46% | 22% | 4% |
| Contracted price [2] | Low-$50 | Low-$50 | Mid-$50 |
| Forward Alberta pool prices | $58 | $50 | $43 |

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** | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | **Mar 31 2018** | **Dec 31 2017** | **Sep 30 2017** | **Jun 30 2017** | **Mar 31 2017** | **Dec 31 2016** | **Sep 30 2016** | **Jun 30 2016** |
| Revenues and other income | 307 | 261 | 346 | 201 | 338 | 280 | 374 | 226 |
| Energy purchases and fuel, other raw materials and operating charges, staff costs and employee benefits expense, and other administrative expense | (153) | (125) | (198) | (119) | (208) | (148) | (232) | (127) |
| Adjusted EBITDA from joint ventures [1] | 18 | 18 | 10 | 14 | 13 | 12 | 6 | 9 |
| **Adjusted EBITDA** | **172** | **154** | **158** | **96** | **143** | **144** | **148** | **108** |
| Depreciation and amortization | (75) | (72) | (74) | (65) | (60) | (53) | (53) | (54) |
| Impairments | - | - | (83) | - | - | - | (6) | - |
| Losses on termination of power purchase arrangement | - | - | - | - | - | (20) | - | - |
| Foreign exchange gain (loss) | 3 | (4) | 21 | 9 | 2 | (4) | 3 | (1) |
| Net finance expense | (33) | (32) | (31) | (25) | (20) | (24) | (21) | (19) |
| Finance expense and depreciation expense from joint ventures [1] | (7) | (13) | (6) | (2) | (3) | (3) | (3) | (4) |
| Income tax (expense) recovery | (19) | (46) | 8 | 94 | (15) | (14) | (4) | (10) |
| **Net income (loss)** | **41** | **(13)** | **(7)** | **107** | **47** | **26** | **64** | **20** |
| | | | | | | | | |
| **Net income (loss) attributable to:** | | | | | | | | |
| Non-controlling interest | (2) | (3) | (2) | (2) | (3) | (2) | (2) | (3) |
| Shareholders of the Company | 43 | (10) | (5) | 109 | 50 | 28 | 66 | 23 |
| **Net income (loss)** | **41** | **(13)** | **(7)** | **107** | **47** | **26** | **64** | **20** |

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 March 31 | |
|---|---|---|
| | **2018** | **2017** |
| **Net cash flows from operating activities per condensed interim consolidated statements of cash flows** | **143** | **99** |
| Add (deduct) items included in calculation of net cash flows from operating activities per condensed interim consolidated statements of cash flows: | | |
| Interest paid | 25 | 14 |
| Change in fair value of derivatives reflected as cash settlement | (9) | 2 |
| Distributions received from joint ventures | (13) | (8) |
| Miscellaneous financing charges paid [1] | 2 | 2 |
| Income taxes paid | 1 | - |
| Change in non-cash operating working capital | (16) | 2 |
| | (10) | 12 |
| Net finance expense [2] | (25) | (17) |
| Current income tax expense | (4) | (2) |
| Sustaining capital expenditures [3] | (21) | (4) |
| Preferred share dividends paid | (10) | (8) |
| Remove tax equity interests' respective shares of adjusted funds from operations | (2) | (2) |
| Adjusted funds from operations from joint ventures | 14 | 10 |
| **Adjusted funds from operations** | **85** | **88** |
| Weighted average number of common shares outstanding (millions) | 104.2 | 96.3 |
| **Adjusted funds from operations per share ($)** | **0.82** | **0.91** |

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 $2 million for each of the three months ended March 31, 2018 and 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 | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | **Mar 31 2018** | **Dec 31 2017** | **Sep 30 2017** | **Jun 30 2017** | **Mar 31 2017** | **Dec 31 2016** | **Sep 30 2016** | **Jun 30 2016** |
| **Basic earnings (loss) per share ($)** | **0.32** | **(0.20)** | **(0.13)** | **1.03** | **0.44** | **0.21** | **0.63** | **0.19** |
| **Net income (loss) attributable to shareholders of the Company per condensed interim consolidated statements of income (loss)** | **43** | **(10)** | **(5)** | **109** | **50** | **28** | **66** | **23** |
| Preferred share dividends including Part VI.1 tax | (10) | (11) | (9) | (8) | (8) | (8) | (5) | (5) |
| Earnings (loss) attributable to common shareholders | 33 | (21) | (14) | 101 | 42 | 20 | 61 | 18 |
| Realized foreign exchange (gain) loss on settlement of foreign currency derivative instruments | (29) | - | 12 | - | - | - | - | - |
| Unrealized changes in fair value of derivatives [1] | 25 | 14 | (31) | 23 | (7) | (8) | (22) | 10 |
| Income tax adjustment | 2 | - | - | - | - | - | - | - |
| Impairment losses | - | - | 53 | - | - | - | 4 | - |
| Unrealized foreign exchange (gain) loss on revaluation of U.S. dollar denominated debt | - | (1) | 44 | (12) | (1) | 3 | 1 | 1 |
| 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 | - | - |
| Change in unrecognized tax benefits | - | - | - | - | - | - | (27) | - |
| Provision for Line Loss Rule Proceeding | - | 7 | - | - | - | - | - | - |
| U.S. tax reform rate decrease | - | 31 | - | - | - | - | - | - |
| Deferred income tax (reduction) expense related to temporary difference on investment in subsidiary | - | - | - | - | - | (1) | 13 | - |
| 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** | **31** | **25** | **29** | **26** | **33** | **26** | **30** | **29** |
| Weighted average number of common shares outstanding (millions) | 104.2 | 104.3 | 104.1 | 98.1 | 96.3 | 96.1 | 96.1 | 96.1 |
| **Normalized earnings per share ($)** | **0.30** | **0.24** | **0.28** | **0.27** | **0.34** | **0.27** | **0.31** | **0.30** |

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 interests.

## FINANCIAL HIGHLIGHTS

| (unaudited, $ millions, except per share amounts) | Three months ended March 31 | |
|---|---|---|
| | 2018 | 2017 |
| Revenues and other income | 307 | 338 |
| Adjusted EBITDA [1] | 172 | 143 |
| Net income | 41 | 47 |
| Net income attributable to shareholders of the Company | 43 | 50 |
| Normalized earnings attributable to common shareholders [1] | 31 | 33 |
| Basic earnings per share ($) | 0.32 | 0.44 |
| Diluted earnings per share ($) [2] | 0.32 | 0.43 |
| Normalized earnings per share ($) [1] | 0.30 | 0.34 |
| Net cash flows from operating activities | 143 | 99 |
| Adjusted funds from operations [1] | 85 | 88 |
| Adjusted funds from operations per share ($) [1] | 0.82 | 0.91 |
| Purchase of property, plant and equipment and other assets | 40 | 85 |
| Dividends per common share, declared ($) | 0.4175 | 0.3900 |
| Dividends per Series 1 preferred share, declared ($) | 0.1913 | 0.1913 |
| Dividends per Series 3 preferred share, declared ($) | 0.2875 | 0.2875 |
| Dividends per Series 5 preferred share, declared ($) | 0.2813 | 0.2813 |
| Dividends per Series 7 preferred share, declared ($) | 0.3750 | 0.3750 |
| Dividends per Series 9 preferred share, declared ($) | 0.3594 | - |

| | As at | |
|---|---|---|
| | March 31, 2018 | December 31, 2017 |
| Loans and borrowings including current portion | 2,083 | 2,146 |
| Total assets | 6,807 | 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 and adjusted funds from operations per share for the three months ended March 31, 2018 were lower than the same period in 2017 due primarily to higher sustaining capital expenditures and higher finance expense, largely offset by adjusted funds from operations from the new facilities acquired in the second quarter of 2017.

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

## SUBSEQUENT EVENT

### 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.

## CONSOLIDATED NET INCOME AND RESULTS OF OPERATIONS

The primary factors contributing to the change in consolidated net income for the three months ended March 31, 2018 compared with 2017 are presented below followed by further discussion of these items.

| (unaudited, $ millions) | | |
|---|---|---|
| **Consolidated net income for the three months ended March 31, 2017** | | **47** |
| Increase (decrease) in adjusted EBITDA: | | |
| Alberta commercial facilities and portfolio optimization | (3) | |
| Alberta contracted facilities | - | |
| Ontario and British Columbia contracted facilities | 13 | |
| U.S. contracted facilities | 29 | |
| Corporate | - | |
| Change in unrealized net gains or losses related to the fair value of commodity derivatives and emission credits | (10) | 29 |
| Increase in depreciation and amortization expense | | (15) |
| Increase in foreign exchange gain | | 1 |
| Increase in finance expense and depreciation expense from joint ventures | | (4) |
| Increase in net finance expense | | (13) |
| Decrease in income before tax | | (2) |
| Increase in income tax expense | | (4) |
| **Decrease in net income** | | **(6)** |
| **Consolidated net income for the three months ended March 31, 2018** | | **41** |

## Results by facility category and other

| | Three months ended March 31 | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 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 | 5,026 | 3,962 | 96 | 97 | 262 | 184 | | |
| **Alberta commercial facilities** [4] | | | | | | | | |
| Genesee 3 | 479 | 493 | 97 | 99 | 17 | 10 | | |
| Keephills 3 | 420 | 445 | 92 | 93 | 15 | 10 | | |
| Clover Bar Energy Centre 1, 2 and 3 | 175 | 36 | 93 | 99 | 9 | 1 | | |
| Joffre | 128 | 35 | 93 | 92 | 11 | 4 | | |
| Shepard Energy Centre | 795 | 649 | 100 | 99 | 28 | 24 | | |
| Halkirk | 132 | 122 | 98 | 96 | 12 | 9 | | |
| Clover Bar Landfill Gas | - | 5 | - | 95 | - | 1 | | |
| Alberta commercial facilities | 2,129 | 1,785 | 96 | 97 | 92 | 59 | | |
| Portfolio optimization | N/A | N/A | N/A | N/A | 81 | 95 | | |
| | 2,129 | 1,785 | 96 | 97 | 173 | 154 | 55 | 58 |
| **Alberta contracted facilities** [4] | | | | | | | | |
| Genesee 1 | 811 | 846 | 100 | 100 | | | | |
| Genesee 2 | 663 | 811 | 83 | 97 | | | | |
| | 1,474 | 1,657 | 92 | 98 | 61 | 61 | 45 | 45 |
| **Ontario and British Columbia contracted facilities** | | | | | | | | |
| Island Generation | 10 | - | 100 | 100 | 10 | 10 | | |
| York Energy [5] | 2 | N/A | 100 | N/A | - | N/A | | |
| East Windsor [7] | 2 | N/A | 99 | N/A | 9 | N/A | | |
| K2 Wind [6] | 76 | 79 | 98 | 99 | - | - | | |
| Kingsbridge 1 | 36 | 36 | 98 | 98 | 2 | 2 | | |
| Port Dover and Nanticoke | 108 | 93 | 100 | 98 | 14 | 12 | | |
| Quality Wind | 78 | 94 | 97 | 97 | 8 | 11 | | |
| EnPower [8] | 14 | N/A | 97 | N/A | 1 | N/A | | |
| | 326 | 302 | 99 | 99 | 44 | 35 | 53 | 40 |
| **U.S. contracted facilities** | | | | | | | | |
| Roxboro, North Carolina | 76 | 79 | 88 | 93 | 8 | 9 | | |
| Southport, North Carolina | 111 | 92 | 89 | 92 | 15 | 14 | | |
| Decatur Energy, Alabama [9] | 669 | N/A | 100 | N/A | 23 | N/A | | |
| Beaufort Solar, North Carolina | 6 | 6 | 93 | 97 | - | 1 | | |
| Bloom Wind, Kansas [10] | 198 | N/A | 98 | N/A | 15 | N/A | | |
| Macho Springs, New Mexico | 37 | 41 | 97 | 98 | 4 | 5 | | |
| | 1,097 | 218 | 98 | 94 | 65 | 29 | 35 | 6 |
| **Corporate** [11] | | | | | 15 | 14 | (15) | (15) |
| Unrealized changes in fair value of commodity derivatives and emission credits | | | | | (51) | 45 | (1) | 9 |
| **Consolidated revenues and other income and adjusted EBITDA** | | | | | **307** | **338** | **172** | **143** |

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 for three months ended March 31, 2018. 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 $14 million for the three months ended March 31, 2018 and 2017. 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 March 31 | | Year ended December 31, 2017 |
|---|---|---|---|---|
| **Alberta** | **Unit** | **2018** | **2017** | |
| Hedged position [1] | Percentage sold forward at beginning of period (%) | 100 | 100 | 100 |
| Spot power price average | $ per MWh | 35 | 22 | 22 |
| Realized power price [2] | $ per MWh | 47 | 55 | 51 |
| Natural gas price (AECO) [3] | $ per gigajoule (Gj) | 1.99 | 2.56 | 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 $35 per MWh for the three months ended March 31, 2018, which was higher than the corresponding period 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 prices 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 months ended March 31, 2018, generation was higher than the comparable period in 2017 primarily due to higher dispatch at Shepard, Joffre, and Cloverbar Energy Centre. Availability for the three months ended March 31, 2018 was comparable to the same period in 2017.

Revenues and other income for the three months ended March 31, 2018 increased compared with the corresponding period in 2017 primarily due to increased generation from commercial facilities. Adjusted EBITDA for the three months ended March 31, 2018 decreased compared to the corresponding period in 2017, as a result of lower realized revenues on portfolio optimization activities as well as higher carbon costs.

### *Alberta contracted facilities*

Generation and availability for the three months ended March 31, 2018 were lower compared with the corresponding period in 2017 primarily due to timing of the Genesee 2 planned maintenance outage which commenced in the first quarter of 2018 as compared to the Genesee 1 outage which occurred in the second quarter of 2017. Revenues and other income and adjusted EBITDA were consistent with the corresponding period in 2017.These results reflected lower net availability incentive payments received due to the planned maintenance outage for the three months ended March 31, 2018, offset by higher capacity revenues due to higher PPA indices and higher average power prices as compared to the three months ended March 31, 2017.

### *Ontario and British Columbia contracted facilities*

Generation, revenues and other income and adjusted EBITDA for the three months ended March 31, 2018 were higher compared with the corresponding period in 2017 due to higher generation at Port Dover and Nanticoke and the additions of York Energy, East Windsor and EnPower which were acquired in the second quarter of 2017. Overall availability is consistent for the three months ended March 31, 2018 and 2017. 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, revenues and other income and adjusted EBITDA increased in the three months ended March 31, 2018 compared with the corresponding period in 2017 primarily due to the addition of Decatur Energy and Bloom Wind (commenced commercial operations June 1, 2017). Higher EBITDA for the first quarter of 2018 was slightly offset by the impact of the 2018 Southport outage costs. Lower generation at Southport in the first quarter of 2017 was due to several fuel reserve shutdowns and derates due to sulfur emission restrictions that did not occur in the current year. Availability increased in the three months ended March 31, 2018 compared with the corresponding period in 2017 due to high availability for Decatur Energy and Bloom Wind, partially offset by higher planned outage hours at Southport and Roxboro for the three months ended March 31, 2018 compared with 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 and revenues and other income were consistent with 2017 results for the three months ended March 31, 2018.

### *Unrealized changes in fair value of commodity derivatives and emission credits*

| (unaudited, $ millions) | Three months ended March 31 | | | |
|---|---|---|---|---|
| | **2018** | **2017** | **2018** | **2017** |
| **Unrealized changes in fair value of commodity derivatives and emission credits** | **Revenues and other income** | | **Adjusted EBITDA** | |
| Unrealized (losses) gains on Alberta energy derivatives | (53) | 38 | - | 17 |
| Unrealized losses on U.S. energy derivatives | (1) | - | (1) | - |
| Unrealized (losses) gains on natural gas derivatives | (1) | 7 | 2 | (8) |
| Unrealized gains on emission derivatives | 4 | - | 4 | - |
| Unrealized losses on emission credits held for trading | - | - | (6) | - |
| | **(51)** | **45** | **(1)** | **9** |

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 March 31, 2018 the Alberta energy portfolio recognized an immaterial unrealized gain. For the three months ending March 31, 2017, the Alberta energy portfolio recognized unrealized gains of $17 million, primarily due to 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 quarter.

During the three months ended March 31, 2018, the Company recognized unrealized gains of $2 million on natural gas derivatives, mainly due the reversal of prior year unrealized net losses on forward purchase contracts that settled during the quarter, partially offset by unrealized losses on forward purchase contracts valued against decreasing forward prices. For the comparable period in 2017 the Company recognized unrealized net losses of $8 million on natural gas derivatives primarily due to net forward purchase contracts valued against decreasing forward prices combined with the reversal of prior period unrealized gains on forward purchase contracts that settled during the quarter.

Unrealized gains on emission derivatives of $4 million were recognized during the three months ended March 31, 2018, primarily due to net forward purchase contracts being valued against increasing forward prices.

Unrealized losses on emission credits held for trading of $6 million recognized in 2018 were primarily due to the reversal of prior periods unrealized gains on emission credits sold during the quarter.

## Consolidated other expenses and non-controlling interest

| (unaudited, $ millions) | Three months ended March 31 | |
|---|---|---|
| | 2018 | 2017 |
| Interest on borrowings less capitalized interest | (29) | (17) |
| Other net finance expense – interest on coal compensation from the Province of Alberta, sundry interest, guarantee and other fees | 2 | 3 |
| | (27) | (14) |
| Other net finance expense – amortization and accretion charges, including accretion of deferred revenue pertaining to coal compensation from the Province of Alberta | (6) | (6) |
| Total net finance expense | (33) | (20) |
| Depreciation and amortization | (75) | (60) |
| Foreign exchange gain | 3 | 2 |
| Finance expense and depreciation expense from joint ventures | (7) | (3) |
| Income tax expense | (19) | (15) |
| Net loss attributable to non-controlling interest | 2 | 3 |

### *Net finance expense*

Higher net finance expense for the three months ended March 31, 2018 compared with the same period 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.

### *Depreciation and amortization*

Depreciation and amortization for the three months ended March 31, 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 gain*

As at March 31, 2018, the Company had outstanding foreign currency purchase contracts totalling US$133 million. For the three months ended March 31, 2018, the exchange rate of the Canadian dollar relative to the U.S. dollar weakened resulting in an unrealized gain.

As at March 31, 2017, the Company had outstanding U.S. dollar denominated debt payable totalling US$295 million. Approximately US$195 million was hedged for accounting purposes using foreign currency swaps. 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 months ended March 31, 2017, the exchange rate of the Canadian dollar relative to the U.S. dollar strengthened resulting in an unrealized gain.

### *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*

Income tax expense increased $4 million for the three months ended March 31, 2018 compared with the corresponding period in 2017 primarily due to amounts attributable to tax-equity interests and amounts recognized at a tax rate different than the statutory tax rate.

### *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

| (unaudited, $ millions) | Three months ended March 31 | |
|---|---|---|
| | 2018 | 2017 |
| Net income | 41 | 47 |
| Other comprehensive (loss) income: | | |
| Net unrealized (losses) gains on commodity derivatives designated as cash flow hedges | (13) | 23 |
| Net unrealized losses on derivatives designated as cash flow hedges – joint ventures | - | (1) |
| Net realized gains on commodity derivatives designated as cash flow hedges reclassified to net income | (8) | (17) |
| Net realized losses on commodity derivatives designated as cash flow hedges reclassified to net income– joint ventures | - | 1 |
| Unrealized foreign exchange gain (loss) on the translation of foreign operations | 11 | (2) |
| Total other comprehensive (loss) income, net of tax | (10) | 4 |
| **Comprehensive income** | **31** | **51** |

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

## FINANCIAL POSITION

The significant changes in the consolidated statements of financial position from December 31, 2017 to March 31, 2018 were as follows:

| (unaudited, $ millions) | March 31, 2018 | December 31, 2017 | Increase (decrease) | Primary reason for increase (decrease) |
|---|---|---|---|---|
| Trade and other receivables | 263 | 278 | (15) | Primarily lower generation receivables at various facilities partially offset by timing of environmental portfolio receivables. |
| Inventories | 136 | 120 | 16 | Increase in emission credits held for trading and higher coal inventory. |
| Net derivative financial instruments | (35) | 29 | (64) | Impact of increasing forward Alberta power prices on the fair value of forward sales contracts. |
| Intangible assets | 373 | 401 | (28) | Decrease primarily due to emission credits returned and used for compliance, partially offset by increase in capital costs on project under development. |
| Loans and borrowings (including current portion) | 2,083 | 2,146 | (63) | Decrease due to annual repayment of senior debt payable to EPCOR partially offset by increase in credit facility usage. |
| Deferred revenue and other liabilities (including current portion) | 676 | 639 | 37 | 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. |
| Share capital | 3,246 | 3,262 | (16) | Decrease primarily due to common shares purchased. |

## LIQUIDITY AND CAPITAL RESOURCES

| (unaudited, $ millions) | Three months ended March 31 | | |
|---|---|---|---|
| **Cash inflows (outflows)** | **2018** | **2017** | **Change** |
| Operating activities | 143 | 99 | 44 |
| Investing activities | (30) | (198) | 168 |
| Financing activities | (118) | 60 | (178) |

### Operating activities

Cash flows from operating activities for the three months ended March 31, 2018 increased compared with the same period in 2017 primarily due to cash flows from the facilities acquired in the second quarter of 2017 and Bloom Wind which commenced operations in the second quarter of 2017. In addition, there were working capital cash inflows in 2018 compared with outflows in 2017.

### Investing activities

Cash flows used in investing activities for the three months ended March 31, 2018 decreased compared with the same period in 2017 primarily due to lower year-to-date spend on wind development projects in 2018 compared to Bloom Wind spend in 2017 and the 2017 prepayment related to the amended Genesee Mine Joint Venture Agreement. During the three months ended March 31, 2018 the Company also purchased and canceled 713,100 of its outstanding common shares for a total of $17 million under its Toronto Stock Exchange approved normal course issuer bid.

***Capital expenditures and investments***

| (unaudited, $ millions) | Pre-2018 Actual | Three months ended March 31, 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 | 6 | 156 | 182 | Targeted completion in December 2018 |
| Whitla Wind [6] | 3 | 6 | 44 | 320 | Targeted completion in the fourth quarter of 2019 |
| Cardinal Point Wind [7] | 2 | 1 | 37 | 295 | Targeted completion in March of 2020 |
| Development sites | 9 | 1 | 9 | | |
| **Subtotal growth projects** | | **14** | **246** | | |
| Sustaining – facility maintenance excluding Genesee mine | | 22 | | | |
| Sustaining – Genesee mine maintenance and lands | | 2 | | | |
| **Total capital expenditures** [8] | | **38** | | | |
| Emission credits held for compliance | | 3 | | | |
| Capitalized interest | | (1) | | | |
| **Purchase of property, plant and equipment and other assets** | | **40** | | | |

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.

### Financing activities

The cash flows used in financing activities for the three months ended March 31, 2018 primarily reflected the repayment of loans and borrowings as well as the payment of common and preferred share dividends, 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.

The Company's credit facilities consisted of:

| (unaudited, $ millions) | | As at March 31, 2018 | | | As at December 31, 2017 | | |
|---|---|---|---|---|---|---|---|
| | **Maturity timing** | **Total facilities** | **Credit facility utilization** | **Available** | **Total facilities** | **Credit facility utilization** | **Available** |
| Committed credit facility | 2020/2022 | 1,055 | | | 1,055 | | |
| Letters of credit outstanding | | | 51 | | | 30 | |
| Bankers' acceptances outstanding | | | 71 | | | - | |
| Bank loans outstanding[1] | | | 53 | | | 28 | |
| | | 1,055 | 175 | 880 | 1,055 | 58 | 997 |
| Bilateral demand credit facilities | N/A | 200 | | | 200 | | |
| Letters of credit outstanding | | | 144 | | | 139 | |
| | | 200 | 144 | 56 | 200 | 139 | 61 |
| Demand credit facilities | N/A | 25 | - | 25 | 25 | - | 25 |
| | | **1,280** | **319** | **961** | **1,280** | **197** | **1,083** |

1 U.S. dollar denominated bank loans outstanding totaling USD $41 million (December 31, 2017 – USD $23 million)

As at March 31, 2018, the committed credit facility utilization increased $117 million compared with the utilization as at December 31, 2017, due to issuance of bankers' acceptance, increased U.S. dollar bank loans, and increased letter of credits outstanding. In July 2016, the Company exercised the accordion feature of the committed credit facility to increase the facility size by $55 million. The accordion feature permits an additional $245 million increase to the facility in the future, subject to certain conditions including lender approval. Of the existing credit facilities, $55 million matures in July 2020 and $1 billion matures in July 2022. 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) | **Three months ended March 31, 2018 Actual** | **Balance of 2018 estimated** | **Total 2018 Expected Cash Requirements** |
|---|---|---|---|
| Repayment of debt payable to EPCOR | 163 | 11 | 174 |
| Capital expenditures – sustaining | 21 | 69 | 90 |
| Capital expenditures – ongoing growth projects | 14 | 246 | 260 |
| Capital expenditures – Genesee performance standard | 1 | 14 | 15 |
| Common share dividends [1] | 43 | 132 | 175 |
| Preferred share dividends | 10 | 30 | 40 |
| | **252** | **502** | **754** |

1 Includes 7% annual dividend growth, subject to approval by the Board of Directors of Capital Power.

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 2018.

If the Canadian and U.S. financial markets become unstable, as they did particularly in the period from 2008 to 2010, 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 March 31, 2018, $195 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 | |
| --- | --- | --- |
| | March 31, 2018 | December 31, 2017 |
| Loans and borrowings | 2,083 | 2,146 |
| Finance lease obligation [1] | 18 | 18 |
| Less cash and cash equivalents | (48) | (52) |
| Net debt | 2,053 | 2,112 |
| Share capital | 3,246 | 3,262 |
| Deficit and other reserves | (301) | (248) |
| Non-controlling interest | 46 | 48 |
| Total equity | 2,991 | 3,062 |
| **Total capital** | **5,044** | **5,174** |

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

## CONTINGENT LIABILITIES 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.

### 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 for the non-compliant LLR as well as the possible correction of line loss charges and credits for the years 2006 forward.

Financial adjustment will follow the completion of calculations necessary to determine replacement line loss rates for all years. As at April 27, 2018, no retrospective loss factors have yet been produced by the AESO using the replacement methodology. According to AESO estimates issued in March of 2018, the complete set of retrospective loss factors under the approved methodology for historic periods is expected to be made available in the first half of 2019.

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 three months ended March 31, 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 March 31, 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 $295 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, 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 Market Renewal Program is to improve how electricity is priced, scheduled and procured in order to meet Ontario's electricity system needs. The Company is actively participating in the Market Renewal Program 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 Market Renewal Program 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:<br>• 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.<br>• 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.<br><br>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.<br><br>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 March 31, 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 March 31, 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 which 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 leased assets and leased obligations with respect to leases previously classified as operating leases which include office space leases and land leases. 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. Management is currently assessing the transition options for the adoption of IFRS 16. | 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 March 31, 2018 and December 31, 2017 were as follows:

| (unaudited, $ millions) | | March 31, 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 | 48 | 48 | 52 | 52 |
| Trade and other receivables [2] | N/A | 186 | 186 | 200 | 200 |
| Government grant receivable [3] | Level 2 | 548 | 548 | 544 | 544 |
| Finance lease receivables [3] | Level 2 | 661 | 737 | 667 | 757 |
| Other financial assets [4] | Level 2 | 3 | 3 | 4 | 4 |
| Fair value through income or loss | | | | | |
| Derivative financial instruments assets – current and non-current | See below | 134 | 134 | 157 | 157 |
| Fair value through other comprehensive income | | | | | |
| Derivative financial instruments assets – current and non-current | See below | 6 | 6 | 14 | 14 |
| **Financial liabilities:** | | | | | |
| Other financial liabilities | | | | | |
| Trade and other payables [5] | N/A | 205 | 205 | 215 | 215 |
| Finance lease obligation [3] | Level 2 | 18 | 20 | 18 | 20 |
| Loans and borrowings [3] | Level 2 | 2,083 | 2,123 | 2,146 | 2,203 |
| Fair value through income or loss | | | | | |
| Derivative financial instruments liabilities – current and non-current | See below | | | | |
| Fair value through other comprehensive income | | 130 | 130 | 112 | 112 |
| Derivative financial instruments liabilities – current and non-current | See below | 45 | 45 | 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 three months ended March 31, 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 March 31, 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 March 31, 2018 | | | |
|---|---|---|---|---|---|
| | **Fair value hierarchy level** | **Commodity cash flow hedges** | **Commodity non-hedges** | **Foreign exchange non-hedges** | **Total** |
| Derivative financial instruments assets | Level 2 | 6 | 99 | 2 | 107 |
| | Level 3 | - | 33 | - | 33 |
| | | 6 | 132 | 2 | 140 |
| Derivative financial instruments liabilities | Level 2 | (45) | (130) | - | (175) |
| | Level 3 | - | - | - | - |
| | | (45) | (130) | - | (175) |
| **Net derivative financial instruments (liabilities) assets** | | **(39)** | **2** | **2** | **(35)** |

| (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 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, or foreign exchange gains and losses.

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 nodes.

### Commodity and foreign exchange derivatives not designated as accounting hedges

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

Unrealized and realized losses on foreign exchange derivatives that are not designated as hedges for accounting purposes are recorded in net income as foreign exchange gains or losses.

## 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 three months ended March 31, 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** | **Mar 31 2018** | **Dec 31 2017** | **Sep 30 2017** | **Jun 30 2017** | **Mar 31 2017** | **Dec 31 2016** | **Sep 30 2016** | **Jun 30 2016** |
| Total generation | 5,026 | 4,839 | 4,720 | 3,673 | 3,962 | 3,793 | 3,930 | 3,707 |
| **Alberta commercial facilities [1]** | | | | | | | | |
| Genesee 3 | 479 | 511 | 509 | 480 | 493 | 341 | 498 | 474 |
| Keephills 3 | 420 | 362 | 380 | 419 | 445 | 478 | 464 | 501 |
| Clover Bar Energy Centre 1, 2 and 3 | 175 | 92 | 140 | 24 | 36 | 94 | 79 | 106 |
| Joffre | 128 | 119 | 101 | 70 | 35 | 66 | 27 | 21 |
| Shepard Energy Centre | 795 | 694 | 730 | 560 | 649 | 410 | 611 | 647 |
| Halkirk | 132 | 168 | 95 | 119 | 122 | 121 | 86 | 124 |
| Clover Bar Landfill Gas | - | 2 | 6 | 6 | 5 | 3 | 1 | 2 |
| | 2,129 | 1,948 | 1,961 | 1,678 | 1,785 | 1,513 | 1,766 | 1,875 |
| **Alberta contracted facilities [1]** | | | | | | | | |
| Genesee 1 | 811 | 860 | 830 | 576 | 846 | 863 | 857 | 770 |
| Genesee 2 | 663 | 864 | 823 | 825 | 811 | 860 | 862 | 582 |
| | 1,474 | 1,724 | 1,653 | 1,401 | 1,657 | 1,723 | 1,719 | 1,352 |
| **Ontario and British Columbia contracted facilities** | | | | | | | | |
| Island Generation | 10 | 3 | 12 | - | - | 37 | 2 | - |
| York Energy | 2 | 2 | 5 | 1 | N/A | N/A | N/A | N/A |
| East Windsor | 2 | 1 | 2 | 1 | N/A | N/A | N/A | N/A |
| K2 Wind | 76 | 57 | 28 | 29 | 79 | 77 | 40 | 34 |
| Kingsbridge 1 | 36 | 37 | 11 | 25 | 36 | 37 | 15 | 16 |
| Port Dover and Nanticoke | 108 | 84 | 39 | 71 | 93 | 92 | 53 | 65 |
| Quality Wind | 78 | 117 | 85 | 84 | 94 | 85 | 78 | 90 |
| EnPower | 14 | 13 | 7 | 2 | N/A | N/A | N/A | N/A |
| | 326 | 314 | 189 | 213 | 302 | 328 | 188 | 205 |
| **U.S. contracted facilities** | | | | | | | | |
| Roxboro, North Carolina | 76 | 86 | 80 | 88 | 79 | 84 | 84 | 82 |
| Southport, North Carolina | 111 | 120 | 124 | 92 | 92 | 107 | 140 | 144 |
| Decatur Energy, Alabama | 669 | 425 | 542 | 107 | N/A | N/A | N/A | N/A |
| Beaufort Solar, North Carolina | 6 | 6 | 7 | 8 | 6 | 6 | 8 | 8 |
| Bloom Wind, Kansas | 198 | 190 | 145 | 46 | N/A | N/A | N/A | N/A |
| Macho Springs, New Mexico | 37 | 26 | 19 | 40 | 41 | 32 | 25 | 41 |
| | 1,097 | 853 | 917 | 381 | 218 | 229 | 257 | 275 |

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** | **Mar 31 2018** | **Dec 31 2017** | **Sep 30 2017** | **Jun 30 2017** | **Mar 31 2017** | **Dec 31 2016** | **Sep 30 2016** | **Jun 30 2016** |
| Total average facility availability | 96 | 95 | 97 | 94 | 97 | 94 | 96 | 90 |
| **Alberta commercial facilities [1]** | | | | | | | | |
| Genesee 3 | 97 | 100 | 100 | 97 | 99 | 68 | 100 | 100 |
| Keephills 3 | 92 | 75 | 83 | 92 | 93 | 99 | 96 | 100 |
| Clover Bar Energy Centre 1, 2 and 3 | 93 | 97 | 93 | 89 | 99 | 99 | 91 | 91 |
| Joffre | 93 | 100 | 100 | 96 | 92 | 98 | 81 | 55 |
| Shepard Energy Centre | 100 | 94 | 99 | 97 | 99 | 76 | 99 | 82 |
| Halkirk | 98 | 97 | 88 | 99 | 96 | 98 | 96 | 98 |
| Clover Bar Landfill Gas | - | 45 | 94 | 95 | 95 | 92 | 27 | 99 |
| | 96 | 93 | 95 | 95 | 97 | 87 | 95 | 87 |
| **Alberta contracted facilities [1]** | | | | | | | | |
| Genesee 1 | 100 | 100 | 97 | 70 | 100 | 100 | 100 | 95 |
| Genesee 2 | 83 | 100 | 96 | 100 | 97 | 100 | 100 | 72 |
| | 92 | 100 | 96 | 85 | 98 | 100 | 100 | 84 |
| **Ontario and British Columbia contracted facilities** | | | | | | | | |
| Island Generation | 100 | 100 | 100 | 100 | 100 | 100 | 92 | 100 |
| York Energy | 100 | 100 | 100 | 100 | N/A | N/A | N/A | N/A |
| East Windsor | 99 | 97 | 99 | 99 | N/A | N/A | N/A | N/A |
| K2 Wind | 98 | 98 | 99 | 100 | 99 | 100 | 98 | 99 |
| Kingsbridge 1 | 98 | 98 | 98 | 95 | 98 | 97 | 95 | 97 |
| Port Dover and Nanticoke | 100 | 96 | 93 | 100 | 98 | 99 | 94 | 100 |
| Quality Wind | 97 | 96 | 91 | 99 | 97 | 97 | 91 | 98 |
| EnPower | 97 | 96 | 95 | 98 | N/A | N/A | N/A | N/A |
| | 99 | 98 | 98 | 99 | 99 | 99 | 93 | 99 |
| **U.S. contracted facilities** | | | | | | | | |
| Roxboro, North Carolina | 88 | 100 | 99 | 100 | 93 | 94 | 100 | 100 |
| Southport, North Carolina | 89 | 99 | 97 | 86 | 92 | 98 | 96 | 92 |
| Decatur Energy, Alabama | 100 | 89 | 100 | 100 | N/A | N/A | N/A | N/A |
| Beaufort Solar, North Carolina | 93 | 97 | 97 | 90 | 97 | 92 | 98 | 91 |
| Bloom Wind, Kansas | 98 | 98 | 97 | 98 | N/A | N/A | N/A | N/A |
| Macho Springs, New Mexico | 97 | 98 | 98 | 96 | 98 | 97 | 97 | 98 |
| | 98 | 92 | 99 | 96 | 94 | 96 | 97 | 95 |

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 | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | **Mar 31 2018** | **Dec 31 2017** | **Sep 30 2017** | **Jun 30 2017** | **Mar 31 2017** | **Dec 31 2016** | **Sep 30 2016** | **Jun 30 2016** |
| **Revenues and other income** | | | | | | | | |
| Alberta commercial facilities and portfolio optimization [1] | 173 | 190 | 160 | 153 | 154 | 172 | 163 | 166 |
| Alberta contracted facilities [1] | 61 | 64 | 61 | 55 | 61 | 65 | 64 | 59 |
| Ontario and British Columbia contracted facilities | 44 | 48 | 31 | 32 | 35 | 33 | 23 | 25 |
| U.S. contracted facilities | 65 | 58 | 77 | 37 | 29 | 29 | 34 | 34 |
| Corporate [2] | 15 | 19 | 14 | 16 | 14 | 11 | 2 | 1 |
| Unrealized changes in fair value of commodity derivatives and emission credits | (51) | (118) | 3 | (92) | 45 | (30) | 88 | (59) |
| | **307** | **261** | **346** | **201** | **338** | **280** | **374** | **226** |
| **Adjusted EBITDA** | | | | | | | | |
| Alberta commercial facilities and portfolio optimization [1] | 55 | 60 | 55 | 55 | 58 | 70 | 74 | 71 |
| Alberta contracted facilities [1] | 45 | 47 | 41 | 37 | 45 | 40 | 38 | 43 |
| Ontario and British Columbia contracted facilities [3] | 53 | 54 | 31 | 40 | 40 | 40 | 21 | 28 |
| U.S. contracted facilities | 35 | 30 | 46 | 10 | 6 | 8 | 11 | 8 |
| Corporate | (15) | (19) | (12) | (17) | (15) | (20) | (24) | (27) |
| Unrealized changes in fair value of commodity derivatives and emission credits | (1) | (18) | (3) | (29) | 9 | 6 | 28 | (15) |
| | **172** | **154** | **158** | **96** | **143** | **144** | **148** | **108** |

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 and foreign exchange derivative contracts.

## Financial highlights

| (unaudited, $ millions except per share amounts) | Three months ended | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | **Mar 31 2018** | **Dec 31 2017** | **Sep 30 2017** | **Jun 30 2017** | **Mar 31 2017** | **Dec 31 2016** | **Sep 30 2016** | **Jun 30 2016** |
| Revenues and other income | 307 | 261 | 346 | 201 | 338 | 280 | 374 | 226 |
| Adjusted EBITDA [1,2] | 172 | 154 | 158 | 96 | 143 | 144 | 148 | 108 |
| Net income (loss) | 41 | (13) | (7) | 107 | 47 | 26 | 64 | 20 |
| Net income (loss) attributable to shareholders of the Company | 43 | (10) | (5) | 109 | 50 | 28 | 66 | 23 |
| Basic earnings (loss) per share ($) | 0.32 | (0.20) | (0.13) | 1.03 | 0.44 | 0.21 | 0.63 | 0.19 |
| Normalized earnings per share ($) [1] | 0.30 | 0.24 | 0.28 | 0.27 | 0.34 | 0.27 | 0.31 | 0.30 |
| Net cash flows from operating activities | 143 | 75 | 120 | 78 | 99 | 69 | 105 | 70 |
| Adjusted funds from operations [1,3] | 85 | 94 | 135 | 44 | 88 | 53 | 76 | 75 |
| Adjusted funds from operations per share ($)[1] | 0.82 | 0.90 | 1.30 | 0.45 | 0.91 | 0.55 | 0.79 | 0.78 |
| Purchase of property, plant and equipment and other assets | 40 | 42 | 28 | 63 | 85 | 174 | 27 | 81 |

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** | **Mar 31 2018** | **Dec 31 2017** | **Sep 30 2017** | **Jun 30 2017** | **Mar 31 2017** | **Dec 31 2016** | **Sep 30 2016** | **Jun 30 2016** |
| Alberta power ($ per MWh) | 35 | 22 | 25 | 19 | 22 | 22 | 18 | 15 |
| Alberta natural gas (AECO) ($ per Gj) | 1.99 | 1.73 | 1.34 | 2.62 | 2.56 | 2.97 | 2.14 | 1.34 |
| **Capital Power's Alberta portfolio average realized power price ($ per MWh)** | 47 | 46 | 49 | 52 | 55 | 67 | 70 | 61 |

## 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 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 continued to reflect 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.

The results for the third quarter of 2016 reflected strong portfolio results as the portfolio was fully hedged at an average realized price of $70 per MWh compared with $61 per MWh in the third quarter of 2015. The spot price average in the third quarter of 2016 was $18 per MWh compared with $26 per MWh in the third quarter of 2015. Because of the lower spot price in 2016 compared with 2015, the portfolio results in the third quarter of 2016 were partially offset by lower revenues from the Alberta commercial and Alberta contracted facilities. Although the Company's portfolio realized higher power prices in the third quarter of 2016, portfolio optimization revenues were lower compared with the same period in 2015 as the Company secured a portion of commercial production for the third quarter of 2015 in June 2015, when forward rates increased temporarily during that month. In the third quarter of 2016, the Alberta energy portfolio recognized unrealized gains of $32 million compared with unrealized gains of $26 million in the third quarter of 2015. The Company also recognized a pre-tax impairment loss of $6 million related to the Southport cash generating unit.

The results for the second quarter of 2016 reflected strong portfolio results as the portfolio was fully hedged at an average realized price of $61 per MWh compared with $46 per MWh in the second quarter of 2015. The spot price average in the second quarter of 2016 was $15 per MWh compared with $57 per MWh in the second quarter of 2015. Because of the lower spot price in 2016 compared with 2015, the portfolio results in the second quarter of 2016 were partially offset by lower revenues from the Alberta commercial and Alberta contracted facilities. In the second quarter of 2016, the Alberta energy portfolio recognized unrealized losses of $29 million compared with unrealized losses of $46 million in the second quarter of 2015. Partially offsetting those unrealized losses in 2016 were unrealized gains on natural gas derivatives of $15 million due to reversals of previously unrealized net losses. There were no such gains reported in 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 | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | **Mar 31 2018** | **Dec 31 2017** | **Sep 30 2017** | **Jun 30 2017** | **Mar 31 2017** | **Dec 31 2016** | **Sep 30 2016** | **Jun 30 2016** |
| **Share price ($/common share)** | | | | | | | | |
| High | 25.14 | 25.59 | 26.51 | 26.14 | 26.43 | 24.49 | 22.16 | 20.23 |
| Low | 22.15 | 23.26 | 23.81 | 24.05 | 23.15 | 19.90 | 18.95 | 17.31 |
| Close | 24.24 | 24.49 | 24.67 | 24.32 | 26.06 | 23.23 | 20.62 | 19.28 |
| **Volume of shares traded (millions)** | 14.0 | 16.9 | 14.1 | 14.8 | 17.0 | 23.2 | 16.0 | 14.8 |

### Outstanding share and partnership unit data

As at April 24, 2018, the Company had 103.299 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 April 24, 2018 were 107.442 million. The outstanding special limited voting share is held by EPCOR.

As at April 24, 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)
Three months ended March 31, 2018 and 2017

# CAPITAL POWER CORPORATION

Condensed Interim Consolidated Financial Statements
Three months ended March 31, 2018 and 2017

**Condensed Interim Consolidated Financial Statements:**


| | |
|---|---|
| Condensed Interim Consolidated Statements of Income | 42 |
| Condensed Interim Consolidated Statements of Comprehensive Income | 43 |
| Condensed Interim Consolidated Statements of Financial Position | 44 |
| Condensed Interim Consolidated Statements of Changes in Equity | 45 |
| Condensed Interim Consolidated Statements of Cash Flows | 47 |
| Notes to the Condensed Interim Consolidated Financial Statements | 48 |

# CAPITAL POWER CORPORATION

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

| | Three months ended March 31, 2018 | 2017 |
|---|---|---|
| Revenues | $ 280 | $ 322 |
| Other income | 27 | 16 |
| Energy purchases and fuel | (64) | (131) |
| **Gross margin** | 243 | 207 |
| Other raw materials and operating charges | (32) | (23) |
| Staff costs and employee benefits expense | (34) | (34) |
| Depreciation and amortization | (75) | (60) |
| Other administrative expenses | (23) | (20) |
| Foreign exchange gain | 3 | 2 |
| **Operating income** | 82 | 72 |
| Net finance expense | (33) | (20) |
| Income from joint ventures | 11 | 10 |
| **Income before tax** | 60 | 62 |
| Income tax expense (note 5) | (19) | (15) |
| **Net income** | $ 41 | $ 47 |
| **Attributable to:** | | |
| Non-controlling interest | $ (2) | $ (3) |
| Shareholders of the Company | $ 43 | $ 50 |

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

| | 2018 | 2017 |
|---|---|---|
| Basic (note 6) | $ 0.32 | $ 0.44 |
| Diluted (note 6) | $ 0.32 | $ 0.43 |

See accompanying notes to the condensed interim consolidated financial statements

# CAPITAL POWER CORPORATION

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

| | Three months ended March 31, 2018 | Three months ended March 31, 2017 |
|---|---|---|
| **Net income** | $ 41 | $ 47 |
| | | |
| **Other comprehensive (loss) income:** | | |
| **Items that are or may be reclassified subsequently to net income:** | | |
| Cash flow hedges: | | |
| Unrealized (losses) gains on derivative instruments[1] | (13) | 23 |
| Unrealized losses on derivative instruments – joint ventures[2] | - | (1) |
| Reclassification of gains on derivative instruments to net income for the period[3] | (8) | (17) |
| Reclassification of losses on derivative instruments to net income for the period – joint ventures[4] | - | 1 |
| Net investment in foreign subsidiaries: | | |
| Unrealized gains (losses)[5] | 11 | (2) |
| Total items that are or may be reclassified subsequently to net income, net of tax | (10) | 4 |
| Total other comprehensive (loss) income, net of tax | (10) | 4 |
| | | |
| **Total comprehensive income** | $ 31 | $ 51 |
| | | |
| **Attributable to:** | | |
| Non-controlling interest | $ (2) | $ (3) |
| Shareholders of the Company | $ 33 | $ 54 |

[1] For the three months ended March 31, 2018 and 2017, net of income tax recovery of $5 and income tax expense of $9, respectively.

[2] For the three months ended March 31, 2018 and 2017, net of income tax recovery of nil.

[3] For the three months ended March 31, 2018 and 2017, net of reclassification of income tax expense of $3 and $6, respectively.

[4] For the three months ended March 31, 2018 and 2017, net of reclassification of income tax recovery of nil.

[5] For the three months ended March 31, 2018 and 2017, net of income tax of nil.

See accompanying notes to the condensed interim consolidated financial statements

# CAPITAL POWER CORPORATION

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

| | March 31, 2018 | December 31, 2017 |
|---|---|---|
| Assets | | |
| Current assets: | | |
| Cash and cash equivalents | $ 48 | $ 52 |
| Trade and other receivables | 263 | 278 |
| Inventories | 136 | 120 |
| Derivative financial instruments assets (note 7) | 56 | 92 |
| | 503 | 542 |
| Non-current assets: | | |
| Other assets | 63 | 68 |
| Derivative financial instruments assets (note 7) | 84 | 79 |
| Finance lease receivables | 638 | 644 |
| Government grant receivable | 497 | 493 |
| Deferred tax assets | 71 | 74 |
| Equity-accounted investments | 181 | 184 |
| Intangible assets | 373 | 401 |
| Property, plant and equipment | 4,362 | 4,378 |
| Goodwill | 35 | 35 |
| Total assets | $ 6,807 | $ 6,898 |
| Liabilities and equity | | |
| Current liabilities: | | |
| Trade and other payables | $ 206 | $ 216 |
| Derivative financial instruments liabilities (note 7) | 111 | 86 |
| Loans and borrowings | 325 | 239 |
| Deferred revenue and other liabilities | 64 | 58 |
| Provisions | 32 | 37 |
| | 738 | 636 |
| Non-current liabilities: | | |
| Derivative financial instruments liabilities (note 7) | 64 | 56 |
| Loans and borrowings | 1,758 | 1,907 |
| Finance lease obligation | 17 | 17 |
| Deferred revenue and other liabilities | 612 | 581 |
| Deferred tax liabilities | 364 | 374 |
| Provisions | 263 | 265 |
| | 3,078 | 3,200 |
| Equity: | | |
| Equity attributable to shareholders of the Company | | |
| Share capital (note 8) | 3,246 | 3,262 |
| Deficit | (224) | (181) |
| Other reserves | (77) | (67) |
| Deficit and other reserves | (301) | (248) |
| | 2,945 | 3,014 |
| Non-controlling interest | 46 | 48 |
| Total equity | 2,991 | 3,062 |
| Total liabilities and equity | $ 6,807 | $ 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 | - | - | - | - | - | 43 | 43 | (2) | 41 |
| Other comprehensive (loss) income: | | | | | | | | | |
| Cash flow derivative hedge losses | - | (18) | - | - | - | - | (18) | - | (18) |
| Reclassification of gains to net income | - | (11) | - | - | - | - | (11) | - | (11) |
| Unrealized gain on foreign currency translation | - | - | 11 | - | - | - | 11 | - | 11 |
| Tax on items recognized directly in equity | - | 8 | - | - | - | - | 8 | - | 8 |
| Other comprehensive (loss) income | $ - | $ (21) | $ 11 | $ - | $ - | $ - | $ (10) | $ - | $ (10) |
| Total comprehensive (loss) income | - | (21) | 11 | - | - | 43 | 33 | (2) | 31 |
| Common share dividends (note 8) | - | - | - | - | - | (43) | (43) | - | (43) |
| Preferred share dividends (note 8) | - | - | - | - | - | (10) | (10) | - | (10) |
| Common shares purchased (note 8) | (17) | - | - | - | - | - | (17) | - | (17) |
| Share options exercised | 1 | - | - | - | - | - | 1 | - | 1 |
| Equity as at March 31, 2018 | $ 3,246 | $ (60) | $ (16) | $ (11) | $ 10 | $ (224) | $ 2,945 | $ 46 | $ 2,991 |

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

See accompanying notes to the condensed interim consolidated financial statements

# CAPITAL POWER CORPORATION

Condensed Interim Consolidated Statements of 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 | - | - | - | - | - | 50 | 50 | (3) | 47 |
| Other comprehensive income (loss): | | | | | | | | | |
| Cash flow derivative hedge gains | - | 32 | - | - | - | - | 32 | - | 32 |
| Cash flow derivative hedge losses – joint venture | - | (1) | - | - | - | - | (1) | - | (1) |
| Reclassification of gains to net income | - | (23) | - | - | - | - | (23) | - | (23) |
| Reclassification of losses to net income – joint venture | - | 1 | - | - | - | - | 1 | - | 1 |
| Unrealized loss on foreign currency translation | - | - | (2) | - | - | - | (2) | - | (2) |
| Tax on items recognized directly in equity | - | (3) | - | - | - | - | (3) | - | (3) |
| Other comprehensive income (loss) | $ - | $ 6 | $ (2) | $ - | $ - | $ - | $ 4 | $ - | $ 4 |
| Total comprehensive income (loss) | - | 6 | (2) | - | - | 50 | 54 | (3) | 51 |
| Common share dividends (note 8) | - | - | - | - | - | (38) | (38) | - | (38) |
| Preferred share dividends (note 8) | - | - | - | - | - | (8) | (8) | - | (8) |
| Share-based payments | - | - | - | - | (1) | - | (1) | - | (1) |
| Share options exercised | 13 | - | - | - | - | - | 13 | - | 13 |
| Equity as at March 31, 2017 | $ 2,931 | $ 28 | $ 24 | $ (10) | $ 10 | $ (120) | $ 2,863 | $ 55 | $ 2,918 |

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

See accompanying notes to the condensed interim consolidated financial statements

# CAPITAL POWER CORPORATION

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

| | Three months ended March 31, 2018 | 2017 |
|---|---|---|
| **Cash flows from operating activities:** | | |
| Net income | $ 41 | $ 47 |
| Non-cash adjustments to reconcile net income to net cash flows from operating activities: | | |
| Depreciation and amortization | 75 | 60 |
| Net finance expense | 33 | 20 |
| Fair value changes on commodity derivative instruments and emission credits held for trading | - | (9) |
| Foreign exchange gain | (3) | (3) |
| Income tax expense | 19 | 15 |
| Income from joint ventures | (11) | (10) |
| Reduction in finance lease receivable | 6 | 5 |
| Recognition of government grant deferred revenue | (13) | (13) |
| Other items | (12) | 2 |
| Change in fair value of derivative instruments reflected as cash settlement | 9 | (2) |
| Distributions received from joint ventures | 13 | 8 |
| Interest paid[1] | (25) | (14) |
| Other cash items | (5) | (5) |
| Change in non-cash operating working capital | 16 | (2) |
| Net cash flows from operating activities | 143 | 99 |
| **Cash flows used in investing activities:** | | |
| Purchase of property, plant and equipment and other assets | (40) | (85) |
| Genesee Coal Mine prepayment | - | (70) |
| Other cash flows from investing activities | 3 | 5 |
| Change in non-cash investing working capital | 7 | (48) |
| Net cash flows used in investing activities | (30) | (198) |
| **Cash flows (used in) from financing activities:** | | |
| Proceeds from issue of loans and borrowings | 95 | 103 |
| Repayment of loans and borrowings | (168) | (3) |
| Realized gain on settlement of foreign currency derivative instruments | 33 | - |
| Proceeds from exercise of share options | 1 | 13 |
| Common shares purchased (note 8) | (17) | - |
| Dividends paid (note 8) | (53) | (46) |
| Capitalized interest paid[1] | (1) | (3) |
| Income taxes paid | (8) | (4) |
| Net cash flows (used in) from financing activities | (118) | 60 |
| Foreign exchange gain on cash held in a foreign currency | 1 | 6 |
| Net decrease in cash and cash equivalents | (4) | (33) |
| Cash and cash equivalents at beginning of period | 52 | 98 |
| Cash and cash equivalents at end of period | $ 48 | $ 65 |

[1] Total interest paid.

See accompanying notes to the condensed interim consolidated financial statement

**1. Reporting entity:**

Capital Power Corporation (the Company or Capital Power) develops, acquires, owns, and operates power generation 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”.

**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 April 27, 2018.

**3. Changes in significant accounting policies:**

Effective January 1, 2018, the Company has 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 of revenues 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 10.

(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*

**Disaggregation of revenues**

| 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 revenues 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 revenues from the U.S. Contracted facilities that are managed under power purchase arrangements (PPAs) determined to be leases are accounted for under IAS 17 – Leases and therefore are excluded from the scope of IFRS 15. In addition, Bloom Wind contains a revenue swap arrangement that is accounted for under IFRS 9 – Financial Instruments which is also excluded from 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 March 31, 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 in 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 months ended March 31, 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 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.

## 3. Changes in significant accounting policies, continued:

*IFRS 9 – Financial Instruments, continued*

**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.

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 March 31, 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 March 31, 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.

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

**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 assets and liabilities for all leases, which will require the Company to recognize a leased asset and leased obligation for all leases. IFRS 16 is effective for annual periods beginning on or after January 1, 2019. The standard will require the Company to recognize leased assets and leased obligations with respect to leases previously classified as operating leases which include office space leases and land leases. 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. Management is currently assessing the transition options for the adoption of IFRS 16.

**5. Income tax:**

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

| | Three months ended March 31, 2018 | 2017 |
|---|---|---|
| Net Income before tax | $ 60 | $ 62 |
| Income tax at the statutory rate of 27% | 16 | 17 |
| Increase (decrease) resulting from: | | |
| Non-deductible (taxable) amounts | (6) | (1) |
| Amounts attributable to non-controlling interest and tax-equity interests | 4 | 1 |
| Statutory and other rate differences | 4 | (1) |
| Change in unrecognized tax benefits | - | (1) |
| Other | 1 | - |
| Income tax expense | $ 19 | $ 15 |

**6. Earnings per share:**

**Basic earnings per share**

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

| | Three months ended March 31, 2018 | 2017 |
|---|---|---|
| Income for the period attributable to shareholders of the Company | $ 43 | $ 50 |
| Preferred share dividends of the Company[1] | (10) | (8) |
| Earnings used in the calculation of basic earnings per share | $ 33 | $ 42 |

[1] Includes preferred share dividends declared in respect of the current periods and related taxes.

| | Three months ended March 31, 2018 | 2017 |
|---|---|---|
| Weighted average number of common shares used in the calculation of basic earnings per share | 104,169,516 | 96,312,118 |

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

**6. Earnings per share, continued:**

**Diluted earnings per share**

The earnings used in the calculation of diluted earnings per share does not differ from the earnings used in the calculation of basic earnings per share for the three months ended March 31, 2018 and 2017. The weighted average number of common shares for the purposes of diluted earnings per share reconciles to the weighted average number of common shares used in the calculation of basic earnings per share as follows:

| | Three months ended March 31, 2018 | 2017 |
|---|---|---|
| Weighted average number of common shares used in the calculation of basic earnings per share | 104,169,516 | 96,312,118 |
| Effect of dilutive share purchase options[2] | 260,145 | 380,970 |
| Weighted average number of common shares used in the calculation of diluted earnings per share | 104,429,661 | 96,693,088 |

[2] For the three months ended March 31, 2018, the average market price of the Company's common shares exceeded the exercise price of certain granted share purchase options, but had a neutral effect on earnings per share. For the three months ended March 31, 2017, the average market price of the Company's common shares was above the exercise price of the granted share purchase options and had a dilutive impact on earnings per share.

**7. Derivative financial instruments and hedge accounting:**

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

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

| | March 31, 2018 | | | |
|---|---|---|---|---|
| | Energy and emission allowances | | Foreign exchange | |
| | cash flow hedges | non-hedges | non-hedges | Total |
| Derivative instruments assets: | | | | |
| Current | $ 2 | $ 54 | $ - | $ 56 |
| Non-current | 4 | 78 | 2 | 84 |
| Derivative instruments liabilities: | | | | |
| Current | (34) | (77) | - | (111) |
| Non-current | (11) | (53) | - | (64) |
| Net fair value | $ (39) | $ 2 | $ 2 | $ (35) |
| Net notional buys (sells) (millions): | | | | |
| Megawatt hours of electricity | (7) | (11) | | |
| Gigajoules of natural gas | | 3 | | |
| Metric tons of emission allowances | | 2 | | |
| Number of renewable energy credits | | (11) | | |
| Forward currency buys (U.S. dollars) | | | $ 133 | |
| Range of remaining contract terms in years | 0.1 to 4.8 | 0.1 to 12.9 | 1.1 to 1.6 | |

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

**7. 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 allowance | | 1 | | |
| Number of renewable energy credits | | (6) | | |
| Cross currency interest rate swaps (U.S. dollars) [1] | | | $ 195 | |
| Forward currency sales (U.S. dollars) [1] | | | $ (80) | |
| Range of remaining contract terms in years[2] | 0.1 to 4.0 | 0.1 to 13.2 | 1.4 to 1.9 | |

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

[2] 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 values will differ from future outcomes and the impact of such variations could be material.

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

| | Three months ended March 31, 2018 | | Three months ended March 31, 2017 | |
|---|---|---|---|---|
| | Unrealized (losses) gains | Realized gains | Unrealized gains (losses) | Realized gains |
| Energy cash flow hedges | $ (29) | $ 11 | $ 11 | $ 23 |
| Energy and emission allowances non-hedges | 5 | 22 | 9 | 13 |
| Foreign exchange cash flow hedges[3] | - | - | (2) | - |
| Foreign exchange non-hedges | (30) | 33 | - | - |

[3] For the three months ended March 31, 2018, unrealized losses of nil (three months ended March 31, 2017 – unrealized losses of $2 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.

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

**7. Derivative financial instruments and hedge accounting, continued:**

Realized gains and losses relate only to derivative financial instruments. The following realized and unrealized gains and losses are included in the Company's statements of income for the three months ended March 31, 2018 and 2017:

| | Three months ended March 31, 2018 | 2017 |
|---|---|---|
| Revenues | $ 11 | $ 110 |
| Energy purchases and fuel | 27 | (65) |
| Foreign exchange gain (loss) | 3 | (1) |

The Company has elected to apply hedge accounting on certain derivatives it uses to manage commodity price risk relating to electricity prices and during the comparative period to manage currency risk relating to U.S. dollar denominated loans and borrowings. For the three months ended March 31, 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 months ended March 31, 2017 – gain of $1 million recorded to foreign exchange gain).

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:

| | March 31, 2018 |
|---|---|
| Within one year | $ (48) |
| Between 1 – 5 years | (4) |
| After more than 5 years | 10 |
| | $ (42) |

**8. Share capital:**

| | Dividends declared | | | | Dividends paid | | | |
|---|---|---|---|---|---|---|---|---|
| | 2018 | | 2017 | | 2018 | | 2017 | |
| | Per share | Total | Per share | Total | Per share | Total | Per share | Total |
| Common | $ 0.4175 | $43 | $ 0.3900 | $ 38 | $ 0.4175 | $ 43 | $ 0.3900 | $ 38 |
| Preference, Series 1 | 0.1913 | 1 | 0.1913 | 1 | 0.1913 | 1 | 0.1913 | 1 |
| Preference, Series 3 | 0.2875 | 2 | 0.2875 | 2 | 0.2875 | 2 | 0.2875 | 2 |
| Preference, Series 5 | 0.2813 | 2 | 0.2813 | 2 | 0.2813 | 2 | 0.2813 | 2 |
| Preference, Series 7 | 0.3750 | 3 | 0.3750 | 3 | 0.3750 | 3 | 0.3750 | 3 |
| Preference, Series 9 | 0.3594 | 2 | - | - | 0.3594 | 2 | - | - |

During the three months ended March 31, 2018, the Company purchased and canceled 713,100 of its outstanding common shares for a total of $17 million (three months ended March 31, 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)

## 9. Financial instruments:

### Fair values

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

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 these 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:

| | | March 31, 2018 | | December 31, 2017 | |
|---|---|---|---|---|---|
| | Fair value hierarchy level | Carrying amount[1] | Fair value | Carrying amount[1] | Fair value |
| Other financial assets[2] | Level 2 | $ 3 | $ 3 | $ 4 | $ 4 |
| Finance lease receivables | Level 2 | 661 | 737 | 667 | 757 |
| Government grant receivable | Level 2 | 548 | 548 | 544 | 544 |
| Loans and borrowings | Level 2 | 2,083 | 2,123 | 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.

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

**9. Financial instruments, continued:**

**Fair value hierarchy, continued**

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 of change in circumstances that caused the transfer. The transfers between levels in the fair value hierarchy for the three months ended March 31, 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.

| | March 31, 2018 | | | |
|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Total |
| Derivative financial instruments assets | $ - | $ 107 | $ 33 | $ 140 |
| Derivative financial instruments liabilities | - | (175) | - | (175) |

| | 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*

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. As forward market prices are not available for the full period of this contract, its fair value is derived using a forecast based on internal modelling. Accordingly, this financial instrument is classified as Level 3.

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. As forward market prices are not available for the full period of this contract, its fair value is derived using a forecast based on internal modelling. Accordingly, this financial instrument is classified as Level 3.

In addition, as at March 31, 2018 and December 31, 2017, the Company holds a contract for the sale of renewable energy credits (RECs) for which pricing beyond two years is not readily observable and is 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.

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

**9. Financial instruments, continued:**

**Fair value hierarchy, continued**

*Valuation techniques used in determination of fair values within Level 3, continued*

The table below presents ranges for the Company's Level 3 inputs:

| | March 31, 2018 | December 31, 2017 |
|---|---|---|
| REC pricing (per certificate) | $ 0.90 | $0.80 to $0.86 |
| Power pricing (per MWh) – Bloom Wind | $18.86 to $30.83 | $16.75 to $31.91 |
| Power pricing (per MWh) – New Frontier Wind | $19.49 to $37.59 | $18.98 to $35.64 |

*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 internal 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:

| | March 31, 2018 | December 31, 2017 |
|---|---|---|
| REC pricing[1] | $ 1 | $ 1 |
| Power pricing[1] - Bloom Wind | $ 8 | $ 8 |
| Power pricing[1] - New Frontier Wind | $ 4 | $ 4 |

[1] 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:

| | Three months ended March 31, 2018 | Year ended December 31, 2017 |
|---|---|---|
| As at January 1[1] | $ 30 | $ (10) |
| Unrealized and realized gains included in net income[2] | 4 | 8 |
| Unrealized and realized gains included in other comprehensive (loss) income | 1 | 32 |
| Settlements[3] | - | 2 |
| Transfers[4] | (2) | (2) |
| As at end of period | $ 33 | $ 30 |
| Total unrealized gains for the period included in other comprehensive (loss) income | $ 1 | $ 32 |
| Total unrealized gains for the period included in net income[2] | $ 4 | $ 10 |

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

[2] Gains are recorded in revenues.

[3] Relates to settlement of financial derivative instruments.

[4] Relates to transfers from Level 3 to Level 2 when pricing inputs became readily observable.

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

**9. Financial instruments, continued:**

**Fair value hierarchy, continued**

*Continuity of Level 3 balances, continued*

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.

**10. Segment information:**

The Company operates in one reportable business segment involved in the operation of electrical generation facilities within Canada (Alberta, British Columbia and Ontario) and in the U.S. (North Carolina, 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 which is under development in North Dakota.

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

| | Three months ended March 31, 2018 | | | | Three months ended March 31, 2017 | | | |
|---|---|---|---|---|---|---|---|---|
| | Canada | U.S. | Inter-area eliminations | Total | Canada | U.S. | Inter-area eliminations | Total |
| Revenues - external | $ 218 | $ 62 | $ - | $ 280 | $ 286 | $ 36 | $ - | $ 322 |
| Revenues - inter-area | 5 | 6 | (11) | - | 9 | 18 | (27) | - |
| Other income | 15 | 12 | - | 27 | 16 | - | - | 16 |
| Total revenues and other income | $ 238 | $ 80 | $ (11) | $ 307 | $ 311 | $ 54 | $ (27) | $ 338 |

| | As at March 31, 2018 | | | As at December 31, 2017 | | |
|---|---|---|---|---|---|---|
| | Canada | U.S. | Total | Canada | U.S. | Total |
| Property, plant and equipment | $ 3,435 | $ 927 | $ 4,362 | $ 3,465 | $ 913 | $ 4,378 |
| Intangible assets | 279 | 94 | 373 | 309 | 92 | 401 |
| Goodwill | 35 | - | 35 | 35 | - | 35 |
| Other assets | 62 | 1 | 63 | 67 | 1 | 68 |
| | $ 3,811 | $ 1,022 | $ 4,833 | $ 3,876 | $1,006 | $ 4,882 |

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

**10. Segment information, continued**:

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

| | Three months ended March 31, 2018 | | | | | | |
|---|---|---|---|---|---|---|---|
| | Alberta Commercial | Alberta Contracted | Ontario and British Columbia Contracted | U.S. Contracted | Total from contracts with customers | Other sources | Total |
| Energy revenues | $ 104 | $ 1 | $ 1 | $ 20 | $ 126 | $ 132 | $ 258 |
| Emission credit revenues | 8 | - | - | 1 | 9 | 13 | 22 |
| Total revenues[1] | $ 112 | $ 1 | $ 1 | $ 21 | $ 135 | $ 145 | $ 280 |

[1] Included within trade and other receivables, as at March 31, 2018, were amounts related to contracts with customers of $55 million.

**11. Subsequent event**:

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.