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

For release: July 26, 2017

Capital Power reports second quarter 2017 results and announces a 7.1% dividend increase for its common shares

Company also extends its 7% annual dividend growth guidance out to 2020

EDMONTON, Alberta – Capital Power Corporation (Capital Power, or the Company) (TSX: CPX) today released financial results for the second quarter ended June 30, 2017.

Net income attributable to shareholders in the second quarter of 2017 was $109 million and basic earnings per share attributable to common shareholders was $1.03 per share, compared with $23 million, or $0.19 per share, in the comparable period of 2016. Normalized earnings attributable to common shareholders in the second quarter of 2017, after adjusting for non-recurring items and fair value adjustments, were $26 million or $0.27 per share compared with $29 million or $0.30 per share in the second quarter of 2016.

Net cash flows from operating activities were $78 million in the second quarter of 2017 compared with $70 million in the second quarter of 2016. Adjusted funds from operations were $47 million in the second quarter of 2017, compared to $79 million in the second quarter of 2016.

For the six months ended June 30, 2017, net income attributable to shareholders was $159 million and basic earnings per share attributable to common shareholders was $1.47 per share compared with $17 million and $0.07 for the six months ended June 30, 2016. For the six months ended June 30, 2017, normalized earnings attributable to common shareholders were $59 million, or $0.61 per share, compared with $61 million, or $0.63 per share, in the first six months of 2016.

Net cash flows from operating activities were $177 million for the six months ended June 30, 2017 compared with $201 million for the six months ended June 30, 2016. Adjusted funds from operations were $138 million for the first six months of 2017, compared to $172 million in the comparable six month period last year.

"Capital Power's financial results for the second quarter of 2017 were in line with management's expectations," said Brian Vaasjo, President and CEO of Capital Power. "Second quarter results benefitted from strong operating performance with average facility availability of 94% and a solid contribution from our portfolio optimization activities. Our trading desk captured an average realized Alberta power price of $52 per megawatt hour (MWh) in the second quarter, well above the average spot price of $19 per MWh."

"In the second quarter, the Company continued to execute on its growth strategy by adding nearly 1,300 megawatts of contracted generation through the acquisitions of Veresen Inc.'s thermal power business and the Decatur Energy Center, in addition to the start of commercial operations for our Bloom Wind project. Construction costs for Bloom Wind were under budget and the project was completed one month ahead of schedule. The addition of these six facilities has materially increased the Company's contracted cash flows and has further diversified the generation fleet throughout North America," stated Mr. Vaasjo.

"Based on Capital Power's outlook and consistent with our 7% annual dividend growth guidance for 2017, I am pleased to announce that the Board of Directors has approved a 7.1% or $0.11 per common share dividend increase that increases the annualized dividend to $1.67 per share effective for the third quarter 2017 quarterly dividend payment," continued Mr. Vaasjo. "With the recent additions to our fleet that have strengthened our contracted cash flow profile, we are extending our current 7% annual dividend growth guidance for 2018 by an additional two years to the end of 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."

Operational and Financial Highlights [1] (unaudited)	**Three months ended June 30**		**Six months ended June 30**	
(millions of dollars except per share and operational amounts)	**2017**	**2016**	**2017**	**2016**
Electricity generation (excluding Sundance C power purchase arrangement (Sundance PPA)) (Gigawatt hours)	3,674	3,707	7,636	7,605
Generation facility availability (excluding Sundance PPA)	94%	90%	96%	93%
Revenues and other income	$ 201	$ 226	$ 539	$ 560
Adjusted EBITDA [2]	$ 96	$ 108	$ 239	$ 228
Net income	$ 107	$ 20	$ 154	$ 12
Net income attributable to shareholders of the Company	$ 109	$ 23	$ 159	$ 17
Basic and diluted earnings per share	$ 1.03	$ 0.19	$ 1.47	$ 0.07
Normalized earnings attributable to common shareholders [2]	$ 26	$ 29	$ 59	$ 61
Normalized earnings per share [2]	$ 0.27	$ 0.30	$ 0.61	$ 0.63
Net cash flows from operating activities	$ 78	$ 70	$ 177	$ 201
Adjusted funds from operations [2, 3]	$ 47	$ 79	$ 138	$ 172
Purchase of property, plant and equipment and other assets	$ 63	$ 81	$ 148	$ 112
Dividends per common share, declared	$ 0.3900	$ 0.3650	$ 0.7800	$ 0.7300

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 six months ended June 30, 2017.

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

3 Commencing with the Company's March 31, 2017 quarter-end, 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.

Capital Power and Siksika Resource Developments Limited announce partnership

On July 5, 2017, Capital Power and Siksika Resource Developments Limited (SRDL) entered into an exclusive agreement to jointly develop power projects on the Siksika Nation reserve. The Siksika Nation is located approximately 100 kilometers southeast of Calgary. The Siksika Nation controls one of the largest reserves in Canada comprising 172,000 acres of land with excellent solar, wind and gas projects potential. The location is attractive for the development of power projects given the existing transmission and distribution infrastructure, and ample water.

Capital Power and SRDL expect to develop multiple power projects including both renewable and natural gas-fired technologies. The agreement contemplates Capital Power as the lead developer and operator with both SRDL and Capital Power taking joint ownership positions in projects. The purpose is also to foster economic development and provide socioeconomic benefits to the Siksika Nation and its members such as employment, business opportunities for Siksika Nation owned companies, education, training and support for traditional language and cultural enrichment.

SRDL is a wholly-owned company of the Siksika Nation. It currently operates several enterprises on the Siksika Nation reserve. The Siksika Nation has approximately 6,000 members.

Significant events

Acquisition of Decatur Energy and $183 million public offering

On April 12, 2017, the Company announced that it entered into an agreement to acquire all of the ownership interests in Decatur Power Holdings, LLC, which owns the Decatur Energy Center (Decatur Energy) from an affiliate of LS Power Equity Partners III for $603 million (US$448 million), including working capital and other closing adjustments of $9 million (US$7 million). Decatur Energy is a 795 MW natural gas-fired combined cycle power generation facility located in Decatur, Alabama that operates under a tolling agreement.

Decatur Energy sells capacity and energy to a regional entity under a long-term contract which has an original term of 10 years and expires December 31, 2022. Decatur Energy is well-positioned, given anticipated market conditions, as well as significant remaining useful life, to be re-contracted or to pursue other commercial alternatives at the end of the current long-term contract, including the ability to sell power into the Pennsylvania, New Jersey, and Maryland interconnection market starting in 2023.

Financing of the Decatur Energy acquisition consisted of a combination of debt and equity. On April 24, 2017, the Company announced the completion of its previously announced public offering of 7,375,000 subscription receipts (Subscription Receipts), on a bought deal basis, at an issue price of $24.75 per Subscription Receipt, for total gross proceeds of $183 million less issue costs of $7 million. On June 13, 2017, upon closing of the Decatur Energy acquisition, each Subscription Receipt was converted for one common share of the Company. No dividend record date occurred during the period when the Subscription Receipts were outstanding and as such, no obligations to make any cash dividend equivalent payments were triggered.

The balance of the purchase price was financed through debt utilizing a temporary expansion of Capital Power's credit facilities and is expected to be followed by permanent financing with an issuance of long-term debt later in 2017.

The Decatur Energy acquisition supports the Company's growth strategy and increases the Company's geographical diversification and contracted cash flows. During the first full year of operations, the Decatur Energy acquisition is expected to increase adjusted funds from operations by $43 million and increase adjusted EBITDA by $60 million.

Bloom Wind begins commercial operation

On June 1, 2017, the Company's 178MW Bloom Wind facility commenced commercial operations. On June 12, 2017, the Company received $244 million (US $181 million) in financing from an affiliate of Goldman Sachs in exchange for Class A interests of a subsidiary of the Company. The Company incurred issue costs of $7 million (US$5 million) associated with the financing. Effective July 1, 2017, Bloom Wind will operate under a 10-year proxy revenue swap agreement with Allianz Risk Transfer, a subsidiary of Allianz SE. Under the contract, which was executed on April 21, 2016, Capital Power swaps the market revenue of the project's generation for a fixed annual payment for a 10-year term. The agreement secures long-term predictable revenues and mitigates generation volume uncertainty.

Acquisition of thermal facilities

On February 21, 2017, the Company announced that it entered into an agreement to acquire the thermal power business of Veresen Inc. Under the terms of the agreement, Capital Power acquired 284 MW of generation from two natural gas-fired power assets in Ontario consisting of the 84 MW East Windsor Cogeneration Centre (East Windsor) and a 50% interest in the 400 MW York Energy Centre (York Energy), and operates both facilities. The transaction also includes 10 MW of zero-emissions waste heat generation from two facilities (5 MW each), together known as EnPower Green Energy Generation (EnPower), located at Westcoast Energy's BC Gas Pipeline compressor stations in Savona and 150 Mile House, British Columbia.

On April 13, 2017, the Company announced that it had completed the acquisition of the two natural gas-fired power facilities in Ontario. The purchase price for the natural gas-fired facilities consisted of (i) $235 million in total cash consideration, including working capital and other closing adjustments of $11 million, and (ii) the assumption of $253 million of project level debt (proportionate basis at acquisition date net book value).

On June 1, 2017, the Company completed the acquisition of EnPower. The purchase price consisted of (i) $8 million of total cash consideration, including working capital and other closing adjustments of $3 million, and (ii) the assumption of $18 million of project level debt.

The acquisitions of these facilities support the Company's growth strategy and are consistent with the Company's technology and operating focus. During the first full year of operations, these acquisitions are expected to increase adjusted funds from operations by $24 million and increase adjusted EBITDA by $55 million.

Appointments to the Board of Directors

Effective April 3, 2017, Keith Trent and Katharine Stevenson were appointed to the Capital Power Board of Directors.

Amendment of Genesee Coal Mine Joint Venture Agreement

On March 28, 2017, the Company announced that it entered into an agreement (the Amending Agreement) to amend its Genesee Mine Joint Venture Agreement with Prairie Mines & Royalty ULC (PMRU), a subsidiary of Westmoreland Coal Company, to accelerate the repayment of amounts it would otherwise have owed to PMRU during the term of the agreement and eliminate all future payments to PMRU relating to existing capital assets at the Genesee Coal Mine (Coal Mine). Capital Power will continue to pay PMRU contracted mining fees for PMRU's ongoing operation of the Coal Mine.

By accelerating the $70 million repayment of capital expenditures to PMRU, the transaction will reduce Capital Power's cost of coal for the Genesee facility, and enhance the Company's net income, adjusted EBITDA, net cash flows from operating activities and adjusted funds from operations. These cost reductions were anticipated to take place and have been included in the adjusted funds from operations guidance that was provided as part of the Company's year-end disclosure on February 17, 2017. As a result of the transaction, net cash flows from operating activities are expected to increase by $14 million for 2017. The operations and management of the Coal Mine are unchanged as a result of the Amending Agreement and the Company will continue to control the Coal Mine and treat it as a subsidiary.

Coal for the Genesee facility is supplied by the adjacent Coal Mine under a long-term, cost of service supply agreement. Prior to the Amending Agreement, Capital Power paid PMRU a fee to cover PMRU's depreciation expense and certain other costs, as well as provide a variable rate of return to PMRU. These fees paid to PMRU were included as part of Capital Power's cost of coal for operating the Genesee facility, and will be eliminated with the Amending Agreement.

The cost savings for Capital Power will be magnified through 2030 with the phase-out of coal-fired generation under the Alberta Climate Leadership Plan, which would accelerate the amounts in respect of depreciation that would have been paid to PMRU due to the shortened asset lives.

<u>Subsequent events</u>

Dividend increase

On July 25, 2017, the Company's Board of Directors approved an increase of 7.1% in the annual dividend for holders of its common shares, from $1.56 per common share to $1.67 per common share. This increased common dividend will commence with the third quarter 2017 quarterly dividend payment on October 31, 2017 to shareholders of record at the close of business on September 29, 2017.

Analyst conference call and webcast

Capital Power will be hosting a conference call and live webcast with analysts on July 26, 2017 at 9:00 am (MT) to discuss its second quarter operating and 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) adjusted EBITDA, (ii) adjusted funds from operations, (iii) normalized earnings attributable to common shareholders, and (iv) normalized earnings per share as financial performance measures. These terms are not defined financial measures according to GAAP and do not have standardized meanings prescribed by GAAP, and, therefore, are unlikely to be comparable to similar measures used by other enterprises. These measures should not be considered alternatives to net income, net income attributable to shareholders of the Company, net cash flows from operating activities or other measures of financial performance calculated in accordance with GAAP. Rather, these measures are provided to complement GAAP measures in the analysis of the Company's results of operations from management's perspective. Reconciliations of adjusted EBITDA to net income (loss), adjusted funds from operations to net cash flows from operating activities and normalized earnings attributable to common shareholders to net income (loss) attributable to shareholders of the Company are disclosed below and are discussed further in the Company's Management's Discussion and Analysis, prepared as of July 25, 2017, for the six months ended June 30, 2017 which is available under the Company's profile on SEDAR at www.SEDAR.com.

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							
	Jun 30 2017	**Mar 31 2017**	**Dec 31 2016**	**Sep 30 2016**	**Jun 30 2016**	**Mar 31 2016**	**Dec 31 2015**	**Sep 30 2015**
Revenues and other income	201	338	280	374	226	334	337	466
Energy purchases and fuel, other raw materials and operating charges, staff costs and employee benefits expense, and other administrative expense	(119)	(208)	(148)	(232)	(127)	(225)	(216)	(318)
Adjusted EBITDA from joint ventures [1]	14	13	12	6	9	11	13	6
Adjusted EBITDA	**96**	**143**	**144**	**148**	**108**	**120**	**134**	**154**
Depreciation and amortization	(65)	(60)	(53)	(53)	(54)	(56)	(56)	(53)
Impairment	-	-	-	(6)	-	-	-	-
Losses on termination of power purchase arrangement	-	-	(20)	-	-	(53)	-	-
Foreign exchange gain (loss)	9	2	(4)	3	(1)	8	-	(8)
Net finance expense	(25)	(20)	(24)	(21)	(19)	(22)	(27)	(25)
Finance expense from joint ventures [1]	(2)	(3)	(3)	(3)	(4)	(3)	(3)	(2)
Income tax recovery (expense)	94	(15)	(14)	(4)	(10)	(2)	(14)	(16)
Net income (loss)	**107**	**47**	**26**	**64**	**20**	**(8)**	**34**	**50**
Net income (loss) attributable to:								
Non-controlling interests	(2)	(3)	(2)	(2)	(3)	(2)	(1)	1
Shareholders of the Company	109	50	28	66	23	(6)	35	49
Net income (loss)	**107**	**47**	**26**	**64**	**20**	**(8)**	**34**	**50**

1 Total income from joint ventures as per the Company's consolidated statements of income.

Adjusted funds from operations

Adjusted funds from operations represents net cash flows from operating activities adjusted to include net finance expenses and current income tax expenses and exclude changes in operating working capital and distributions received from the Company's joint venture interests. Net finance expenses and current income tax expenses 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 distribution is calculated after the effect of joint venture debt payments, which are not considered an operating activity. Adjusted funds from operations also exclude 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. The Company includes interest and current income tax expenses excluding Part VI.1 tax recorded during the period rather than interest and income taxes paid. 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.

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

(unaudited, $ millions)	**Three months ended June 30**		**Six months ended June 30**	
	2017	**2016**	**2017**	**2016**
Net cash flows from operating activities per condensed interim consolidated statements of cash flows	**78**	**70**	**177**	**201**
Add (deduct) items included in calculation of net cash flows from operating activities per consolidated statements of cash flows:				
Interest paid	23	23	37	41
Change in fair value of derivatives reflected as cash settlement	(2)	13	-	13
Distributions received from joint ventures	(6)	(3)	(14)	(17)
Miscellaneous financing charges paid [1]	-	-	2	1
Income taxes paid	-	1	-	1
Change in non-cash operating working capital	8	16	10	(3)
	23	50	35	36
Net finance expense [2]	(24)	(17)	(42)	(39)
Current income tax expense	(5)	(2)	(7)	(7)
Decrease in current income tax expense due to Part VI.1 tax	4	2	6	7
Sustaining capital expenditures [3]	(31)	(24)	(35)	(30)
Preferred share dividends paid	(8)	(5)	(16)	(10)
Adjusted funds from operations from joint ventures	10	5	20	14
Adjusted funds from operations	**47**	**79**	**138**	**172**

1 Included in other items of non-cash adjustments to reconcile net income to net cash flows from operating activities.

2 Excludes unrealized changes on interest rate derivative contracts and amortization and accretion charges.

3 Includes sustaining capital expenditures net of joint venture contributions of $2 million and $4 million for the three and six months ended June 30, 2017, respectively, compared with $3 million and $5 million for the three and six months ended June 2016, 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							
	Jun 30 2017	**Mar 31 2017**	**Dec 31 2016**	**Sep 30 2016**	**Jun 30 2016**	**Mar 31 2016**	**Dec 31 2015**	**Sep 30 2015**
Basic earnings (loss) per share ($)	**1.03**	**0.44**	**0.21**	**0.63**	**0.19**	**(0.11)**	**0.29**	**0.44**
Net income (loss) attributable to shareholders of the Company per condensed interim consolidated statements of income (loss)	**109**	**50**	**28**	**66**	**23**	**(6)**	**35**	**49**
Preferred share dividends including Part VI.1 tax	(8)	(8)	(8)	(5)	(5)	(5)	(6)	(5)
Earnings (loss) attributable to common shareholders	101	42	20	61	18	(11)	29	44
Recognition of U.S. deferred tax assets related to non-capital losses	(86)	-	-	-	-	-	-	-
Unrealized changes in fair value of derivatives	23	(7)	(8)	(22)	10	5	11	(19)
Unrealized foreign exchange (gain) loss on revaluation of U.S. dollar denominated debt	(12)	(1)	3	1	1	(8)	1	6
Loss on de-recognition of the Sundance C power purchase arrangement (Sundance PPA)	-	-	-	-	-	46	-	-
Change in unrecognized tax benefits	-	-	-	(27)	-	-	-	-
Settlement of Sundance power purchase arrangement legal action	-	-	15	-	-	-	-	-
Deferred income tax (reduction) expense related to temporary difference on investment in subsidiary	-	-	(1)	13	-	-	-	-
Impairment loss on Southport goodwill	-	-	-	4	-	-	-	-
Success fee received related to development project	-	-	(3)	-	-	-	-	-
Restructuring charges	-	-	-	-	-	-	-	2
Release of tax liability on foreign domiciled investment	-	(1)	-	-	-	-	-	-
Normalized earnings attributable to common shareholders	**26**	**33**	**26**	**30**	**29**	**32**	**41**	**33**
Weighted average number of common shares outstanding (millions)	98.1	96.3	96.1	96.1	96.1	96.4	98.7	100.9
Normalized earnings per share ($)	**0.27**	**0.34**	**0.27**	**0.31**	**0.30**	**0.33**	**0.42**	**0.33**

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: (i) expectations pertaining to the amendment of the Genesee Coal Mine Joint Venture Agreement regarding reduction to Capital Power's cost of coal and expected enhancements to the Company's net income, adjusted EBITDA, net cash flows from operating activities and adjusted funds from operations, (ii) expectations pertaining to the financial impacts of the acquisition of the Veresen thermal facilities including expected impacts to adjusted funds from operations and adjusted EBITDA, and (iii) expectations pertaining to the acquisition of Decatur Energy including: financing plans for the acquisition, financial impacts including expected impacts to adjusted funds from operations and adjusted EBITDA, and re-contracting of the facility.

These statements are based on certain assumptions and analyses made by the Company in light of its experience and perception of historical trends, current conditions, expected future developments and other factors it believes are appropriate. The material factors and assumptions used to develop these forward-looking statements relate to: (i) electricity and other energy 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) acquisitions and developments including timing and costs of regulatory approvals and construction, (vii) changes in market prices and availability of fuel, and (viii) changes in general economic and competitive conditions. See Risks and Risk Management in the Company's Management's Discussion and Analysis for the year ended December 31, 2016, prepared as of February 17, 2017, 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 July 25, 2017, should be read in conjunction with the unaudited condensed interim consolidated financial statements of Capital Power Corporation and its subsidiaries for the six months ended June 30, 2017, the audited consolidated financial statements and MD&A of Capital Power Corporation for the year ended December 31, 2016, the annual information form of Capital Power Corporation dated March 6, 2017, and the cautionary statements regarding forward-looking information which begin on page 11. 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 six months ended June 30, 2017 and the six months ended June 30, 2016 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 July 25, 2017.

Contents

FORWARD-LOOKING INFORMATION

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

Material forward-looking information in this MD&A includes 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,
- facility availability and planned outages,
- capital expenditures for facility maintenance and other (sustaining capital, future growth projects),
- the impact of environmental regulations on the Company, its businesses, accounting policies, and emissions compliance costs,
- the impact of the transition to a capacity market on the Company's future growth projects including the Genesee 4 and 5 project,
- expectations pertaining to the financial impacts of the acquisition of the Veresen thermal facilities (see Significant Events), including expected impacts to adjusted funds from operations and adjusted EBITDA,
- expectations pertaining to the amendment of the Genesee Coal Mine Joint Venture Agreement (see Significant Events) regarding reduction to Capital Power's cost of coal and expected enhancements to the Company's net income, adjusted EBITDA, net cash flows from operating activities and adjusted funds from operations,
- expectations pertaining to the acquisition of Decatur Energy (see Significant Events) regarding: (i) financing plans for the acquisition, (ii) financial impacts including expected impacts to adjusted funds from operations and adjusted EBITDA, and (iii) re-contracting of the facility, 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 including its review of purchased businesses and assets. The material factors and assumptions used to develop these forward-looking statements relate to:

- electricity and other energy prices,
- performance,
- business prospects and opportunities including expected growth and capital projects,
- status of and impact of policy, legislation and regulations,
- effective tax rates,
- other matters discussed under the Performance Overview and Outlook, and
- anticipated performance of the acquired Veresen thermal facilities and Decatur Energy (see Significant Events).

Whether actual results, performance or achievements will conform to the Company's expectations and predictions is subject to a number of known and unknown risks and uncertainties which could cause actual results and experience to differ materially from the Company's expectations. Such material risks and uncertainties are:

- changes in electricity prices in markets in which the Company operates,
- changes in energy commodity market prices and use of derivatives,
- regulatory and political environments including changes to environmental, financial reporting, market structure and tax legislation,
- generation facility availability and performance including maintenance of equipment,
- ability to fund current and future capital and working capital needs,
- acquisitions and developments including timing and costs of regulatory approvals and construction,
- changes in market prices and availability of fuel,
- ability to realize the anticipated benefits of the acquisitions,
- limitations inherent in the Company's review of purchased business and assets, and
- changes in general economic and competitive conditions.

See Risks and Risk Management in the Company's December 31, 2016 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, operates and optimizes power generation from a variety of energy sources. Including the acquisitions of the Ontario natural gas-fired generation assets, EnPower and Decatur Energy (see Significant Events), all of which closed in the second quarter of 2017, Capital Power owns approximately 4,500 megawatts (MW) of power generation capacity across North America. More than 500 MW of owned generation capacity is in advanced development in Alberta.

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 2016 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	2017 target [1]	Actual results for the six months ended June 30, 2017
Facility availability average	95% or greater	96%
Sustaining capital expenditures	$80 million	$34 million [2]
Genesee performance standard [3]	$10 million	$1 million
Facility operating and maintenance expenses	$215 million to $240 million	$104 million

1 The targets presented at the Company's Investor Day in December 2016 were revised to include the expected impacts of the acquisitions of the thermal power business of Veresen Inc. and the Decatur Energy Center for the periods subsequent to the close of those transactions (see Significant Events).

2 Includes sustaining capital expenditures net of joint venture contributions of $4 million.

3 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 Genesee, Shepard, Clover Bar Energy Centre, Kingsbridge 1, Roxboro, Southport and East Windsor. Unplanned outages also occurred at Keephills 3, Southport, Genesee, Joffre, Shepard, Clover Bar Energy Centre and Quality Wind.

Sustaining capital expenditures for the six months ended June 30, 2017 were lower than target for the year to date and the full year expenditures are expected to be below target due largely to lower expected mine capital spending. Expenditures for the Genesee performance standard for the six months ended June 30, 2017 were lower than target for the year to date and are expected to be below target due to reductions in the project scope and the deferral of certain activities into future periods.

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 six months ended June 30, 2017 were lower than target for the year to date but the full year expenditures are expected to be consistent with the target.

Disciplined growth

Performance measure	2017 target	Status as at June 30, 2017
Bloom Wind	Complete Bloom Wind on time and on budget.	Bloom Wind began commercial operations on June 1, 2017 (See Significant Events). Construction was completed ahead of schedule and construction costs were below budget.
New development	Execute contracts for the output of two new developments.	On track with target and are progressing with the Company's development sites.

Financial stability and strength

Performance measure	2017 target [1]	Actual results for the six months ended June 30, 2017
Adjusted funds from operations [2]	$340 million to $385 million	$138 million

1 The target presented at the Company's Investor Day in December 2016 was revised to include the expected impacts of the acquisitions of the thermal power business of Veresen Inc. and the Decatur Energy Center for the periods subsequent to the close of those transactions (see Significant Events).

2 Adjusted funds from operations is a non-GAAP measure. See Non-GAAP Financial Measures. Commencing with the Company's March 31, 2017 quarter-end, adjusted funds from operations will be used as management views this as a better measure of its available cash generated from current operating activities to fund growth capital expenditures, common share dividends and debt repayments for future periods.

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 2016, the Company introduced a new financial metric and provided financial guidance for 2017 adjusted funds from operations (see Non-GAAP Financial Measures) in the range of $305 million to $345 million. This range was subsequently revised as a result of the acquisition of the thermal power business of Veresen Inc. (see Significant Events) to be $320 million to $365 million, which includes the expected results of the acquired assets subsequent to transaction close. With the addition of the Decatur Energy facility (see Significant Events) the projected range for 2017 adjusted funds from operations was increased to $340 million to $385 million. Based on the actual results for the first half of 2017 and the Company's forecast for the remainder of 2017, adjusted funds from operations for the full year is expected to be near the mid-point of the target range.

Priorities for the Company in 2017 will be to efficiently integrate the thermal power facilities acquired from Veresen Inc. and Decatur Energy (see Significant Events), work with the Government of Alberta concerning the transition away from an energy-only market to a capacity market and to work diligently with regulators and other generators in the Province to implement the Carbon Competitiveness Regulation (CCR). The Company will also work to manage its carbon costs by utilizing its credit inventory and by pursuing generation facility modifications. The Company is well positioned to be competitive in the current Renewable Electricity Program procurement process.

In 2017, Capital Power's availability target of 95% reflects major scheduled maintenance outages for Genesee 1, Clover Bar Energy Centre, Southport, Roxboro and Keephills 3 compared to those scheduled for Genesee 2, Genesee 3, Clover Bar Energy Centre, Southport, Roxboro, Joffre and Shepard in 2016.

The Alberta portfolio position, contracted prices and forward Alberta pool prices for 2018, 2019 and 2020, as at June 30, 2017, were:

Alberta commercial portfolio positions and power prices	Full year 2018	Full year 2019	Full year 2020
Percentage of baseload generation sold forward [1]	66%	45%	29%
Contracted price [2]	High-$40 per megawatt hour (MWh)	Low-$50 per MWh	High-$40 per MWh
Forward Alberta pool prices	$45	$46	$47

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

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

The 2017 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, beyond those described in Significant Events, 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 2016, the Company confirmed 7% annual dividend growth guidance for 2017 and 2018. With the recent growth in the Company's contracted cash flows, management has extended this dividend growth guidance to the end of 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.

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 from its joint venture interests, and gains or losses on disposals (adjusted EBITDA), (ii) adjusted funds from operations, (iii) normalized earnings attributable to common shareholders, and (iv) normalized earnings per share as financial performance measures.

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

Adjusted EBITDA

Capital Power uses adjusted EBITDA to measure the operating performance of 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.

Commencing with the Company's March 31, 2016 quarter-end, the reported adjusted EBITDA measure was changed to include Capital Power's share of adjusted EBITDA from its joint venture interests. All comparative adjusted EBITDA amounts for quarters prior to those ended on March 31, 2016 were revised to conform with this change.

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

(unaudited, $ millions)	Three months ended							
	Jun 30 2017	**Mar 31 2017**	**Dec 31 2016**	**Sep 30 2016**	**Jun 30 2016**	**Mar 31 2016**	**Dec 31 2015**	**Sep 30 2015**
Revenues and other income	201	338	280	374	226	334	337	466
Energy purchases and fuel, other raw materials and operating charges, staff costs and employee benefits expense, and other administrative expense	(119)	(208)	(148)	(232)	(127)	(225)	(216)	(318)
Adjusted EBITDA from joint ventures [1]	14	13	12	6	9	11	13	6
Adjusted EBITDA	**96**	**143**	**144**	**148**	**108**	**120**	**134**	**154**
Depreciation and amortization	(65)	(60)	(53)	(53)	(54)	(56)	(56)	(53)
Impairment	-	-	-	(6)	-	-	-	-
Losses on termination of power purchase arrangement	-	-	(20)	-	-	(53)	-	-
Foreign exchange gain (loss)	9	2	(4)	3	(1)	8	-	(8)
Net finance expense	(25)	(20)	(24)	(21)	(19)	(22)	(27)	(25)
Finance expense from joint ventures [1]	(2)	(3)	(3)	(3)	(4)	(3)	(3)	(2)
Income tax recovery (expense)	94	(15)	(14)	(4)	(10)	(2)	(14)	(16)
Net income (loss)	**107**	**47**	**26**	**64**	**20**	**(8)**	**34**	**50**
Net income (loss) attributable to:								
Non-controlling interests	(2)	(3)	(2)	(2)	(3)	(2)	(1)	1
Shareholders of the Company	109	50	28	66	23	(6)	35	49
Net income (loss)	**107**	**47**	**26**	**64**	**20**	**(8)**	**34**	**50**

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

Adjusted funds from operations

Commencing with the Company's March 31, 2017 quarter-end, 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. Previously, the Company used funds from operations as a measure of the Company's ability to generate cash from its current operating activities to fund capital expenditures, debt repayments, dividends to the Company's shareholders and distributions to non-controlling interests.

Adjusted funds from operations represents net cash flows from operating activities adjusted to include net finance expenses and current income tax expenses and exclude changes in operating working capital and distributions received from the Company's joint venture interests. Net finance expenses and current income tax expenses 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 distribution is calculated after the effect of joint venture debt payments, which are not considered an operating activity. Adjusted funds from operations also exclude 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. The Company includes interest and current income tax expenses excluding Part VI.1 tax recorded during the period rather than interest and income taxes paid. 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.

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

(unaudited, $ millions)	**Three months ended June 30**		**Six months ended June 30**	
	2017	**2016**	**2017**	**2016**
Net cash flows from operating activities per condensed interim consolidated statements of cash flows	**78**	**70**	**177**	**201**
Add (deduct) items included in calculation of net cash flows from operating activities per consolidated statements of cash flows:				
Interest paid	23	23	37	41
Change in fair value of derivatives reflected as cash settlement	(2)	13	-	13
Distributions received from joint ventures	(6)	(3)	(14)	(17)
Miscellaneous financing charges paid [1]	-	-	2	1
Income taxes paid	-	1	-	1
Change in non-cash operating working capital	8	16	10	(3)
	23	50	35	36
Net finance expense [2]	(24)	(17)	(42)	(39)
Current income tax expense	(5)	(2)	(7)	(7)
Decrease in current income tax expense due to Part VI.1 tax	4	2	6	7
Sustaining capital expenditures [3]	(31)	(24)	(35)	(30)
Preferred share dividends paid	(8)	(5)	(16)	(10)
Adjusted funds from operations from joint ventures	10	5	20	14
Adjusted funds from operations	**47**	**79**	**138**	**172**

1 Included in other items of non-cash adjustments to reconcile net income to net cash flows from operating activities.

2 Excludes unrealized changes on interest rate derivative contracts and amortization and accretion charges.

3 Includes Genesee performance standard expenditures and sustaining capital expenditures net of joint venture contributions of $2 million and $4 million for the three and six months ended June 30, 2017, respectively, compared with $3 million and $5 million for the three and six months ended June 2016, 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							
	Jun 30 2017	**Mar 31 2017**	**Dec 31 2016**	**Sep 30 2016**	**Jun 30 2016**	**Mar 31 2016**	**Dec 31 2015**	**Sep 30 2015**
Basic earnings (loss) per share ($)	**1.03**	**0.44**	**0.21**	**0.63**	**0.19**	**(0.11)**	**0.29**	**0.44**
Net income (loss) attributable to shareholders of the Company per condensed interim consolidated statements of income (loss)	**109**	**50**	**28**	**66**	**23**	**(6)**	**35**	**49**
Preferred share dividends including Part VI.1 tax	(8)	(8)	(8)	(5)	(5)	(5)	(6)	(5)
Earnings (loss) attributable to common shareholders	101	42	20	61	18	(11)	29	44
Recognition of U.S. deferred tax assets related to non-capital losses	(86)	-	-	-	-	-	-	-
Unrealized changes in fair value of derivatives	23	(7)	(8)	(22)	10	5	11	(19)
Unrealized foreign exchange (gain) loss on revaluation of U.S. dollar denominated debt	(12)	(1)	3	1	1	(8)	1	6
Loss on de-recognition of the Sundance C power purchase arrangement (Sundance PPA)	-	-	-	-	-	46	-	-
Change in unrecognized tax benefits	-	-	-	(27)	-	-	-	-
Settlement of Sundance power purchase arrangement legal action	-	-	15	-	-	-	-	-
Deferred income tax (reduction) expense related to temporary difference on investment in subsidiary	-	-	(1)	13	-	-	-	-
Impairment loss on Southport goodwill	-	-	-	4	-	-	-	-
Success fee received related to development project	-	-	(3)	-	-	-	-	-
Restructuring charges	-	-	-	-	-	-	-	2
Release of tax liability on foreign domiciled investment	-	(1)	-	-	-	-	-	-
Normalized earnings attributable to common shareholders	**26**	**33**	**26**	**30**	**29**	**32**	**41**	**33**
Weighted average number of common shares outstanding (millions)	98.1	96.3	96.1	96.1	96.1	96.4	98.7	100.9
Normalized earnings per share ($)	**0.27**	**0.34**	**0.27**	**0.31**	**0.30**	**0.33**	**0.42**	**0.33**

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 June 30		Six months ended June 30	
	2017	2016	2017	2016
Revenues and other income	201	226	539	560
Adjusted EBITDA [1]	96	108	239	228
Net income	107	20	154	12
Net income attributable to shareholders of the Company	109	23	159	17
Normalized earnings attributable to common shareholders [1]	26	29	59	61
Basic and diluted earnings per share ($) [2]	1.03	0.19	1.47	0.07
Normalized earnings per share ($) [1]	0.27	0.30	0.61	0.63
Net cash flows from operating activities	78	70	177	201
Adjusted funds from operations [1, 3]	47	79	138	172
Purchase of property, plant and equipment and other assets	63	81	148	112
Dividends per common share, declared ($)	0.3900	0.3650	0.7800	0.7300
Dividends per Series 1 preferred share, declared ($)	0.1913	0.1913	0.3826	0.3826
Dividends per Series 3 preferred share, declared ($)	0.2875	0.2875	0.5750	0.5750
Dividends per Series 5 preferred share, declared ($)	0.2813	0.2813	0.5626	0.5626
Dividends per Series 7 preferred share, declared ($)	0.3750	-	0.7500	-

	As at	
	June 30, 2017	December 31, 2016
Loans and borrowings including current portion	2,434	1,508
Total assets	7,171	6,062

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

2 Diluted earnings per share was calculated after giving effect to outstanding share purchase options.

3 Commencing with the Company's March 31, 2017 quarter-end, 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.

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

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

See Liquidity and Capital Resources for discussion of the key drivers of the changes in net cash flows from operating activities. Adjusted funds from operations for the three and six months ended June 30, 2017 was lower than adjusted funds from operations for the same periods in 2016 as a result of lower adjusted EBITDA before unrealized changes in fair value of commodity derivatives and emission credits and before the recognition of coal compensation from the Province of Alberta into income, higher preferred share dividends paid in 2017 compared with 2016 and higher expenditures on sustaining capital expenditures in 2017 compared with 2016. These decreases to adjusted funds from operations are partially offset by a higher adjusted funds from operations contributed from the Company's joint venture interests in 2017 compared with 2016.

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

SIGNIFICANT EVENTS

Acquisition of Decatur Energy and $183 million public offering

On April 12, 2017, the Company announced that it entered into an agreement to acquire all of the ownership interests in Decatur Power Holdings, LLC, which owns the Decatur Energy Center (Decatur Energy) from an affiliate of LS Power Equity Partners III. On June 13, 2017, the Company completed the acquisition of Decatur Energy for $603 million (US$448 million), including working capital and other closing adjustments of $9 million (US$7 million). Decatur Energy is a 795 MW natural gas-fired combined cycle power generation facility located in Decatur, Alabama that operates under a tolling agreement.

Decatur Energy sells capacity and energy to a regional entity under a long-term contract which has an original term of 10 years and expires December 31, 2022. Decatur Energy is well-positioned, given anticipated market conditions, as well as significant remaining useful life, to be re-contracted or to pursue other commercial alternatives at the end of the current long-term contract, including the ability to sell power into the Pennsylvania, New Jersey, and Maryland interconnection market starting in 2023.

Financing of the Decatur Energy acquisition consisted of a combination of debt and equity. On April 24, 2017, the Company announced the completion of its previously announced public offering of 7,375,000 subscription receipts (Subscription Receipts), on a bought deal basis, at an issue price of $24.75 per Subscription Receipt, for total gross proceeds of $183 million less issue costs of $7 million. On June 13, 2017, upon closing of the Decatur Energy acquisition, each Subscription Receipt was converted for one common share of the Company. No dividend record date occurred during the period when the Subscription Receipts were outstanding and as such, no obligations to make any cash dividend equivalent payments were triggered.

The balance of the purchase price was financed through debt utilizing a temporary expansion of Capital Power's credit facilities and is expected to be followed by permanent financing with an issuance of long-term debt later in 2017.

The Decatur Energy acquisition supports the Company's growth strategy and increases the Company's geographical diversification and contracted cash flows. During the first full year of operations, the Decatur Energy acquisition is expected to increase adjusted funds from operations by $43 million and increase adjusted EBITDA by $60 million.

Bloom Wind begins commercial operation

On June 1, 2017, the Company's 178 MW Bloom Wind facility commenced commercial operations. On June 12, 2017, the Company received $244 million (US$181 million) in financing from an affiliate of Goldman Sachs (Project Investor) in exchange for Class A interests of a subsidiary of the Company. The Company incurred issue costs of $7 million (US$5 million) associated with the financing. Effective July 1, 2017, Bloom Wind will operate under a 10-year proxy revenue swap agreement with Allianz Risk Transfer, a subsidiary of Allianz SE. Under the contract, which was executed on April 21, 2016, Capital Power swaps the market revenue of the project's generation for a fixed annual payment for a 10-year term. The agreement secures long-term predictable revenues and mitigates generation volume uncertainty.

Acquisition of thermal facilities

On February 21, 2017, the Company announced that it entered into an agreement to acquire the thermal power business of Veresen Inc. Under the terms of the agreement, Capital Power acquired 284 MW of generation from two natural gas-fired power assets in Ontario consisting of the 84 MW East Windsor Cogeneration Centre (East Windsor) and a 50% interest in the 400 MW York Energy Centre (York Energy), and operates both facilities. The transaction also includes 10 MW of zero-emissions waste heat generation from two facilities (5 MW each), together known as EnPower Green Energy Generation (EnPower), located at Westcoast Energy's BC Gas Pipeline compressor stations in Savona and 150 Mile House, British Columbia.

On April 13, 2017, the Company announced that it had completed the acquisition of the two natural gas-fired power facilities in Ontario. The purchase price for the natural gas-fired facilities consisted of (i) $235 million in total cash consideration, including working capital and other closing adjustments of $11 million, and (ii) the assumption of $253 million of project level debt (proportionate basis at acquisition date net book value).

On June 1, 2017, the Company completed the acquisition of EnPower. The purchase price consisted of (i) $8 million of total cash consideration, including working capital and other closing adjustments of $3 million, and (ii) the assumption of $18 million of project level debt.

The acquisitions of these facilities support the Company's growth strategy and are consistent with the Company's technology and operating focus. During the first full year of operations, these acquisitions are expected to increase adjusted funds from operations by $24 million and increase adjusted EBITDA by $55 million.

Appointments to the Board of Directors

Effective April 3, 2017, Keith Trent and Katharine Stevenson were appointed to the Capital Power Board of Directors.

Amendment of Genesee Coal Mine Joint Venture Agreement

On March 28, 2017, the Company announced that it entered into an agreement (the Amending Agreement) to amend its Genesee Mine Joint Venture Agreement with Prairie Mines & Royalty ULC (PMRU), a subsidiary of Westmoreland Coal Company, to accelerate the repayment of amounts it would otherwise have owed to PMRU during the term of the agreement and eliminate all future payments to PMRU relating to existing capital assets at the Genesee Coal Mine (Coal Mine). Capital Power will continue to pay PMRU contracted mining fees for PMRU's ongoing operation of the Coal Mine.

By accelerating the $70 million repayment of capital expenditures to PMRU, the transaction will reduce Capital Power's cost of coal for the Genesee facility, and enhance the Company's net income, adjusted EBITDA, net cash flows from operating activities and adjusted funds from operations. These cost reductions were anticipated to take place and have been included in the adjusted funds from operations guidance that was provided as part of the Company's year-end disclosure on February 17, 2017. As a result of the transaction, net cash flows from operating activities are expected to increase by $14 million for 2017. The operations and management of the Coal Mine are unchanged as a result of the Amending Agreement and the Company will continue to control the Coal Mine and treat it as a subsidiary.

Coal for the Genesee facility is supplied by the adjacent Coal Mine under a long-term, cost of service supply agreement. Prior to the Amending Agreement, Capital Power paid PMRU a fee to cover PMRU's depreciation expense and certain other costs, as well as provide a variable rate of return to PMRU. These fees paid to PMRU were included as part of Capital Power's cost of coal for operating the Genesee facility, and will be eliminated with the Amending Agreement.

The cost savings for Capital Power will be magnified through 2030 with the phase-out of coal-fired generation under the CLP, which would accelerate the amounts in respect of depreciation that would have been paid to PMRU due to the shortened asset lives.

SUBSEQUENT EVENT

Dividend increase

On July 25, 2017, the Company's Board of Directors approved an increase of 7.1% in the annual dividend for holders of its common shares, from $1.56 per common share to $1.67 per common share. This increased common dividend will commence with the third quarter 2017 quarterly dividend payment on October 31, 2017 to shareholders of record at the close of business on September 29, 2017.

CONSOLIDATED NET INCOME AND RESULTS OF OPERATIONS

The primary factors contributing to the change in consolidated net income for the three and six months ended June 30, 2017 compared with the three and six months ended June 30, 2016 are presented below followed by further discussion of these items.

(unaudited, $ millions)	Three months		Six months	
Consolidated net income for the periods ended June 30, 2016		**20**		**12**
(Decrease) increase in adjusted EBITDA:				
Alberta commercial facilities and portfolio optimization	(16)		(22)	
Alberta contracted facilities	(6)		(3)	
Ontario and British Columbia contracted facilities	12		14	
U.S. contracted facilities	2		-	
Corporate	10		19	
Change in unrealized net gains or losses related to the fair value of commodity derivatives and emission credits	(14)	(12)	3	11
Increase in depreciation and amortization expense		(11)		(15)
Change in foreign exchange gain or loss		10		4
Prior year loss on termination of power purchase arrangement		-		53
Decrease in finance expense from joint ventures		2		2
Increase in net finance expense		(6)		(4)
(Decrease) increase in income before tax		(17)		51
Change in income tax expense or recovery		104		91
Increase in net income		**87**		**142**
Consolidated net income for the periods ended June 30, 2017		**107**		**154**

Results by facility category and other

	Three months ended June 30							
	2017	2016	2017	2016	2017	2016	2017	2016
	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	3,674	3,707	94	90	177	173		
Alberta commercial facilities								
Genesee 3	480	474	97	100	9	6		
Keephills 3	419	501	92	100	8	7		
Clover Bar Energy Centre 1, 2 and 3	24	106	89	91	1	2		
Joffre	70	21	96	55	4	6		
Shepard Energy Centre	560	647	97	82	23	23		
Halkirk	119	124	99	98	8	8		
Clover Bar Landfill Gas	6	2	95	99	-	-		
Alberta commercial facilities – owned	1,678	1,875	95	87	53	52		
Portfolio optimization	N/A	N/A	N/A	N/A	100	114		
	1,678	1,875	95	87	153	166	55	71
Alberta contracted facilities								
Genesee 1	576	770	70	95				
Genesee 2	825	582	100	72				
	1,401	1,352	85	84	55	59	37	43
Ontario and British Columbia contracted facilities								
Island Generation	-	-	100	100	9	9		
York Energy [5, 6]	2	N/A	100	N/A	N/A	N/A		
East Windsor [5]	1	N/A	99	N/A	8	N/A		
K2 Wind [7]	29	34	100	99	N/A	N/A		
Kingsbridge 1	25	16	95	97	1	1		
Port Dover and Nanticoke	71	65	100	100	9	8		
Quality Wind	84	90	99	98	5	7		
EnPower [8]	2	N/A	98	N/A	-	N/A		
	214	205	99	99	32	25	40	28
U.S. contracted facilities								
Roxboro, North Carolina	88	82	100	100	10	9		
Southport, North Carolina	92	144	86	92	14	19		
Decatur Energy, Alabama [9]	107	N/A	100	N/A	4	N/A		
Beaufort Solar, North Carolina	8	8	90	91	-	1		
Bloom Wind, Kansas [10]	46	8	98	91	4	1		
Macho Springs, New Mexico	40	41	96	98	5	5		
	381	275	96	95	37	34	10	8
Corporate [11]					16	1	(17)	(27)
Unrealized changes in fair value of commodity derivatives and emission credits					(92)	(59)	(29)	(15)
Consolidated revenues and other income and adjusted EBITDA					**201**	**226**	**96**	**108**

	Six months ended June 30							
	2017	2016	2017	2016	2017	2016	2017	2016
	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 excluding the Sundance PPA	7,636	7,605	96	93	361	361		
Alberta commercial facilities and Sundance PPA								
Genesee 3	973	948	98	100	19	14		
Keephills 3	864	889	93	95	18	14		
Clover Bar Energy Centre 1, 2 and 3	60	154	94	95	2	3		
Joffre	105	104	94	72	8	12		
Shepard Energy Centre	1,209	1,224	98	91	47	44		
Halkirk	241	248	98	98	17	16		
Clover Bar Landfill Gas	11	3	95	99	1	-		
Alberta commercial facilities – owned	3,463	3,570	96	92	112	103		
Sundance PPA [4]	N/A	655	N/A	95	-	13		
Portfolio optimization	N/A	N/A	N/A	N/A	195	238		
	3,463	4,225	96	93	307	354	113	135
Alberta contracted facilities								
Genesee 1	1,422	1,613	85	98				
Genesee 2	1,636	1,415	98	85				
	3,058	3,028	92	91	116	123	82	85
Ontario and British Columbia contracted facilities								
Island Generation	-	-	100	100	19	19		
York Energy [5, 6]	2	N/A	100	N/A	N/A	N/A		
East Windsor [5]	1	N/A	99	N/A	8	N/A		
K2 Wind [7]	108	105	99	99	N/A	N/A		
Kingsbridge 1	61	50	96	96	3	3		
Port Dover and Nanticoke	164	160	99	99	21	20		
Quality Wind	178	181	98	99	16	17		
EnPower [8]	2	N/A	98	N/A	-	N/A		
	516	496	99	99	67	59	80	66
U.S. contracted facilities								
Roxboro, North Carolina	167	148	96	95	19	17		
Southport, North Carolina	184	271	88	88	28	38		
Decatur Energy, Alabama [9]	107	N/A	100	N/A	4	N/A		
Beaufort Solar, North Carolina	14	15	94	95	1	2		
Bloom Wind, Kansas[10]	46	N/A	98	N/A	4	N/A		
Macho Springs, New Mexico	81	77	97	97	10	9		
	599	511	95	92	66	66	16	16
Corporate [11]					30	3	(32)	(51)
Unrealized changes in fair value of commodity derivatives and emission credits					(47)	(45)	(20)	(23)
Consolidated revenues and other income and adjusted EBITDA					**539**	**560**	**239**	**228**

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 The Company's role as Buyer of the Sundance PPA was terminated effective March 24, 2016. Revenues, adjusted EBITDA, electricity generation, and facility availability in 2016 include the results of the Sundance PPA up to that date.

5 East Windsor and York Energy were acquired on April 13, 2017 (see Significant Events).

6 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 $6 million for the three and six months ended June 30, 2017, respectively. The facility's revenues are not included in the above results.

7 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 $11 million and $25 million for the three and six months ended June 30, 2017, respectively, compared with $10 million and $23 million for the three and six months ended June 30, 2016, respectively. The facility's revenues are not included in the above results.

8 EnPower was acquired on June 1, 2017 (see Significant Events).

9 Decatur Energy was acquired on June 13, 2017 (see Significant Events).

10 Bloom Wind was commissioned on June 1, 2017 (see Significant Events).

11 Corporate revenues were offset by interplant category eliminations.

Energy prices and hedged positions

		Three months ended June 30		Six months ended June 30		Year ended December
Alberta	**Unit**	**2017**	**2016**	**2017**	**2016**	**31, 2016**
Hedged position [1]	Percentage sold forward at beginning of period (%)	100	100	100	100	100
Spot power price average	$/MWh	19	15	21	17	18
Realized power price [2]	$/MWh	52	61	54	56	61
Natural gas price (AECO) [3]	$/gigajoule (Gj)	2.62	1.34	2.60	1.54	2.03

1 Hedged position is for the Alberta baseload facilities as well as a portion of Joffre and the uncontracted portion of Shepard. The Sundance PPA is no longer a part of Capital Power's baseload generation effective March 24, 2016.

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, Sundance PPA and portfolio optimization

The Alberta spot price averaged $19 per MWh and $21 per MWh for the three and six months ended June 30, 2017, respectively which were slightly higher than the corresponding periods in 2016. Spot prices for 2017 and 2016 reflected minimal market volatility combined with conservative offer strategies from market participants, stable coal supply, strong imports and fewer unplanned baseload facility outages.

Generation, availability, revenues and other income and adjusted EBITDA for the Alberta commercial facilities include results of the Sundance PPA up to the effective termination date of March 24, 2016.

For the three months ended June 30, 2017, generation was lower than the comparable period in 2016 primarily due to lower dispatch at Shepard and Clover Bar Energy Centre and an unplanned outage at Keephills 3 during the second quarter of 2017 partially offset by a shorter planned outage at Shepard during the second quarter of 2017 compared with the same period in 2016. Generation for the six months ended June 30, 2017 was lower primarily due to the termination of the Sundance PPA in the first quarter of 2016 and lower dispatch at Clover Bar Energy Centre. Availability for the three and six months ended June 30, 2017 was higher than the same periods in 2016 primarily due to an extended outage at Joffre in the second quarter of 2016 and a shorter planned outage at Shepard in the second quarter of 2017 compared with the same period in 2016.

Revenues and other income and adjusted EBITDA for the three months ended June 30, 2017 decreased compared with the corresponding periods in 2016 primarily due to lower realized prices in 2017 compared with 2016, which resulted in lower revenues earned on portfolio optimization activities. On a year to date basis, lower revenues and other income and adjusted EBITDA compared to 2016 further reflected lower realized prices, reduction in volume of commercial production sold forward in 2017 and the termination of the Sundance PPA in the first quarter of 2016.

Alberta contracted facilities

Generation and availability for the three and six months ended June 30, 2017 were comparable with the same periods in 2016. Revenues and other income were lower for the three and six months ended June 30, 2017 compared with the corresponding periods in 2016 primarily due to lower capacity revenues primarily due to lower PPA input rates. Adjusted EBITDA decreased for the three and six months ended June 30, 2017 compared with the corresponding periods in 2016, primarily due to the aforementioned lower capacity revenue. In addition, coal costs increased in the three months ended June 30, 2017 compared with the same period in 2016 due to higher mining activity in the second quarter of 2016 compared to the same period in 2017. These unfavourable variances were partially offset by favourable impacts related to the Amending Agreement related to the Genesee Coal Mine (See Significant Events) for the three and six months ended June 30, 2017 with no similar impacts in the same periods in 2016.

Ontario and British Columbia contracted facilities

Generation, revenue and other income and adjusted EBITDA for the three and six months ended June 30, 2017 were higher compared with the corresponding periods in 2016 primarily due to the additions of York Energy, East Windsor and EnPower (see Significant Events) in the second quarter of 2017. Availability for the three and six months ended June 30, 2017 was comparable with the same periods in 2016. 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 and availability for the three and six months ended June 30, 2017 were higher primarily due to the addition of Decatur Energy (see Significant Events) and the commencement of operations at Bloom Wind (see Significant Events) in the second quarter of 2017. These increases were partially offset by lower generation at Southport due largely to derates due to sulfur emission restrictions. Revenue and other income and adjusted EBITDA for the three and six months ended June 30, 2017 were comparable with the corresponding periods in 2016 due to the aforementioned Decatur Energy acquisition and the commissioning of Bloom Wind offset by lower generation at Southport.

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 decreased and revenue and other income increased in the three and six months ended June 30, 2017 compared with the corresponding periods in 2016 primarily due to coal compensation from the Province of Alberta that is recognized monthly as other income commencing December 2016. The increase to net corporate expenditures is partially offset by increased business development expenses in 2017 compared with 2016 primarily due to the facilities acquired in 2017 (see Significant Events).

Unrealized changes in fair value of commodity derivatives and emission credits

(unaudited, $ millions)	Three months ended June 30			
	2017	**2016**	**2017**	**2016**
Unrealized changes in fair value of commodity derivatives and emission credits	**Revenues and other income**		**Adjusted EBITDA**	
Unrealized losses on Alberta energy derivatives	(98)	(52)	(27)	(29)
Unrealized gains (losses) on natural gas derivatives	4	(6)	(5)	15
Unrealized gains (losses) on emission derivatives	2	(1)	2	(1)
Unrealized gains on emission credits held for trading	-	-	1	-
	(92)	**(59)**	**(29)**	**(15)**

(unaudited, $ millions)	Six months ended June 30			
	2017	**2016**	**2017**	**2016**
Unrealized changes in fair value of commodity derivatives and emission credits	**Revenues and other income**		**Adjusted EBITDA**	
Unrealized losses on Alberta energy derivatives	(60)	(39)	(10)	(28)
Unrealized gains (losses) on natural gas derivatives	11	(1)	(13)	13
Unrealized gains (losses) on emission derivatives	2	(5)	2	(5)
Unrealized gains (losses) on emission credits held for trading	-	-	1	(3)
	(47)	**(45)**	**(20)**	**(23)**

The Company's financial results relating to its Alberta commercial facilities and portfolio optimization include unrealized changes in the fair value of commodity and other derivatives.

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

During the three months ended June 30, 2017 and 2016 the Alberta energy portfolio recognized unrealized losses of $27 million and $29 million, respectively, primarily due to the impact of increasing forward Alberta power prices on net forward sales contracts and the reversal of prior period unrealized net gains on forward sales contracts that settled during the corresponding periods. During the six months ended June 30, 2017 and 2016, the Alberta energy portfolio recognized unrealized losses of $10 million and $28 million, respectively. This reflected the reversal of prior periods' unrealized net gains on forward sales contracts that settled during the first six months in the corresponding years. Unrealized losses in 2017 are partially offset by the impact of decreasing forward Alberta power prices on net forward sales contracts. For the six months ended June 30, 2016, there were additional unrealized losses that were the result of increasing forward Alberta power prices on certain net forward sales contracts.

Unrealized losses on natural gas derivatives reported by the Company in 2017 were attributable to net forward purchase contracts valued against decreasing forward natural gas prices. In 2016, the unrealized gains on natural gas derivatives reported by the Company reflected the impact of net forward purchase contracts which were valued against increasing forward natural gas prices during the corresponding periods and reversals of prior period unrealized losses on forward purchase contracts that settled during the corresponding periods.

Unrealized gains on emission derivatives reported by the Company in 2017 were primarily due to forward purchase contracts on emissions allowances and renewable energy credits which were valued against increasing forward prices and the impact of the reversal of previously unrealized losses on positions that settled during the period. In 2016, the unrealized losses on emission derivatives reported by the Company were mostly attributable to net forward purchase contracts on allowances and renewable energy credits which were valued at decreasing prices and the reversal of prior period unrealized gains on positions settled during the first six months of the year, partially offset by gains on net forward sales contracts valued at decreasing prices.

Consolidated other expenses and non-controlling interests

(unaudited, $ millions)	Three months ended June 30		Six months ended June 30	
	2017	2016	2017	2016
Interest on borrowings less capitalized interest	(23)	(17)	(40)	(38)
Other net finance expense – interest on coal compensation from the Province of Alberta, sundry interest, guarantee and other fees	4	-	7	(1)
	(19)	(17)	(33)	(39)
Unrealized loss representing changes in the fair value of interest rate derivatives	-	(1)	-	-
Other finance expense – amortization and accretion charges, including accretion of deferred revenue pertaining to coal compensation from the Province of Alberta	(6)	(1)	(12)	(2)
Total finance expense	(25)	(19)	(45)	(41)
Depreciation and amortization	(65)	(54)	(125)	(110)
Foreign exchange gain (loss)	9	(1)	11	7
Loss on termination of power purchase arrangement	-	-	-	(53)
Finance expense from joint ventures	(2)	(4)	(5)	(7)
Income tax recovery (expense)	94	(10)	79	(12)
Net loss attributable to non-controlling interests	2	3	5	5

Net finance expense

Higher net finance expense for the three and six months ended June 30, 2017 compared with the same periods in the prior year was primarily due to debt added as a result of the acquisition of Veresen thermal facilities and Decatur Energy (see Significant Events) in the second quarter of 2017 and interest on the $160 million private placement debt issued in the third quarter of 2016. These increases were partially offset by the EPCOR debt repayment in the first quarter of 2016 and higher capitalized interest resulting from Bloom Wind construction, which commenced in the second quarter of 2016.

Depreciation and amortization

Depreciation and amortization for the three and six months ended June 30, 2017 increased compared with the same periods in the prior year primarily due to the facility acquisitions in the second quarter of 2017 (see Significant Events) and the shortening of asset lives in late 2016 related to the coal-fired facilities. The components of the coal-fired facilities that are unique to coal-fired generation had their useful lives shortened to 2030 while those components which can be utilized upon conversion to natural gas facilities had their useful lives shortened to 2045.

Foreign exchange gain (loss)

As at June 30, 2017 the Company had outstanding U.S. dollar denominated debt payable totalling US$595 million. Approximately US$300 million is hedged using foreign currency derivative instruments. The foreign exchange gain consisted primarily of the gain incurred on the revaluation of U.S. dollar denominated debt not hedged for accounting purposes. For the three and six months ended June 30, 2017, the exchange rate of the Canadian dollar relative to the U.S. dollar strengthened, resulting in an unrealized gain in both periods. For the three and six months ended June 30, 2016, the Canadian dollar weakened and strengthened, respectively, compared to the U.S. dollar.

Loss on termination of power purchase arrangement

On March 24, 2016, the Company notified the Balancing Pool of the Company's decision to terminate its role as Buyer of the Sundance PPA and recorded a pre-tax loss of $53 million with respect to the de-recognition of the Sundance PPA intangible asset.

Finance expense from joint ventures

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

Income tax recovery (expense)

For the three and six months ended June 30, 2017, the Company has recorded an income tax recovery, compared with income tax expense in the corresponding periods in 2016. The change is primarily due to the reversal, in the second quarter of 2017, of a previous write-down related to U.S. income tax losses. As disclosed in previous periods, a non-cash write-down was recorded in the third quarter of 2014 as at that time, it was not considered probable that sufficient future taxable income would be available based on the Company's forecast for U.S. taxable income for the then existing U.S. income tax loss carryforwards to be recognized. With the acquisition of Decatur Energy and the commissioning of Bloom Wind (see Significant Events), the Company's forecast for U.S. taxable income has improved and as a result, the Company has recognized a deferred tax asset in the amount of $86 million on a portion of the U.S. income tax losses that are expected to be utilized against future taxable income that will be generated from the U.S. operations.

Non-controlling interests

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

COMPREHENSIVE INCOME (LOSS)

(unaudited, $ millions)	Three months ended June 30		Six months ended June 30	
	2017	**2016**	**2017**	**2016**
Net income	107	20	154	12
Other comprehensive loss:				
Net unrealized (losses) gains on commodity derivatives designated as cash flow hedges	(27)	(18)	(4)	19
Net unrealized gains (losses) on derivatives designated as cash flow hedges – joint venture	1	(6)	-	(9)
Net realized gains on commodity derivatives designated as cash flow hedges reclassified to net income	(18)	(19)	(35)	(49)
Net realized losses on commodity derivatives designated as cash flow hedges reclassified to net income – joint venture	1	1	2	1
Unrealized foreign exchange loss on the translation of foreign operations	(19)	(1)	(21)	(13)
Actuarial gain related to the Company's defined benefit pension plan	2	-	2	-
	(60)	(43)	(56)	(51)
Comprehensive income (loss)	**47**	**(23)**	**98**	**(39)**

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

FINANCIAL POSITION

The significant changes in the consolidated statements of financial position from December 31, 2016 to June 30, 2017 were as follows:

(unaudited, $ millions)	June 30, 2017	December 31, 2016	Increase (decrease)	Acquisitions through business combinations	Other	Primary other changes
Trade and other receivables	224	223	1	14	(13)	Primarily lower generation receivables at various facilities and the timing of receipts at Quality Wind.
Inventories	131	118	13	4	9	Increase in emission credits held for trading and higher coal inventory.
Other assets	72	20	52	-	52	Increase primarily due to the non-current portion of the prepayment related to the amendment of the Genesee Coal Mine Joint Venture Agreement (see Significant Events).
Net derivative financial instruments assets	95	177	(82)	-	(82)	Impact of increasing forward Alberta power prices on the fair value of forward sales contracts.
Equity-accounted investments	183	18	165	153	12	Net income partially offset by distributions received.
Intangible assets	574	299	275	217	58	Increase primarily due to the receipt and purchase of emission credit inventory.
Property, plant and equipment	4,378	3,764	614	611	3	Capital additions, primarily Bloom Wind, partially offset by depreciation and amortization.
Goodwill	75	23	52	54	(2)	Impact of foreign exchange.

(unaudited, $ millions)	June 30, 2017	December 31, 2016	Increase (decrease)	Acquisitions through business combinations	Other	Primary other changes
Trade and other payables	198	217	(19)	3	(22)	Decrease primarily due to the timing of Bloom Wind construction and Genesee Mine payables and the settlement of emissions compliance payables, partially offset by emission compliance liabilities to the Balancing Pool for emission credits received and payables related to the Genesee 1 planned outage.
Loans and borrowings (including current portion)	2,434	1,508	926	175	751	Addition of debt related to Bloom Wind, increase in committed credit facilities related to the acquisition of Decatur Energy (see Significant Events) and overall increased credit facility utilization (see Liquidity and Capital Resources).
Deferred revenue and other liabilities (including current portion)	671	689	(18)	-	(18)	Decrease primarily due to the recognition into income of deferred revenue for compensation related to the phase out of coal-fired generation.
Net deferred tax liabilities	297	363	(66)	33	(99)	Decrease primarily due to the recognition of previously unrecognized net operating losses as a result of the acquisition of Decatur Energy and the commissioning of Bloom Wind (see Significant Events).
Provisions (including current portion)	274	257	17	3	14	Increased decommissioning provisions primarily due to interest rate reductions.
Share capital	3,110	2,918	192	-	192	Increase due to common shares issued and share options exercised, partially offset by share issue costs.
Deficit	(59)	(124)	65	-	65	Net income less common and preferred share dividends.
Other reserves	(8)	49	(57)	-	(57)	Unrealized loss on foreign exchange translation and reclassification of unrealized gains on cash flow hedges.

LIQUIDITY AND CAPITAL RESOURCES

(unaudited, $ millions)	Six months ended June 30		
Cash inflows (outflows)	**2017**	**2016**	**Change**
Operating activities	177	201	(24)
Investing activities	(1,102)	(112)	(990)
Financing activities	878	(139)	1,017

Operating activities

Cash flows from operating activities for the six months ended June 30, 2017 decreased compared with the same period in 2016 primarily due to working capital cash outflows in 2017 compared with inflows in 2016, lower cash distributions received from K2 Wind and lower adjusted EBITDA before unrealized changes in fair value of commodity derivatives and emission credits and before the recognition of coal compensation from the Province of Alberta into income. These decreases were partially offset by a cash outflow in 2016 compared with no cash impact in 2017 of the fair value changes in certain unsettled derivative financial instruments that are charged or credited to the Company's bank margin account held with a specific exchange counterparty.

Investing activities

Cash flows used in investing activities for the six months ended June 30, 2017 increased compared with the same period in 2016 primarily due to the acquisition of Veresen thermal facilities and Decatur Energy (see Significant Events), construction of Bloom Wind, which began in the third quarter of 2016 and the prepayment related to the Amending Agreement (see Significant Events).

Capital expenditures and investments

(unaudited, $ millions)	Pre-2017 Actual	Six months ended June 30, 2017 Actual	Balance of 2017 Estimated [1, 2]	Actual or Projected Total [2, 3]	Timing
Genesee 4 and 5 [4]	16	1	2	700	Targeted completion as early as 2021 and 2022, respectively
Bloom Wind	219	91	2	312 [5]	Completed in the second quarter of 2017
Development sites	-	3	-	3	
Subtotal growth projects		**95**			
Sustaining – plant maintenance excluding Genesee mine		32			
Sustaining – Genesee mine maintenance and lands [6]		7			
Total capital expenditures [7]		**134**			
Emission credits held for compliance		20			
Capitalized interest		(6)			
Purchase of property, plant and equipment and other assets		**148**			

1 The Company's 2017 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 the previously announced Genesee 4 and 5 and Bloom Wind projects are based on management's estimates. Projected capital expenditures for development sites, based on management's estimates, are for 2017 only.

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 Excludes a $31 million (US$23 million) developer fee paid to a subsidiary of the Company.

6 Capital expenditures for Genesee mine maintenance represent only those capital expenditures funded by the Company for its share of the Genesee mine operation.

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

Financing activities

The cash flows from financing activities for the six months ended June 30, 2017 primarily reflected the net issuance of loans and borrowings, issuance of common shares (see Significant Events) and Project Investor financing received for Bloom Wind (see Significant Events) partially offset by the repayment of loans and borrowings and the sum of common share dividends and preferred share dividends.

The Company's credit facilities consisted of:

(unaudited, $ millions)		As at June 30, 2017			As at December 31, 2016		
	Maturity timing	Total facilities	Credit facility utilization	Available	Total facilities	Credit facility utilization	Available
Committed credit facilities	2018/ 2020/ 2021	1,444			1,055		
Letters of credit outstanding			22			58	
Bankers' acceptance outstanding			225			-	
Bank loans outstanding (U.S. dollars)			478			134	
		1,444	725	719	1,055	192	863
Bilateral demand credit facilities	N/A	200			200		
Letters of credit outstanding			115			114	
		200	115	85	200	114	86
Demand credit facilities	N/A	25	-	25	25	-	25
		1,669	**840**	**829**	**1,280**	**306**	**974**

As at June 30, 2017, the committed credit facility utilization increased $534 million compared with the utilization as at December 31, 2016. The increase in credit facility utilization is primarily due to increased U.S. dollar bank loans and banker's acceptances issued used to fund the acquisitions of Decatur Energy and the acquisition of the thermal power business of Veresen Inc. (see Significant Events). In June 2017, the Company increased its committed credit facilities by $389 million (US$300 million). In July 2016, the Company extended the maturity date of its then existing committed credit facilities to July 9, 2021. In addition, 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, $389 million matures in June 2018, $55 million matures in July 2020 and $1 billion matures in July 2021. 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.

On April 3, 2017, DBRS Limited (DBRS) revised the Company's senior unsecured long-term debt credit rating from BBB to BBB (low) with a stable outlook. 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 2017 include:

(unaudited, $ millions)	**Six months ended June 30, 2017 Actual**	**Balance of 2017 estimated**	**Total 2017 Expected Cash Requirements**
Repayment of debt payable to EPCOR	10	-	10
Capital expenditures – sustaining	38	37	75
Capital expenditures – ongoing growth projects [1]	95	4	99
Capital expenditures – Genesee performance standard	1	4	5
Common share dividends [2]	75	85	160
Preferred share dividends	16	16	32
	235	**146**	**381**

1 Ongoing growth projects do not reflect the acquisitions noted in Significant Events.

2 Includes 7% annual dividend growth (see Subsequent Events).

The current portion of loans and borrowings on the June 30, 2017 condensed interim consolidated statement of financial position included $174 million of senior debt payable to EPCOR that has been classified as current since the debt is callable and, therefore, all potentially repayable within one year.

The Company funded the construction of Bloom Wind using existing bank credit facilities, cash flows from operating activities and Project Investor equity contributions. The Company's other cash requirements identified above are funded with cash on hand, cash flows from operating activities, and use of existing bank credit facilities.

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 June 30, 2017, $137 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	
	June 30, 2017	December 31, 2016
Loans and borrowings	2,434	1,508
Finance lease obligation [1]	19	20
Less cash and cash equivalents	47	98
Net debt	2,406	1,430
Share capital	3,110	2,918
Deficit and other reserves	(67)	(75)
Non-controlling interests	53	58
Total equity	3,096	2,901
Total capital	**5,502**	**4,331**

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

CONTINGENT LIABILITIES

Line Loss Rule Proceeding

Capital Power is participating in the Line Loss Rule (LLR) Proceeding currently underway 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 intends to address the replacement for the currently non-compliant LLR as well as the possible correction of line loss charges and credits for the years 2006 forward through three modules. In January 2015, the AUC issued its “Module A” decision and concluded that it has the jurisdiction and authority to retroactively adjust line loss rates. The Module A decision was subsequently appealed by multiple parties, including the Company and consideration of those appeals has been deferred until after the completion of “Module C”.

The AUC approved principles for the new LLR in “Module B” in November 2015 and directed the Alberta Electric System Operator (AESO) to provide a plan for implementing the new LLR. In June 2016, the AUC rejected applications for review and variance of the Module B decision that had been submitted by two parties, ruling that it would be premature to review the decision prior to completing Module C, but noting that the parties could resubmit the Module B review applications upon completion of Module C. The AUC approved the AESO’s Compliance Filing relating to the new LLR on November 30, 2016. In July 2017, the AESO provided loss factors calculated under the new LLR that will be in effect on a prospective basis, retroactive to January 1, 2017. One party has filed an application for review and variance of the AUC’s approval of the AESO’s Compliance Filing, though the AUC has yet to establish a process to consider the application.

In January 2016, the AUC initiated Module C, to determine what retrospective adjustments, if any, are to be paid to or received by the various parties, and what methodology will be adopted for the purposes of determining retroactive adjustments. In September 2016, the AUC provided its decisions regarding various preliminary issues relating to the scope for Module C. These decisions were largely procedural in nature. In January 2017, the AUC established a process and schedule to consider all remaining issues relating to Module C, including the methodology to be used to recalculate and adjust the line loss factor for the historic period and the process to be employed for the collection and payment of retroactive adjustments. The written phase of the process concluded in May 2017, and the AUC subsequently held an oral hearing that concluded in June 2017. The AUC has established a schedule for the submission of Final and Reply arguments related to Module C. Based on this schedule, the Company expects a decision related to Module C by the end of 2017.

As at July 10, 2017, no prospective (Module B) loss factors or retroactive (Module C) loss factors for the full historic period have been produced by the AESO using the new LLR, nor has any alternative or supplemental mechanism for determining retrospective adjustments been established by the AUC. While the AUC Module C decision that is expected by the end of 2017 will establish the retrospective methodology, it is unclear at this time when retrospective loss factors under any approved methodology will be made available by the AESO.

Capital Power may incur material additional transmission charges on a retroactive and go-forward basis but a provision has not been recorded in the Company’s unaudited condensed interim consolidated financial statements since the outcome of the LLR Proceeding continues to be unknown. As a result of the termination of the Company’s role as Buyer of the Sundance PPA and the settlement of the Government of Alberta’s related legal action, the Company has no further obligations, and the Balancing Pool has assumed all obligations, of Buyer under the Sundance PPA, without exception or limitation. Any potential retroactive liability relating to the Company’s role as Buyer of the Sundance PPA for losses has therefore been transferred to the Balancing Pool and Capital Power’s total remaining liability pertaining to its Alberta assets has been cut approximately in half.

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.

North Carolina facility permitting

The North Carolina Department of Air Quality (DAQ) has indicated that new permits will be required for the Company's Roxboro and Southport facilities based on 2015 carbon monoxide and particulate matter emissions. The required permits have been applied for, however the DAQ advised in June 2017 that it is also pursuing permits for sulfur dioxide emissions. It is unknown at this time what, if any, new capital investment may be required under these permits.

RISKS AND RISK MANAGEMENT

There have been no material changes in the six months ended June 30, 2017 to the Company's business and operational risks as described in the Company's December 31, 2016 MD&A.

ENVIRONMENTAL MATTERS

The Company recorded decommissioning provisions of $219 million as at June 30, 2017 ($195 million as at December 31, 2016) 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 $242 million in future years and expects to mostly use these credits to comply with applicable environmental regulations, including the proposed CCR.

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 has been no significant changes to the Company's use of judgments and estimates as described in the Company's December 31, 2016 MD&A.

ACCOUNTING CHANGES

Effective January 1, 2017

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

Standard	Description	Impact to Capital Power
Statement of Cash Flows (amendments to IAS 7)	Amendments issued to improve disclosures of changes in financing liabilities to allow users of financial statements to evaluate changes in liabilities arising from financing activities.	The Company added disclosure of changes in liabilities arising from financing activities in the Company's interim financial statement disclosures.

Future

The IASB issued the following new standards and amendments to existing standards that were not yet effective as of June 30, 2017 and are relevant to Capital Power:

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.	Management has assessed the applicability of this new standard on the Company's various contracts and reporting systems and does not expect significant changes or reclassifications to the consolidated financial statements as a result of this transition. In addition, a number of the Company's revenue contracts are accounted for under IFRS 11 – Joint Arrangements, IAS 17 – Leases, IAS 39 – Financial Instruments: Recognition and Measurement and are therefore excluded from the scope of IFRS 15. Management will utilize the cumulative effect method when initially applying the new standard which will reflect an adjustment to the opening equity balance at the date of initial application. This transition method also requires disclosure of what the transition year financial statements would have presented under the previous accounting standards. For those contracts affected by IFRS 15, management anticipates increased disclosure requirements to consist of: separately disclosed and disaggregated revenue, opening and closing balances of receivables, contract assets and liabilities; and the explanation of significant changes in contract asset and liability balances during the reporting period.	Effective for annual periods beginning on or after January 1, 2018; early application permitted and to be applied retrospectively.
Financial instruments (IFRS 9)	New standard, replacing IAS 39, which addresses requirements for classification and measurement, impairment, hedge accounting and de-recognition of financial assets and liabilities.	Management has assessed the applicability of IFRS 9 on the Company's various contracts and reporting systems and does not expect a significant impact to the consolidated financial statements.	Effective for annual periods beginning on or after January 1, 2018; early application permitted.
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.	Management is currently assessing whether certain PPAs, that are currently considered to be finance leases with the Company as the lessor, will continue to be considered leases upon adoption of IFRS 16. This assessment and any associated practical expedients will also affect disclosures under IFRS 15. Early application is permitted if IFRS 15 has also been applied. This standard will require the Company to recognize leased assets and leased obligations with respect to its lease arrangements for office space.	Effective for annual periods beginning on or after January 1, 2019. Early application is permitted if IFRS 15 has also been applied.

FINANCIAL INSTRUMENTS

The classification, carrying amounts and fair values of financial instruments held at June 30, 2017 and December 31, 2016 were as follows:

(unaudited, $ millions)		June 30, 2017		December 31, 2016	
	Fair value hierarchy level [1]	Carrying amount	Fair value	Carrying amount	Fair value
Financial assets:					
Loans and receivables					
Cash and cash equivalents	N/A	47	47	98	98
Trade and other receivables [2]	N/A	147	147	147	147
Government grant receivable [3]	Level 2	603	603	594	594
Finance lease receivables [3]	Level 2	678	764	689	762
Other financial assets [3]	Level 2	5	5	7	7
Designated at fair value through income or loss					
Derivative financial instruments assets – current and non-current	See Below	180	180	269	269
Financial liabilities:					
Other financial liabilities					
Trade and other payables [4]	N/A	196	196	216	216
Finance lease obligation [3]	Level 2	19	21	20	20
Loans and borrowings [3]	Level 2	2,434	2,520	1,508	1,540
Designated at fair value through income or loss					
Derivative financial instruments liabilities – current and non-current	See Below	85	85	92	92

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 Excludes current portion of finance lease obligation.

Risk management and hedging activities

There have been no material changes in the six months ended June 30, 2017 to the Company's risk management and hedging activities as described in the Company's December 31, 2016 MD&A.

The derivative financial instruments assets and liabilities held at June 30, 2017 compared with December 31, 2016 and used for risk management purposes were measured at fair value and consisted of the following:

(unaudited, $ millions)		As at June 30, 2017				
	Fair value hierarchy level	**Commodity cash flow hedges**	**Commodity non-hedges**	**Foreign exchange hedges**	**Foreign exchange non-hedges**	**Total**
Derivative financial instruments assets	Level 2	35	85	50	-	170
	Level 3	-	10	-	-	10
		35	95	50	-	180
Derivative financial instruments liabilities	Level 2	(6)	(57)	-	(4)	(67)
	Level 3	(18)	-	-	-	(18)
		(24)	(57)	-	(4)	(85)
Net derivative financial instruments assets		**11**	**38**	**50**	**(4)**	**95**

(unaudited, $ millions)		As at December 31, 2016			
	Fair value hierarchy level	**Commodity cash flow hedges**	**Commodity non-hedges**	**Foreign exchange hedges**	**Total**
Derivative financial instruments assets	Level 2	69	133	58	260
	Level 3	-	9	-	9
		69	142	58	269
Derivative financial instruments liabilities	Level 2	(3)	(70)	-	(73)
	Level 3	(19)	-	-	(19)
		(22)	(70)	-	(92)
Net derivative financial instruments assets		**47**	**72**	**58**	**177**

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 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 termination of the Sundance PPA, certain derivatives that were previously designated as accounting hedges were de-designated as the hedged transactions were no longer expected to occur. The Company performed a hedge effectiveness test before and after the de-designation and concluded no ineffectiveness was present. Unrealized gains and losses associated with these de-designated hedges began to flow through net income as revenues starting in the first quarter of 2016.

Commodity and interest rate derivatives not designated as accounting hedges

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

Unrealized and realized losses on 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 six months ended June 30, 2017 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	**Jun 30 2017**	**Mar 31 2017**	**Dec 31 2016**	**Sep 30 2016**	**Jun 30 2016**	**Mar 31 2016**	**Dec 31 2015**	**Sep 30 2015**
Total generation excluding Sundance PPA	3,674	3,962	3,793	3,930	3,707	3,898	3,929	3,687
Alberta commercial facilities and Sundance PPA								
Genesee 3	480	493	341	498	474	474	500	498
Keephills 3	419	445	478	464	501	388	489	258
Clover Bar Energy Centre 1, 2 and 3	24	36	94	79	106	48	41	39
Joffre	70	35	66	27	21	83	84	62
Shepard	560	649	410	611	647	577	387	572
Halkirk	119	122	121	86	124	124	129	88
Clover Bar Landfill Gas	6	5	3	1	2	1	1	2
Alberta commercial facilities – owned	1,678	1,785	1,513	1,766	1,875	1,695	1,631	1,519
Sundance PPA [1]	N/A	-	-	-	-	655	717	688
	1,678	1,785	1,513	1,766	1,875	2,350	2,348	2,207
Alberta contracted facilities								
Genesee 1	576	846	863	857	770	843	842	865
Genesee 2	825	811	860	862	582	833	861	843
	1,401	1,657	1,723	1,719	1,352	1,676	1,703	1,708
Ontario and British Columbia contracted facilities								
Island Generation	-	-	37	2	-	-	5	37
York Energy	2	N/A	N/A	N/A	N/A	N/A	N/A	N/A
East Windsor	1	N/A	N/A	N/A	N/A	N/A	N/A	N/A
K2 Wind	29	79	77	40	34	71	102	46
Kingsbridge 1	25	36	37	15	16	34	36	13
Port Dover and Nanticoke	71	93	92	53	65	95	95	44
Quality Wind	84	94	85	78	90	91	121	97
EnPower	2	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	214	302	328	188	205	291	359	237
U.S. contracted facilities								
Roxboro, North Carolina	88	79	84	84	82	66	77	76
Southport, North Carolina	92	92	107	140	144	127	131	128
Decatur Energy, Alabama	107	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Beaufort Solar, North Carolina	8	6	6	8	8	7	-	N/A
Bloom Wind, Kansas	46	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Macho Springs, New Mexico	40	41	32	25	41	36	28	19
	381	218	229	257	275	236	236	223

[1] The Company's role as Buyer of the Sundance PPA was terminated effective March 24, 2016. Results of the Sundance PPA were recognized up to March 24, 2016.

(%)	Three months ended							
Facility availability	**Jun 30 2017**	**Mar 31 2017**	**Dec 31 2016**	**Sep 30 2016**	**Jun 30 2016**	**Mar 31 2016**	**Dec 31 2015**	**Sep 30 2015**
Total average facility availability excluding Sundance PPA	94	97	94	96	90	97	99	95
Alberta commercial facilities and Sundance PPA								
Genesee 3	97	99	68	100	100	99	100	100
Keephills 3	92	93	99	96	100	90	100	63
Clover Bar Energy Centre 1, 2 and 3	89	99	99	91	91	99	97	88
Joffre	96	92	98	81	55	89	100	100
Shepard	97	99	76	99	82	100	98	100
Halkirk	99	96	98	96	98	99	96	97
Clover Bar Landfill Gas	95	95	92	27	99	99	84	81
Alberta commercial facilities – owned	95	97	87	95	87	96	98	92
Sundance PPA [1]	N/A	-	-	-	-	95	92	91
	95	97	87	95	87	96	96	92
Alberta contracted facilities								
Genesee 1	70	100	100	100	95	100	99	100
Genesee 2	100	97	100	100	72	99	100	98
	85	98	100	100	84	99	100	99
Ontario and British Columbia contracted facilities								
Island Generation	100	100	100	92	100	100	100	100
York Energy	100	N/A	N/A	N/A	N/A	N/A	N/A	N/A
East Windsor	99	N/A	N/A	N/A	N/A	N/A	N/A	N/A
K2 Wind	100	99	100	98	99	99	99	98
Kingsbridge 1	95	98	97	95	97	94	98	94
Port Dover and Nanticoke	100	98	99	94	100	97	98	95
Quality Wind	99	97	97	91	98	99	98	94
EnPower	98	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	99	99	99	93	99	99	99	97
U.S. contracted facilities								
Roxboro, North Carolina	100	93	94	100	100	89	99	94
Southport, North Carolina	86	92	98	96	92	83	93	94
Decatur Energy, Alabama	100	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Beaufort Solar, North Carolina	90	97	92	98	91	98	100	N/A
Bloom Wind, Kansas	98	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Macho Springs, New Mexico	96	98	97	97	98	97	96	96
	96	94	96	97	95	89	96	95

1 The Company's role as Buyer of the Sundance PPA was terminated effective March 24, 2016. Results of the Sundance PPA were recognized up to March 24, 2016.

Financial results

(unaudited, $ millions)	Three months ended							
	Jun 30 2017	**Mar 31 2017**	**Dec 31 2016**	**Sep 30 2016**	**Jun 30 2016**	**Mar 31 2016**	**Dec 31 2015**	**Sep 30 2015**
Revenues and other income								
Alberta commercial facilities, Sundance PPA and portfolio optimization [1]	153	154	172	163	166	188	199	237
Alberta contracted facilities	55	61	65	64	59	64	66	69
Ontario and British Columbia contracted facilities	32	35	33	23	25	34	40	23
U.S. contracted facilities	37	29	29	34	34	32	30	29
Corporate [2]	16	14	11	2	1	2	1	2
Unrealized changes in fair value of commodity derivatives and emission credits	(92)	45	(30)	88	(59)	14	1	106
	201	**338**	**280**	**374**	**226**	**334**	**337**	**466**
Adjusted EBITDA								
Alberta commercial facilities, Sundance PPA and portfolio optimization [1]	55	58	70	74	71	64	70	72
Alberta contracted facilities	37	45	40	38	43	42	45	52
Ontario and British Columbia contracted facilities [3]	40	40	40	21	28	38	45	22
U.S. contracted facilities	10	6	8	11	8	8	10	6
Corporate	(17)	(15)	(20)	(24)	(27)	(24)	(24)	(25)
Unrealized changes in fair value of commodity derivatives and emission credits	(29)	9	6	28	(15)	(8)	(12)	27
	96	**143**	**144**	**148**	**108**	**120**	**134**	**154**

1 The Company's role as Buyer of the Sundance PPA was terminated effective March 24, 2016. Results of the Sundance PPA were recognized up to March 24, 2016.

2 Revenues are offset by interplant category revenue eliminations.

3 Commencing with the first quarter of 2016, the reported Ontario and British Columbia contracted facilities' adjusted EBTIDA was changed to include the adjusted EBITDA from joint ventures and the applicable comparative periods have been adjusted to conform to the current period's presentation.

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, foreign exchange and interest rate derivative contracts.

Financial highlights

(unaudited, $ millions except per share amounts)	Three months ended							
	Jun 30 2017	**Mar 31 2017**	**Dec 31 2016**	**Sep 30 2016**	**Jun 30 2016**	**Mar 31 2016**	**Dec 31 2015**	**Sep 30 2015**
Revenues and other income	201	338	280	374	226	334	337	466
Adjusted EBITDA [1,2]	96	143	144	148	108	120	134	154
Net income (loss)	107	47	26	64	20	(8)	34	50
Net income (loss) attributable to shareholders of the Company	109	50	28	66	23	(6)	35	49
Basic earnings (loss) per share ($)	1.03	0.44	0.21	0.63	0.19	(0.11)	0.29	0.44
Normalized earnings per share ($) [1]	0.27	0.34	0.27	0.31	0.30	0.33	0.42	0.33
Net cash flows from operating activities	78	99	69	105	70	131	114	184
Adjusted funds from operations [1]	47	91	56	79	79	93	118	83
Purchase of property, plant and equipment and other assets	63	85	174	27	81	31	17	36

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

2 Commencing with the first quarter of 2016, the reported Ontario and British Columbia contracted facilities' adjusted EBTIDA was changed to include the adjusted EBITDA from joint ventures and the applicable comparative periods have been adjusted to conform to the current period's presentation.

	Three months ended							
Spot price averages	**Jun 30 2017**	**Mar 31 2017**	**Dec 31 2016**	**Sep 30 2016**	**Jun 30 2016**	**Mar 31 2016**	**Dec 31 2015**	**Sep 30 2015**
Alberta power ($ per MWh)	19	22	22	18	15	18	21	26
Alberta natural gas (AECO) ($ per Gj)	2.62	2.56	2.97	2.14	1.34	1.72	2.35	2.77
Capital Power's Alberta portfolio average realized power price ($ per MWh)	52	55	67	70	61	52	55	61

Factors impacting results for the previous quarters

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

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 short positions 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. During the quarter the Company announced a 6.8% increase in the annual dividend for holders of its common shares commencing with the third quarter dividend paid on October 31, 2016.

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.

Financial results for the first quarter of 2016 reflected the impact of lower Alberta power pricing averaging $18 per MWh. Revenues were lower compared with the corresponding period in 2015 mainly due to lower Alberta average spot prices and lower average realized prices on the Alberta portfolio. Adjusted EBITDA decreased quarter over quarter mainly due to unrealized losses recognized on commodity derivatives and emission credits held for trading. Adjusted EBITDA was also negatively impacted by increased environmental compliance costs resulting from higher contributions to the Climate Change and Emissions Fund and decreased generation at Quality Wind. The Company exercised its right to terminate the Sundance PPA effective March 24, 2016. As a result, Capital Power's first quarter net income was negatively impacted by a non-cash $53 million pre-tax loss with respect to the de-recognition of the Sundance PPA intangible asset.

For the quarter ended December 31, 2015, the Company recorded net income attributable to shareholders of $35 million and normalized earnings per share of $0.42, compared to $39 million and $0.20, respectively, for the quarter ended December 31, 2014. Net income attributable to common shareholders was lower for the quarter compared to the same quarter in the prior year primarily due to lower adjusted EBITDA, increased depreciation on new assets and net finance expense on additional financing, partially offset by the contribution of K2 equity earnings and lower taxes. Generating facilities contributed higher adjusted EBITDA for the fourth quarter with higher generation across the fleet, including the fully hedged Alberta baseload units, the addition of Shepard and a full quarter of Macho Springs compared to the same quarter in the prior year. These additions were more than offset by the quarter over quarter decrease in unrealized changes in the fair value of derivative contracts. In the fourth quarter of 2014, the Company reported unrealized gains of $37 million due to declining forward prices on its forward sales contracts. In the fourth quarter of 2015, the Company reported unrealized losses on its forward electricity sales contracts upon reversal of prior quarter gains and declining prices combined with its forward natural gas purchase contracts. Normalized earnings per share of $0.42 in the fourth quarter of 2015 was higher than the comparable amount of $0.20 in the fourth quarter of 2014 primarily due to the increase in adjusted EBITDA after removing the effects of unrealized changes in fair value of derivative contracts.

The results for the third quarter of 2015 reflected strong portfolio optimization results due to the forward sale of 100% of its commercial production realizing a price of $61 per MWh compared with the $26 per MWh Alberta spot power price average for the three months ended September 30, 2015. Alberta commercial facility results reflected the Keephills 3 planned outage and an unplanned outage at Clover Bar Energy Centre Unit 2. The Alberta electricity portfolio accounted for unrealized net gains of $27 million due to decreasing Alberta forward prices combined with the portfolio's net forward sales contracts.

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							
	Jun 30 2017	**Mar 31 2017**	**Dec 31 2016**	**Sep 30 2016**	**Jun 30 2016**	**Mar 31 2016**	**Dec 31 2015**	**Sep 30 2015**
Share price ($/common share)								
High	26.14	26.43	24.49	22.16	20.23	18.93	20.21	22.42
Low	24.05	23.15	19.90	18.95	17.31	16.37	15.41	18.28
Close	24.32	26.06	23.23	20.62	19.28	18.00	17.77	18.88
Volume of shares traded (millions)	14.8	17.0	23.2	16.0	14.8	19.2	20.5	19.4

Outstanding share and partnership unit data

As at July 20, 2017, the Company had 104.112 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, 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 July 20, 2017 were 108.322 million. The outstanding special limited voting share is held by EPCOR.

As at July 20, 2017, CPLP had 21.750 million general partnership units outstanding, 80.953 million common limited partnership units outstanding. All of the outstanding general partnership units and the outstanding common limited partnership units are held by the Company.

ADDITIONAL INFORMATION

Additional information relating to Capital Power Corporation, including the Company's annual information form and other continuous disclosure documents, is available on SEDAR at www.sedar.com.

Condensed Interim Consolidated Financial Statements of

CAPITAL POWER CORPORATION

(Unaudited, in millions of Canadian dollars)
Six months ended June 30, 2017 and 2016

CAPITAL POWER CORPORATION

Condensed Interim Consolidated Financial Statements
Six months ended June 30, 2017 and 2016

Condensed Interim Consolidated Financial Statements:

CAPITAL POWER CORPORATION

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

	Three months ended June 30, 2017	Three months ended June 30, 2016	Six months ended June 30, 2017	Six months ended June 30, 2016
Revenues	$ 182	$ 225	$ 504	$ 557
Other income	19	1	35	3
Energy purchases and fuel	(33)	(42)	(164)	(190)
Gross margin	168	184	375	370
Other raw materials and operating charges	(30)	(31)	(53)	(57)
Staff costs and employee benefits expense	(33)	(31)	(67)	(63)
Depreciation and amortization	(65)	(54)	(125)	(110)
Loss on termination of power purchase arrangement	-	-	-	(53)
Other administrative expense	(23)	(23)	(43)	(42)
Foreign exchange gain (loss)	9	(1)	11	7
Operating income	26	44	98	52
Net finance expense	(25)	(19)	(45)	(41)
Income from joint ventures	12	5	22	13
Income before tax	13	30	75	24
Income tax recovery (expense) (note 5)	94	(10)	79	(12)
Net income	$ 107	$ 20	$ 154	$ 12
Attributable to:				
Non-controlling interests	$ (2)	$ (3)	$ (5)	$ (5)
Shareholders of the Company	$ 109	$ 23	$ 159	$ 17
Earnings per share (attributable to common shareholders of the Company):				
Basic (note 6)	$ 1.03	$ 0.19	$ 1.47	$ 0.07
Diluted (note 6)	$ 1.03	$ 0.19	$ 1.47	$ 0.07

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

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

	Three months ended June 30, 2017	Three months ended June 30, 2016	Six months ended June 30, 2017	Six months ended June 30, 2016
Net income	$ 107	$ 20	$ 154	$ 12
Other comprehensive loss:				
Items that will not be reclassified subsequently to net income:				
Defined benefit plans:				
Actuarial gains[1]	2	-	2	-
Items that are or may be reclassified subsequently to net income:				
Cash flow hedges:				
Unrealized (losses) gains on derivative instruments[2]	(27)	(18)	(4)	19
Unrealized gains (losses) on derivative instruments – joint venture[3]	1	(6)	-	(9)
Reclassification of gains on derivative instruments to income for the period[4]	(18)	(19)	(35)	(49)
Reclassification of losses on derivative instruments to net income for the period – joint venture[5]	1	1	2	1
Net investment in foreign subsidiaries:				
Unrealized losses[6]	(19)	(1)	(21)	(13)
Total items that are or may be reclassified subsequently to net income, net of tax	(62)	(43)	(58)	(51)
Total other comprehensive loss, net of tax	(60)	(43)	(56)	(51)
Total comprehensive income (loss)	$ 47	$ (23)	$ 98	$ (39)
Attributable to:				
Non-controlling interests	$ (2)	$ (3)	$ (5)	$ (5)
Shareholders of the Company	$ 49	$ (20)	$ 103	$ (34)

[1] For the three and six months ended June 30, 2017 and June 30, 2016, net of income tax expense of nil.

[2] For the three and six months ended June 30, 2017, net of income tax recovery of $10 million and $1 million respectively. For the three and six months ended June 30, 2016, net of income tax recovery of $6 million and income tax expense of $7 million respectively.

[3] For the three and six months ended June 30, 2017, net of income tax expense of nil. For the three and six months ended June 30, 2016, net of income tax recovery of $2 million and $3 million respectively.

[4] For the three and six months ended June 30, 2017, net of reclassification of income tax expense of $7 million and $13 million respectively. For the three and six months ended June 30, 2016, net of reclassification of income tax expense of $7 million and $18 million respectively.

[5] For the three and six months ended June 30, 2017, net of reclassification of income tax recovery of nil and $1 million, respectively. For the three and six months ended June 30, 2016, net of reclassification of income tax expense of nil.

[6] For the three and six months ended June 30, 2017, net of income tax expense of $1 million. For the three and six months ended June 30, 2016, net of income tax recovery 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)

	June 30, 2017	December 31, 2016
Assets		
Current assets:		
Cash and cash equivalents	$ 47	$ 98
Trade and other receivables (note 8)	224	223
Inventories	131	118
Derivative financial instruments assets (note 9)	132	115
	534	554
Non-current assets:		
Other assets (note 8)	72	20
Derivative financial instruments assets (note 9)	48	154
Finance lease receivables	656	667
Government grant receivable	550	542
Other financial assets	3	5
Deferred tax assets	98	16
Equity-accounted investments	183	18
Intangible assets	574	299
Property, plant and equipment	4,378	3,764
Goodwill (note 7)	75	23
Total assets	$ 7,171	$ 6,062
Liabilities and equity		
Current liabilities:		
Trade and other payables	$ 198	$ 217
Derivative financial instruments liabilities (note 9)	48	48
Loans and borrowings	623	200
Deferred revenue and other liabilities	58	57
Provisions	20	26
	947	548
Non-current liabilities:		
Derivative financial instruments liabilities (note 9)	37	44
Loans and borrowings (notes 7 & 11)	1,811	1,308
Finance lease obligation	18	19
Deferred revenue and other liabilities	613	632
Deferred tax liabilities	395	379
Provisions	254	231
	3,128	2,613
Equity:		
Equity attributable to shareholders of the Company		
Share capital (note 10)	3,110	2,918
Deficit	(59)	(124)
Other reserves	(8)	49
Deficit and other reserves	(67)	(75)
	3,043	2,843
Non-controlling interests	53	58
Total equity	3,096	2,901
Total liabilities and equity	$ 7,171	$ 6,062

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 interests	Total
Equity as at January 1, 2017	$ 2,918	$ 22	$ 26	$ (10)	$ 11	$ (124)	$ 2,843	$ 58	$ 2,901
Net income	-	-	-	-	-	159	159	(5)	154
Other comprehensive income (loss):									
Defined benefit plan actuarial gains	-	-	-	2	-	-	2	-	2
Cash flow derivative hedge losses	-	(5)	-	-	-	-	(5)	-	(5)
Reclassification of gains to net income	-	(48)	-	-	-	-	(48)	-	(48)
Reclassification of losses to net income – joint venture	-	3	-	-	-	-	3	-	3
Unrealized loss on foreign currency translation	-	-	(20)	-	-	-	(20)	-	(20)
Tax on items recognized directly in equity	-	13	(1)	-	-	-	12	-	12
Other comprehensive income (loss)	$ -	$ (37)	$ (21)	$ 2	$ -	$ -	$ (56)	$ -	$ (56)
Total comprehensive income (loss)	-	(37)	(21)	2	-	159	103	(5)	98
Common share dividends (note 10)	-	-	-	-	-	(78)	(78)	-	(78)
Preferred share dividends (note 10)	-	-	-	-	-	(16)	(16)	-	(16)
Issue of share capital (note 10)	183	-	-	-	-	-	183	-	183
Share issue costs (note 10)	(7)	-	-	-	-	-	(7)	-	(7)
Deferred taxes on share issue costs	2	-	-	-	-	-	2	-	2
Share-based payment	-	-	-	-	(1)	-	(1)	-	(1)
Share options exercised	14	-	-	-	-	-	14	-	14
Equity as at June 30, 2017	$ 3,110	$ (15)	$ 5	$ (8)	$ 10	$ (59)	$ 3,043	$ 53	$ 3,096

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

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

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

	Share capital	Cash flow hedges[1]	Cumulative translation account[1]	Defined benefit plan actuarial losses[1]	Employee benefits reserve	Deficit	Equity attributable to shareholders of the Company	Non-controlling interests	Total
Equity as at January 1, 2016	$ 2,744	$ 42	$ 31	$ (9)	$ 10	$ (70)	$ 2,748	$ 68	$ 2,816
Net income	-	-	-	-	-	17	17	(5)	12
Other comprehensive loss:									
Cash flow derivative hedge gains	-	26	-	-	-	-	26	-	26
Cash flow derivative hedge losses – joint venture	-	(12)	-	-	-	-	(12)	-	(12)
Reclassification of gains to net income	-	(67)	-	-	-	-	(67)	-	(67)
Reclassification of losses to net income – joint venture	-	1	-	-	-	-	1	-	1
Unrealized loss on foreign currency translation	-	-	(13)	-	-	-	(13)	-	(13)
Tax on items recognized directly in equity	-	14	-	-	-	-	14	-	14
Other comprehensive loss	$ -	$ (38)	$ (13)	$ -	$ -	$ -	$ (51)	$ -	$ (51)
Total comprehensive income (loss)	-	(38)	(13)	-	-	17	(34)	(5)	(39)
Common share dividends (note 10)	-	-	-	-	-	(70)	(70)	-	(70)
Preferred share dividends (note 10)	-	-	-	-	-	(10)	(10)	-	(10)
Common shares purchased	(22)	-	-	-	-	-	(22)	-	(22)
Equity as at June 30, 2016	$ 2,722	$ 4	$ 18	$ (9)	$ 10	$ (133)	$ 2,612	$ 63	$ 2,675

[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)

	Six months ended June 30, 2017	2016
Cash flows from operating activities:		
Net income	$ 154	$ 12
Non-cash adjustments to reconcile net income to net cash flows from operating activities:		
Loss on termination of power purchase arrangement	-	53
Depreciation and amortization	125	110
Net finance expense	45	41
Fair value changes on commodity derivative instruments and emission credits held for trading	20	23
Unrealized foreign exchange gains	(11)	(6)
Income tax (recovery) expense	(79)	12
Income from joint venture	(22)	(13)
Reduction in finance lease receivable	11	10
Recognition of government grant deferred revenue	(26)	-
Other items	2	(6)
Change in fair value of derivative instruments reflected as cash settlement	-	(13)
Distributions received from joint ventures	14	17
Interest paid[1]	(37)	(41)
Other cash items	(9)	(1)
Change in non-cash operating working capital	(10)	3
Net cash flows from operating activities	177	201
Cash flows used in investing activities:		
Purchase of property, plant and equipment and other assets	(148)	(112)
Business acquisitions, net of acquired cash (note 7)	(839)	-
Genesee Coal Mine prepayment (note 8)	(70)	-
Other cash flows from investing activities	6	9
Change in non-cash investing working capital	(51)	(9)
Net cash flow used in investing activities	(1,102)	(112)
Cash flows from (used in) financing activities:		
Proceeds from issue of loans and borrowings (note 12)	820	115
Repayment of loans and borrowings	(21)	(146)
Issue costs on loans and borrowings	(7)	-
Issue of share capital (note 10)	183	-
Share issue costs (note 10)	(7)	-
Proceeds from exercise of share options	13	-
Common shares purchased (note 10)	-	(22)
Common share dividends paid (note 10)	(75)	(71)
Preferred share dividends paid (note 10)	(16)	(10)
Capitalized interest paid[1]	(6)	(1)
Income taxes paid	(6)	(4)
Net cash flows from (used in) financing activities	878	(139)
Foreign exchange loss on cash held in a foreign currency	(4)	(2)
Net decrease in cash and cash equivalents	(51)	(52)
Cash and cash equivalents at beginning of period	98	80
Cash and cash equivalents at end of period	$ 47	$ 28

[1] Total interest paid.

See accompanying notes to the condensed interim consolidated financial statements

1. Reporting entity:

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

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

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

2. Basis of presentation:

These condensed interim consolidated financial statements have been prepared by management in accordance with International Accounting Standards (IAS) 34, Interim Financial Reporting. The condensed interim consolidated financial statements do not include all of the information required for full annual financial statements and should be read in conjunction with the Company’s 2016 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 July 25, 2017.

3. Current accounting changes:

Effective January 1, 2017, the Company has adopted the following amendment:

IAS 7 - Statement of Cash Flows (Amendment) - The objective of this amendment is to improve disclosures of changes in financing liabilities to allow users of the financial statements to evaluate changes in liabilities arising from financing activities. The IAS 7 amendment is effective for annual periods beginning on or after January 1, 2017 and the resulting disclosure is presented in note 12.

4. Future accounting changes:

IFRS 15 – Revenue from Contracts with Customers – IFRS 15 is a single and comprehensive framework for revenue recognition that replaces previous revenue standards. IFRS 15 is effective for annual periods beginning on or after January 1, 2018 and is to be applied retrospectively. Management has assessed the applicability of this new standard on the Company’s various contracts and reporting systems and does not expect significant changes or reclassifications to the consolidated financial statements as a result of this transition. In addition, a number of the Company’s revenue contracts are accounted for under IFRS 11 – Joint Arrangements, IAS 17 – Leases, IAS 39 – Financial Instruments: Recognition and Measurement and are therefore excluded from the scope of IFRS 15. Management will utilize the cumulative effect method when initially applying the new standard which will reflect an adjustment to the opening equity balance at the date of initial application. This transition method also requires disclosure of what the transition year financial statements would have presented under the previous accounting standards. For those contracts affected by the new standard, Management anticipates increased disclosure requirements to consist of: separately disclosed and disaggregated revenue, opening and closing balances of receivables, contract assets and liabilities; and the explanation of significant changes in contract asset and liability balances during the reporting period.

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

4. Future accounting changes, continued:

IFRS 9 – Financial Instruments – IFRS 9 addresses the classification and measurement requirements of financial assets and liabilities and is intended to 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. IFRS 9 is effective for annual periods beginning on or after January 1, 2018 and is to be applied retrospectively. Earlier application is permitted. Management has assessed the applicability of this new standard on the Company's various contracts and reporting systems and does not expect a significant impact to the consolidated financial statements.

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 with respect to its lease arrangements for office space. IFRS 16 is effective for annual periods beginning on or after January 1, 2019. Management is currently assessing whether certain PPAs that are currently considered to be finance leases with the Company as the lessor will continue to be considered leases upon adoption of this new standard. This assessment and any associated practical expedients will also affect disclosures under IFRS 15 – Revenue from Contracts with Customers. Early application is permitted if IFRS 15 – Revenue from Contracts with Customers has also been applied.

5. Income tax:

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

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Income before tax	$ 13	$ 30	$ 75	$ 24
Income tax at the statutory rate of 27%	3	8	20	6
Increase (decrease) resulting from:				
(Non-taxable) non-deductible amounts	(5)	-	(6)	5
Amounts attributable to non-controlling interests	-	1	1	2
Change in unrecognized tax benefits[1]	(90)	-	(91)	(1)
Statutory and other rate differences	-	-	(1)	(2)
Other	(2)	1	(2)	2
Income tax (recovery) expense	$ (94)	$ 10	$ (79)	$ 12

[1] During the three months ended June 30, 2017, the Company reversed a previous write-down of deferred tax assets of $86 million related to the tax benefit associated with the Company's U.S. income tax loss carryforwards. As a result of the acquisition of Decatur Energy (see note 7) and the commissioning of Bloom Wind (see note 11), the Company expects to utilize a portion of its existing U.S. income tax loss carryforwards that were previously written down as it is now probable that sufficient future taxable income will be available from U.S. operations to utilize the underlying losses.

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

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 June 30, 2017	Three months ended June 30, 2016	Six months ended June 30, 2017	Six months ended June 30, 2016
Income for the period attributable to shareholders of the Company	$ 109	$ 23	$ 159	$ 17
Preferred share dividends of the Company[1]	(8)	(5)	(16)	(10)
Earnings used in the calculation of basic earnings per share	$ 101	$ 18	$ 143	$ 7

[1] Includes preferred share dividends and related taxes in respect of the three and six months ended June 30, 2017 and 2016 respectively.

	Three months ended June 30, 2017	Three months ended June 30, 2016	Six months ended June 30, 2017	Six months ended June 30, 2016
Weighted average number of common shares used in the calculation of basic earnings per share	98,094,096	96,138,650	97,208,030	96,293,747

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 and six months ended June 30, 2017 and 2016. 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 June 30, 2017	Three months ended June 30, 2016	Six months ended June 30, 2017	Six months ended June 30, 2016
Weighted average number of common shares used in the calculation of basic earnings per share	98,094,096	96,138,650	97,208,030	96,293,747
Effect of dilutive share purchase options[2]	349,441	23,025	353,476	-
Weighted average number of common shares used in the calculation of diluted earnings per share	98,443,537	96,161,675	97,561,506	96,293,747

[2] For the three and six months ended June 30, 2017, the average market price of the Company's common shares exceeded the exercise price of certain granted share purchase options, but had a neutral effect on earnings per share. For the three months ended June 30, 2016, 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 six months ended June 30, 2016, the average market price of the Company's common shares was below the exercise price of all granted share purchase options and as a result none of the share purchase options had a dilutive effect on earnings per share.

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

7. Business acquisitions

Acquisition of Decatur Energy

On June 13, 2017, a subsidiary of the Company acquired all of the equity interests in Decatur Power Holdings, LLC, which owns the Decatur Energy Center (Decatur Energy) from an affiliate of LS Power Equity Partners III. Decatur Energy is a 795 MW natural gas-fired combined cycle power generation facility located in Alabama. The purchase price consisted of $603 million (US$448 million), including working capital and other closing adjustments of $9 million (US$7 million). The preliminary allocation of the purchase price to the assets acquired and liabilities assumed based on their estimated fair values is as described below.

Acquisition of thermal facilities

During the first quarter of 2017, the Company entered into an agreement to acquire the thermal power business of Veresen Inc. On April 13, 2017, the Company announced that it had completed the acquisition of the two natural gas-fired power facilities in Ontario consisting of the 84 MW East Windsor Cogeneration Center (East Windsor) and a 50% interest in the 400 MW York Energy Center (York Energy). The purchase price for the natural gas-fired facilities consisted of (i) $235 million in total cash consideration, including working capital and other closing adjustments of $11 million, and (ii) the assumption of $253 million of project level debt (proportionate basis at acquisition date net book value). On June 1, 2017, the Company completed the acquisition of EnPower Green Energy Generation (EnPower) consisting of 10 MW of zero-emissions waste heat generation from two facilities (5 MW each) in British Columbia. The purchase price consisted of (i) $8 million of total cash consideration, including working capital and other closing adjustments of $3 million, and (ii) the assumption of $18 million of project level debt.

Purchase price allocation information

The preliminary allocations of the respective purchase prices to the assets acquired and liabilities assumed based on their estimated fair values is as follows:

	Decatur Energy	East Windsor	York Energy	EnPower	Total
Cash and cash equivalents	$ 1	$ 4	$ -	$ 2	$ 7
Trade and other receivables	8	6	-	-	14
Inventories	2	2	-	-	4
Equity accounted investment	-	-	153	-	153
Intangible assets	25	192	-	-	217
Property, plant and equipment	516	67	-	28	611
Goodwill	54	-	-	-	54
Trade and other payables	(2)	(1)	-	-	(3)
Loans and borrowings	-	(157)	-	(18)	(175)
Provisions	(1)	(1)	-	(1)	(3)
Deferred tax liabilities	-	(30)	-	(3)	(33)
Fair value of net assets acquired	$ 603	$ 82	$ 153	$ 8	$ 846

The Company expects to finalize the purchase price allocations for all acquisitions in the second half of 2017. The preliminary allocations of the assets acquired and liabilities assumed related to the acquisitions of East Windsor and York Energy require the finalization of working capital adjustments, which will occur in the third quarter of 2017. Due to the timing of the closing dates of the acquisitions of EnPower and Decatur Energy, information required to finalize those purchase price allocations is outstanding. As a result, the estimated fair values allocated to the acquired assets and assumed liabilities are subject to change.

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

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

7. Business acquisitions, continued:

The amounts allocated to trade and other receivables for the acquisitions above represent both the estimated fair value and the gross contractual amounts receivable. As at June 30, 2017, for each acquisition respectively, the Company estimated that all of the contractual cash flows pertaining to the acquired trade and other receivables were collectible.

The goodwill recognized on the acquisition of Decatur Energy is deductible for tax purposes and is primarily attributable to the potential for favourable re-contracting of the facility, and the potential to pursue other favourable commercial alternatives at the end of the current long-term contract, including the ability to sell power into the Pennsylvania, New Jersey, and Maryland interconnection market starting in 2023.

The project level debt assumed related to East Windsor bears interest at a rate of 6.28%, is repayable quarterly, and matures in September 2029. The project level debt assumed related to EnPower bears interest at a rate of 6.65%, is repayable monthly, and matures in October 2018.

The results of operations of Decatur Energy, East Windsor, York Energy and EnPower are included in the Company's consolidated statements of income and statements of changes in equity from the dates of acquisition. Such results of operations and the related assets and liabilities at the statement of financial position date are included in the consolidated statement of financial position. Since each respective acquisition date, the following revenues and income are included in the consolidated statements of income for the three and six months ended June 30, 2017:

	Decatur Energy	East Windsor	York Energy	EnPower	Total
Revenues	$ 4	$ 8	$ N/A	$ -	$ 12
Net income	2	1	6	-	9

Had the acquisitions occurred at January 1, 2017, the combined entity of the Company, Decatur Energy, East Windsor, York Energy and EnPower would have had a total of $204 million of revenues and $115 million of net income for the three months ended June 30, 2017 and a total of $552 million of revenues and $175 million of net income for the six months ended June 30, 2017, respectively.

In conjunction with the acquisition of the thermal power business of Veresen Inc., for the three and six months ended June 30, 2017, the Company incurred $5 million and $6 million, respectively, in acquisition costs which have been recorded on the Company's statement of income as other administrative expenses. The Company incurred less than $1 million in acquisition costs, for the three and six months ended June 30, 2017, in conjunction with the acquisition of Decatur Energy.

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

8. Amendment of Genesee Coal Mine Joint Venture Agreement:

On March 28, 2017, the Company entered into an agreement (the Amending Agreement) to amend the Genesee Coal Mine Joint Venture Agreement to accelerate the repayment of $70 million it would otherwise have owed to an external party during the term of the agreement and eliminate all future payments to the external party relating to existing capital assets of the Genesee Coal Mine (Coal Mine). Capital Power will also receive a security interest in the portion of the Coal Mine held by the external party.

The operations and management of the Coal Mine are unchanged as a result of the Amending Agreement. The Company will continue to control the Coal Mine and treat it as a subsidiary and will continue to pay the third party contracted mining fees for the ongoing operation of the Coal Mine. This payment is recorded as a prepayment, with the current and non-current portions recorded within trade and other receivables and other assets, respectively. The prepayment will be recognized into income through 2030, within energy purchases and fuel, based on the remaining lives of the existing capital assets of the Coal Mine.

9. 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:

	June 30, 2017				
	Energy and emission allowances		Foreign exchange	Foreign exchange	
	cash flow hedges	non-hedges	cash flow hedges	non-hedges	Total
Derivative instruments assets:					
Current	$ 21	$ 61	$ 50	$ -	$ 132
Non-current	14	34	-	-	48
Derivative instruments liabilities:					
Current	(4)	(40)	-	(4)	(48)
Non-current	(20)	(17)	-	-	(37)
Net fair value	$ 11	$ 38	$ 50	$ (4)	$ 95
Net notional buys (sells) (millions):					
Megawatt hours of electricity	(15)	(3)			
Gigajoules of natural gas		37			
Metric tons of emission allowances		(1)			
Number of renewable energy credits		(3)			
Cross currency interest rate swaps and forward currency purchases (U.S. dollars)			$ 195	$ 105	
Range of remaining contract terms in years [1]	0.1 to 10.0	0.1 to 7.9	3.9 to 8.9	0.3	

[1] Terms of foreign exchange cash flow hedge contracts require settlement in 1.0 years. The remaining years of the underlying derivatives of these contracts are reflected in the table above.

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

9. Derivative financial instruments and hedge accounting, continued:

	December 31, 2016			
	Energy and emission allowances		Foreign exchange	
	cash flow hedges	non-hedges	cash flow hedges	Total
Derivative instruments assets:				
Current	$ 38	$ 75	$ 2	$ 115
Non-current	31	67	56	154
Derivative instruments liabilities:				
Current	(5)	(43)	-	(48)
Non-current	(17)	(27)	-	(44)
Net fair value	$ 47	$ 72	$ 58	$ 177
Net notional buys (sells) (millions):				
Megawatt hours of electricity	(15)	(6)		
Gigajoules of natural gas		26		
Number of renewable energy credits		(1)		
Cross currency interest rate swaps (U.S. dollars)			$ 195	
Range of remaining contract terms in years[2]	0.1 to 10.5	0.1 to 8.4	4.5 to 9.5	

[2] Terms of foreign exchange cash flow hedge contracts require settlement in 1.5 years. The remaining years of the underlying derivatives of these contracts are reflected in the table above.

Fair values of derivative instruments are determined, using valuation techniques, inputs, and assumptions as described in the Company's 2016 annual consolidated financial statements. It is possible that the assumptions used in establishing fair value amounts will differ from future outcomes and the impact of such variations could be material.

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

	Three months ended June 30, 2017		Three months ended June 30, 2016	
	Unrealized (losses) gains	Realized gains	Unrealized (losses) gains	Realized gains
Energy cash flow hedges	$ (63)	$ 23	$ (53)	$ 26
Energy and emission allowances non-hedges	(30)	14	(15)	38
Foreign exchange cash flow hedges[3]	1	1	3	1
Interest rate non-hedges	-	-	(1)	-
Foreign exchange non-hedges	(4)	-	-	-

[3] For the three months ended June 30, 2017, unrealized losses of $7 million (three months ended June 30, 2016 – unrealized losses of $1 million) related to foreign exchange cash flow hedges were reclassified from other comprehensive loss 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)

9. Derivative financial instruments and hedge accounting, continued:

	Six months ended June 30, 2017		Six months ended June 30, 2016	
	Unrealized losses	Realized gains	Unrealized (losses) gains	Realized gains
Energy cash flow hedges	$ (52)	$ 46	$ (45)	$ 62
Energy and emission allowances non-hedges	(21)	27	(20)	68
Foreign exchange cash flow hedges[4]	(1)	1	4	1
Foreign exchange non-hedges	(4)	-	-	-

[4] For the six months ended June 30, 2017, unrealized losses of $9 million (six months ended June 30, 2016 – unrealized losses of $18 million) related to foreign exchange cash flow hedges were reclassified from other comprehensive loss to net income to offset the impact to unrealized foreign exchange gains from the revaluation of U.S. dollar denominated loans and borrowings.

Realized and unrealized gains and losses relate only to financial derivative instruments. The following realized and unrealized gains and losses are included in the Company's statements of income for the three and six months ended June 30, 2017 and 2016:

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Revenues	$ (26)	$ 35	$ 84	$ 153
Energy purchases and fuel	33	14	(32)	(43)
Foreign exchange loss	(9)	-	(10)	(17)
Finance expense	-	(1)	-	-

The Company has elected to apply hedge accounting on certain derivatives it uses to manage commodity price risk relating to electricity prices and currency risk relating to U.S. dollar denominated loans and borrowings. For the three and six months ended June 30, 2017 the changes in the fair value of the ineffective portion of hedging derivatives required to be recognized in the statement of income was a gain of $1 million and $2 million respectively recorded to foreign exchange gain (three and six months ended June 30, 2016 – nil).

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:

	June 30, 2017
Within one year	$ 21
Between 1 – 5 years	(7)
After more than 5 years	(6)
	$ 8

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

10. Share capital:

	Dividends declared							
	For the three months ended June 30,				For the six months ended June 30,			
	2017		2016		2017		2016	
	Per share	Total	Per share	Total	Per share	Total	Per share	Total
Common	$ 0.3900	$ 40	$ 0.3650	$ 35	$ 0.7800	$ 78	$ 0.7300	$ 70
Preference, Series 1	0.1913	1	0.1913	1	0.3826	2	0.3826	2
Preference, Series 3	0.2875	2	0.2875	2	0.5750	4	0.5750	4
Preference, Series 5	0.2813	2	0.2813	2	0.5626	4	0.5626	4
Preference, Series 7	0.3750	3	-	-	0.7500	6	-	-

	Dividends paid							
	For the three months ended June 30,				For the six months ended June 30,			
	2017		2016		2017		2016	
	Per share	Total	Per share	Total	Per share	Total	Per share	Total
Common	$ 0.3900	$ 38	$ 0.3650	$ 35	$ 0.7800	$ 75	$ 0.7300	$ 71
Preference, Series 1	0.1913	1	0.1913	1	0.3826	2	0.3826	2
Preference, Series 3	0.2875	2	0.2875	2	0.5750	4	0.5750	4
Preference, Series 5	0.2813	2	0.2813	2	0.5626	4	0.5626	4
Preference, Series 7	0.3750	3	-	-	0.7500	6	-	-

During the three and six months ended June 30, 2017, the Company did not purchase and cancel any of its outstanding common shares (three and six months ended June 30, 2016 – 59,388 and 1,245,600, respectively) under its Toronto Stock Exchange approved normal course issuer bids.

On April 24, 2017, the Company announced the completion of its previously announced public offering of 7,375,000 subscription receipts (Subscription Receipts), on a bought deal basis, at an issue price of $24.75 per Subscription Receipt, for total gross proceeds of $183 million less issue costs of $7 million. On June 13, 2017, upon closing of the Decatur Energy acquisition, each Subscription Receipt was converted for one common share of the Company. No dividend record date occurred during the period when the Subscription Receipts were outstanding and as such, no obligations to make any cash dividend equivalent payments were triggered.

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

11. Project equity financing for Bloom Wind:

On June 1, 2017, the Company commenced commercial operation of Bloom Wind. On June 12, 2017, the Company received $244 million (US$181 million) in financing from an affiliate of Goldman Sachs (Project Investor) in exchange for Class A interests of a subsidiary of the Company. The Company incurred issue costs of $7 million (US$5 million) associated with the financing. The interest of the Project Investor is accounted for as tax equity financing within loans and borrowings and will be adjusted for earnings, tax benefits and cash distributions paid. The maturity date of this obligation is subject to change and is driven by the date on which the Project Investor receives the agreed upon rate of return.

12. Reconciliation of movements of liabilities to cash flows arising from financing activities:

	Total loans and borrowings[1]	Finance lease obligation[2]	Net foreign exchange contracts used for hedging - assets
As at January 1, 2017	$ 1,508	$ 20	$ 58
Changes from financing cash flows:			
Proceeds from issue of loans and borrowings[3]	820	-	-
Repayment of loans and borrowings	(21)	-	-
Deferred debt issue costs	(7)	-	-
Addition through business acquisitions (note 7)	175	-	-
Total changes from financing cash flows	967	-	-
Effect of changes in foreign exchange rates	(41)	(1)	-
Change in fair value[4]	-	-	(12)
Total other changes	(41)	(1)	(12)
As at June 30, 2017	$ 2,434	$ 19	$ 46

[1] Includes deferred debt issue costs.

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

[3] In June 2017, the Company increased its committed credit facilities by $389 million (US$300 million), which matures in June 2018. Proceeds from issue of loans and borrowings include the use of this increase in committed credit facilities, the use of existing credit facilities and the Bloom Wind project equity financing described in note 11.

[4] Includes the change in fair value of $4 million related to the forward currency purchases entered into in the second quarter of 2017 (see note 9).

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

13. Financial instruments:

Fair values

Details of the fair values of the Company's derivative instruments are described in note 9.

The classification and measurement of the Company's other short-term financial instruments are consistent with the methodologies described in the Company's 2016 annual consolidated financial statements. Due to the short-term nature of the financial instruments, the fair values are not materially different from their carrying amounts.

The fair values of the Company's other long-term financial instruments are determined using the same valuation techniques, inputs, and assumptions as described in the Company's 2016 annual consolidated financial statements. The classification, carrying amount and fair value of the Company's other financial instruments are summarized as follows:

		June 30, 2017		December 31, 2016	
	Fair value hierarchy level	Carrying amount	Fair value	Carrying amount	Fair value
Loans and receivables[1]					
Other financial assets	Level 2	$ 5	$ 5	$ 7	$ 7
Finance lease receivables	Level 2	678	764	689	762
Government grant receivable	Level 2	603	603	594	594
Other financial liabilities[1]					
Loans and borrowings	Level 2	2,434	2,520	1,508	1,540
Finance lease obligation	Level 2	19	21	20	20

[1] Includes current portion.

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, 2016.

The fair value measurement of a financial instrument is included in only one of the three levels described in the Company's 2016 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. There were no significant transfers between levels in the fair value hierarchy for the three and six months ended June 30, 2017 and the year ended December 31, 2016.

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 2016 annual consolidated financial statements.

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

13. Financial instruments, continued:

Fair value hierarchy, continued

	June 30, 2017			
	Level 1	Level 2	Level 3	Total
Derivative financial instruments assets	$ -	$ 170	$ 10	$ 180
Derivative financial instruments liabilities	-	(67)	(18)	(85)

	December 31, 2016			
	Level 1	Level 2	Level 3	Total
Derivative financial instruments assets	$ -	$ 260	$ 9	$ 269
Derivative financial instruments liabilities	-	(73)	(19)	(92)

Valuation techniques used in determination of fair values within 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 June 30, 2017 and December 31, 2016, the Company holds a contract for the sale of renewable energy certificates (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. The table below presents ranges for the Company's Level 3 inputs:

	June 30, 2017	December 31, 2016
REC pricing (per certificate)	$0.50 to $0.54	$0.54 to $0.58
Power pricing (per megawatt hour)	$24.41 to $40.13	$22.67 to $44.44

Valuation process applied to Level 3

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

	June 30, 2017	December 31, 2016
REC pricing[1]	$ 1	$ 1
Power pricing[1]	8	$ 8

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

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

13. Financial instruments, continued:

Fair value hierarchy, continued

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:

	Six months ended June 30, 2017	Year ended December 31, 2016
As at January 1[1]	$ (10)	$ 11
Unrealized and realized gains included in net income[2]	2	1
Unrealized and realized losses included in other comprehensive loss	1	(19)
Settlements[3]	(1)	(3)
As at end of period	$ (8)	$ (10)
Total unrealized gains (losses) for the period included in other comprehensive loss	$ 1	$ (19)
Total unrealized gains (losses) for the period included in net income[2]	$ 1	$ (2)

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

[2] Gains (losses) are recorded in revenues.

[3] Relates to settlement of financial derivative instruments.

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

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

14. 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.

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

	Three months ended June 30, 2017				Three months ended June 30, 2016			
	Canada	U.S.	Inter-area eliminations	Total	Canada	U.S.	Inter-area eliminations	Total
Revenues - external	$ 138	$ 44	$ -	$ 182	$ 197	$ 28	$ -	$ 225
Revenues - inter-area	9	11	(20)	-	(4)	(16)	20	-
Other income	16	3	-	19	1	-	-	1
Total revenues and other income	$ 163	$ 58	$ (20)	$ 201	$ 194	$ 12	$ 20	$ 226

	Six months ended June 30, 2017				Six months ended June 30, 2016			
	Canada	U.S.	Inter-area eliminations	Total	Canada	U.S.	Inter-area eliminations	Total
Revenues - external	$ 425	$ 79	$ -	$ 504	$ 489	$ 68	$ -	$ 557
Revenues - inter-area	18	29	(47)	-	5	(1)	(4)	-
Other income	32	3	-	35	3	-	-	3
Total revenues and other income	$ 475	$ 111	$ (47)	$ 539	$ 497	$ 67	$ (4)	$ 560

	As at June 30, 2017			As at December 31, 2016		
	Canada	U.S.	Total	Canada	U.S.	Total
Property, plant and equipment	$ 3,391	$ 987	$ 4,378	$ 3,348	$ 416	$ 3,764
Intangible assets	497	77	574	249	50	299
Goodwill	-	75	75	-	23	23
Other assets	71	1	72	19	1	20
	$ 3,959	$ 1,140	$ 5,099	$ 3,616	$ 490	$ 4,106

15. Subsequent event:

On July 25, 2016, the Company's Board of Directors approved an increase of 7.1% in the annual dividend to $1.67 per common share effective for the third quarter of 2017.

16. Comparative figures:

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