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Capital Power reports fourth quarter and year-end 2016 results

EDMONTON, Alberta – Capital Power Corporation (Capital Power, or the Company) (TSX: CPX) today released financial results for the fourth quarter and year ended December 31, 2016.

Net income attributable to shareholders in the fourth quarter of 2016 was $28 million and basic earnings per share attributable to common shareholders was $0.21 per share, compared with $35 million, or $0.29 per share, in the comparable period of 2015. Normalized earnings attributable to common shareholders in the fourth quarter of 2016, after adjusting for one-time items and fair value adjustments, were $26 million or $0.27 per share compared with $41 million or $0.42 per share in the fourth quarter of 2015.

Net cash flows from operating activities were $69 million in the fourth quarter of 2016 compared with $114 million in the fourth quarter of 2015. Funds from operations (FFO) were $75 million in the fourth quarter of 2016, compared to $125 million in the fourth quarter of 2015.

For the year ended December 31, 2016, net income attributable to shareholders was $111 million and basic earnings per share attributable to common shareholders was $0.91 per share compared with $90 million and $0.70 for the year ended December 31, 2015. For the year ended December 31, 2016, normalized earnings attributable to common shareholders were $117 million, or $1.22 per share, compared with $111 million, or $1.15 per share in 2015.

Net cash flows from operating activities were $375 million for the year ended December 31, 2016 compared with $419 million for the year ended December 31, 2015. FFO totaled $384 million in 2016 compared with $400 million in 2015.

"In 2016, Capital Power met its annual operating and financial targets, while continuing to deliver on its corporate priorities," said Brian Vaasjo, President and CEO of Capital Power. "We achieved these objectives despite challenging market and economic conditions that contributed to record-low spot power prices and unprecedented changes to the Alberta power market."

"Our facilities produced an average availability of 94% and we generated FFO of $384 million, which was consistent with our $380 to $430 million target range," continued Mr. Vaasjo. "Our FFO results reflected the one-time $20 million Sundance PPA settlement payment in the fourth quarter of 2016 to the Alberta Balancing Pool."

"We arrived at a satisfactory agreement with the Government of Alberta on fair compensation for the early retirement of our coal assets and settled the Sundance PPA dispute issue. The resolution of these two issues has removed the largest uncertainties the Company has ever faced. We can now move forward with confidence, knowing that developing generation opportunities in Alberta will continue to be predicated on market and economic signals."

"For 2017, we continue to focus on increasing our contracted cash flows to support a sustainable and growing dividend to our shareholders," added Mr. Vaasjo. "The completion of our Bloom Wind project in the third quarter and the commencement of annual coal compensation payments of $52 million per year, will add to our contracted cash flows and with a strong balance sheet and financial flexibility to fund growth, Capital Power is well-positioned to add both renewable and thermal assets in Canada and the United States."

Operational and Financial Highlights [1] (unaudited)	**Three months ended December 31**		**Year ended December 31**	
(millions of dollars except per share and operational amounts)	**2016**	**2015**	**2016**	**2015**
Electricity generation (excluding Sundance C power purchase arrangement (Sundance PPA)) (Gigawatt hours)	3,793	3,929	15,328	14,567
Generation facility availability (excluding Sundance PPA) (%)	94%	99%	94%	95%
Revenues	$ 280	$ 337	$ 1,214	$ 1,241
Adjusted EBITDA [2]	$ 144	$ 134	$ 520	$ 482
Net income	$ 26	$ 34	$ 102	$ 86
Net income attributable to shareholders of the Company	$ 28	$ 35	$ 111	$ 90
Basic and diluted earnings per share	$ 0.21	$ 0.29	$ 0.91	$ 0.70
Normalized earnings attributable to common shareholders [2]	$ 26	$ 41	$ 117	$ 111
Normalized earnings per share [2]	$ 0.27	$ 0.42	$ 1.22	$ 1.15
Net cash flows from operating activities	$ 69	$ 114	$ 375	$ 419
Funds from operations [2]	$ 75	$ 125	$ 384	$ 400
Purchase of property, plant and equipment and other assets	$ 174	$ 17	$ 313	$ 140
Dividends per common share, declared	$ 0.3900	$ 0.3650	$ 1.5100	$ 1.4100

1 The operational and financial highlights in this press release should be read in conjunction with the Company's Management's Discussion and Analysis and the audited Consolidated Financial Statements for the year ended December 31, 2016.

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

Significant events

Project equity financing and completion of contract for output for Bloom Wind

Bloom Wind is a 178 megawatt (MW) facility in southwestern Kansas consisting of 54 3.3 MW turbines and is anticipated to cost $358 million (US$272 million). Construction of Bloom Wind commenced during the third quarter of 2016. Commercial operation of the facility is expected in the third quarter of 2017. Capital Power will operate Bloom Wind under a 10-year fixed price contract with Allianz Risk Transfer (rated AA- stable by Standard & Poor's), a subsidiary of Allianz SE, the worldwide insurance and asset management group, covering 100% of the project's output. Under the contract, which was executed on April 21, 2016, Capital Power will swap the market revenue of the project's generation for a fixed annual payment for a 10-year term. The agreement will secure long-term predictable revenues and mitigate generation volume uncertainty related to wind resources, allowing Bloom Wind to secure renewable energy tax equity financing and provide Capital Power the opportunity to complete its first wind development project in the growing U.S. renewables market.

On December 13, 2016, the Company reached an agreement with Goldman Sachs Alternative Energy Group (Project Investor) to fund an expected 65 to 70 percent of Bloom Wind costs through equity contributions in exchange for Class A shares of a subsidiary of the Company. These equity contributions are expected to begin upon the completion of the project and satisfaction of all conditions precedent, which is currently anticipated to occur in the third quarter of 2017. The Project Investor is entitled to the majority of income and tax benefits from the project until the Project Investor achieves an agreed upon target rate of return. Subsequent to this date, the structure "flips" and the Company is entitled to the majority of income, cash flows and tax benefits, while the Project Investor's equity investment will be accounted for as a non-controlling interest. Prior to the Project Investor achieving their target rate of return, their interest will be accounted for as tax equity financing within loans and borrowings.

Termination of the Sundance PPA

On March 24, 2016, Capital Power notified the Balancing Pool of the Company's decision to terminate its role as Buyer of the Sundance PPA. The Company recorded a pre-tax non-cash loss of $53 million ($46 million post-tax) with respect to the de-recognition of the Sundance PPA intangible asset. Effective March 24, 2016, the Company also de-designated certain energy cash flow hedges related to forecasted transactions no longer expected to occur as a result of the Sundance PPA termination, which resulted in the reclassification of unrealized gains of $5 million ($4 million post-tax) from other comprehensive income (loss) to net income. No hedge ineffectiveness resulted from the de-designation of the cash flow hedges.

During the third quarter of 2016, the Government of Alberta commenced legal action that sought to retroactively amend and restate certain power purchase arrangements, including the Sundance PPA, and prevent the Balancing Pool from accepting Capital Power's termination of its role as Buyer of the Sundance PPA. On November 24, 2016, the Government of Alberta agreed to discontinue its legal action against Capital Power and to arrange for the Balancing Pool to accept Capital Power's termination of its role as a Buyer of the Sundance PPA in accordance with the terms of the Sundance PPA. In consideration of these actions, Capital Power and its syndicate partners agreed to pay the Balancing Pool $39 million, of which Capital Power's portion is $20 million ($15 million post-tax).

Off-coal agreement

On November 24, 2016, the Company announced it had reached an agreement with the Government of Alberta related to the transition away from coal-fired generation in Alberta by 2030. As compensation for the capital that the Company invested in coal generating assets that will be stranded effective December 31, 2030, Capital Power will receive cash payments from the Province of Alberta of $52 million annually for 14 years, commencing July 31, 2017 through to July 31, 2030, for a total of $734 million. Capital Power has agreed to continue to participate in the Alberta electricity market, support the local communities surrounding the coal facilities through 2030, and fulfill its pension and other commitments to employees. This settlement also recognizes the potential for extending the economic lives of certain assets through conversion to natural gas.

Alberta electricity market design

On November 23, 2016, the Government of Alberta announced the transition of Alberta's electricity market from an energy-only market to a capacity market, for which the framework is expected to be in place by 2021. The Government of Alberta has committed to ensuring that existing investments will be treated fairly, and that the new market framework will continue to promote a level playing field between existing and potential new capacity. Design and implementation activities will be undertaken in 2017 and 2018, with the Alberta Electric System Operator (AESO) currently targeting having the first capacity auction in 2019 for delivery in 2021.

Canadian federal regulation of natural gas generation

On November 21, 2016, the Government of Canada announced its plan to phase-out traditional coal-fired electricity by 2030, and to establish emission standards for natural gas-fired turbines, including new boilers, existing boilers, and existing coal boilers converted to natural gas. Under the proposal, coal boilers that are converted to natural gas would be subject to an interim emissions standard that would apply for the earlier of 15 years, or 2045, after which time the units would be required to meet the emissions standards for new generation.

The implementation of the phase-out and finalization of the natural gas regulations will be the subject of industry consultations expected to commence in 2017. At this time, it is expected that publication of the natural gas regulation in Canada Gazette Part I will be in late 2017, with final publication in Canada Gazette Part II in late 2018.

Updates to Alberta's Climate Leadership Plan

In late September 2016, the Government of Alberta initiated formal consultations regarding the performance standard and carbon pricing framework that will apply, effective January 1, 2018, to facilities that are currently subject to the Specified Gas Emitters Regulation (SGER). The standard and pricing framework will be reflected in a new Carbon Competitiveness Regulation that will replace the current SGER regulation. The Company expects that the performance standard for the electricity sector will be consistent with the emissions performance of a combined-cycle natural gas-fired facility in Alberta, with specific details to be developed through consultation.

Alberta renewable electricity procurement

On January 26, 2016, the Government of Alberta tasked the AESO to develop and implement a plan to bring on new renewable electricity generation capacity to the grid by 2030 in connection with the Climate Leadership Plan. The AESO undertook a process to receive industry perspectives regarding various elements of the Renewable Electricity Program (REP), and provided its recommendations regarding the REP to the Government of Alberta on May 31, 2016. On September 14, 2016, the Government of Alberta confirmed a firm target of achieving 30% of Alberta's electricity use by 2030 from renewable energy sources, and announced that the Government of Alberta would support 5000 MW of additional renewable capacity to help achieve that target. The AESO has provided a timeline for the first REP auction in 2017 with a request for proposals expected in the fourth quarter of 2017 with winning bids required to be operational in 2019. Financial support for projects funded through the first REP auction will reflect a contract-for-differences approach, and be for a 20-year term. Future REP auctions may be structured differently with respect to the form and amount of financial support provided, and contract length.

Preferred share offering

On October 4, 2016, the Company issued 8 million Cumulative Minimum Rate Reset Preference Shares, Series 7 (Series 7 Shares) priced at $25.00 per share for gross proceeds of $200 million less issue costs of $5 million on a bought deal basis with a syndicate of underwriters. The preferred shares will pay fixed cumulative dividends of $1.50 per share per annum, yielding 6.00% per annum, payable on the last business day of March, June, September and December of each year, as and when declared by the Board of Directors of Capital Power, for the initial period ending December 31, 2021. The dividend rate will be reset on December 31, 2021 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 5.26%, provided that in any event such rate shall not be less than 6.00%. The Series 7 Shares are redeemable by Capital Power, at its option, on December 31, 2021 and every five years thereafter at a value of $25.00 per share.

Holders of the Series 7 Shares will have the right to convert all or any part of their shares into Cumulative Floating Rate Preference Shares, Series 8 (Series 8 Shares), subject to certain conditions, on December 31, 2021 and every five years thereafter. Holders of the Series 8 Shares will be entitled to receive a cumulative quarterly floating dividend at a rate equal to the sum of the then 90-day Government of Canada Treasury Bill yield plus 5.26%, as and when declared by the Board of Directors of Capital Power. The Series 8 Shares would be redeemable by Capital Power, at its option, on December 31, 2026 and December 31 of every fifth year thereafter at a value of $25.00 per share. The Series 8 shares would also be redeemable by Capital Power, at its option, on any date after December 31, 2021, excluding December 31 of every fifth year, at a value of $25.50 per share.

$160 million private placement debt financing

On September 13, 2016, the Company issued a $160 million, 10-year unsecured senior note to Prudential Capital Group. The note bears an annual interest rate of 3.85%, payable semi-annually, and matures in September 2026. The net proceeds of the offering were used to repay amounts owing under credit facilities and for general corporate purposes.

K2 Wind partnership

On August 9, 2016, a consortium composed of Axium Infrastructure, Alberta Teachers' Retirement Fund Board, and Manulife Financial Corporation acquired Samsung Renewable Energy's one-third interest in K2 Wind. There is no change to the remaining interest in K2 Wind, which is still held equally by Pattern Energy Group Inc. and the Company.

Dividend increase

On July 25, 2016, the Company announced that its Board of Directors approved a 6.8% increase in the annual dividend for holders of its common shares, from $1.46 per common share to $1.56 per common share. This increased common dividend commenced with the third quarter 2016 quarterly dividend paid on October 31, 2016 to shareholders of record at the close of business on September 30, 2016.

Preferred Shares (Series 1) dividend rate reset

On February 18, 2016, the Board of Directors of Capital Power declared a quarterly dividend of $0.19125 per share on the Company's Cumulative 5-Year Rate Reset Preference Shares, Series 1 (Series 1 Shares). This quarterly dividend was paid on March 31, 2016. The Annual Fixed Dividend Rate for the Series 1 Shares for the next five-year period was reset from 4.60% to 3.06% on December 31, 2015 at a rate equal to the sum of the then Government of Canada bond yield and 2.17%. The Annual Fixed Dividend Rate will be next reset on December 31, 2020 and every five years thereafter.

Subsequent events

Appointments to the Board of Directors

On February 17, 2017, the Capital Power Board of Directors approved the appointment of Keith Trent and Kate Stevenson to the Board of Directors. The appointments will be effective April 3, 2017.

Acquisition of thermal facilities

On February 21, 2017, the Company announced that is has entered into an agreement to acquire the thermal power business of Veresen Inc., consisting of two gas-fired and two waste-heat generation facilities.

Under the terms of the agreement, Capital Power will acquire 284 MW of generation from two natural gas-fired power facilities 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 will operate both facilities. Both East Windsor and York Energy are under long-term power purchase agreements, with the A rated Ontario Independent Electricity System Operator, with original terms expiring in 2029 and 2032, respectively. Both facilities earn revenue through fixed capacity payments partly indexed to inflation and are compensated for operations and maintenance, and fuel (commodity and transportation) as well as start-up costs. Additionally, East Windsor is under a long-term steam supply agreement with a BBB rated third party.

The transaction also includes 10 MW of zero-emissions waste-heat generation from two facilities (5 MW each) located at Westcoast Energy's BC Gas Pipeline compressor stations in Savona and 150 Mile

House, British Columbia. The waste heat facilities are under 20-year Electricity Purchase Agreements (EPAs), with AA rated BC Hydro, with original terms expiring in 2028. The EPAs provide for partial inflation indexation as well as premium pricing under peak load hours. A third party provides operations and maintenance services for the assets under a long-term agreement.

The purchase price for the acquisition is $225 million in total cash consideration, subject to working capital adjustments and other closing adjustments, and the assumption of $275 million of project level debt (on a proportionate basis). Capital Power expects to finance the transaction through existing cash and its credit facilities. The transaction is expected to close in the second quarter of 2017, subject to regulatory approvals and satisfaction of closing conditions.

Analyst conference call and webcast

Capital Power will be hosting a conference call and live webcast with analysts on February 21, 2017 at 9:00 am (MST) to discuss the fourth quarter and 2016 year-end 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) 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), 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 contained in the Company's Management's Discussion and Analysis, prepared as of February 17, 2017, for the year ended December 31, 2016 which is available under the Company's profile on SEDAR at www.SEDAR.com.

Forward-looking information

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

Material forward-looking information in this press release includes expectations regarding: (i) the transition to and structure of the proposed capacity market in Alberta, (ii) growth opportunities that may come to the Company as a result of new renewable electricity generation capacity, (iii) future contracted cash flows, dividend growth and business growth, (iv) financing plans for the acquisition of the thermal facilities, (v) closing of the acquisition of the thermal facilities, and (vi) timing of the closing date of the acquisition of the thermal facilities.

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, 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.

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CAPITAL POWER CORPORATION

Management's Discussion and Analysis

This management's discussion and analysis (MD&A), prepared as of February 17, 2017, should be read in conjunction with the audited consolidated financial statements of Capital Power Corporation and its subsidiaries for the years ended December 31, 2016 and December 31, 2015, the annual information form of Capital Power Corporation for the year ended December 31, 2016 and the cautionary statements regarding forward-looking information which begin on page 9. 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 years ended December 31, 2016, 2015 and 2014 is based on the audited consolidated financial statements of the Company 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 February 17, 2017.

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FORWARD-LOOKING INFORMATION

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

Material forward-looking information in this MD&A includes expectations regarding:

- future revenues, expenses, earnings and adjusted funds from operations,
- the future pricing of electricity and market fundamentals in existing and target markets,
- future dividend growth,
- the Company's future cash requirements including interest and principal repayments, capital expenditures, dividends and distributions,
- the Company's sources of funding, adequacy and availability of committed bank credit facilities and future borrowings,
- future growth and emerging opportunities in the Company's target markets including the focus on certain technologies,
- the timing of, funding of, and costs for existing, planned and potential development projects and acquisitions,
- 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, and
- expectations pertaining to the acquisition of thermal facilities (see Subsequent Events) regarding: (i) financing plans for the transaction, (ii) closing of the transaction and (iii) financial impacts including expected accretion in adjusted funds from operations and earnings.

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 Targets for 2017 sections, and
- anticipated performance of the acquired thermal facilities (see Subsequent 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 acquisition,
- 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 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. Capital Power owns more than 3,200 megawatts (MW) of power generation capacity across North America and owned 371 MW of capacity through its interest in the Sundance C power purchase arrangement (Sundance PPA) until the Company terminated its role as Buyer of the Sundance PPA, effective March 24, 2016 (See Significant Events). More than 700 MW of owned generation capacity is in advanced development in Alberta and under construction in Kansas.

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

Capital Power's corporate strategy is based on its vision to be recognized as one of North America's most respected, reliable and competitive power generators. The corporate strategy comprises the business strategy to operate as a competitive power producer and the financial strategy designed to provide consistent access to low-cost capital. The Company is committed to a position that provides for future dividend growth, an investment-grade credit rating supported by contracted cash flows, and a prudent expansion strategy.

(a) **Geographic focus** – Canada and the U.S. for contracted power generation and Alberta for merchant power generation.

(b) **Technology focus** – large-scale thermal technologies, renewable wind and solar facilities with a limited number of technologies and suppliers for each type of generation.

(c) **Financial strategy** – supportive of the business strategy; intended to provide access to cost competitive capital throughout the business cycle. This is facilitated by maintaining an investment grade credit rating with a stable and growing dividend. This requires a moderate risk profile where price volatility from merchant facilities is balanced with long-term contracted assets and hedging of merchant power price risk through forward sales.

(d) **Operational excellence** – safely manage, operate and maintain its power generation facilities in a manner that optimizes efficiency, productivity and reliability, and minimizes costs while reducing environmental impact and risk.

(e) **Disciplined growth** – restricted to the geographic and technology focuses with specific financial hurdles and rigorous due diligence processes.

The Company continues to pursue growth in contracted power generation across North America as well as creating additional value in the Alberta market through power generation growth and portfolio trading strategies. During 2016, the Company commenced construction of the Bloom Wind project (Bloom Wind) (see Significant Events) and continued the development of Genesee 4 and 5. Continuation and timing of the Genesee 4 and 5 project will be considered once more Alberta market structure certainty exists and new generation is required in Alberta to balance supply and demand.

The Company is assessing a number of additional projects in various stages of development, including future uses of the Genesee site and potential conversions of the Company's coal-fired generation facilities to natural gas, and it continues to evaluate acquisition prospects to strengthen its existing portfolio. To help ensure that the Company's growth strategy does not compromise its financial condition, it employs hurdle rates of return for acquisition and development project opportunities and evaluates them against the Company's current strategic plan. As part of the Company's growth strategy through developing and building new assets, the Company views power facility construction as a core competency.

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 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.

Alberta Climate Leadership Plan

	2016 target	2016 actual results
Compensation	Ensure fair compensation will be received for the proposed accelerated closure of the Company's coal facilities.	During the fourth quarter of 2016, the Company reached an agreement with the Government of Alberta related to compensation for the phase-out of coal-fired generation by 2030.

On November 24, 2016, the Company announced details of the agreement reached with the Government of Alberta related to the 2030 phase-out of coal-fired generation. As compensation for the capital that the Company invested in coal generating assets that will be stranded effective December 31, 2030, the Company will receive cash payments from the Province of Alberta (the Province) of $52 million annually for 14 years, commencing July 31, 2017, for a total of $734 million. The Company has agreed to continue to participate in the Alberta electricity market, support the local communities surrounding the coal facilities through 2030, and fulfill its pension and other commitments to employees.

Operational excellence

Performance measure	2016 target	2016 actual results
Facility availability average [1]	94% or greater	94%
Capital expenditures for facility maintenance, Genesee mine extension and other (sustaining capital expenditures) [2]	$65 million	$55 million
Facility operating and maintenance expenses	$200 million to $220 million	$205 million

1 All facilities excluding the Sundance PPA.

2 Includes sustaining capital expenditures net of joint venture contributions of $7 million.

The Company's facility availability averaged 94% which reflected planned outages at Genesee 2, Genesee 3, Clover Bar Energy Centre, Southport, Roxboro and Joffre as well as an extension of the planned outage at Shepard. Unplanned outages also occurred at Keephills 3, Southport, Genesee, Clover Bar Energy Centre, Beaufort Solar and Joffre.

Sustaining capital expenditures were less than target primarily due to lower expenditures for the Company's planned outages and the deferral of various projects 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 2016 were consistent with the target range.

Disciplined growth

Performance measure	2016 target	Status as at December 31, 2016
Genesee 4 and 5	Proceed with construction based on clarification regarding the Alberta Climate Leadership Plan (CLP) and price signals from the energy only market.	In 2016, limited construction activities took place and full notice to proceed was deferred. Continuation and timing of the Genesee 4 and 5 project will be considered once more Alberta market structure certainty exists and new generation is required in Alberta to balance supply and demand.
New development	Execute a contract for the output of a new development.	Construction of Bloom Wind commenced in the third quarter of 2016, and Capital Power will operate the facility under a 10-year fixed price contract which was executed on April 21, 2016 (see Significant Events).

Financial stability and strength

Performance measure	2016 target	2016 actual results
Funds from operations [1]	$380 million to $430 million	$384 million

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

Actual funds from operations for the year ended December 31, 2016 was in the target range and lower than the expectation of exceeding the mid-point of the target range as disclosed after the third quarter of 2016 primarily due to the payment made to the Balancing Pool to terminate the Company's role as a Buyer of the Sundance PPA (see Significant Events).

OUTLOOK AND TARGETS FOR 2017

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 Subsequent Events) to be $320 million to $365 million, which includes the expected results of the acquired assets subsequent to transaction close. The 2017 guidance was based on a price of $44 per megawatt hour (MWh) for 2017 for the Alberta baseload assets which are 100% hedged. The 2017 Alberta forward power price average of $32 per MWh is materially lower than the hedged price due to a combination of events including lower forward natural gas prices for 2017 and continued expected low economic growth in Alberta and its expected impact on Alberta power demand growth. Lower expected growth in the Alberta economy is largely the result of the continuation of depressed global oil prices.

Priorities for the Company in 2017 will be to work with the Government of Alberta concerning the transition away from an energy-only market to a capacity market (see Significant Events) 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 upcoming Renewable Electricity Program (REP) procurement process (see Significant Events).

In 2017, Capital Power's availability target of 95% reflects major scheduled maintenance outages for Genesee 1, Clover Bar Energy Centre 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 2016 (as at the beginning of the year) compared with 2017, 2018 and 2019 (all as at December 31, 2016) were:

Alberta commercial portfolio positions and power prices	2016	2017	2018	2019
Percentage of baseload generation sold forward [1]	100%	100%	53%	40%
Contracted price [2]	High-$40 per MWh	Mid-$40 per MWh	Low-$50 per MWh	Low-$50 per MWh
Forward Alberta pool prices	$35	$32	$39	$41

1 Based on the Alberta baseload plants plus 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 (see Significant Events).

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 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. Each annual increase is subject to changing circumstances and approval by the Board of Directors of Capital Power at the time of the increase.

See Liquidity and Capital Resources for discussion of future cash requirements and expected sources of funding. It is expected that no additional common share equity will be required in 2017.

Performance measure targets for 2017

Performance measure	2017 target
Operational excellence [1]	
Facility availability average	95% or greater
Sustaining capital expenditures	$75 million
Genesee performance standard [2]	$10 million
Facility operating and maintenance expenses	$205 million to $230 million
Disciplined growth	
Bloom Wind	Complete Bloom Wind (see Significant Events) on time and on budget.
New development	Execute contracts for the output of two new developments.
Financial stability and strength [1]	
Adjusted funds from operations [3]	$320 million to $365 million

1 These performance measures include the expected impact of the acquisition of the thermal power business of Veresen Inc. (see Subsequent Events) for the period subsequent to transaction close.

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

3 Adjusted funds from operations is a non-GAAP measure. See Non-GAAP Financial Measures. Commencing with the MD&A for the three months ended March 31, 2017, the Company will use adjusted funds from operations as management views this as a better measure of its cash available to fund growth capital expenditures, common share dividends and debt repayments for future periods. Adjusted funds from operations is funds from operations reduced by sustaining capital expenditures and preferred share dividends and adjusted to include cash from coal compensation that will be received annually (see Significant Events).

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 joint venture, and gains or losses on disposals (adjusted EBITDA), (ii) funds from operations (through 2016), (iii) adjusted funds from operations (commencing in 2017), (iv) normalized earnings attributable to common shareholders, and (v) normalized earnings per share as financial performance measures.

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

Adjusted EBITDA

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

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 joint venture. 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)	Year ended December 31		Three months ended							
	2016	2015	Dec 2016	Sep 2016	Jun 2016	Mar 2016	Dec 2015	Sep 2015	Jun 2015	Mar 2015
Revenues and other income	1,214	1,241	280	374	226	334	337	466	81	357
Energy purchases and fuel, other raw materials and operating charges, staff costs and employee benefits expense, and other administrative expense	(732)	(780)	(148)	(232)	(127)	(225)	(216)	(318)	(36)	(210)
Adjusted EBITDA from joint venture [1]	38	21	12	6	9	11	13	6	2	-
Adjusted EBITDA	**520**	**482**	**144**	**148**	**108**	**120**	**134**	**154**	**47**	**147**
Depreciation and amortization	(216)	(215)	(53)	(53)	(54)	(56)	(56)	(53)	(55)	(51)
Impairment	(6)	-	-	(6)	-	-	-	-	-	-
Losses on termination of power purchase arrangement	(73)	-	(20)	-	-	(53)	-	-	-	-
Foreign exchange gain (loss)	6	(15)	(4)	3	(1)	8	-	(8)	1	(8)
Net finance expense	(86)	(94)	(24)	(21)	(19)	(22)	(27)	(25)	(24)	(18)
Finance expense from joint venture [1]	(13)	(6)	(3)	(3)	(4)	(3)	(3)	(2)	(1)	-
Income tax expense	(30)	(66)	(14)	(4)	(10)	(2)	(14)	(16)	(16)	(20)
Net income (loss)	**102**	**86**	**26**	**64**	**20**	**(8)**	**34**	**50**	**(48)**	**50**
Net income (loss) attributable to:										
Non-controlling interests	(9)	(4)	(2)	(2)	(3)	(2)	(1)	1	(14)	10
Shareholders of the Company	111	90	28	66	23	(6)	35	49	(34)	40
Net income (loss)	**102**	**86**	**26**	**64**	**20**	**(8)**	**34**	**50**	**(48)**	**50**

[1] Total income from joint venture as per the Company's Consolidated Statements of Income.

Funds from operations

Capital Power uses funds from operations as a measure of the Company's ability to generate cash from its current operating activities to fund capital expenditures, debt repayments, dividends to the Company's shareholders and distributions to non-controlling interests. Funds from operations are net cash flows from operating activities adjusted to include finance and current income tax expenses and exclude changes in operating working capital. They 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. The timing of cash receipts and payments of interest and income taxes and the resulting cash basis amounts are not comparable from period to period. The timing of cash receipts and payments also affects the period-to-period comparability of changes in operating working capital which are also excluded from funds from operations.

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

(unaudited, $ millions)	Year ended December 31		Three months ended December 31	
	2016	2015	2016	2015
Net cash flows from operating activities per Consolidated Statements of Cash Flows	**375**	**419**	**69**	**114**
Add (deduct) items included in calculation of net cash flows from operating activities per Consolidated Statements of Cash Flows:				
Interest paid	73	80	19	28
Change in fair value of derivatives reflected as cash settlement	31	(8)	11	(3)
Realized losses (gains) on the settlement of interest rate derivatives	9	(3)	10	(2)
Miscellaneous financing charges paid [1]	4	5	1	2
Income taxes paid (recovered)	-	1	-	-
Change in non-cash operating working capital	(20)	(11)	(8)	8
	97	64	33	33
Net finance expense [2]	(85)	(82)	(27)	(22)
Current income tax expense	(15)	(10)	(3)	(1)
Decrease in current income tax expense due to Part VI.1 tax	12	9	3	1
Funds from operations	**384**	**400**	**75**	**125**

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, accretion charges and non-cash finance charges incurred on early debt extinguishment.

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)	**Year ended December 31**		**Three months ended**							
	2016	**2015**	**Dec 2016**	**Sep 2016**	**Jun 2016**	**Mar 2016**	**Dec 2015**	**Sep 2015**	**Jun 2015**	**Mar 2015**
Basic earnings (loss) per share ($)	**0.91**	**0.70**	**0.21**	**0.63**	**0.19**	**(0.11)**	**0.29**	**0.44**	**(0.39)**	**0.41**
Net income (loss) attributable to shareholders of the Company per Consolidated Statements of Income	**111**	**90**	**28**	**66**	**23**	**(6)**	**35**	**49**	**(34)**	**40**
Preferred share dividends including Part VI.1 tax	(23)	(23)	(8)	(5)	(5)	(5)	(6)	(5)	(6)	(6)
Earnings (loss) attributable to common shareholders	88	67	20	61	18	(11)	29	44	(40)	34
Loss on de-recognition of the Sundance power purchase arrangement	46	-	-	-	-	46	-	-	-	-
Change in unrecognized tax benefits	(27)	-	-	(27)	-	-	-	-	-	-
Settlement of Sundance power purchase arrangement legal action	15	-	15	-	-	-	-	-	-	-
Unrealized changes in fair value of derivatives	(15)	8	(8)	(22)	10	5	11	(19)	33	(17)
Deferred income tax expense related to temporary difference on investment in subsidiary	12	-	(1)	13	-	-	-	-	-	-
Impairment loss on Southport goodwill	4	-	-	4	-	-	-	-	-	-
Unrealized foreign exchange (gain) loss on revaluation of U.S. dollar denominated debt	(3)	15	3	1	1	(8)	1	6	(2)	10
Success fee received related to development project	(3)	-	(3)	-	-	-	-	-	-	-
Income tax expense related to increase in deferred tax liabilities caused by change in Alberta statutory corporate income tax rate	-	19	-	-	-	-	-	-	19	-
Restructuring charges	-	2	-	-	-	-	-	2	-	-
Recognition of tax liability on foreign domiciled investment	-	1	-	-	-	-	-	-	1	-
Impact of change in non-controlling interest percentage on adjustments of previous quarters	-	(1)	-	-	-	-	-	-	(1)	-
Normalized earnings attributable to common shareholders	**117**	**111**	**26**	**30**	**29**	**32**	**41**	**33**	**10**	**27**
Weighted average number of common shares outstanding (millions)	96.2	96.4	96.1	96.1	96.1	96.4	98.7	100.9	102.1	83.7
Normalized earnings per share ($)	**1.22**	**1.15**	**0.27**	**0.31**	**0.30**	**0.33**	**0.42**	**0.33**	**0.10**	**0.32**

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)	Year ended December 31		
	2016	2015	2014
Revenues and other income	1,214	1,241	1,218
Adjusted EBITDA [1]	520	482	423
Net income	102	86	50
Net income attributable to shareholders of the Company	111	90	46
Normalized earnings attributable to common shareholders [1]	117	111	59
Basic and diluted earnings per share ($) [2]	0.91	0.70	0.28
Normalized earnings per share ($) [1]	1.22	1.15	0.72
Funds from operations [1, 3]	384	400	362
Purchase of property, plant and equipment and other assets	306	140	220
Dividends per common share, declared ($)	1.510	1.410	1.310
Dividends per Series 1 preferred share, declared ($)	0.765	1.150	1.150
Dividends per Series 3 preferred share, declared ($)	1.150	1.150	1.150
Dividends per Series 5 preferred share, declared ($)	1.125	1.125	1.125
Dividends per Series 7 preferred share, declared ($)	0.3616	-	-

	As at December 31		
	2016	2015	2014
Loans and borrowings including current portion	1,508	1,615	1,586
Total assets	6,062	5,393	5,420

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

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

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

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. In addition, the number of common shares outstanding decreased primarily due to share purchases under the Company's normal course issuer bid (see Significant Events).

Funds from operations for 2016 were lower compared with funds from operations for 2015, primarily due to the settlement of the legal action related to the termination of the Sundance PPA (see Significant Events), a net realized loss on the termination of interest rate derivatives and the payment of fees related to the completion of the Bloom Wind contract in 2016. These decreases were partially offset by higher adjusted EBITDA before unrealized changes in fair value of commodity derivatives and emission credits and before Capital Power's share of the adjusted EBITDA from K2 Wind, lower interest expenses, and higher cash distributions received from K2 Wind.

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

SIGNIFICANT EVENTS

Project equity financing and completion of contract for output for Bloom Wind

Bloom Wind is a 178 MW facility in southwestern Kansas consisting of 54 3.3 MW turbines and is anticipated to cost $358 million (US$272 million). Construction of Bloom Wind commenced during the third quarter of 2016. Commercial operation of the facility is expected in the third quarter of 2017. Capital Power will operate Bloom Wind under a 10-year fixed price contract with Allianz Risk Transfer (rated AA- stable by Standard & Poor's), a subsidiary of Allianz SE, the worldwide insurance and asset management group, covering 100% of the project's output. Under the contract, which was executed on April 21, 2016, Capital Power will swap the market revenue of the project's generation for a fixed annual payment for a 10-year term. The agreement will secure long-term predictable revenues and mitigate generation volume uncertainty related to wind resources, allowing Bloom Wind to secure renewable energy tax equity financing and provide Capital Power the opportunity to complete its first wind development project in the growing U.S. renewables market.

On December 13, 2016, the Company reached an agreement with Goldman Sachs Alternative Energy Group (Project Investor) to fund an expected 65 to 70 percent of Bloom Wind costs through equity contributions in exchange for Class A shares of a subsidiary of the Company. These equity contributions are expected to begin upon the completion of the project and satisfaction of all conditions precedent, which is currently anticipated to occur in the third quarter of 2017. The Project Investor is entitled to the majority of income and tax benefits from the project until the Project Investor achieves an agreed upon target rate of return. Subsequent to this date, the structure "flips" and the Company is entitled to the majority of income, cash flows and tax benefits, while the Project Investor's equity investment will be accounted for as a non-controlling interest. Prior to the Project Investor achieving their target rate of return, their interest will be accounted for as tax equity financing within loans and borrowings.

Termination of the Sundance PPA

On March 24, 2016, Capital Power notified the Balancing Pool of the Company's decision to terminate its role as Buyer of the Sundance PPA. The Company recorded a pre-tax non-cash loss of $53 million ($46 million post-tax) with respect to the de-recognition of the Sundance PPA intangible asset. Effective March 24, 2016, the Company also de-designated certain energy cash flow hedges related to forecasted transactions no longer expected to occur as a result of the Sundance PPA termination, which resulted in the reclassification of unrealized gains of $5 million ($4 million post-tax) from other comprehensive income (loss) to net income. No hedge ineffectiveness resulted from the de-designation of the cash flow hedges.

During the third quarter of 2016, the Government of Alberta commenced legal action that sought to retroactively amend and restate certain power purchase arrangements, including the Sundance PPA, and prevent the Balancing Pool from accepting Capital Power's termination of its role as Buyer of the Sundance PPA. On November 24, 2016, the Government of Alberta agreed to discontinue its legal action against Capital Power and to arrange for the Balancing Pool to accept Capital Power's termination of its role as a Buyer of the Sundance PPA in accordance with the terms of the Sundance PPA. In consideration of these actions, Capital Power and its syndicate partners agreed to pay the Balancing Pool $39 million, of which Capital Power's portion is $20 million ($15 million post-tax).

Off-coal agreement

On November 24, 2016, the Company announced it had reached an agreement with the Government of Alberta related to the transition away from coal-fired generation in Alberta by 2030. As compensation for the capital that the Company invested in coal generating assets that will be stranded effective December 31, 2030, Capital Power will receive cash payments from the Province of $52 million annually for 14 years, commencing July 31, 2017 through to July 31, 2030, for a total of $734 million. Capital Power has agreed to continue to participate in the Alberta electricity market, support the local communities surrounding the coal facilities through 2030, and fulfill its pension and other commitments to employees. This settlement also recognizes the potential for extending the economic lives of certain assets through conversion to natural gas.

Alberta electricity market design

On November 23, 2016, the Government of Alberta announced the transition of Alberta's electricity market from an energy-only market to a capacity market, for which the framework is expected to be in place by 2021. The Government of Alberta has committed to ensuring that existing investments will be treated fairly, and that the new market framework will continue to promote a level playing field between existing and potential new capacity. Design and implementation activities will be undertaken in 2017 and 2018, with the Alberta Electric System Operator (AESO) currently targeting having the first capacity auction in 2019 for delivery in 2021.

Canadian federal regulation of natural gas generation

On November 21, 2016, the Government of Canada announced its plan to phase-out traditional coal-fired electricity by 2030, and to establish emission standards for natural gas-fired turbines, including new boilers, existing boilers, and existing coal boilers converted to natural gas. Under the proposal, coal boilers that are converted to natural gas would be subject to an interim emissions standard that would apply for the earlier of 15 years, or 2045, after which time the units would be required to meet the emissions standards for new generation.

The implementation of the phase-out and finalization of the natural gas regulations will be the subject of industry consultations expected to commence in 2017. At this time, it is expected that publication of the natural gas regulation in Canada Gazette Part I will be in late 2017, with final publication in Canada Gazette Part II in late 2018.

Updates to Alberta's Climate Leadership Plan

In late September 2016, the Government of Alberta initiated formal consultations regarding the performance standard and carbon pricing framework that will apply, effective January 1, 2018, to facilities that are currently subject to the Specified Gas Emitters Regulation (SGER). The standard and pricing framework will be reflected in a new CCR that will replace the current SGER regulation. The Company expects that the performance standard for the electricity sector will be consistent with the emissions performance of a combined-cycle natural gas-fired facility in Alberta, with specific details to be developed through consultation.

Alberta renewable electricity procurement

On January 26, 2016, the Government of Alberta tasked the AESO to develop and implement a plan to bring on new renewable electricity generation capacity to the grid by 2030 in connection with the CLP. The AESO undertook a process to receive industry perspectives regarding various elements of the REP, and provided its recommendations regarding the REP to the Government of Alberta on May 31, 2016. On September 14, 2016, the Government of Alberta confirmed a firm target of achieving 30% of Alberta's electricity use by 2030 from renewable energy sources, and announced that the Government of Alberta would support 5000 MW of additional renewable capacity to help achieve that target. The AESO has provided a timeline for the first REP auction in 2017 with a request for proposals expected in the fourth quarter of 2017 with winning bids required to be operational in 2019. Financial support for projects funded through the first REP auction will reflect a contract-for-differences approach, and be for a 20-year term. Future REP auctions may be structured differently with respect to the form and amount of financial support provided, and contract length.

Capital Power will remain actively engaged with the Government of Alberta as the Alberta power market continues to evolve and looks forward to further clarifications of the REP and the growth opportunities that the REP and the transition to a capacity market may bring to the Company.

Preferred share offering

On October 4, 2016, the Company issued 8 million Cumulative Minimum Rate Reset Preference Shares, Series 7 (Series 7 Shares) priced at $25.00 per share for gross proceeds of $200 million less issue costs of $5 million on a bought deal basis with a syndicate of underwriters. The preferred shares will pay fixed cumulative dividends of $1.50 per share per annum, yielding 6.00% per annum, payable on the last business day of March, June, September and December of each year, as and when declared by the Board of Directors of Capital Power, for the initial period ending December 31, 2021. The dividend rate will be reset on December 31, 2021 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 5.26%, provided that in any event such rate shall not be less than 6.00%. The Series 7 Shares are redeemable by Capital Power, at its option, on December 31, 2021 and every five years thereafter at a value of $25.00 per share.

Holders of the Series 7 Shares will have the right to convert all or any part of their shares into Cumulative Floating Rate Preference Shares, Series 8 (Series 8 Shares), subject to certain conditions, on December 31, 2021 and every five years thereafter. Holders of the Series 8 Shares will be entitled to receive a cumulative quarterly floating dividend at a rate equal to the sum of the then 90-day Government of Canada Treasury Bill yield plus 5.26%, as and when declared by the Board of Directors of Capital Power. The Series 8 Shares would be redeemable by Capital Power, at its option, on December 31, 2026 and December 31 of every fifth year thereafter at a value of $25.00 per share. The Series 8 shares would also be redeemable by Capital Power, at its option, on any date after December 31, 2021, excluding December 31 of every fifth year, at a value of $25.50 per share.

Impairment loss on Southport

During the three months ended September 30, 2016, the Company recognized a pre-tax impairment charge of $6 million with respect to its Southport plant which reduced the carrying amount of the related goodwill. This impairment was based on reduced expected future cash flows as a result of lower than expected generation and realized prices. The impairment charge had no cash flow impact.

$160 million private placement debt financing

On September 13, 2016, the Company issued a $160 million, 10-year unsecured senior note to Prudential Capital Group. The note bears an annual interest rate of 3.85%, payable semi-annually, and matures in September 2026. The net proceeds of the offering were used to repay amounts owing under credit facilities and for general corporate purposes.

K2 Wind partnership

On August 9, 2016, a consortium composed of Axium Infrastructure, Alberta Teachers' Retirement Fund Board, and Manulife Financial Corporation acquired Samsung Renewable Energy's one-third interest in K2 Wind. There is no change to the remaining interest in K2 Wind, which is still held equally by Pattern Energy Group Inc. and the Company.

Dividend increase

On July 25, 2016, the Company announced that its Board of Directors approved a 6.8% increase in the annual dividend for holders of its common shares, from $1.46 per common share to $1.56 per common share. This increased common dividend commenced with the third quarter 2016 quarterly dividend paid on October 31, 2016 to shareholders of record at the close of business on September 30, 2016.

Approval of normal course issuer bid

On April 25, 2016, Capital Power announced that the Toronto Stock Exchange (TSX) approved the Company's normal course issuer bid (NCIB) to purchase and cancel up to 8.6 million of its outstanding common shares during the one-year period from April 28, 2016 to April 27, 2017. Capital Power purchased and cancelled 7.1 million common shares under its prior NCIB approved by the TSX on March 25, 2015 for the period from April 7, 2015 to April 6, 2016, but has not yet purchased and cancelled any common shares under the NCIB approved on April 25, 2016.

Preferred Shares (Series 1) dividend rate reset

On February 18, 2016 the Board of Directors of Capital Power declared a quarterly dividend of $0.19125 per share on the Company's Cumulative 5-Year Rate Reset Preference Shares, Series 1 (Series 1 Shares). This quarterly dividend was paid on March 31, 2016. The Annual Fixed Dividend Rate for the Series 1 Shares for the next five-year period was reset from 4.60% to 3.06% on December 31, 2015 at a rate equal to the sum of the then Government of Canada bond yield and 2.17%. The Annual Fixed Dividend Rate will be next reset on December 31, 2020 and every five years thereafter.

SUBSEQUENT EVENTS

Appointments to the Board of Directors

On February 17, 2017, the Capital Power Board of Directors approved the appointment of Keith Trent and Kate Stevenson to the Board of Directors. The appointments will be effective April 3, 2017.

Acquisition of thermal facilities

On February 21, 2017, the Company announced that it has entered into an agreement to acquire the thermal power business of Veresen Inc., consisting of two gas-fired and two waste-heat generation facilities.

Under the terms of the agreement, Capital Power will acquire 284 megawatts of generation from two natural gas-fired power facilities 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 will operate both facilities. Both East Windsor and York Energy are under long-term PPAs, with the A rated Ontario Independent Electricity System Operator, with original terms expiring in 2029 and 2032, respectively. Both facilities earn revenue through fixed capacity payments partly indexed to inflation and are compensated for operations and maintenance, and fuel (commodity and transportation) as well as start-up costs. Additionally, East Windsor is under a long-term steam supply agreement with a BBB rated third party.

The transaction also includes 10 MW of zero-emissions waste-heat generation from two facilities (5 MW each) located at Westcoast Energy's BC Gas Pipeline compressor stations in Savona and 150 Mile House, British Columbia. The waste heat facilities are under 20-year Electricity Purchase Agreements (EPAs), with AA rated BC Hydro, with original terms expiring in 2028. The EPAs provide for partial inflation indexation as well as premium pricing under peak load hours. A third party provides operations and maintenance services for the assets under a long-term agreement.

The purchase price for the acquisition is $225 million in total cash consideration, subject to working capital adjustments and other closing adjustments, and the assumption of $275 million of project level debt (on a proportionate basis). Capital Power expects to finance the transaction through existing cash and its credit facilities. The transaction is expected to close in the second quarter of 2017, subject to regulatory approvals and satisfaction of closing conditions.

The acquisition is expected to increase adjusted funds from operations and be accretive to the Company's earnings per share.

FACILITIES AND PORTFOLIO OPTIMIZATION OPERATIONS

Facility category and facility	Type of generating facility	Year commissioned	Capacity (MW) Facility	Capacity (MW) Capital Power interest	Revenues based on [2]	Contract expiry
Alberta commercial facilities [1]						
Genesee 3	Supercritical coal-fired	2005	516	258	Merchant	-
Keephills 3	Supercritical coal-fired	2011	516	258	Merchant	-
Clover Bar Energy Centre 1, 2 and 3	Natural gas-fired simple cycle	2008 (Unit 1) 2009 (Units 2 and 3)	243	243	Merchant	-
Joffre	Natural gas-fired combined cycle cogeneration	2000	480	192	Merchant (mid-merit)	-
Shepard	Natural gas-fired combined cycle	2015	800	400	Merchant with tolling agreement for 50% of owned capacity plus additional 25% contracted for 2015 to 2017	2035 (tolling agreement)
Halkirk	Wind turbine	2012	150	150	Merchant with RECs sold under fixed price agreement	2032 (RECs)
Clover Bar Landfill Gas	Landfill gas-fired	2005	5	5	Merchant with emission credits purchased by Capital Power from the City of Edmonton	-
Alberta contracted facilities [1]						
Genesee 1	Coal-fired steam turbine	1994	430	430	Capacity and output sold under Alberta PPA to Alberta Balancing Pool	2020
Genesee 2	Coal-fired steam turbine	1989	430	430	Capacity and output sold under Alberta PPA to Alberta Balancing Pool	2020
Ontario and British Columbia contracted facilities						
Island Generation	Natural gas-fired combined cycle	2002	275	275	PPA with BC Hydro	2022
K2 Wind	Wind turbine	2015	270	90	PPA with IESO	2035
Kingsbridge 1	Wind turbine	2001 and 2006	40	40	Energy supply contracts with IESO	2026
Port Dover and Nanticoke	Wind turbine	2013	105	105	Energy supply contract with IESO	2033
Quality Wind	Wind turbine	2012	142	142	EPA with BC Hydro	2037
U.S. contracted facilities						
Roxboro, North Carolina	Solid fuels (wood residuals, tire-derived and coal)	1987	46	46	PPA with Duke Energy Progress Inc.	2021
Southport, North Carolina	Solid fuels (wood residuals, tire-derived and coal)	1987	88	88	PPA with Duke Energy Progress Inc.	2021
Beaufort Solar, North Carolina	Solar	2015	15	15	PPA with Duke Energy Progress, LLC	2030
Macho Springs, New Mexico	Wind turbine	2011	50	50	PPA with Tucson Electric Power	2031

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

2 Certain of the Company's facilities derive revenues under power purchase agreements or arrangements (PPAs).

Facility category and facility	Type of generating facility	Year to be commissioned	Capacity (MW) Facility	Capacity (MW) Capital Power interest	Revenues based on	Contract expiry
Under construction or in advanced development						
Bloom Wind	Wind turbine	2017	178	178	Fixed price contract with Allianz Risk Transfer (see Significant Events)	2027
Genesee 4 and 5	Natural gas-fired combined cycle	To be determined [1]	1,060	530	Merchant with approximately 250 MW contracted to ENMAX for an initial term of 8 years	To be determined

1 Contingent on Alberta market structure certainty and future Alberta electricity demand requiring the addition of new generation.

Portfolio optimization

Capital Power's commodity portfolio is comprised of generation assets, customer positions and trading positions. All commodity risk management and optimization activities are centrally managed by Capital Power's commodity portfolio management group. Portfolio optimization includes activities undertaken to manage Capital Power's exposure to commodity risk and enhance earnings. Overall commodity exposure within the portfolio is managed within limits established under Capital Power's risk management policies.

Capital Power manages its output from its commercial and contracted facilities with residual commodity exposure on a portfolio basis. Capital Power sells and/or buys physical and/or financial forward contracts that are non-unit specific, to reduce exposure to facility specific availabilities. Capital Power also takes positions in the environmental commodity markets outside of Alberta to develop capability to support Capital Power's growth strategy and to generate trading profits.

CONSOLIDATED NET INCOME AND RESULTS OF OPERATIONS

The primary factors contributing to the change in consolidated net income for 2016 compared with 2015 are presented below followed by further discussion of these items.

(unaudited, $ millions)		
Consolidated net income for the year ended December 31, 2015		**86**
Increase (decrease) in adjusted EBITDA:		
Alberta commercial facilities, Sundance PPA and portfolio optimization [1,2]	25	
Alberta contracted facilities [2]	(21)	
Ontario and British Columbia contracted facilities	9	
U.S. contracted facilities	8	
Corporate	5	
Change in unrealized net gains or losses related to the fair value of commodity derivatives and emission credits	12	38
Impairment		(6)
Increase in depreciation and amortization expense		(1)
Losses on termination of power purchase arrangement		(73)
Change in foreign exchange gain or loss		21
Decrease in net finance expense		8
Increase in finance expense from joint venture		(7)
Decrease in income before tax		(20)
Decrease in income tax expense		36
Increase in net income		**16**
Consolidated net income for the year ended December 31, 2016		**102**

1 The Company's role as Buyer of the Sundance PPA was terminated effective March 24, 2016 (see Significant Events). Adjusted EBITDA in 2016 includes the results of the Sundance PPA up to that date.

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

Results by facility category and other

	Year ended December 31							
	2016	2015	2016	2015	2016	2015	2016	2015
	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 Sundance PPA	15,328	14,567	94	95	704	770		
Alberta commercial facilities and Sundance PPA [4]								
Genesee 3	1,787	1,982	92	100	28	63		
Keephills 3	1,831	1,640	96	90	33	51		
Clover Bar Energy Centre 1, 2 and 3	327	248	95	94	9	26		
Joffre	197	308	81	97	19	29		
Shepard Energy Centre [5]	2,245	1,462	89	89	88	64		
Halkirk	455	460	98	97	31	34		
Clover Bar Landfill Gas	7	8	79	89	-	-		
Alberta commercial facilities – owned	6,849	6,108	92	94	208	267		
Sundance PPA [6]	655	2,661	95	88	13	81		
Portfolio optimization	N/A	N/A	N/A	N/A	468	434		
	7,504	8,769	92	92	689	782	279	254
Alberta contracted facilities [4]								
Genesee 1	3,333	3,130	99	92				
Genesee 2	3,137	3,378	93	99				
	6,470	6,508	96	96	252	265	163	184
Ontario and British Columbia contracted facilities								
Island Generation	39	79	98	100	38	38		
K2 Wind [7]	222	167	99	98	N/A	N/A		
Kingsbridge 1	102	101	96	96	6	6		
Port Dover and Nanticoke	305	299	98	97	38	36		
Quality Wind	344	408	96	97	33	44		
	1,012	1,054	98	98	115	124	127	118
U.S. contracted facilities								
Roxboro, North Carolina	316	282	96	95	36	32		
Southport, North Carolina	518	506	92	91	73	70		
Beaufort Solar, North Carolina [8]	29	-	95	100	3	-		
Macho Springs, New Mexico	134	109	97	98	17	12		
	997	897	95	94	129	114	35	27
Corporate [9]					16	8	(95)	(100)
Unrealized changes in fair value of commodity derivatives and emission credits					13	(52)	11	(1)
Consolidated revenues and other income and adjusted EBITDA					**1,214**	**1,241**	**520**	**482**

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

2 Facility availability represents the percentage of time in the period that the facility was available to generate power regardless of whether it was running, and therefore is reduced by planned and unplanned outages.

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

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

5 Shepard was commissioned on March 11, 2015.

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

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 venture on the Company's Consolidated Statements of Income. The facility was commissioned on May 29, 2015 and the equivalent of Capital Power's share of the facility's revenue and adjusted EBITDA was $47 million and $41 million, respectively for 2016 compared with $25 million and $21 million, respectively, for 2015. The facility's revenues are not included in the above results.

8 Beaufort Solar was commissioned on December 22, 2015.

9 Corporate revenues were offset by interplant category eliminations.

Energy prices and hedged positions

		Year ended December 31	
Alberta	**Unit**	**2016**	**2015**
Hedged position [1]	Percentage sold forward at beginning of year (%)	100	97
Spot power price average	$ per MWh	18	33
Realized power price [2]	$ per MWh	61	55
Natural gas price (AECO) [3]	$ per gigajoule (Gj)	2.03	2.60

1 Hedged position is for the Alberta baseload plants 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 (see Significant Events).

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

Generation, availability, revenues and adjusted EBITDA for the Alberta commercial facilities include results of the Sundance PPA up to the effective termination date of March 24, 2016 (see Significant Events).

Generation in 2016 compared with 2015 decreased primarily due to the termination of the Sundance PPA in the first quarter of 2016, a planned outage at Genesee 3 in 2016 with no comparable outage in 2015 and an extended planned outage at Joffre in 2016 compared with 2015. These decreases were partially offset by higher generation at Keephills 3 as the facility underwent a planned outage in 2015 and higher generation at Shepard in 2016, due to an extended unplanned outage at the facility in 2015, along with the commissioning of the facility in March 2015.

Revenues for the Alberta commercial facilities were lower in 2016 compared with 2015 primarily due to lower Alberta spot prices and the termination of the Sundance PPA (see Significant Events), partially offset by a full year of operations at Shepard in 2016. Adjusted EBITDA increased in 2016 compared to 2015 primarily due to an increase in portfolio optimization revenues as the Company was required to cover a short market position at higher prices in the second quarter of 2015, and the Company was able to realize a higher power price for the portfolio in 2016 as compared to 2015 based on portfolio optimization activities.

Alberta contracted facilities

Generation and availability in 2016 were comparable to those of 2015. Revenues were lower in 2016 compared to 2015 primarily due to lower excess energy and incentive revenues resulting from lower Alberta pool prices in 2016. Adjusted EBITDA was lower in 2016 compared to 2015, primarily due to higher coal costs and the aforementioned lower excess energy and incentive revenues.

Ontario and British Columbia contracted facilities

Generation decreased in 2016 compared to 2015 primarily due to lower dispatch at Quality Wind and Island Generation, the latter of which experienced a planned outage in 2016 with no comparable outage in 2015 and lower dispatch in 2016. Despite this outage, availability in 2016 was consistent with 2015. The lower generation was partially offset by the addition of the K2 Wind facility which began commercial operations on May 29, 2015. The addition of K2 Wind also positively impacted adjusted EBITDA for 2016 when compared with 2015, partially offset by the lower generation at Quality Wind. Revenue does not include K2 Wind, which is accounted for under the equity method. Revenue decreased in 2016 compared to 2015 primarily due to the lower generation at Quality Wind.

U.S. contracted facilities

Generation, revenues and adjusted EBITDA increased in 2016 compared to 2015 mainly due to higher off-peak generation at Southport and Roxboro, the addition of Beaufort Solar in the fourth quarter of 2015 and increased wind generation at Macho Springs. Availability in 2016 was consistent with 2015.

Corporate

Corporate results include (i) revenues for cost recoveries, (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 in 2016 decreased compared to 2015 primarily due to the receipt of a success fee related to a development project that the Company did not proceed with, but for which the Company entered into an agreement to be compensated if another developer successfully proceeded with the project.

Unrealized changes in fair value of commodity derivatives and emission credits

(unaudited, $ millions)	Year ended December 31			
	2016	**2015**	**2016**	**2015**
Unrealized changes in fair value of commodity derivatives and emission credits	**Revenues and other income**		**Adjusted EBITDA**	
Unrealized gains (losses) on Alberta energy derivatives	26	1	(7)	(1)
Unrealized (losses) gains on natural gas derivatives	(9)	(53)	13	-
Unrealized losses on emission derivatives	(4)	-	(4)	-
Unrealized gains on emission credits held for trading	-	-	9	-
	13	**(52)**	**11**	**(1)**

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.

Unrealized net losses on Alberta energy derivatives of $7 million for the year ended December 31, 2016 were due to the reversal of prior period unrealized net gains on forward sales contracts that settled during the year, partially offset by the impact of decreasing forward Alberta power prices on net forward sales contracts. Unrealized changes in the fair value of Alberta energy derivatives were immaterial for the year ended December 31, 2015.

Unrealized net gains on natural gas derivatives of $13 million for the year ended December 31, 2016 were due to the reversal of prior period unrealized net losses on forward purchase contracts that settled during the year, as well as forward purchase contracts valued against increasing forward prices. Unrealized changes in the fair value of natural gas derivatives were immaterial for the year ended December 31, 2015.

Unrealized net losses on emission derivatives of $4 million for the year ended December 31, 2016 were due to net forward purchase contracts on allowances and energy credits which were valued against decreasing forward prices, as well as the reversal of prior period gains on positions that settled during the year. Unrealized changes in the fair value of emission derivatives were immaterial for the year ended December 31, 2015.

During the year ended December 31, 2016, the Company recognized unrealized gains of $9 million on the fair value of emission credits held for trading. This was primarily due to the fair value adjustment on a portfolio of credits that were transferred into held for trading during the year. Partially offsetting this was the reversal of prior period unrealized gains on emission credits that were sold during the year. Unrealized changes in the fair value of emission credits held for trading were immaterial for the year ended December 31, 2015.

Consolidated other expenses and non-controlling interests

(unaudited, $ millions)	Year ended December 31	
	2016	2015
Interest on borrowings less capitalized interest	(74)	(80)
Realized (losses) gains on settlement of interest rate derivatives	(9)	3
Other finance expense – sundry interest and guarantee and other fees	(2)	(5)
	(85)	(82)
Unrealized gain (loss) representing changes in the fair value of interest rate derivatives	6	(5)
Other finance expense – amortization and accretion charges	(7)	(6)
Other finance expense – finance charges incurred on early debt extinguishment	-	(1)
Total net finance expense	(86)	(94)
Impairments	(6)	-
Depreciation and amortization	(216)	(215)
Foreign exchange gain (loss)	6	(15)
Losses on termination of power purchase agreement	(73)	-
Finance expense from joint venture	(13)	(6)
Income tax expense	(30)	(66)
Net loss attributable to non-controlling interests	9	4

Net finance expense

Lower net finance expense for 2016 compared with 2015 was primarily due to higher capitalized interest resulting from the commencement of Bloom Wind construction, reduced interest expense incurred on long-term debt as a result of the EPCOR debt repayment in the first quarter of 2016 and the retirement of medium-term notes in November 2015. These reductions to expense were partially offset by a net loss on the termination of the Company's interest rate swaps in the fourth quarter of 2016, increased interest on credit facility usage in 2016, interest on the private placement debt financing issued in the third quarter of 2016 (see Significant Events) and by decreased capitalized interest related to Shepard as that facility was completed in March 2015.

Impairments

During the third quarter of 2016, the Company recognized a pre-tax impairment loss of $6 million related to the Southport cash generating unit (see Significant Events).

Depreciation and amortization

Depreciation and amortization for 2016 increased compared with the prior year primarily due to higher expense recognized for Shepard, which commenced commercial operations in March 2015 and the shortening of asset lives in late 2016 related to the coal-fired assets. These increases were primarily offset by the de-recognition of intangible assets associated with the termination of the Sundance PPA.

Foreign exchange gain (loss)

As at December 31, 2016, the Company had outstanding U.S. dollar denominated debt payable totalling US$295 million. Approximately US$195 million is hedged for accounting purposes using foreign currency swaps. 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 2016, the exchange rate of the Canadian dollar relative to the U.S. dollar increased, resulting in an unrealized gain.

Losses 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. On November 24, 2016, the Government of Alberta agreed to arrange for the Balancing Pool to accept Capital Power's termination of its role as a Buyer of the Sundance PPA. In consideration of these actions, Capital Power and its syndicate partners agreed to pay the Balancing Pool $39 million, of which Capital Power's portion is $20 million ($15 million post-tax) (see Significant Events).

Finance expense from joint venture

Finance expense from joint venture includes Capital Power's share of finance expenses of K2 Wind accounted for under the equity method. This facility was commissioned on May 29, 2015.

Income tax expense

Income tax expense for 2016 decreased by $36 million compared with 2015 primarily due to the recognition of previously unrecognized deductible temporary differences partially offset by the recognition of a taxable temporary difference relating to an investment in a subsidiary in the third quarter of 2016.

In 2016, a deferred tax liability was recognized on the Company's investment in a subsidiary. The deferred tax liability had not previously been recognized as the Company did not expect the taxable temporary difference to reverse in the foreseeable future. This increase in the deferred tax liability was offset by a benefit relating to previously unrecognized deferred tax assets as it was determined it was probable that these deferred tax assets would be realized.

Tax expense in 2016 decreased due to the above impacts. Compared to 2015, no non-cash tax expense was recorded in 2016 relating to a statutory rate change. The Alberta statutory income tax rate increased in the second quarter of 2015.

Non-controlling interests

For the year ended December 31, 2016, none (January 1, 2015 to April 2, 2015, 18%) of CPLP's net income was attributable to EPCOR which was reported as net income attributable to non-controlling interests by the Company in 2015. Effective April 2, 2015, EPCOR disposed of all its interest in CPLP. Subsequent to April 2, 2015, non-controlling interests consist only of the Coal Mine partner's share of the consolidated depreciation expense of the Coal Mine.

COMPREHENSIVE INCOME

(unaudited, $ millions)	**Year ended December 31**	
	2016	**2015**
Net income	102	86
Other comprehensive income:		
Net unrealized gains on commodity derivatives designated as cash flow hedges	68	73
Net unrealized losses on derivatives designated as cash flow hedges – joint venture	(4)	(8)
Net realized losses on commodity derivatives designated as cash flow hedges reclassified to net income – joint venture	4	-
Net realized gains on commodity derivatives designated as cash flow hedges reclassified to revenues and other income and/or energy purchases and fuel	(88)	(59)
Unrealized foreign exchange (loss) gain on the translation of foreign operations	(5)	34
Actuarial (loss) gain related to the company's defined benefit pension plan	(1)	4
	(26)	44
Comprehensive income	**76**	**130**

Other comprehensive income includes fair value adjustments on financial instruments held by the Company to hedge market risks and which meet the requirements of hedges for accounting purposes. To the extent that such hedges are ineffective, any related gains or losses are recognized in net income. Other unrealized fair value changes on derivatives designated as cash flow hedges and foreign currency translation gain or loss are subsequently recognized in net income when the hedged transactions are completed and the foreign operations are disposed of or otherwise terminated. The actuarial gains or losses are not subsequently recognized in net income. As a result of the termination of the Sundance PPA (see Significant Events), certain derivatives that were previously designated as accounting hedges were de-designated as the hedged transactions are no longer expected to occur. The de-designation resulted in the reclassification of unrealized gains of $5 million ($4 million post tax) from other comprehensive loss to net income.

FINANCIAL POSITION

The significant changes in the Consolidated Statements of Financial Position from December 31, 2015 to December 31, 2016 were as follows:

(unaudited, $ millions)	As at December 31		Increase	
	2016	**2015**	**(decrease)**	**Primary reason for increase (decrease)**
Trade and other receivables	223	190	33	Increase primarily due to the current portion of the government grant receivable for compensation related to the phase-out of coal-fired generation (see Significant Events), partially offset by the termination of the Sundance PPA (see Significant Events).
Finance lease receivables	667	689	(22)	Reduction in net investment in finance leases due to the recognition of accounting minimum lease payments partially offset by unearned finance income.
Inventories	118	99	19	Increase in emission credits held for trading reclassified from intangible assets and increase in generation facility inventory, partially offset by net sales of emission credits.
Government grant receivable	542	-	542	Amortized cost of the government grant receivable for compensation related to the phase-out of coal-fired generation (see Significant Events).
Intangible assets	299	336	(37)	De-recognition of assets related to the Sundance PPA (see Significant Events) and reclassification of emission credits to held-for-trading inventory, partially offset by net additions of emission credits.
Goodwill	23	30	(7)	Due to impairment loss recognized on Southport goodwill (see Significant Events) and foreign currency translation adjustments.
Property, plant and equipment	3,764	3,677	87	Capital additions, primarily Bloom Wind, partially offset by depreciation and amortization.
Trade and other payables	217	181	36	Increase primarily due to Bloom Wind construction payables, partially offset by prior year accrual for Shepard construction incentive which settled in 2016.
Loans and borrowings (including current portion)	1,508	1,615	(107)	Repayment of bankers' acceptances and debt payable to EPCOR, partly offset by the issuance of the $160 million private placement note (see Significant Events).
Deferred revenue and other liabilities (including current portion)	689	99	590	Increase due to deferred revenue for compensation related to the phase-out of coal-fired generation (see Significant Events).
Provisions (including current portion)	257	232	25	Increased decommissioning provisions primarily due to changes in the Coal Mine plan and increased employee benefits provisions.
Share capital	2,918	2,744	174	Issuance of preferred shares offset by common shares purchased by Capital Power.
Deficit	(124)	(70)	(54)	Net income offset by common and preferred share dividends.
Other reserves	49	74	(25)	Unrealized losses on foreign currency translation and reclassification of unrealized gains on cash flow hedges, partly offset by unrealized gains on cash flow hedges.

LIQUIDITY AND CAPITAL RESOURCES

(unaudited, $ millions)	Year ended December 31		
Cash inflows (outflows)	**2016**	**2015**	**Change**
Operating activities	375	419	(44)
Investing activities	(253)	(136)	(117)
Financing activities	(102)	(280)	178

Operating activities

Cash flows from operating activities for 2016 decreased compared with 2015 primarily due to the payment for the settlement of the legal action related to the termination of the Sundance PPA (see Significant Events), a net realized loss on the termination of interest rate derivatives, the payment of fees related to the completion of the Bloom Wind contract in 2016 and a cash outflow in 2016 compared with a cash inflow in 2015 for 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. These decreases were partially offset by higher adjusted EBITDA before unrealized changes in fair value of commodity derivatives and emission credits and before Capital Power's share of the adjusted EBITDA from K2 Wind, lower interest expenses, and higher cash distributions received from K2 Wind.

Investing activities

Cash flows used in investing activities for 2016 were higher than those for 2015, primarily due to the construction of Bloom Wind, which began in 2016.

Capital expenditures and investments

(unaudited, $ millions)	Pre-2015 Actual	Year ended December 31 2015 Actual	2016 Actual	2017 Estimated [1,2]	Actual or Projected Total [2]	Timing
Genesee 4 & 5 [3,4]	2	7	7	3	700	To be determined [4]
Bloom Wind	-	-	219	139	358	Targeted completion in the third quarter of 2017
Subtotal growth projects		**76**	**226**			
Sustaining – facility maintenance excluding Genesee mine		51	59			
Sustaining – Genesee mine maintenance and lands [5]		6	3			
Sustaining – other		5	-			
Total capital expenditures [6]		**138**	**288**			
Emission credits held for compliance		11	28			
Capitalized interest		(9)	(3)			
Purchase of property, plant and equipment and other assets		**140**	**313**			

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 project are based on management's estimates.

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

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

Financing activities

The cash flows used in financing activities for 2016 primarily reflected the repayment of loans and borrowings and the sum of common share dividends, preferred share dividends, and common shares purchased under the Company's NCIB (see Significant Events), partially offset by the issuance of preferred shares (see Significant Events) and the issuance of private placement debt financing (see Significant Events).

The Company's credit facilities consisted of:

(unaudited, $ millions)		As at December 31, 2016			As at December 31, 2015		
	Maturity timing	**Total facilities**	**Credit facility utilization**	**Available**	**Total facilities**	**Credit facility utilization**	**Available**
CPLP committed credit facility	2020/2021	1,055			1,000		
Letters of credit outstanding			58			15	
Bankers' acceptances outstanding			-			212	
U.S. dollar bank loans outstanding			134			27	
		1,055	192	863	1,000	254	746
CPLP bilateral demand credit facilities	N/A	200			200		
Letters of credit outstanding			114	86		110	90
CPLP demand credit facility	N/A	20	-	20	20	-	20
Capital Power Corporation demand credit facility	N/A	5	-	5	5	-	5
		1,280	**306**	**974**	**1,225**	**364**	**861**

As at December 31, 2016, the committed credit facility utilization decreased $62 million compared with the utilization as at December 31, 2015 primarily due to decreased bankers' acceptances outstanding partially offset by increased U.S. dollar bank loans and letters of credit outstanding. The proceeds from the $160 million private placement note and the $200 million offering of Series 7 Preferred Shares (see Significant Events), which were received in September and October 2016 respectively, reduced the credit facility usage. These proceeds were partially offset by the debt repayment to EPCOR in the first quarter of 2016 which had previously increased the credit facility utilization. In July 2016, the Company extended the maturity date of the 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. Following this extension, $1 billion of the committed credit facilities mature on July 9, 2021 and $55 million mature on July 9, 2020. The accordion feature permits an additional $245 million increase to the facility in the future, subject to certain conditions including lender approval. The available credit facilities provide the Company with adequate funding for ongoing development projects.

The Company has a corporate credit rating of BBB- with a stable outlook from Standard & Poor's (S&P). The BBB rating category assigned by S&P is the fourth highest rating of S&P's ten rating categories for long-term debt obligations. According to S&P, a BBB corporate credit rating exhibits adequate capacity to meet financial commitments. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitments.

The Company has a senior unsecured long-term debt credit rating of BBB from DBRS Limited (DBRS) and on March 10, 2016, DBRS changed the trend of the rating from stable to negative. The negative trend indicates the possibility of a downgrade to BBB (low). The BBB rating assigned by DBRS is the fourth highest rating of DBRS' ten rating categories for long-term debt obligations. According to DBRS, long-term debt rated BBB is of adequate credit quality. The capacity of the payment of financial obligations is considered acceptable but the entity is vulnerable to future events.

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

The loan and credit agreements require Capital Power to meet certain financial covenants as described below:

Financial covenant	Required at the end of each fiscal quarter	Actual as at December 31, 2016
Consolidated senior debt to consolidated capitalization ratio [1]	Not more than 0.65 to 1.0	0.40
Consolidated EBITDA to consolidated interest expense [1, 2]	Not less than 2.5 to 1.0	4.5

[3] As defined in the relevant agreements.

[4] Only in the event that Capital Power is assigned a rating of less than BBB- by S&P and less than BBB (low) by DBRS.

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)	2017 Expected Cash Requirements
Repayment of debt payable to EPCOR	10
Capital expenditures – sustaining	85
Capital expenditures – growth projects	149
Common share dividends [1]	155
Preferred share dividends	30

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

The current portion of loans and borrowings on the December 31, 2016 Consolidated Statements of Financial Position included $184 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. As at December 31, 2016, Capital Power's total loans and borrowings payable to EPCOR were $184 million (December 31, 2015 - $325 million), at interest rates ranging from 5.80% to 9.00% per annum, and maturing between 2017 and 2018. Since EPCOR owns less than 20% of the outstanding limited partnership units of CPLP, EPCOR may, by written notice, require repayment of all or any portion of the outstanding principal amount of this debt and accrued interest thereon. If the principal amount specified in such repayment is less than $200 million, then it and the accrued interest thereon shall be payable on or before 180 days after delivery of notice.

The Company expects to fund the construction of the Bloom Wind project using existing bank credit facilities, cash flows from operating activities and expected Project Investor equity contributions (see Significant Events). The Company's other cash requirements identified above are expected to be funded with cash on hand, cash flows from operating activities, and use of existing bank credit facilities.

The Company 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. On October 4, 2016, under a prospectus supplement to the short-form base shelf prospectus, the Company issued 8 million Series 7 Preferred Shares (see Significant Events) utilizing $200 million of capacity under the short-form base shelf prospectus.

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 December 31, 2016, $172 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 December 31	
	2016	2015
Loans and borrowings	1,508	1,615
Finance lease obligation [1]	20	22
Less cash and cash equivalents	98	80
Net debt	1,430	1,557
Share capital	2,918	2,744
Deficit and other reserves	(75)	4
Non-controlling interests	58	68
Total equity	2,901	2,816
Total capital	**4,331**	**4,373**

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

CONTRACTUAL OBLIGATIONS AND CONTINGENT LIABILITIES

(unaudited, $ millions)	Payments due by period						
	2017	2018	2019	2020	2021	Thereafter	Total
Loans and borrowings	26	185	259	306	446	294	1,516
Interest on loans and borrowings	76	70	57	51	25	69	348
Finance lease obligations	1	1	1	2	2	13	20
Capital – growth projects [1]	142	25	254	188	86	128	823
Decommissioning provisions [2]	3	4	3	3	3	311	327
Energy purchase and transportation contracts [3]	45	38	37	33	33	449	635
Operating and maintenance contracts	25	26	25	29	35	191	331
Operating leases	8	8	8	8	7	59	98
Environmental credits	73	35	39	28	16	30	221
Commodity and other derivatives liabilities net of financial assets	9	9	9	5	3	6	41
Total	**408**	**401**	**692**	**653**	**656**	**1,550**	**4,360**

1 Capital Power's obligations for capital – growth projects include Bloom Wind and Genesee 4 and 5 and excludes interest to fund construction and refundable transmission system contribution payments.

2 Capital Power's decommissioning provisions reflect the undiscounted cash flows required to settle obligations for the retirement of its generation facilities and the Genesee coal mine.

3 Energy purchase and transportation contracts include natural gas transportation contracts which are based on estimates subject to changes in regulated rates for transportation and have expiry terms ranging from 2019 to 2023.

Contingent liabilities

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 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. The AESO has noted it expects to be able to produce prospective loss factors in March 2017 to be effective January 1, 2017. One party has subsequently 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 Commission 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 is currently scheduled to conclude by May 2017 and an oral hearing, if determined to be required by the AUC, would commence in June 2017.

As at February 17, 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. It is unclear when retrospective loss factors will be made available, and the timing of a Module C decision remains unknown. 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 audited consolidated financial statements since the outcome of the LLR Proceeding is not known. 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 (see Significant Events), 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 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.

TRANSACTIONS WITH RELATED PARTIES

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

The power sales and purchases of energy, fuel, raw materials and other services transactions with EPCOR and the City of Edmonton were in the normal course of operations and were recorded at exchange amounts based on normal commercial rates. CPLP paid distributions to EPCOR for the three months ended March 31, 2015 based on EPCOR's unit holdings during that period.

(unaudited, $ millions)	Period from January 1, 2015 to April 2, 2015
Revenues – energy sales:	
EPCOR and City of Edmonton	5
Purchase of raw materials and other services:	
EPCOR	2
Finance expense:	
EPCOR	5
CPLP distributions paid [1]	
EPCOR	7
Repayment of unsecured senior debt payable	
EPCOR	9

1 Distributions of $6 million were paid on April 30, 2015 based on EPCOR's unit holdings outstanding as of March 31, 2015.

As at December 31, 2016, Capital Power's loans and borrowings payable to EPCOR were $184 million (December 31, 2015 - $325 million).

RISKS AND RISK MANAGEMENT

The Company's approach to risk management is to identify, monitor and manage the key controllable risks facing the Company and to consider appropriate actions to respond to uncontrollable risks. Risk management includes the controls and procedures for reducing controllable risks to acceptable levels and the identification of the appropriate actions in cases of events occurring outside of management's control. Acceptable levels of risk are established by the Board of Directors of Capital Power and govern the Company's decisions and policies associated with risk. The Board of Directors of Capital Power reviews the Company's risk profile on a quarterly basis and material changes to the risk profile as required.

Capital Power employs an Enterprise Risk Management Program (ERM Program) to identify, evaluate, report and monitor key risks that may affect the achievement of the Company's strategic and related business objectives. The ERM Program aligns with the International Organization for Standardization's standard for risk management, ISO 31000, and the Company's approach is to undertake risk assessment in conjunction with core corporate processes.

Risk management at Capital Power is carried out at several levels and is subject to the oversight of the Board of Directors of Capital Power. The President and Chief Executive Officer (CEO) has ultimate accountability for managing the Company's risks and approves the framework for enterprise risk management. The President and CEO as well as the rest of the executive team provide general oversight and policy reviews and recommendations, meeting periodically to review enterprise risk management performance and to evaluate significant or emerging risks. The Risk Oversight Council (consisting of the senior management representatives appointed by the President and CEO) establishes the overall direction, structure, conduct and control of Capital Power's commodity exposure management activities, both in physical and financial derivatives markets. The Vice President of Risk Management and Internal Audit is responsible for the enterprise risk management framework, including developing risk management policies and processes and monitoring the Company's compliance with said policies and processes by performing periodic reviews and internal audits. He is also responsible for the leadership of the commodity and credit risk management (middle office) function, security and contingency planning, as well as insurance risk management. Individual executive risk owners are accountable for carrying out the risk management and mitigation activities associated with the risks in their respective operations. All Capital Power employees are expected to understand the risks that fall within their areas of responsibility and to manage these risks within approved risk tolerances.

Management views risk management as an ongoing process and continually looks for ways to enhance the Company's risk management framework.

Capital Power's principal risk factors could have an adverse impact on the Company's business, prospects, financial condition, results of operations, cash flow, liquidity, capital expenditures, or resources. Not only do these risks provide Capital Power with exposure to negative consequences but also to the possibility that positive consequences will be missed. The identified risk factors are interdependent and the potential impact of any one factor is generally difficult to quantify as the impact of other risk factors changes at the same time or at a subsequent time. These principal risk factors are discussed below:

Legal, regulatory and stakeholder risk

Capital Power is subject to risk associated with changing political conditions and with changes in federal, provincial, state, or local laws and regulations or common law and their interpretation by administrative tribunals or the courts. It is not possible to predict changes in the legislative and regulatory environment or their impact on the Company's business, income tax status, operations, or the markets in which the Company operates.

In 2016, developments concerning the CLP removed some uncertainties that Capital Power was previously subject to; of particular note are the following developments:

- The agreement reached between the Company and the Government of Alberta on November 24, 2016 for the phase-out of coal-fired generation by 2030 (see Significant Events) removed the risk of stranded assets and any adverse impacts on Capital Power arising from inadequate compensation.
- Risks associated with the termination of the Sundance PPA, including the termination date and financial exposure, were removed as a result of an agreement reached between the Company and the Government of Alberta on November 24, 2016 (see Significant Events).

Further to the above-noted developments, during the fourth quarter of 2016 the Government of Alberta announced the transition of Alberta's energy-only market to a capacity market structure for which the framework is expected to be in place by 2021. This increases regulatory risk due to the uncertainty surrounding the details of the capacity market design. The Government of Alberta has committed to ensuring that existing investments will be treated fairly and that the new market framework will continue to promote a level playing field between existing and potential new capacity. In addition, the Government of Alberta and AESO confirmed details for the REP (see Significant Events). Further to these announcements, the Canadian Federal government announced the details of the Pan-Canadian Framework (PCF) on Clean Growth and Climate Change. The key elements of the PCF are carbon pricing as implemented by the provinces, coal phase-out by 2030, and the opportunity to extend the life of coal units through conversion to natural gas. The announcements have removed some uncertainties as to the direction of change for the Canadian power markets in which Capital Power operates. However, uncertainties still remain, as details and implementation of the capacity market framework and the PCF are in development.

Capital Power is required to maintain numerous licenses, permits and governmental approvals for the development, construction and operation of its projects and participation in its markets. If Capital Power fails to satisfy the conditions of these instruments, there could be an adverse impact on the effectiveness and cost of those projects or operations. Many of the regulatory approval processes for the development, construction and operation of power generation facilities require stakeholder input. Accordingly, progress in Capital Power's development, construction and operational activities could be impeded by stakeholder intervention. Changes in law and regulatory requirements may also adversely impact the market dynamics for Capital Power, the participation levels of counterparties that Capital Power relies on to support its portfolio optimization strategies and the costs associated with participating in these markets.

Capital Power's assets are emitters of various air pollutants including CO_2, NO_x, SO_2, mercury, and particulate matter. Accordingly, Capital Power's operations are subject to extensive environmental laws, regulations and guidelines relating to the generation and transmission of electricity, pollution and protection of the environment, health and safety, air emissions, water usage, wastewater discharges, hazardous material handling and storage, treatment and disposal of waste and other materials, remediation of sites, and land-use responsibility.

These regulations can impose a liability for costs to investigate or remediate contamination. Compliance with new regulatory requirements may require Capital Power to incur significant capital expenditures, additional operating expenses or cause operations at certain facilities to end prior to the end of their economic life; failure to comply with such regulations could result in fines, penalties or the curtailment of operations. Further, there can be no assurance that compliance with or changes to environmental regulations will not materially adversely impact Capital Power's business, prospects, financial condition, operations or cash flow.

Capital Power's ability to develop new projects is also affected by the availability of transmission and distribution systems. If restrictive transmission price regulation is imposed, transmission companies may not have sufficient incentive to invest in expansion of the transmission infrastructure. Capital Power cannot predict whether transmission facilities will be expanded in specific markets to accommodate competitive access to those markets.

Capital Power's operations are complex and the determination of income taxes involves income tax interpretations, regulations and legislation that are continually changing. Future changes in tax legislation may have an adverse impact on Capital Power, its shareholders and the value of the Company's common shares.

Strategies employed for managing legal, regulatory and stakeholder risk:

- Identify existing, new or changed laws or regulations, or changed interpretations of such, and prepare appropriate responses or plans.
- Comply with all applicable laws, regulations and guidelines and monitor compliance.
- Perform environmental compliance audits with corrective actions as necessary.
- Establish positive relationships with all levels of government and stakeholders.
- Consult with all levels of government with respect to policy development and current and proposed legislation.
- Execute on-time permitting, license renewals and other activities associated with laws and regulations.
- Proactively identify environmental risks within operations, maintenance and construction activities and promote awareness throughout and at all levels of the Company.
- Ensure that contractors align with Capital Power's environmental policies and procedures.
- Support the timely development of appropriate transmission capability through active relationships with regulators and government.
- Develop and maintain tax expertise and resources necessary to interpret tax legislation.
- Consult with all levels of government with respect to tax policy development and proposed legislation.

Performance of assets of joint arrangements risk

Some of Capital Power's assets are operated through joint arrangements under which Capital Power is not the operator of the associated assets. There is a risk that the assets will not be operated in accordance with Capital Power's expectations or requirements which could result in financial loss to the Company. While contractual agreements help minimize risk, there can be no assurance that such operations will continue to be effective.

The occurrence of an event which disrupts the ability of facilities operated by external parties to produce or sell power or thermal energy for an extended period would likely require Capital Power to replace the electricity at market prices prevailing at that time. Depending on market liquidity, these market prices could be significantly higher than the prices inherent in the joint arrangements, thus increasing the cost of energy purchases to Capital Power.

Strategies employed for joint arrangements risk:

- Work with facility owner and/or operator to execute appropriate operating and maintenance practices to minimize the likelihood of prolonged unplanned down time.
- Measure performance against benchmarks.
- Establish positive relationships with all parties to the joint arrangements.
- Actively participate in management committees of joint operations.
- Proactively manage the contract's rights and obligations based on thorough understanding of the contract.
- Proactively assess and resolve any contract issues including force majeure claims and appropriately respond with dialogue, advocacy, negotiation, arbitration and legal actions, as required.

Commodity price volatility risk

The market price for electricity, in the jurisdictions and markets in which Capital Power operates, affects Capital Power's revenues. Capital Power buys and sells some of its electricity in the Alberta wholesale market and such transactions are settled at spot market prices. Market electricity prices are dependent upon a number of factors including: the projected supply and demand of electricity, the bidding strategy of other generators offering electricity in Alberta, the asset management plans of the Balancing Pool, the price of raw materials that are used to generate electricity, the cost of complying with applicable environmental and other regulatory requirements, the structure of the particular market, and weather conditions. Natural gas price levels may impact power prices in the markets that the Company participates in. It is not possible to predict future electricity prices with certainty, and electricity price volatility could therefore have a material effect on Capital Power.

Electricity sales associated with the PPA for Genesee 1 and 2 are accounted for as long-term fixed margin contracts, which limits the impact of swings in wholesale electricity spot prices, unless plant availability drops significantly below the PPA target availability for an extended period. Electricity sales and steam sales associated with the Joffre facility located at the Nova Chemicals Company (NOVA) petrochemical complex are subject to market price variability as there are provisions in the contract with NOVA that require the facility to run to provide steam to the host facility, irrespective of market prices. Although the Company's 50% interests in Genesee 3 and Keephills 3 are not covered by long-term commercial contracts, the units are baseload coal-fired generating plants with relatively low variable costs and generally run when they are available. For the Company's Genesee 3, Keephills 3, CBEC and Joffre plants, spot electricity prices, the plants' variable costs, and planned and unplanned outages affect profitability.

Capital Power uses derivative instruments, including futures, forwards, options and swaps, to manage its commodity and financial market risks inherent in its electricity generation operations. These activities, although intended to mitigate price volatility, expose Capital Power to other risks. When Capital Power sells power forward, it gives up the opportunity to sell power at potentially higher prices in the future. Selling forward may also result in losses if the underlying price to provide replacement power, in the event of an outage, turns out to be greater than the contract price. In addition, Capital Power purchases and sells commodity-based contracts in the natural gas and electricity markets for trading purposes. In the future, Capital Power could recognize financial losses on these contracts as a result of volatility in the market values of the underlying commodities.

Capital Power is exposed to market risks through its power marketing business, which involves the sale of energy, capacity and related products, and the purchase and sale of fuel, transmission services and emission allowances. These market risks primarily include volatility arising from location and from timing differences that may be associated with buying and transporting fuel, converting fuel into energy and delivering the energy to a buyer.

When aggregate customer electricity consumption (load shape) changes unexpectedly, Capital Power is exposed to price risk. Load shape refers to the different pattern of consumption between peak hours and off-peak hours. Consumption is higher during peak hours when people and organizations are most active; conversely, consumption is lower during off-peak hours at night or early morning.

Strategies employed for managing commodity price volatility risk:

- Execute Company's growth strategy and re-contract generation facilities under new or extended contracts to maintain a balance of contracted and non-contracted facilities.
- Limit exposure to market price volatility by entering into long-term power contracts on certain of our generation units.
- Maintain a commodity risk management program which provides the infrastructure to manage commodity and trading risks associated with the commodity business.
- Take market risk positions within authorized limits approved by Capital Power's executive team and Board of Directors.
- Report monthly key risk measures in relation to applicable limits to the executive team with quarterly review by the Board of Directors of Capital Power.
- Perform regular commodity portfolio stress testing to observe the effects of plausible scenarios taking into account historical maximum volatilities and observed price movements.
- Minimize exposure to extreme price fluctuations, especially during higher priced peak hour periods. To do this, Capital Power relies on historical load shape data provided by load settlement agents and local distribution companies to anticipate what the aggregate customer electricity consumption will be during peak hours. When consumption varies from historical consumption patterns and from the volume of electricity purchased for any given peak hour period, Capital Power is exposed to prevailing market prices because it must either buy electricity if it is short or sell electricity if it is long. Such exposures can be exacerbated by other events such as unexpected generation facility outages and unusual weather patterns.
- Limit exposure to spot price variability within specified risk limits by entering into various purchase and sale arrangements for periods of varying duration. Due to limited market liquidity and the variability of electricity consumption between peak hours and off-peak hours, it is not possible to hedge all positions every hour. The Company operates under specific policy limits, such as total commodity risk and stop-loss limits, and generally trades in electricity to reduce the Company's exposure to changes in electricity prices or to match physical or financial obligations.

Operation and maintenance of equipment and systems risk

Power facilities operations are susceptible to outages due to failure of generation equipment, transmission lines, pipelines or other equipment, which could make the impacted facility unavailable to provide service.

The inability of Capital Power's generation facilities to generate the expected amount of electricity to be sold under contract or to the applicable market could have a significant adverse impact on the Company's revenues. In addition, counterparties to PPAs have remedies available to them if Capital Power fails to operate facilities in accordance with contract requirements, including the recovery of damages and termination of contractual arrangements. To the extent that facility equipment requires significant capital and other operation and maintenance expenditures to maintain efficiency, requires longer than forecast down-times for maintenance and repair, experiences outages due to equipment failure or suffers disruptions of power generation for other reasons, Capital Power's cost of generating electricity will increase and its revenues may be negatively affected. As an adopter of new technology, Capital Power can be exposed to design flaws or other issues, the impacts of which may not be covered by warranties or insurance. The failure of Capital Power's facilities to operate at required capacity levels may result in the facilities having their contracted capacity reduced and, in certain cases, Capital Power having to make payments on account of reduced capacity to power purchasers.

The terms of the PPAs for owned facilities provide appropriate incentives to facility owners to keep the facilities well maintained and operational. They also provide force majeure protection for high-impact, low-probability events including major equipment failure.

Many of Capital Power's generation facilities operate under PPAs or other similar contracts which are subject to a number of risks. PPA contracts contain performance benchmarks that must be achieved and other obligations that must be complied with by Capital Power. Capital Power may incur charges in the event of unplanned outages or variations from the contract performance benchmarks. PPAs expire at various times and there can be no assurance that a subsequent PPA will be available or, if available, that it will be on terms, or at prices that permit the operation of the facility on a profitable basis.

Capital Power depends on transmission facilities owned and operated by external parties to deliver the wholesale power from its power generation facilities to its customers. If transmission is disrupted or if the transmission capacity infrastructure is inadequate, there may be a material adverse effect on Capital Power's ability to sell and deliver wholesale power.

Capital Power employs several key computer application systems to support its operations, such as electricity facility control, energy trading risk management, and enterprise resource planning systems. Failure of any of these systems, during or after implementation, could result in significant lost revenues, increased costs or regulatory fines. Capital Power is also susceptible to the external risk of unauthorized access to and/or penetration of its computer networks and applications.

Strategies employed for managing operation and maintenance of equipment and systems risk:

- Establish long-term service agreements with original equipment manufacturers on key assets. Should a LMS 100 unit at CBEC fail, down time is reduced by replacing a failed unit with a replacement unit provided by the manufacturer under the terms of the long-term service agreement with that manufacturer.
- Ensure constructive relationships with original equipment manufacturers.
- Execute appropriate operating and maintenance practices (reliability program) to minimize the likelihood of prolonged unplanned down time for the Company's facilities.
- Maintain an inventory of strategic spare parts which can reduce down time in the event of failure.
- Employ a root cause analysis program to ensure that problems are properly identified and addressed and that learnings are shared across the fleet.
- Establish and maintain appropriate business interruption, property, and boiler and machinery insurance to reduce the impact of prolonged outages caused by insured events.
- Minimize the customization of commercial software, monitor the impacts on processes and internal controls and undertake remedial actions, as required.
- Ensure operations and implementation projects are properly resourced with qualified and trained staff and contractors.
- Employ robust firewalls and access security protocols as well as detection systems that will identify or prevent unauthorized systems or devices.

People risk

Capital Power's ability to continuously operate its facilities and grow the business is dependent upon attracting, retaining and developing sufficient labour and management resources. Capital Power is experiencing a demographic shift as a significant number of its employees are expected to retire over the next several years**.** Failure to secure sufficient qualified labour may negatively impact Capital Power's operations or construction and development projects, or may increase expenses. Capital Power's current collective bargaining agreements expire periodically and Capital Power may not be able to renew them without a labour disruption or without agreeing to significant increases in labour costs.

The Company's collective agreement with IBEW 1007, which represents all employees directly engaged in the maintenance of the electrical generation at Genesee, expired December 12, 2015. A new collective agreement was ratified and was in effect as of September 22, 2016.

The Company's collective agreement with UNIFOR 829, which represents all power engineers at Genesee, expired December 24, 2016. All existing terms, conditions and wage rates in the expired collective agreement will continue in force and effect until a new collective agreement is reached. Negotiations related to a new collective agreement are expected to begin in the first quarter of 2017.

Strategies employed for managing human resources risk:

- Maintain good human resource programs and practices including monitoring developments and contingency plans.
- Maintain competitive compensation programs.
- Maintain succession plans for key positions.
- Maintain good collective bargaining capability, programs and practices.

The development, construction, ownership and operation of Capital Power's generation assets carry an inherent risk of liability related to public health, and worker health and safety due to exposure to high voltage electricity, high pressure steam, moving and rotating machinery, heavy equipment, driving, and environmental hazards.

Strategies employed for managing health and safety risk:

- Maintain an organization-wide health and safety culture and system with regular measurements and compliance audits.
- Maintain facility specific safety programs and work procedures.
- Ensure that contractors and other stakeholders align with Capital Power's health and safety policies and procedures.

Capital Power strives to right size the resources required to operate and grow in its markets and minimize the cost of those resources. Failure to do so could negatively impact culture, growth and earnings and place the Company at a competitive disadvantage.

Strategies employed for managing cost optimization and efficiency risk:

- Set performance targets and measure and report results compared with those targets. Measure performance against benchmarks.
- Develop and undertake efficiency initiatives and programs.
- Support internal resources by utilizing retention programs and assessing employee engagement with appropriate communication and follow-up.

Finance risk

Capital Power's ability to fund current and future capital requirements, along with its working capital needs is dependent upon access to financial markets. Uncertainty and volatility in the Canadian and U.S. financial markets may adversely affect Capital Power's ability to access and arrange financing under favourable terms and conditions. The cost of capital will also depend upon prevailing market conditions and the business performance of Capital Power as indicated by the assigned corporate credit ratings (see Liquidity and Capital Resources). If Capital Power is unable to access sufficient amounts of capital on acceptable terms, there could be an adverse effect on its business plan and financial condition.

Strategies employed for managing credit rating risk:

- Maintain strong relationships with credit rating agencies.
- Develop flexible financial structuring to adapt if circumstances would cause a credit rating downgrade from investment grade.

When Capital Power uses financial instruments to sell power forward, it may be required to post significant amounts of cash collateral or other credit support to its counterparties.

Strategies employed for managing liquidity risk:

- Monitor cash and currency requirements on a regular basis by preparing short-term and long-term cash flow forecasts and by matching the maturity profiles of financial assets and liabilities to identify financing requirements.
- Maintain strong relationships with banks, investment banks and other financial counterparties.
- Meet financing requirements through a combination of committed and demand revolving credit facilities, financings in public and private capital debt markets, and equity offerings.

Counterparty risk is the possible financial loss associated with the potential inability of counterparties to satisfy their contractual obligations to Capital Power, including payment and performance. In the event of default by a purchasing counterparty, existing PPAs and other agreements may not be replaceable on similar terms. Capital Power is also dependent upon its cogeneration hosts and suppliers of fuel to its plants. If a wholesale electricity market counterparty defaults, Capital Power may not be able to replace such counterparty to effectively manage short or long energy positions, resulting in reduced revenues or increased power costs. Furthermore, a prolonged deterioration in economic conditions could increase the foregoing risks.

Strategies employed for managing counterparty credit risk:

- Maintain a credit policy including limits for credit risk exposure levels.
- Conduct periodic credit reviews on existing counterparties.
- Use credit enhancements such as cash deposits, prepayments, parent company guarantees, bank letters of credit, master netting agreements, margin accounts and credit derivatives.
- Monitor and report credit risk exposures.

Extreme natural and other unexpected events risk

Capital Power's operations are exposed to potential damage resulting from extreme storm and other weather conditions and natural disasters. In addition, major accidents or events including environmental incidents, cyber-attacks on our key information technology systems to support our core operations, and physical terrorist attacks are possible and the negative consequences could be significant.

Strategies employed for managing extreme events risk:

- Establish and maintain emergency and other related contingency planning measures to enable the timely response to and recovery from extreme weather and other events.
- Maintain appropriate insurance coverage.
- Regular monitoring and surveillance of the Company's information technology systems.
- Periodic audits of the effectiveness of the Company's information technology security systems.

Competition, acquisition, development and construction risk

In the course of assessing development and acquisition opportunities, Capital Power may be required to incur significant expenditures, such as those related to preliminary engineering, permitting, legal and other expenses, before determining whether a project is feasible and economically viable. There can be no assurance that Capital Power will pursue or win any opportunity assessed.

The risks associated with acquisitions of additional companies or assets in the power generation industry include the failure to identify material problems during due diligence, the overpayment for assets and the inability to arrange financing for an acquisition. Further, the integration and consolidation of acquisitions requires substantial human, financial and other resources. There can be no assurances that any future acquisitions will perform as expected or that the returns from such acquisitions will cover the cost of financing incurred to acquire them or the capital expenditures needed to develop them.

In developing and constructing a power generation facility, there are numerous tasks Capital Power must complete. These include obtaining government permits and approvals, site agreements, construction contracts, access to power grids, electrical transmission agreements, fuel supply and transportation agreements, equipment, and financing. There can be no assurance that Capital Power will be successful in completing such tasks on a timely basis or at all. The development and future operation of power generation facilities can be adversely affected by changes in government policy and regulation, environmental concerns, stakeholder activism, increases in capital costs, increases in interest rates, competition in the industry, labour availability, labour disputes, increases in material costs and other matters beyond the control of Capital Power. In the event that a project is not completed or does not operate at anticipated performance levels, Capital Power may not be able to recover its investment.

Strategies employed for managing competition, acquisition, development, and construction risk:

- Perform detailed project analyses, risk assessments and due diligence prior to and during construction or acquisition.
- Perform post-implementation evaluation of all major acquisition and development projects to improve internal capabilities and processes and to leverage lessons learned for future projects. When necessary, corrective actions are taken to increase the likelihood of investment recovery.
- Enter into favourable long-term contracts for the projects' output, whenever possible.

Ongoing research and development activities improve upon existing power technologies and reduce the cost of alternative methods of power generation. As identified by ongoing research and development activities, Capital Power's facilities may over time be unable to compete with newer more efficient facilities utilizing improvements to existing power technologies and cost-efficient new technologies.

Energy supply risk

Capital Power requires energy from sources such as coal, natural gas, wind, wood waste, tire derived fuel (TDF) and the sun to generate electricity. A disruption in the supply or a significant increase in the price of any supplies required by Capital Power could have a material adverse impact on Capital Power's business, financial condition and results of operation. The price of fuel supplies is dependent upon a number of factors, including: (i) the supply and demand for such fuel supplies, (ii) the quality of the fuel, and (iii) the cost of transporting such fuel supplies to Capital Power's facilities. Changes in any of these factors could increase Capital Power's cost of generating electricity or decrease Capital Power's revenues due to production cutbacks.

Coal for the Genesee and Keephills 3 plants is supplied under long-term agreements where the price is based on a cost-of-service model with annual updates for inflation, interest rate and capital budget parameters and is therefore not subject to coal market price volatility. A shortage of coal supply resulting from significant disruption of the coal mine equipment and operation could negatively impact generation and revenues from these plants. Most of Capital Power's natural gas-fired plants are operated as merchant facilities and as such are susceptible to the risks associated with the volatility of natural gas prices and the prevailing electricity market prices. Natural gas purchases for these power plants are made under variable price contracts and when a facility's heat rate (a measure of fuel efficiency) does not meet expectations, unit profitability is affected. Island Generation operates under a long-term PPA with fuel cost flow-through provisions. The facilities at Southport and Roxboro operate using a fuel mixture of wood waste, TDF, and a small amount of coal. Coal is sourced with regional coal suppliers, while the TDF and wood residuals are supplied under long-term agreements.

Capital Power's wind and solar power facilities are dependent on the availability and constancy of sufficient wind and solar resources to meet projected capacity factors. Fluctuations in wind speed or duration, as well as hours of sunlight could have a material negative impact on revenues for these facilities in any year.

Strategies employed for managing energy supply risk:

- Establish long-term supply agreements.
- Maintain coal stock-pile inventories.
- Establish contracts with fuel cost flow-through provisions, where possible.
- Actively participate on the Genesee Coal Mine Joint Venture Committee and exercise contractual rights as required.
- Thorough research and collection of wind and solar data prior to development or acquisition of facilities.
- Keep apprised of new technology that may increase generation by capturing more wind or sun.

General economic conditions, business environment and other risks

In addition to all the risks previously described, the Company is subject to adverse changes in its markets and general economic conditions. The Company is exposed to risks associated with income tax filings, foreign exchange, weather, legal and arbitration proceedings, and risks that are not fully covered by various insurance policies.

Environmental risk is incorporated in several different types of risks discussed in this and other subsections of this Risk and Risk Management section including legal, regulatory and stakeholder risk, people risk, operation and maintenance of equipment and systems risk, extreme natural and other unexpected occurrences, energy supply risk, and reputation risk.

Capital Power's tax filings are subject to audit by taxation authorities. While Capital Power maintains that its tax filings have been made in accordance with all such tax interpretations, regulations, and legislation, Capital Power cannot guarantee that it will not have disagreements with taxation authorities with respect to its tax filings.

The statutory income tax rates on income before tax for 2016 and 2015 were 27% and 26%, respectively. The effective income tax rate can change depending on the mix of earnings from various jurisdictions, and on deductions and inclusions in determining taxable income that do not fluctuate with earnings.

Strategies employed for managing tax compliance risk:

- Develop and maintain tax expertise and resources necessary to understand tax legislation.
- Comply with tax laws of jurisdictions that Capital Power operates in.

Fluctuations in the exchange rate between the U.S. dollar and the Canadian dollar affect Capital Power's capital and operating costs, revenues and cash flows and could have an adverse impact on Capital Power's financial performance and condition. The U.S. facility operations and the foreign-sourced equipment required for capital projects are transacted in U.S. dollars. In addition, certain indebtedness is denominated in U.S. dollars.

Strategies employed for managing foreign exchange risk:

- Utilize foreign currency forward contracts.
- Contract significant purchases or borrowings in Canadian dollars.
- Utilize U.S. dollar denominated debt to finance U.S. acquisitions and developments.

The Company is dependent upon cash dividends, distributions or other transfers from its subsidiaries, including CPLP, in order to repay any debt the Company may incur, to make dividend payments to its shareholders and to meet its other obligations. The right of the Company, as a unitholder or shareholder of these entities, to realize on the assets of these entities in the event of their bankruptcy or insolvency, would be subordinate to the rights of their creditors and claimants preferred by statute. CPLP's credit facilities prohibit CPLP from making distributions, if an event of default has occurred and is continuing or would reasonably be expected to result from the distribution. As of December 31, 2016, the Company loaned $1,364 million to CPLP under subordinated debt agreements. The terms of these agreements allow interest to be deferred. If interest is deferred, then CPLP has covenanted not to make distributions on any of its outstanding common limited partnership units.

Weather can have a significant impact on Capital Power's operations. Temperature levels, seasonality and precipitation, both within Capital Power's markets and adjacent geographies, can affect the level of demand for electricity and natural gas, thus resulting in electricity and natural gas price volatility.

In the normal course of Capital Power's operations, it may become involved in various legal proceedings including arbitration of the interpretation of any contract. The outcome with respect to outstanding, pending or future proceedings cannot be predicted with certainty. However, the Company does not believe that the outcome of any claims or potential claims of which it is aware will have a material adverse effect on Capital Power's financial condition and results of operations (see Contractual Obligations and Contingent Liabilities).

The Company considers reputation risk to be a consequence of all other risks that it faces. If a certain risk factor results in positive or negative consequences to the Company, its reputation may also be positively or negatively affected. In part, the Company manages its reputation risk by employing appropriate risk management strategies for all identified risks.

Capital Power's property, boiler and machinery, business interruption and liability insurance coverages are established and maintained to minimize financial exposures associated with extreme weather and other events. The insurance coverages are subject to deductibles, limits and exclusions, and may not provide sufficient coverage for these and other insurable risks. There can be no assurance that such insurance will continue to be offered on an economically feasible basis or that all events that could give rise to a loss or liability are insurable.

There can be no assurance that any risk management steps taken by Capital Power with the objective of mitigating the foregoing risks will avoid future loss due to the occurrence of such risks.

ENVIRONMENTAL MATTERS

The Company recorded decommissioning provisions of $195 million as at December 31, 2016 ($184 million as at December 31, 2015) for its generation facilities and the Genesee 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 $221 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 audited 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.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to estimates are recognized prospectively.

Critical judgments in applying accounting policies

The main judgments that were used in preparing the Company's audited consolidated financial statements relate to:

Judgment	Management applies judgment to evaluate	Resulting conclusions
Cash generating units	What constitutes a CGU based on the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets.	CGUs were determined giving consideration to geographic proximity and shared risk exposure and risk management. During the fourth quarter of 2016, management reviewed the grouping of its assets into the Alberta Contracted and Alberta Commercial CGUs. Given that the contracted period of the Alberta Contracted assets runs through 2020, the majority of the useful lives of those assets and the resulting future cash flows are now commercial in nature. As a result, effective for the fourth quarter of 2016, the Alberta Contracted and Alberta Commercial CGUs have been combined into one Alberta CGU for impairment testing purposes.
Asset impairment	Whether events or circumstances may indicate that an asset's carrying amount exceeds its recoverable amount.	During the fourth quarter of 2015, the Government of Alberta announced its CLP. The CLP was not in itself a triggering event for purposes of assessing potential asset impairment. However, the uncertainties created by the CLP combined with the impact of low Alberta power prices and general negative market reaction to Alberta's economic conditions led to a substantial decline in the Company's market capitalization, particularly in the last quarter of 2015. This led to impairment testing being completed in the fourth quarter of 2015, with no resulting impairment to the Alberta Contracted and Alberta Commercial CGUs. On November 24, 2016, the Company announced details of the agreement reached with the Government of Alberta related to the 2030 phase-out of coal-fired generation and the resulting compensation (See Significant Events). On November 23, 2016, the Government of Alberta announced the transition of Alberta's electricity market from an energy-only market to a capacity market, for which the framework is expected to be in place by 2021. These announcements are additional components of the CLP. The Company's market capitalization has recovered since the last quarter of 2015, particularly in the period after the announcements in late November 2016. However, the 2015 impairment testing was based on the assumption that the coal-fired generation facilities would continue to operate until the end of their previous useful lives, as a proxy for fair compensation being received for the post 2030 period. As a result of the announcement of compensation details and the transition to a capacity market, impairment testing has been triggered for the Company's Alberta CGU which was tested for impairment during the fourth quarter of 2016, with no resulting impairment for 2016. The Company determined that no other CGUs were affected by the triggering event, since they operate in geographic regions that are not directly impacted by the events in Alberta.

Judgment	Management applies judgment to evaluate	Resulting conclusions
Whether an arrangement contains a lease and classification of leases	Whether a PPA or similar contract conveys the right to use the Company's property, plant and equipment in return for payment, and, if so, a lease exists. Whether substantially all the risks and rewards of ownership of property are transferred to determine if the lease is accounted for as a finance lease or, if not, the lease is accounted for as an operating lease.	Contracts that convey the right to use Capital Power's property, plant and equipment and, therefore, contain a lease: 1. **Finance leases as the lessor** (substantially all the risks and rewards are transferred) • Kingsbridge energy supply contract • Port Dover and Nanticoke energy supply contract • Quality Wind electricity purchase agreement 2. **Operating leases as the lessor** (substantially all the risks and rewards remain with Capital Power) • Genesee 1 and 2 PPA • Island Generation PPA • Roxboro PPA 3. **Finance lease as the lessee** (substantially all the risks and rewards remain with Capital Power) • Beaufort Solar sale and leaseback agreement
Control of subsidiaries that are less than wholly-owned	Whether certain subsidiaries are controlled by the Company even though the subsidiaries are less than wholly-owned.	Since the Company has majority rights, the Genesee Coal Mine is consolidated and has a non-controlling interest.
Classification of joint arrangements	How joint arrangements structured through a separate vehicle should be classified; either as a joint venture or a joint operation.	K2 Wind is accounted for as a joint venture because each of the partners effectively has rights to the net assets of the arrangement. Genesee 3, Keephills 3, Joffre, Shepard and Genesee 4 and 5 are accounted for as joint operations because each of the joint operators has rights to the assets and obligations for the liabilities of the arrangement and rights to the corresponding revenues and obligations for the corresponding expenses.
Operating segments	Whether the Company operates in one or multiple business segments, and if the Company operates in multiple segments, how the aggregation criteria are applied to reportable segments.	The Company has aggregated its operating segments into one reportable business segment as its operating segments have similar products, production processes, types of customers, product distribution methods, regulatory environments and economic characteristics. Each operating segment is involved with the generation and sale of electricity, which includes the process of turning various fuel sources into electricity and managing the revenues and costs of such electricity, including engaging in trading activities. The Company's customers tend to be large industrial and commercial customers, independent system operators and government owned or sponsored entities. Given the similar size and credit profiles of these counterparties, they are deemed to be similar types of customers. The method of distributing electricity is the same across all facilities, and none of the Company's entities are rate-regulated.

Assumptions and estimation uncertainties

The following identifies key information about assumptions and estimation uncertainties that could have a significant risk of resulting in material adjustments:

Estimate	Impacts and assumptions subject to estimation uncertainty
Measurement of fair values	Carrying amounts for financial instruments • Amounts and timing of future cash flows • Future prices • Future interest rate yield curves • Volatility
	Impairment of financial and non-financial assets and liabilities • Discount rates • Growth rates • Other cash flow assumptions including revenues, expenses and capital expenditures • Future generating capacity • Contract renewals and rates adjusted for inflation • Fuel mix at optimized levels
	Decommissioning and other provisions • Discount rates • Amount and timing of asset retirement • Extent of site remediation required • Future cash flows based on amount and timing of settlement of obligation • Expected customer renewals for other provisions
	Share-based payments • Expected volatility, option life and dividend yield • Risk-free interest rate
	Purchase price allocations to financial and non-financial assets and liabilities • Same fair value measurement factors and assumptions as applicable to determine carrying amounts for derivative financial instruments, impairment of financial and non-financial assets and liabilities, and decommissioning and other provisions.
Depreciation and amortization	Assets useful lives are based on the life characteristics of common assets and the expectation of coal asset fuel conversion to allow for generation post-2030. During the fourth quarter of 2016, the Company revised the estimated useful lives for the major components of its coal-fired generation facilities and related equipment as a result of the phase-out of coal-fired generation by the end of 2030 and the expectation of converting those facilities to natural gas facilities.
Recognition of deferred tax assets and availability of future taxable income against which carry forward tax losses can be used.	Deferred tax assets and income tax provisions are based on the likelihood that tax losses will be recovered from future taxable income.
Revenue recognition	The value of electricity and natural gas consumed by customers but not billed until after year-end is based on data provided by the parties delivering the commodity.

ACCOUNTING CHANGES

Effective January 1, 2016

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

Standard	Description	Impact to Capital Power
Presentation of financial statements (amendments to IAS 1)	Amendments providing guidance on materiality and aggregation on the statements of financial position, clarification of presentation issues on the statements of income or loss and other comprehensive income or loss, and providing additional examples of ways of ordering notes.	There was no impact to the Company's interim and annual financial statement disclosures.
Acquisition of an interest in a joint operation (amendments to IFRS 11)	Provides guidance on how a joint operator accounts for the acquisition of an interest in a joint operation that is a business. It requires a joint operator to account for such an acquisition by applying IFRS 3 Business Combinations and other standards, and disclosing the relevant information specified in those IFRSs for business combinations.	No immediate impact but would affect applicable future transactions.

Future

The IASB issued the following new standards and amendments to existing standards that were not yet effective as of December 31, 2016 and are relevant to Capital Power:

Standard	Description	Impact to Capital Power and current implementation status.	Effective Date
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 amendments will require further disclosures with respect to cash and non-cash debt transactions.	Effective for annual periods beginning on or after January 1, 2017.
Revenue from contracts with customers (IFRS 15)	New standard on revenue recognition consisting of a single and comprehensive framework for revenue recognition to ensure consistent treatment for all transactions in all industries and capital markets.	May change the timing of revenue recognized from any contracts with a number of discrete performance obligations (multiple-element arrangements), require separate line disclosure of credit losses, and require more extensive disclosures on annual and interim basis. Capital Power is currently assessing the applicability of this new standard on its various contracts and the associated system requirements and expects to provide more detailed information in 2017.	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.	May change the measurement of certain financial instruments and the recording of expected credit losses. Capital Power is currently analyzing the requirements to determine the impacts on its existing financial instruments and expects to provide more detailed information in 2017.	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.	Will require the Company to recognize leased assets and leased obligations with respect to its lease arrangements for office space. Management is currently assessing whether certain PPAs 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.	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 December 31, 2016 and 2015 were as follows:

(unaudited, $ millions)			As at December 31			
			2016		2015	
	Classification	Fair value hierarchy level [1]	Carrying amount	Fair value	Carrying amount	Fair value
Financial assets:						
Cash and cash equivalents	Loans and receivables	N/A	98	98	80	80
Trade and other receivables (excluding current portion of government grant receivable and finance lease receivables)	Loans and receivables	N/A	149	149	169	169
Government grant receivable (including current portion disclosed within trade and other receivables)	Loans and receivables	Level 2	594	594	-	-
Derivative financial instruments assets – current and non-current	Financial assets designated at fair value through income or loss	See Below	269	269	220	220
Finance lease receivables (including current portion disclosed within trade and other receivables)	Loans and receivables	Level 2	689	762	710	807
Other financial assets	Loans and receivables	Level 2	4	4	12	12
Financial liabilities:						
Trade and other payables (excluding current portion of finance lease obligation)	Other financial liabilities	N/A	216	216	180	180
Derivative financial instruments liabilities – current and non-current	Financial liabilities designated at fair value through income or loss	See Below	92	92	53	53
Finance lease obligation (including current portion disclosed within trade & other payables)	Other financial liabilities	Level 2	20	20	22	22
Loans and borrowings (including current portion)	Other financial liabilities	Level 2	1,508	1,540	1,615	1,623

[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 performed by the Company's commodity risk group and reviewed by management.

Risk management and hedging activities

The Company is exposed to changes in energy commodity prices, foreign currency exchange rates and interest rates. The Company uses various risk management techniques, including derivative instruments such as forward contracts, fixed-for-floating swaps, and option contracts, to reduce this exposure. These derivative instruments are recorded at fair value on the Consolidated Statements of Financial Position except for non-financial derivatives that are entered into and continue to be held for the purpose of receipt or delivery of a non-financial item in accordance with the Company's expected purchase, sale or usage requirements.

Unrealized changes in the fair value of financial and non-financial derivatives that do not qualify for hedge accounting and non-financial derivatives that do not qualify for the expected purchase, sale or usage requirements of the Company are recognized in net income as revenues or energy purchases and fuel. The corresponding unrealized changes in the fair value of the associated economically hedged exposures are not recognized in income. Accordingly, derivative instruments that are recorded at fair value can produce volatility in net income as a result of fluctuating forward commodity prices, foreign exchange rates and interest rates which are not offset by the unrealized fair value changes of the exposure being hedged on an economic basis. As a result, accounting gains or losses relating to changes in fair values of derivative instruments do not necessarily represent the underlying economics of the hedging transaction.

For example, the Company usually has more physical supply of power in Alberta from its generating units than the Company has contracted to physically sell. The Company utilizes financial sales contracts to reduce its exposure to changes in the price of power in Alberta. Economically, the Company benefits from higher Alberta power prices due to the net long position held since the Company's expected physical supply is in excess of the Company's physical and financial sales contracts. However, financial sales contracts that are not hedged for accounting purposes are recorded at fair value at each statement of financial position date and the offsetting anticipated future physical supply or economically hedged item is not. Accordingly, an increase in forward Alberta power prices can result in fair value losses for accounting purposes whereas on an economic basis, these losses are offset by unrecognized gains on the physical supply. The economic gains will be recognized in later periods when the power is produced and sold. The opposite is true for forward price decreases in Alberta power.

The derivative financial instruments assets and liabilities held at December 31, 2016 and 2015 and used for risk management purposes were measured at fair value and consisted of the following:

(unaudited, $ millions)		**As at December 31, 2016**				
	Fair value hierarchy level	**Commodity cash flow hedges**	**Commodity non-hedges**	**Foreign exchange hedges**	**Interest rate non-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	(22)	(51)	-	-	(73)
	Level 3	(19)	-	-	-	(19)
		(41)	(51)	-	-	(92)
Net derivative financial instruments assets		**28**	**91**	**58**	**-**	**177**

(unaudited, $ millions)		**As at December 31, 2015**				
	Fair value hierarchy level	**Commodity cash flow hedges**	**Commodity non-hedges**	**Foreign exchange hedges**	**Interest rate non-hedges**	**Total**
Derivative financial instruments assets	Level 2	64	72	68	5	209
	Level 3	-	11	-	-	11
		64	83	68	5	220
Derivative financial instruments liabilities	Level 2	(4)	(38)	-	(11)	(53)
Net derivative financial instruments assets (liabilities)		**60**	**45**	**68**	**(6)**	**167**

Commodity and foreign exchange derivatives designated as accounting hedges

Unrealized gains and losses for fair value changes on commodity and foreign exchange derivatives that qualify for hedge accounting are recorded in other comprehensive income (loss) and, when realized, are reclassified to net income as revenues, energy purchases and fuel, or foreign exchange gains and losses. As a result of the termination of the Sundance PPA (see Significant Events), certain derivatives that were previously designated as accounting hedges were de-designated as the hedged transactions are 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 interest rate derivatives that are not designated as hedges for accounting purposes are recorded in net income as finance expense.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

As at December 31, 2016, management conducted an evaluation of the design and operation of the Company's disclosure controls and procedures to provide reasonable assurance that:

(i) material information relating to the Company is made known to management by others, particularly during the period in which the Company's annual filings are being prepared, and

(ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation.

The evaluation took into consideration the Company's Disclosure Policy and internal sub-certification process, and the functioning of its Disclosure Committee. In addition, the evaluation covered the Company's processes, systems and capabilities relating to public disclosures and the identification and communication of material information. Based on that evaluation, the Company's Chief Executive Officer and Chief Financial Officer have concluded that the Company's disclosure controls and procedures are appropriately designed and effective.

As at December 31, 2016, management conducted an evaluation of the design and operation of internal controls over financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that the Company's internal controls over financial reporting are appropriately designed and effective.

These evaluations were conducted in accordance with the Internal Control – Integrated Framework (2013), issued by the Committee of Sponsoring Organizations of the Treadway Commission and the requirements of the Canadian Securities Administrators' National Instrument 52-109.

SUMMARY OF QUARTERLY RESULTS

(GWh)	Three months ended							
Electricity generation	**Dec 31 2016**	**Sep 30 2016**	**Jun 30 2016**	**Mar 31 2016**	**Dec 31 2015**	**Sep 30 2015**	**Jun 30 2015**	**Mar 31 2015**
Total generation excluding Sundance PPA	3,793	3,930	3,707	3,898	3,929	3,687	3,553	3,398
Alberta commercial facilities and Sundance PPA [1]								
Genesee 3	341	498	474	474	500	498	491	493
Keephills 3	478	464	501	388	489	258	436	457
Clover Bar Energy Centre 1, 2 and 3	94	79	106	48	41	39	98	70
Joffre	66	27	21	83	84	62	76	86
Shepard	410	611	647	577	387	572	443	60
Halkirk	121	86	124	124	129	88	107	136
Clover Bar Landfill Gas	3	1	2	1	1	2	3	2
Alberta commercial facilities – owned	1,513	1,766	1,875	1,695	1,631	1,519	1,654	1,304
Sundance PPA [2]	-	-	-	655	717	688	565	691
	1,513	1,766	1,875	2,350	2,348	2,207	2,219	1,995
Alberta contracted facilities [1]								
Genesee 1	863	857	770	843	842	865	608	815
Genesee 2	860	862	582	833	861	843	838	836
	1,723	1,719	1,352	1,676	1,703	1,708	1,446	1,651
Ontario and British Columbia contracted facilities								
Island Generation	37	2	-	-	5	37	37	-
K2 Wind	77	40	34	71	102	46	19	N/A
Kingsbridge 1	37	15	16	34	36	13	21	31
Port Dover and Nanticoke	92	53	65	95	95	44	69	91
Quality Wind	85	78	90	91	121	97	82	108
	328	188	205	291	359	237	228	230
U.S. contracted facilities								
Roxboro, North Carolina	84	84	82	66	77	76	70	59
Southport, North Carolina	107	140	144	127	131	128	118	129
Beaufort Solar, North Carolina	6	8	8	7	-	N/A	N/A	N/A
Macho Springs, New Mexico	32	25	41	36	28	19	37	25
	229	257	275	236	236	223	225	213

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

2 The Company's role as Buyer of the Sundance PPA was terminated effective March 24, 2016 (see Significant Events). Results of the Sundance PPA were recognized up to March 24, 2016.

(%)	Three months ended							
Facility availability	**Dec 31 2016**	**Sep 30 2016**	**Jun 30 2016**	**Mar 31 2016**	**Dec 31 2015**	**Sep 30 2015**	**Jun 30 2015**	**Mar 31 2015**
Total average facility availability excluding Sundance PPA	94	96	90	97	99	95	90	98
Alberta commercial facilities and Sundance PPA [1]								
Genesee 3	68	100	100	99	100	100	100	100
Keephills 3	99	96	100	90	100	63	97	100
Clover Bar Energy Centre 1, 2 and 3	99	91	91	99	97	88	95	97
Joffre	98	81	55	89	100	100	87	99
Shepard	76	99	82	100	98	100	73	80
Halkirk	98	96	98	99	96	97	98	99
Clover Bar Landfill Gas	92	27	99	99	84	81	93	100
Alberta commercial facilities – owned	87	95	87	96	98	92	89	97
Sundance PPA [2]	-	-	-	95	92	91	79	92
	87	95	87	96	96	92	86	95
Alberta contracted facilities [1]								
Genesee 1	100	100	95	100	99	100	72	98
Genesee 2	100	100	72	99	100	98	100	100
	100	100	84	99	100	99	86	99
Ontario and British Columbia contracted facilities								
Island Generation	100	92	100	100	100	100	100	100
K2 Wind	100	98	99	99	99	98	98	N/A
Kingsbridge 1	97	95	97	94	98	94	95	97
Port Dover and Nanticoke	99	94	100	97	98	95	97	99
Quality Wind	97	91	98	99	98	94	97	98
	99	93	99	99	99	97	98	99
U.S. contracted facilities								
Roxboro, North Carolina	94	100	100	89	99	94	87	97
Southport, North Carolina	98	96	92	83	93	94	88	89
Beaufort Solar, North Carolina	92	98	91	98	100	N/A	N/A	N/A
Macho Springs, New Mexico	97	97	98	97	96	96	99	99
	96	97	95	89	96	95	91	94

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

2 The Company's role as Buyer of the Sundance PPA was terminated effective March 24, 2016 (see Significant Events). Results of the Sundance PPA were recognized up to March 24, 2016.

Financial results

(unaudited, $ millions)	Three months ended							
	Dec 31 2016	**Sep 30 2016**	**Jun 30 2016**	**Mar 31 2016**	**Dec 31 2015**	**Sep 30 2015**	**Jun 30 2015**	**Mar 31 2015**
Revenues and other income								
Alberta commercial facilities, Sundance PPA and portfolio optimization [1,2]	172	163	166	188	199	237	130	216
Alberta contracted facilities [2]	65	64	59	64	66	69	65	65
Ontario and British Columbia contracted facilities	33	23	25	34	40	23	25	36
U.S. contracted facilities	29	34	34	32	30	29	28	27
Corporate [3]	11	2	1	2	1	2	4	1
Unrealized changes in fair value of commodity derivatives and emission credits	(30)	88	(59)	14	1	106	(171)	12
	280	**374**	**226**	**334**	**337**	**466**	**81**	**357**
Adjusted EBITDA								
Alberta commercial facilities, Sundance PPA and portfolio optimization [1,2]	70	74	71	64	70	72	49	63
Alberta contracted facilities [2]	40	38	43	42	45	52	45	42
Ontario and British Columbia contracted facilities [4]	40	21	28	38	45	22	21	30
U.S. contracted facilities	8	11	8	8	10	6	6	5
Corporate	(20)	(24)	(27)	(24)	(24)	(25)	(27)	(24)
Unrealized changes in fair value of commodity derivatives and emission credits	6	28	(15)	(8)	(12)	27	(47)	31
	144	**148**	**108**	**120**	**134**	**154**	**47**	**147**

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

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

3 Revenues are offset by interplant category revenue eliminations.

4 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 venture 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							
	Dec 31 2016	**Sep 30 2016**	**Jun 30 2016**	**Mar 31 2016**	**Dec 31 2015**	**Sep 30 2015**	**Jun 30 2015**	**Mar 31 2015**
Revenues and other income	280	374	226	334	337	466	81	357
Adjusted EBITDA [1,2]	144	148	108	120	134	154	47	147
Net income (loss)	26	64	20	(8)	34	50	(48)	50
Net income (loss) attributable to shareholders of the Company	28	66	23	(6)	35	49	(34)	40
Basic earnings (loss) per share ($)	0.21	0.63	0.19	(0.11)	0.29	0.44	(0.39)	0.41
Normalized earnings per share ($) [1]	0.27	0.31	0.30	0.33	0.42	0.33	0.10	0.32
Funds from operations [1]	75	94	106	109	125	97	70	108
Purchase of property, plant and equipment and other assets	174	27	81	31	17	36	35	52

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

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 venture and the applicable comparative periods have been adjusted to conform to the current period's presentation.

	Three months ended							
Spot price averages	**Dec 31 2016**	**Sep 30 2016**	**Jun 30 2016**	**Mar 31 2016**	**Dec 31 2015**	**Sep 30 2015**	**Jun 30 2015**	**Mar 31 2015**
Alberta power ($ per MWh)	22	18	15	18	21	26	57	29
Alberta natural gas (AECO) ($ per Gj)	2.97	2.14	1.34	1.72	2.35	2.77	2.52	2.63
Capital Power's Alberta portfolio average realized power price ($ per MWh)	67	70	61	52	55	61	46	59

Factors impacting results for the fourth 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 (see Significant Events) 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.

Factors impacting results for the previous quarters

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

The results for the 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 (see Significant Events). 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 price 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 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 on its long natural gas position. 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.

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

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

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							
	Dec 31 2016	Sep 30 2016	Jun 30 2016	Mar 31 2016	Dec 31 2015	Sep 30 2015	Jun 30 2015	Mar 31 2015
Share price ($/common share)								
High	24.49	22.16	20.23	18.93	20.21	22.42	25.58	27.12
Low	19.90	18.95	17.31	16.37	15.41	18.28	21.53	23.77
Close	23.23	20.62	19.28	18.00	17.77	18.88	21.54	24.51
Volume of shares traded (millions)	23.2	16.0	14.8	19.2	20.5	19.4	21.1	18.8

Outstanding share and partnership unit data

As at February 14, 2017, the Company had 96.217 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 February 14, 2017 were 100.271 million. The outstanding special limited voting share is held by EPCOR.

As at February 14, 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.

Consolidated Financial Statements of

CAPITAL POWER CORPORATION

(In millions of Canadian dollars)
Years ended December 31, 2016 and 2015

Management's responsibility for financial reporting

The preparation and presentation of the accompanying consolidated financial statements of Capital Power Corporation (the Company) are the responsibility of management and the consolidated financial statements have been approved by the Board of Directors. In management's opinion, the consolidated financial statements have been prepared within reasonable limits of materiality in accordance with International Financial Reporting Standards. The preparation of financial statements necessarily requires judgment and estimation when events affecting the current year depend on determinations to be made in the future. Management has exercised careful judgment where estimates were required, and these consolidated financial statements reflect all information available to February 17, 2017. Financial information presented elsewhere in the Company's annual report is consistent with that in the consolidated financial statements.

To discharge its responsibility for financial reporting, management maintains systems of internal controls designed to provide reasonable assurance that the Company's assets are safeguarded, that transactions are properly authorized and that reliable financial information is relevant, accurate and available on a timely basis. The internal control systems are monitored by management, and evaluated by an internal audit function that regularly reports its findings to management and the Audit Committee of the Board of Directors.

The consolidated financial statements have been examined by KPMG LLP, the Company's external auditors. The external auditors are responsible for examining the consolidated financial statements and expressing their opinion on the fairness of the financial statements in accordance with International Financial Reporting Standards. The independent auditors' report outlines the scope of their audit examination and states their opinion.

The Board of Directors, through the Audit Committee, is responsible for ensuring management fulfills its responsibilities for financial reporting and internal controls. The Audit Committee, which is comprised of independent directors, meets regularly with management, the internal auditors and the external auditors to satisfy itself that each group is discharging its responsibilities with respect to internal controls and financial reporting. The Audit Committee reviews the consolidated financial statements and annual report and recommends their approval to the Board of Directors. The external auditors have full and open access to the Audit Committee, with and without the presence of management. The Audit Committee is also responsible for reviewing and recommending the annual appointment of the external auditors and approving the annual external audit plan.

On behalf of management,

Brian Vaasjo
President and Chief Executive Officer

Bryan DeNeve
Senior Vice President, Finance and
Chief Financial Officer

February 17, 2017

CAPITAL POWER CORPORATION

Consolidated Financial Statements

Years ended December 31, 2016 and 2015

KPMG LLP
2200, 10175 101 St NW
Edmonton AB T5J 0H3
Telephone (780) 429-7300
Fax (780) 429-7379
www.kpmg.ca

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Capital Power Corporation

We have audited the accompanying consolidated financial statements of Capital Power Corporation, which comprise the consolidated statements of financial position as at December 31, 2016 and December 31, 2015, the consolidated statements of income, comprehensive income, changes in equity and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Capital Power Corporation as at December 31, 2016 and December 31, 2015, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards.

KPMG LLP

Chartered Professional Accountants
February 17, 2017
Edmonton, Canada

CAPITAL POWER CORPORATION

Consolidated Statements of Income
(In millions of Canadian dollars, except per share amounts)

Years ended December 31

	2016	2015
Revenues and other income	$ 1,214	$ 1,241
Energy purchases and fuel (note 4)	(420)	(479)
Gross margin	794	762
Other raw materials and operating charges	(102)	(96)
Staff costs and employee benefits expense (note 4)	(124)	(120)
Depreciation and amortization (note 4)	(216)	(215)
Losses on termination of power purchase arrangement (note 5)	(73)	-
Impairment (note 9)	(6)	-
Other administrative expense (note 4)	(86)	(85)
Foreign exchange gain (loss)	6	(15)
Operating income	193	231
Net finance expense (note 6)	(86)	(94)
Income from joint venture (note 33)	25	15
Income before tax	132	152
Income tax expense (note 7)	(30)	(66)
Net income	$ 102	$ 86
Attributable to:		
Non-controlling interests (note 32)	$ (9)	$ (4)
Shareholders of the Company	$ 111	$ 90

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

	2016	2015
Basic (note 8)	$ 0.91	$ 0.70
Diluted (note 8)	$ 0.91	$ 0.70

See accompanying notes to the consolidated financial statements

CAPITAL POWER CORPORATION

Consolidated Statements of Comprehensive Income
(In millions of Canadian dollars)

Years ended December 31

	2016	2015
Net income	$ 102	$ 86
Other comprehensive (loss) income:		
Items that will not be reclassified subsequently to net income:		
Defined benefit plans:		
Actuarial (losses) gains [1]	(1)	4
Items that are or may be reclassified subsequently to net income:		
Cash flow hedges:		
Unrealized gains on derivative instruments [2]	68	73
Unrealized losses on derivative instruments – joint venture (note 33) [3]	(4)	(8)
Reclassification of losses on derivative instruments to net income for the year – joint venture (note 33) [4]	4	-
Reclassification of gains on derivative instruments to net income for the year [5]	(88)	(59)
Net investment in foreign subsidiaries:		
Unrealized (loss) gain [6]	(5)	34
Total items that are or may be reclassified subsequently to net income, net of tax	(25)	40
Total other comprehensive (loss) income, net of tax	(26)	44
Total comprehensive income	$ 76	$ 130
Attributable to:		
Non-controlling interests (note 32)	$ (9)	$ (2)
Shareholders of the Company	$ 85	$ 132

[1] For the year ended December 31, 2016, net of income tax expense of nil. For the year ended December 31, 2015, net of income tax expense of $1.

[2] For the year ended December 31, 2016, net of income tax expense of $25. For the year ended December 31, 2015, net of income tax expense of $28.

[3] For the year ended December 31, 2016, net of income tax recovery of $1. For the year ended December 31, 2015, net of income tax recovery of $3.

[4] For the year ended December 31, 2016, net of reclassification of income tax recovery of $1. For the year ended December 31, 2015, net of reclassification of income tax expense of nil.

[5] For the year ended December 31, 2016, net of reclassification of income tax expense of $32. For the year ended December 31, 2015, net of reclassification of income tax expense of $22.

[6] For the years ended December 31, 2016 and December 31, 2015, net of income tax of nil.

See accompanying notes to the consolidated financial statements

CAPITAL POWER CORPORATION

Consolidated Statements of Financial Position
(In millions of Canadian dollars)

As at December 31

	2016	2015
Assets		
Current assets:		
Cash and cash equivalents (note 10)	$ 98	$ 80
Trade and other receivables (note 11)	223	190
Inventories (note 12)	118	99
Derivative financial instruments assets (note 13)	115	93
	554	462
Non-current assets:		
Other assets	20	24
Derivative financial instruments assets (note 13)	154	127
Finance lease receivables (note 14)	667	689
Government grant receivable (note 15)	542	-
Other financial assets	5	13
Deferred tax assets (note 16)	16	18
Equity-accounted investment (note 33)	18	17
Intangible assets (note 17)	299	336
Property, plant and equipment (note 18)	3,764	3,677
Goodwill (note 19)	23	30
Total assets	$ 6,062	$ 5,393

See accompanying notes to the consolidated financial statements

Approved on behalf of the Board:

Donald Lowry
Director and Chairman of the Board

Philip Lachambre
Director and Chairman of the Audit Committee

CAPITAL POWER CORPORATION

Consolidated Statements of Financial Position
(In millions of Canadian dollars)

As at December 31

	2016	2015
Liabilities and equity		
Current liabilities:		
Trade and other payables (note 20)	$ 217	$ 181
Derivative financial instruments liabilities (note 13)	48	27
Loans and borrowings (note 21)	200	339
Deferred revenue and other liabilities (note 22)	57	2
Provisions (note 23)	26	22
	548	571
Non-current liabilities:		
Derivative financial instruments liabilities (note 13)	44	26
Loans and borrowings (note 21)	1,308	1,276
Finance lease obligation (note 14)	19	21
Deferred revenue and other liabilities (note 22)	632	97
Deferred tax liabilities (note 16)	379	376
Provisions (note 23)	231	210
	2,613	2,006
Equity:		
Equity attributable to shareholders of the Company		
Share capital (note 24)	2,918	2,744
Deficit	(124)	(70)
Other reserves (note 25)	49	74
Deficit and other reserves	(75)	4
	2,843	2,748
Non-controlling interests (note 32)	58	68
Total equity	2,901	2,816
Total liabilities and equity	$ 6,062	$ 5,393

See accompanying notes to the consolidated financial statements

CAPITAL POWER CORPORATION

Consolidated Statements of Changes in Equity
(In millions of Canadian dollars)

	Share capital (note 24)	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 (note 32)	Total
Equity as at January 1, 2016	$ 2,744	$ 42	$ 31	$ (9)	$ 10	$ (70)	$ 2,748	$ 68	$ 2,816
Net income	-	-	-	-	-	111	111	(9)	102
Other comprehensive loss:									
Defined benefit plan actuarial losses	-	-	-	(1)	-	-	(1)	-	(1)
Cash flow derivative hedge gains	-	93	-	-	-	-	93	-	93
Cash flow derivative hedge losses – joint venture	-	(5)	-	-	-	-	(5)	-	(5)
Reclassification of losses to net income – joint venture	-	5	-	-	-	-	5	-	5
Reclassification of gains to net income	-	(120)	-	-	-	-	(120)	-	(120)
Unrealized loss on foreign currency translation	-	-	(5)	-	-	-	(5)	-	(5)
Tax on items recognized directly in equity	-	7	-	-	-	-	7	-	7
Other comprehensive loss	$ -	$ (20)	$ (5)	$ (1)	$ -	$ -	$ (26)	**$ -**	$ (26)
Total comprehensive (loss) income	-	(20)	(5)	(1)	-	111	85	(9)	76
Reduction of non-controlling interests	-	-	-	-	-	-	-	(1)	(1)
Issue of preferred share capital	200	-	-	-	-	-	200	-	200
Share issue costs	(6)	-	-	-	-	-	(6)	-	(6)
Deferred taxes on share issue costs	2	-	-	-	-	-	2	-	2
Common share dividends (note 24)	-	-	-	-	-	(145)	(145)	-	(145)
Preferred share dividends (note 24)	-	-	-	-	-	(23)	(23)	-	(23)
Common shares purchased	(22)	-	-	-	-	-	(22)	-	(22)
Other	-	-	-	-	1	3	4	-	4
Equity as at December 31, 2016	$ 2,918	$ 22	$ 26	$ (10)	$ 11	$ (124)	$ 2,843	$ 58	$ 2,901

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

See accompanying notes to the consolidated financial statements

CAPITAL POWER CORPORATION

Consolidated Statements of Changes in Equity
(In millions of Canadian dollars)

	Share capital (note 24)	Cash flow hedges [1]	Cumulative translation reserve [1]	Defined benefit plan actuarial losses [1]	Employee benefits reserve	Retained earnings (deficit)	Equity attributable to shareholders of the Company	Non-controlling interests (note 32)	Total
Equity as at January 1, 2015	$ 2,391	$ 40	$ (1)	$ (13)	$ 9	$ 25	$ 2,451	$ 552	$ 3,003
Net income	-	-	-	-	-	90	90	(4)	86
Other comprehensive income:									
Defined benefit plan actuarial gains	-	-	-	5	-	-	5	-	5
Cash flow derivative hedge gains	-	101	-	-	-	-	101	-	101
Cash flow derivative hedge losses – joint venture	-	(11)	-	-	-	-	(11)	-	(11)
Reclassification of gains to income	-	(81)	-	-	-	-	(81)	-	(81)
Unrealized gain on foreign currency translation	-	-	34	-	-	-	34	-	34
Tax on items recognized directly in equity	-	(3)	-	(1)	-	-	(4)	-	(4)
Attributed to non-controlling interests	-	-	(2)	-	-	-	(2)	2	-
Other comprehensive income	$ -	$ 6	$ 32	$ 4	$ -	$ -	$ 42	$ 2	$ 44
Total comprehensive income (loss)	-	6	32	4	-	90	132	(2)	130
Issue of share capital	449	-	-	-	-	-	449	-	449
Deferred taxes on share issue costs	1	-	-	-	-	-	1	-	1
Distributions to non-controlling interests	-	-	-	-	-	-	-	(6)	(6)
Net additional investment by non-controlling interests	-	-	-	-	-	-	-	6	6
Change in non-controlling interests ownership	-	-	-	-	-	33	33	(482)	(449)
Tax on change in non-controlling interests ownership	-	(4)	-	-	-	(60)	(64)	-	(64)
Common share dividends (note 24)	-	-	-	-	-	(135)	(135)	-	(135)
Preferred share dividends (note 24)	-	-	-	-	-	(22)	(22)	-	(22)
Tax on preferred share dividends	-	-	-	-	-	(1)	(1)	-	(1)
Dividends reinvested	22	-	-	-	-	-	22	-	22
Common shares purchased	(121)	-	-	-	-	-	(121)	-	(121)
Other	2	-	-	-	1	-	3	-	3
Equity as at December 31, 2015	$ 2,744	$ 42	$ 31	$ (9)	$ 10	$ (70)	$ 2,748	$ 68	$ 2,816

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

See accompanying notes to the consolidated financial statements

CAPITAL POWER CORPORATION

Consolidated Statements of Cash Flows
(In millions of Canadian dollars)

Years ended December 31

	2016	2015
Cash flows from operating activities:		
Net income	$ 102	$ 86
Non-cash adjustments to reconcile net income to net cash flows from operating activities:		
Loss on de-recognition of power purchase arrangement (note 5)	53	-
Impairment (note 9)	6	-
Depreciation and amortization (note 4)	216	215
Net finance expense (note 6)	86	94
Fair value changes on commodity derivative instruments and emission credits held for trading	(12)	1
Unrealized foreign exchange (gain) loss	(4)	17
Income tax expense (note 7)	30	66
Income from joint venture (note 33)	(25)	(15)
Reduction in finance lease receivable (note 14)	21	19
Other items	(13)	(5)
Change in fair value of derivative instruments reflected as cash settlement	(31)	8
Distribution received from joint venture (note 33)	24	8
Interest paid [1]	(73)	(80)
Income taxes paid [2]	-	(1)
Other cash items (note 26)	(25)	(5)
Change in non-cash operating working capital (note 26)	20	11
Net cash flows from operating activities	375	419
Cash flows used in investing activities:		
Purchase of property, plant and equipment and other assets	(313)	(140)
Other cash flows from investing activities	21	18
Change in non-cash investing working capital	39	(14)
Net cash flows used in investing activities	(253)	(136)
Cash flows used in financing activities:		
Proceeds from issue of loans and borrowings	164	220
Repayment of loans and borrowings	(260)	(267)
Proceeds on sale and leaseback of generating facility	-	46
Proceeds from issue of preferred shares (note 24)	200	-
Share issue costs (note 24)	(6)	-
Common shares purchased (note 24)	(22)	(121)
Distributions paid to non-controlling interests (note 27)	-	(13)
Common share dividends paid (note 24)	(143)	(106)
Preferred share dividends paid (note 24)	(23)	(22)
Interest paid [1]	(3)	(9)
Income taxes paid [2]	(8)	(9)
Other cash flows (used in) from financing activities	(1)	1
Net cash flows used in financing activities	(102)	(280)
Foreign exchange (loss) gain on cash held in a foreign currency	(2)	6
Net increase in cash and cash equivalents	18	9
Cash and cash equivalents, beginning of year	80	71
Cash and cash equivalents, end of year	$ 98	$ 80

[1] Total interest paid.
[2] Total income taxes paid.

See accompanying notes to the consolidated financial statements

1. Reporting entity:

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

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

2. Significant accounting policies:

(a) Basis of presentation:

These consolidated financial statements have been prepared by management in accordance with International Financial Reporting Standards (IFRS).

These consolidated financial statements have been prepared under the historical cost basis, except for the Company’s derivative instruments, emission credits held for trading, defined benefit pension plan assets and cash-settled share-based payments, which are stated at fair value.

These consolidated financial statements were approved and authorized for issue by the Board of Directors on February 17, 2017.

(b) Basis of consolidation:

These consolidated financial statements include the accounts of Capital Power and its subsidiaries. Subsidiaries are fully consolidated from the date of acquisition, being the date on which the Company obtains control, and continue to be consolidated until the date that such control ceases to exist.

The Company has a 100% interest in Capital Power L.P. (CPLP) (2015 – 100%). Capital Power controls CPLP and therefore CPLP is treated as a subsidiary of Capital Power. As of April 2, 2015 EPCOR Utilities Inc. (EPCOR) reduced its ownership in CPLP to nil and therefore no longer holds a non-controlling interest in CPLP.

Non-controlling interests in subsidiaries are identified separately from equity attributable to shareholders of the Company. The non-controlling interests may be initially measured either at fair value or at the non-controlling interests’ proportionate share of the fair value of the acquired business’ identifiable net assets. The choice of measurement basis is made on an acquisition-by-acquisition basis. Subsequent to acquisition, the carrying amount of non-controlling interests is the amount of those interests at initial recognition plus the non-controlling interest’s share of subsequent changes in equity. Total comprehensive income is attributed to non-controlling interests even if this results in the non-controlling interests having a deficit balance.

All significant intercompany balances and transactions have been eliminated on consolidation.

The financial statements of the subsidiaries are prepared for the same reporting period as Capital Power, using consistent accounting policies.

(c) Changes in accounting policies:

Effective January 1, 2016, the Company has adopted the following amendments:

IAS 1 – Presentation of Financial Statements (Amendment) – The objective of the amendments is to improve the presentation and disclosure in financial reports by providing guidance on materiality, clarifying presentation issues related to the statement of financial position, statement of income and other comprehensive (loss) income and providing additional examples of possible ways of ordering notes. The amendments did not change the presentation and disclosure within the consolidated financial statements as previous treatment applied by the Company was aligned with the amendments.

IFRS 11 – Acquisition of an Interest in Joint Operations (Amendment) – The objective of the amendments issued is to improve comparability of reported financial information by providing guidance on how a joint operator accounts for the acquisition of an interest in a joint operation, in which the activity of the operation constitutes a business. It would require a joint operator to account for such an acquisition by applying IFRS 3 – Business Combinations and other standards, and disclosing the relevant information specified in those IFRSs for business combinations. The amendments to IFRS 11 will affect applicable future transactions.

2. Significant accounting policies, continued:

(d) Business combinations and goodwill:

Business combinations

Acquisitions of subsidiaries and businesses are accounted for using the acquisition method. The consideration of an acquisition is measured as the fair value of the assets given, equity instruments issued and liabilities incurred or assumed at the date of acquisition in exchange for control of the acquired business. Acquisition-related costs are recognized into net income as incurred. Goodwill is measured as the excess of the fair value of the consideration transferred less the fair value of the identifiable assets acquired and liabilities assumed. When the excess is negative, a bargain purchase gain is recognized immediately into net income.

Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the date of acquisition. Where an acquisition involves consideration contingent on future events, any changes in the amount of consideration paid will be recognized into net income.

The Company elects on a transaction-by-transaction basis whether to measure non-controlling interest at its fair value, or at its proportionate share of the recognized amount of the identifiable net assets, at the acquisition date. Transaction costs, other than those associated with the issue of debt or equity securities, that the Company incurs in connection with a business combination are expensed as incurred.

Goodwill

After initial recognition, goodwill is not amortized, but is measured at cost less any accumulated impairment losses. Goodwill is tested for impairment annually, or more frequently if events or changes in circumstances indicate that the carrying amount may be impaired, at the cash-generating unit (CGU) level. For the purpose of impairment testing, goodwill acquired in an acquisition is, from the date of acquisition, allocated to each of the Company's CGUs that are expected to benefit from the acquisition.

For further discussion on impairment of goodwill, refer to the accounting policy for impairment of non-financial assets (note 2(p)).

Where goodwill forms part of a CGU and part of the operation within that unit is disposed of, the goodwill associated with the operation disposed of is included in the carrying amount of the operation when determining the gain or loss on disposal of the operation. Goodwill disposed of in this circumstance is measured based on the relative values of the operation disposed of and the portion of the CGU retained.

(e) Investments in joint arrangements:

Investments in joint operations

Capital Power has interests with other parties (the Joint Operators), whereby in each case the Joint Operators have a contractual arrangement that establishes the Joint Operators' rights to the assets and obligations for the liabilities of the arrangement and the Joint Operators' rights to the corresponding revenues and obligations for the corresponding expenses. These arrangements are considered to be joint operations.

In these situations, Capital Power recognizes its share of the joint operations' assets and liabilities in accordance with those associated rights and obligations, along with its share of the revenues from the output of the joint operation along with its share of any expenses incurred. The accounting policies of these joint operations are aligned with the accounting policies of the Company.

Investment in joint venture

The Company, along with two external parties (the Partners), has an equal interest in a partnership established to develop, construct and operate a wind power project. By contractual agreement, each of the Partners effectively has rights to the net assets of the arrangement and as a result the arrangement is considered to be a joint venture.

2. Significant accounting policies, continued:

(e) Investments in joint arrangements, continued:

Investment in joint venture, continued

The Company's investment in this joint venture is accounted for under the equity method, and was recognized initially at cost and the carrying amount is increased or decreased to recognize the Company's share of the joint venture's net income or loss after the date of acquisition. Distributions received from the joint venture reduce the carrying amount of the investment. The accounting policies of the joint venture are aligned with the accounting policies of the Company except that the Company considers that the power purchase agreement associated with the wind power project contains a lease, whereas the joint venture does not. The Company applies lease accounting principles in the calculation of the Company's share of the joint venture's net income or loss.

(f) Foreign currency translation:

Transactions in foreign currencies are translated to the respective functional currencies of the Company, or the subsidiary concerned, at exchange rates in effect at the transaction date. At each reporting date monetary assets and liabilities denominated in foreign currencies are translated at the exchange rate in effect at the date of the statement of financial position. The translation for other non-monetary assets is not updated from historical exchange rates unless they are carried at fair value. Revenues and other income and expenses are translated at average exchange rates prevailing during the period. The resulting foreign exchange gains and losses are included in net income.

On consolidation, the assets and liabilities of U.S. operations that have a functional currency that is different from the Company's functional currency of Canadian dollars are translated into Canadian dollars at the exchange rates in effect at the date of the statement of financial position. Revenues and other income and expenses are translated at average exchange rates prevailing during the period. The resulting translation gains and losses are deferred and included in accumulated other comprehensive (loss) income as part of translation gains and losses.

(g) Government grant:

Government grants reflect compensation to be received from the Province of Alberta (the Province) related to the phase-out of coal-fired generation by the end of 2030. The Company recognizes government grants initially at fair value, and subsequently at amortized cost using the effective interest method and records such grants as a receivable and deferred revenue when there is reasonable assurance that they will be received and that the Company will comply with the conditions associated with the grant. The government grant receivable earns interest income and the associated deferred revenue is accreted until settlement in 2030. The deferred revenue associated with the grant will be recognized in net income as other income on a straight-line basis through 2030 as this is the period over which costs will be incurred as a result of the 2030 phase-out of coal-fired generation.

(h) Revenue recognition:

Energy sales

Revenues from the sales of electricity and natural gas are recognized when the risks and rewards of ownership pass to the buyer, collection is reasonably assured and the price is reasonably determinable. This occurs upon delivery or availability for delivery under take-or-pay contracts. These revenues include an estimate of the value of electricity and natural gas consumed by customers, but billed subsequent to reporting period-end.

The Company recognizes revenues from certain of its generation units operating under power purchase agreements or arrangements (PPAs) as described in note 2(i). PPAs are a form of long-term sales arrangement between the owner of a generation unit and the contracted purchaser under the PPA.

Revenues from the sale of other goods are recognized when the products have been delivered.

Service revenues

Revenues from operating and management services are recognized when the service has been performed or delivered.

2. Significant accounting policies, continued:

(h) Revenue recognition, continued:

Derivative instruments

Revenues and other income also includes realized and unrealized gains and losses from derivatives used in the risk management of the Company's generation activities related to commodity prices and foreign currency risk, and from the Company's proprietary trading activities. Realized gains and losses are recognized when the settlement of trading positions occurs and unrealized gains and losses are recorded as revenues and other income based on the related changes in the fair value of the financial instrument at the end of each reporting period.

Deferred revenues

Payments received on one of the Company’s operating leases may be in excess of accounting lease revenues. In such cases, the Company records deferred revenue on its consolidated statement of financial position.

The Company records any gains resulting from sale and leaseback transactions as deferred revenue on its consolidated statement of financial position and amortizes the gain to depreciation and amortization on a straight-line basis over the lease term.

The government grant described in note 2(g) is recorded as deferred revenue. Accretion of the deferred revenue is recognized in net finance expense on the consolidated statements of income.

Monetary contributions received from external parties used to provide the Company with ongoing access to a supply of goods or services are measured at fair value of the cash received and are initially recorded as deferred revenue. Revenue is recognized as the service is performed, or if an ongoing service is performed as part of an agreement, over the lesser of the life of the agreement and the life of the asset.

(i) Leases or arrangements containing a lease:

The Company has entered into PPAs to sell power at predetermined prices. PPAs are assessed as to whether they contain leases which convey to the counterparty the right to the use of the Company's property, plant and equipment in return for payment. If the PPAs are determined to contain a lease, the arrangements may be classified as either finance or operating leases. PPAs that transfer substantially all of the benefits and risks of ownership of property from the Company are classified as finance leases. PPAs that do not transfer substantially all of the benefits and risks of ownership of property, plant and equipment are classified as either operating leases or executory contracts.

For those PPAs determined to be finance leases with the Company as the lessor, finance income is recognized in a manner that produces a constant rate of return on the net investment in the lease. The net investment is composed of minimum lease payments and unearned finance income. Unearned finance income is the difference between the total minimum lease payments and the carrying amount of the leased property. Unearned finance income is deferred and recognized into net income over the lease term.

Payments received under PPAs classified as finance leases are segmented into those for the lease and those for other elements of the PPA on the basis of their relative fair values.

For those PPAs determined to be operating leases with the Company as the lessor, revenue is recognized on a straight-line basis unless another method better represents the earnings process.

Where the Company has purchased goods or services as a lessee, and the lease has been determined to be an operating lease, rental payments are expensed as incurred over the life of the lease. Contractual arrangements the Company has entered into as a lessee that transfer substantially all of the risks and rewards of ownership to the Company are considered finance leases. The leased asset and lease obligation are recognized at the lower of fair value or the present value of the minimum lease payments. Lease payments are recorded as interest expense and a reduction of the lease liability. Interest expense is recognized using the effective interest method. The leased asset is depreciated over the shorter of the estimated useful life of the asset and the lease term.

2. Significant accounting policies, continued:

(j) Non-derivative financial instruments:

Financial assets are identified and classified as either available for sale, held at fair value through income or loss or loans and receivables. Financial liabilities are classified as either held at fair value through income or loss or other financial liabilities.

Financial instruments at fair value through income or loss

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

Upon initial recognition transaction costs are recognized into net income as incurred. Financial assets classified as held at fair value through income or loss are measured at fair value with the changes in fair value reported in net income. Fair values are determined in the manner described in note 3.

Gains or losses realized on de-recognition of investments held at fair value through income or loss are recognized into net income.

Loans and receivables

Loans and receivables are financial assets with fixed or determinable payments that are not quoted in an active market. The Company's current loans and receivables comprise its cash and cash equivalents, trade and other receivables and the current portion of the government grant receivable. Non-current loans and other long-term receivables consist of the government grant receivable, promissory notes receivable and amounts due from customers more than one year from the date of the statement of financial position which will be repaid between 2017 and 2030.

The government grant receivable relates to compensation from the Province to the Company for the phase-out of coal-fired generation by the end of 2030, see notes 9 and 15. Interest income on the government grant receivable is recognized in net finance expense.

These assets are recognized initially at fair value plus any directly attributable transaction costs. After initial recognition they are measured at amortized cost using the effective interest method less any impairment losses as described in note 2(p). The effective interest method calculates the amortized cost of a financial asset or liability and allocates the interest income or expense over the term of the financial asset or liability using an effective interest rate.

Other financial liabilities

The Company's loans and borrowings, finance lease obligation and trade and other payables are recognized on the date at which the Company becomes a party to the contractual arrangement. Liabilities are derecognized when the contractual obligations are discharged, cancelled or expired.

Liabilities are recognized initially at fair value plus any directly attributable transaction costs, such as debenture discounts, premiums and issue expenses. Subsequently these liabilities are measured at amortized cost using the effective interest rate method.

Financial assets and financial liabilities are presented on a net basis when the Company has a legally enforceable right to set-off the recognized amounts and intends to settle on a net basis or to realize the asset and settle the liability simultaneously.

The Company participates in a tax-equity structure with a project investor which financed the construction of the Macho Springs project (Macho Springs). This tax-equity structure is used in the U.S. to enable access to U.S income tax benefits such as investment tax credits (ITCs), cash grants, production tax credits (PTCs) and accelerated tax depreciation. In return for purchasing an equity stake in Macho Springs, the project investor receives substantially all earnings, tax benefits and cash flows from Macho Springs until it has yielded an agreed upon target rate of return to the project investor. Immediately thereafter, the structure "flips" such that the Company receives the majority of earnings, tax benefits and cash flows from Macho Springs. The date of

2. Significant accounting policies, continued:

(j) Non-derivative financial instruments, continued:

Other financial liabilities, continued

the “flip” is dependent on the performance of the project. In accordance with the substance of the contractual agreement, the amounts paid by the project investor for their equity stake are classified as loans and borrowings on the consolidated statement of financial position until the “flip” date. Subsequent to the “flip” date, the project investor’s equity investment will be accounted for as a non-controlling interest. At all times, both before and after the “flip”, the Company retains control over Macho Springs.

(k) Derivative instruments and hedging activities:

To reduce its exposure to movements in energy commodity prices, interest rate changes, and foreign currency exchange rates, the Company uses various risk management techniques including the use of derivative instruments. Derivative instruments may include forward contracts, fixed-for-floating swaps, and option contracts. Such instruments may be used to establish a fixed price for an energy commodity, an interest-bearing obligation or an obligation denominated in a foreign currency.

All derivative instruments, including embedded derivatives, are recorded at fair value on the statement of financial position as derivative financial instruments assets or derivative financial instruments liabilities except for embedded derivative instruments that are clearly and closely related to their host contract and the combined instrument is not measured at fair value. Any contract to buy or sell a non-financial item is not treated as a non-financial derivative if that contract was entered into and continues to be held for the purpose of the receipt or delivery of a non-financial item in accordance with the Company’s expected purchase, sale or usage requirements. The Company accounts separately for any embedded derivatives in any hybrid instruments issued or acquired. The Company does not account for foreign currency derivatives embedded in non-financial instrument host contracts when the currency that is commonly used in contracts to purchase or sell non-financial items in the economic environment is that currency in which the transaction takes place.

All changes in the fair value of derivatives are recorded in net income unless cash flow hedge accounting is used. If hedge accounting requirements are met, realized gains and losses on financial energy derivatives are recorded in revenues and other income or energy purchases and fuel and realized gains and losses on foreign exchange derivatives are recorded in revenues and other income or foreign exchange gains and losses, as appropriate, while unrealized gains and losses are recorded in other comprehensive (loss) income. If hedge accounting requirements are not met, unrealized and realized gains and losses on financial energy derivatives are recorded in revenues and other income or energy purchases and fuel as appropriate, unrealized and realized gains and losses on financial foreign exchange derivatives are recorded in revenues and other income or foreign exchange gains and losses and such gains and losses on financial interest rate derivatives are recorded in net finance expense.

Commodity derivative instruments

The Company uses financial contracts-for-differences (or fixed-for-floating swaps) to hedge the Company’s exposure to fluctuations in electricity prices. Under these instruments, the Company agrees to exchange, with creditworthy or adequately secured counterparties, the difference between the variable or indexed price and the fixed price on a notional quantity of the underlying commodity for a specified timeframe.

The Company uses non-financial forward delivery derivatives to manage the Company’s exposure to fluctuations in natural gas prices related to its natural gas customer contracts and obligations arising from its natural gas fired generation facilities. Under these instruments, the Company agrees to sell or purchase natural gas at a fixed price for delivery of a pre-determined quantity under a specified timeframe.

The Company may use non-financial or financial commodity derivative instruments with the intent of benefiting from short-term actual or expected differences between their buying and selling prices or to lock in arbitrage opportunities. Such transactions are recognized on a net basis in the Company’s revenues and other income.

2. Significant accounting policies, continued:

(k) Derivative instruments and hedging activities, continued:

Foreign exchange derivative instruments

Foreign exchange forward contracts are used by the Company to manage foreign exchange exposures, consisting mainly of U.S. dollar exposures, resulting from anticipated transactions denominated in foreign currencies. For transactions involving the development or acquisition of property, plant and equipment, when the real or anticipated transaction subsequently results in the recognition of a financial asset, the associated gains or losses on derivative instruments are included in the initial carrying amount of the asset acquired in the same period or periods in which the asset is acquired or constructed.

Interest rate derivative instruments

The Company uses cross currency interest rate swaps to manage the foreign currency exchange risk on U.S. dollar denominated loans and borrowings. Under these instruments, the Company and the counterparties exchange principal amounts at initiation of the transaction, whereby the Company pays the counterparties U.S. dollar principal amounts and the counterparties pay the Company Canadian dollar principal amounts. Over the terms of these instruments, the Company makes fixed rate interest payments in Canadian dollars on the initial principal to the counterparties while the counterparties make fixed rate interest payments in U.S. dollars to the Company.

The Company uses fixed for floating interest rate swaps to optimize its mix of loans and borrowings at fixed interest rates and those at floating interest rates. Under these instruments, the Company agrees to pay the counterparties floating rate interest payments in exchange for the counterparties paying the Company fixed rate interest payments on the notional amount of loans and borrowings.

Hedge accounting

The Company may use hedge accounting when there is a high degree of correlation between the risk in the item designated as being hedged (the hedged item) and the derivative instrument designated as a hedge (the hedging instrument). The Company documents all relationships between hedging instruments and hedged items at the hedge's inception, including its risk management objectives and its assessment of the effectiveness of the hedging relationship on a retrospective and prospective basis.

The Company uses cash flow hedges for certain of its anticipated transactions to reduce exposure to fluctuations in changes in commodity prices and to reduce exposure to currency risk pertaining to the variability of cash flows on U.S. dollar loans and borrowings. In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is recognized in other comprehensive (loss) income, while the ineffective portion is recognized in energy revenues or energy purchases or fuel, as appropriate. The amounts recognized in other comprehensive (loss) income as cash flow hedging gains/losses are reclassified into net income in the same period or periods in which the hedged item occurs and is recorded in net income when it becomes probable that the hedged items will not occur. The Company has not designated any fair value hedges at the date of the statement of financial position.

A hedging relationship is discontinued if the hedge relationship ceases to be effective, if the hedged item is an anticipated transaction and it is probable that the transaction will not occur by the end of the originally specified time period, if the Company terminates its designation of the hedging relationship, or if either the hedged or hedging instrument ceases to exist as a result of its maturity, expiry, sale, termination or cancellation and is not replaced as part of the Company's hedging strategy.

If a cash flow hedging relationship is discontinued or ceases to be effective, any cumulative gains or losses arising prior to such time are deferred in accumulated other comprehensive (loss) income as part of cash flow hedging gains/losses and recognized in net income in the same period as the hedged item, and subsequent changes in the fair value of the derivative instrument are reflected in net income. If the hedged or hedging item matures, expires, or is sold, extinguished or terminated and the hedging item is not replaced, any gains or losses associated with the hedging item that were previously recognized in other comprehensive (loss) income are recognized in net income in the same period as the corresponding gains or losses on the hedged item.

2. Significant accounting policies, continued:

(k) Derivative instruments and hedging activities, continued:

Hedge accounting, continued

When it is no longer probable that an anticipated transaction will occur within the originally determined period and the associated cash flow hedge has been discontinued, any remaining gains or losses associated with the hedging item that were previously recognized in other comprehensive (loss) income are recognized in net income in the period.

When the conditions for hedge accounting cannot be applied, the changes in fair value of the derivative instruments are recognized in net income. The fair value of derivative financial instruments reflects changes in the commodity market prices, interest rates and foreign exchange rates. Fair value is determined based on exchange or over-the-counter quotations by reference to bid or asking price, as appropriate, in active markets. In illiquid or inactive markets, the Company uses appropriate valuation and price modeling techniques commonly used by market participants to estimate fair value. Fair values determined using valuation models require the use of assumptions concerning the amounts and timing of future cash flows. Fair value amounts reflect management's best estimates using external readily observable market data such as future prices, interest rate yield curves, foreign exchange rates, discount rates for time value, and volatility where available. 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.

(l) Property, plant and equipment:

Property, plant and equipment are recorded at cost, net of accumulated depreciation and/or accumulated impairment losses, if any.

Capitalization

Cost includes contracted services, materials, borrowing costs on qualifying assets, direct labour, directly attributable overhead costs, development costs associated with specific property, plant and equipment and asset retirement costs. When parts of an item of property, plant and equipment have different useful lives, they are accounted for as separate items (major components) of property, plant and equipment.

The cost of replacing a part of an item of property, plant and equipment is capitalized if it is probable that the future economic benefits of the part will flow to the Company and that its cost can be measured reliably. The carrying amount of the replaced part is derecognized. Costs of day to day repairs and maintenance costs are recognized into net income as incurred.

Depreciation

Depreciation is charged to net income on a straight-line basis over the estimated useful lives of each major component of an item of property, plant and equipment, since this most closely reflects the expected pattern of consumption of the asset. Major components of property, plant and equipment are depreciated separately over their respective useful lives. Land and construction work in progress are not depreciated. The estimated useful lives for major components of generation facilities and equipment range from 1 to 40 years. The estimated useful lives, residual values and methods of depreciation are reviewed annually, and adjusted prospectively if appropriate.

Gains and losses on the disposal or retirement of an item of property, plant and equipment are determined as the difference between the net disposal proceeds and the carrying amount at the date of disposal. Gains or losses on disposals are recognized on their own line within the consolidated statements of income while losses on retirements are recognized within depreciation and amortization.

(m) Intangible assets:

Capitalization

Intangible assets with definite lives are recorded at cost, net of accumulated amortization and/or accumulated impairment losses, if any. Intangible assets with definite lives are amortized over the related assets useful lives, as described below. Refer to note 17 for additional discussion on intangible assets.

The only indefinite life intangible assets recorded by the Company are purchased emission credits held for compliance purposes.

2. Significant accounting policies, continued:

(m) Intangible assets, continued:

Amortization

Amortization is charged to net income on a straight-line basis to write-off the cost less the estimated residual value over the estimated remaining term of the agreement or in line with the life of the related generating facility to which it relates. Software work in progress is not amortized as the software is not available for use. Land lease rights are amortized when the related wind power assets are constructed and commissioned for service over the lives of the related wind power assets or the term of the lease, whichever is shorter. Coal supply access rights are amortized over the life of the coal supply agreement related to the Keephills 3 facility. The Company's purchased emission credits held for compliance purposes are not amortized, but are expensed as the associated benefits are realized.

The periods over which intangible assets are amortized are as follows:

Contract rights	7 to 40 years
Software	1 to 10 years

Estimated useful lives, methods of amortization and residual values are reviewed annually, and adjusted prospectively if required.

Gains or losses on the disposal of intangible assets are determined as the difference between the net disposal proceeds and the carrying amount of the asset, and are recognized into net income as gains or losses on disposals.

(n) Development costs:

Development costs related to an acquisition or construction project are capitalized only if they can be measured reliably, future economic benefits are probable, and the Company intends to and has sufficient resources to complete development and to use or sell the asset. Other development costs not meeting these criteria are recognized in income or loss as incurred. Capitalized development costs are measured at cost less accumulated amortization and accumulated impairment losses.

(o) Capitalized borrowing costs:

The Company capitalizes interest during construction on its property, plant and equipment and intangible assets to reflect the costs of borrowing on its construction activities. Where project specific debt is not used to finance construction, interest is applied during construction using the weighted average cost of debt incurred on the Company's external borrowings used to finance qualifying assets. Interest is only capitalized on assets which necessarily take a significant amount of time to get ready for their intended use.

(p) Impairment of non-financial assets:

For the purpose of impairment testing, assets that cannot be tested individually are grouped together into a CGU, which is the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets. For the purposes of goodwill impairment testing, goodwill acquired in a business combination is allocated to the CGU, or the group of CGUs, that is expected to benefit from the synergies of the combination. This allocation reflects the lowest level at which that goodwill is monitored for internal reporting purposes.

The Company reviews the recoverability of non-financial assets subject to depreciation or amortization (property, plant and equipment and definite life intangible assets) when events or changes in circumstances may indicate or cause the asset's carrying amount to exceed its recoverable amount. The Company reviews the recoverability of goodwill and indefinite life intangibles on an annual basis, or more frequently if events or changes in circumstances indicate that the carrying amount may be impaired. The asset's recoverable amount is the higher of its fair value less costs to sell and its value in use. The value in use is the present value of expected future cash flows discounted using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset for which the estimates of future cash flows have not been adjusted. Fair value less costs to sell is determined using estimated market values utilizing actual market transactions, if available. When actual market transactions are not available, a valuation model is used.

2. Significant accounting policies, continued:

(p) Impairment of non-financial assets, continued:

The Company's corporate assets, such as its computer networks and infrastructure, do not generate separate cash inflows. If there is an indication that a corporate asset may be impaired, then the recoverable amount is determined for the CGU to which the corporate asset belongs.

Any impairment loss is recorded in net income in the period when it is determined that the carrying amount of the asset may not be recoverable. The impairment loss is recorded as the excess of the carrying amount of the asset over its recoverable amount. Impairment losses recognized in respect of CGUs are allocated first to reduce the carrying amount of any goodwill allocated to the CGUs, and then to reduce the carrying amounts of the other assets in the CGUs on a pro rata basis.

At the end of each reporting period the Company makes an assessment as to whether there is any indication that previously incurred impairment losses no longer exist. If such an indication exists, the Company estimates the asset's recoverable amount. Any reversal is limited so that the carrying amount of the asset does not exceed its recoverable amount or the carrying amount that would have been determined, after depreciation or amortization, had the original impairment loss not been recognized.

Any reversal is recognized into net income for the period. An impairment loss in respect of goodwill is not reversed.

Financial assets, other than those classified as held at fair value through income or loss, are assessed for indicators of impairment at the end of each reporting period. An impairment loss is recorded for investments recorded at cost where it is identified that there is objective evidence that one or more events has occurred after the initial recognition of the asset, that has had a negative impact on the estimated future cash flows of the asset that can be reliably estimated.

For listed and unlisted equity investments classified as available for sale, a significant or prolonged decline in the fair value of the investment below its cost is considered to be objective evidence of impairment.

For certain categories of financial assets, such as trade receivables, assets that are assessed not to be impaired individually are in addition assessed for impairment on a collective basis. Objective evidence of impairment includes the Company's past experience of collecting payments, as well as observable changes in national or local economic conditions.

For financial assets carried at amortized cost, the amount of the impairment loss recognized is the difference between the asset's carrying amount and the present value of estimated future cash flows, discounted at the asset's original effective interest rate. Any impairment loss is recognized in net income. If, in a subsequent reporting period, the amount of the estimated impairment loss increases or decreases because of an event occurring after the impairment was recognized, the previously recognized impairment loss is adjusted through net income.

(q) Income taxes:

Income tax expense is comprised of current and deferred tax. Current and deferred tax is recognized in net income or loss except to the extent that it relates to a business combination, or items recognized directly in equity, other comprehensive (loss) income, or in loans and borrowings.

Current income taxes

Current income taxes comprise the expected tax payable or receivable on the taxable income or loss for the year and any adjustment to the tax payable or receivable in respect of previous years. The amount of current income tax payable or receivable is the best estimate of the tax amount expected to be paid or received that reflects uncertainty related to income taxes, if any. It is measured using tax rates enacted or substantively enacted at the reporting date. Current income taxes also include any tax arising from dividends. Current income tax assets and liabilities are only offset if certain criteria are met.

2. Significant accounting policies, continued:

(q) Income taxes, continued:

Deferred income taxes

Deferred income taxes are recognized in respect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the respective amounts used for taxation purposes. Deferred income taxes are not recognized for:

- Temporary differences from the initial recognition of assets and liabilities in a transaction that is not a business combination and that affects neither the taxable nor the accounting income;
- Temporary differences related to investments in subsidiaries, associates and joint arrangements to the extent that the Company is able to control the timing of the reversal of the temporary differences and it is probable that they will not reverse in the foreseeable future; and
- Temporary differences arising on the initial recognition of goodwill.

Deferred income tax assets are recognized for unused tax losses, unused tax credits and deductible temporary differences to the extent that it is probable that future taxable income will be available against which they can be used. Future taxable income is determined based on the Company's cash flow projections, which include estimates described in note 3. Deferred income tax assets are reviewed at each reporting date and reduced to the extent that it is no longer probable the related tax benefit will be realized; such reductions are reversed when the probability of future taxable income improves. Unrecognized deferred income tax assets are reassessed at each reporting date and recognized to the extent that it has become probable that future taxable income will be available against which they can be used.

Deferred income taxes are measured at the tax rates that are expected to be applied to temporary differences when they reverse, using tax rates enacted or substantively enacted at the reporting date. The measurement of deferred income taxes reflects the tax consequences that would follow from the manner in which the Company expects, at the reporting date, to recover or settle the carrying amount of its assets and liabilities. Deferred income tax assets and liabilities are offset only if certain criteria are met.

(r) Inventories:

Parts and other consumables and coal, principally all of which are consumed by the Company in the provision of its goods and services, are valued at the lower of cost and net realizable value. Cost includes the purchase price, transportation costs and other costs to bring the inventories to their present location and condition. The cost of any assembled inventory includes direct labour, materials and directly attributable overhead. The costs of inventory items that are interchangeable are determined on an average cost basis. For inventory items that are not interchangeable, cost is assigned using specific identification of their individual costs. Emission credits held for trading are carried at fair value as estimated by quoted market prices available as of the valuation date. Previous write-downs of inventories from cost to net realizable value can be fully or partially reversed if supported by economic circumstance.

(s) Cash and cash equivalents:

Cash and cash equivalents include cash or highly liquid investment-grade short-term investments with original terms to maturity of three months or less, and are measured at amortized cost using the effective interest method.

(t) Provisions:

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. The obligation is discounted using a discount rate that reflects current market assessments of the time value of money and the risks specific to the obligation for which the estimates of future cash flows have not been adjusted. The change in discount rate due to the passage of time is recognized as a finance expense, and is recorded over the estimated time period until settlement of the obligation. Provisions are reviewed and adjusted, when required, to reflect the current best estimate at the end of each reporting period.

2. Significant accounting policies, continued:

(t) Provisions, continued:

The Company recognizes decommissioning provisions in the period in which a legal or constructive obligation is incurred. A corresponding decommissioning cost is added to the carrying amount of the associated property, plant and equipment, and it is depreciated over the estimated useful life of the asset. Unwinding of the discount rate on the decommissioning provisions is recorded in net finance expense over the estimated useful life of the asset.

A provision for onerous contracts is recognized when the expected benefits to be derived by the Company from a contract are lower than the unavoidable cost of meeting its obligations under contract. The provision is measured at the present value of the lower of the expected cost of terminating the contract and the expected net cost of continuing with the contract. Before a provision is established, the Company recognizes any impairment loss on the assets associated with that contract.

(u) Share-based payments:

The Company operates an equity-settled, share-based compensation plan where each stock option converts into one common share. The fair value of the employee services received in exchange for the grant of the options is recognized as a compensation expense within staff costs and credited to the employee benefits reserve. The employee benefits reserve is reduced as the options are exercised and the amount initially recorded as a credit in employee benefits reserve is reclassified to share capital. The total amount to be expensed over the vesting period is determined by reference to the fair value of the options granted.

The Company determines the fair value of stock options using a binomial option pricing model at the date of grant. Measurement inputs include the share price on the measurement date, the exercise price of the instrument, expected volatility, expected term of the instruments (based on historical experience and general option holder behaviour), expected dividends, and the risk-free interest rate (based on government bonds).

The Company has incorporated an estimated forfeiture rate for stock options that will not vest into its determination of share-based compensation for each period.

The Company also operates share-based compensation plans for certain senior employees under a Performance Share Unit (PSU) Plan and a Restricted Share Unit (RSU) Plan. Share-based compensation for directors operates under a Directors' Deferred Share Unit (DSU) Plan. The fair values of the amounts payable to employees/directors in respect of the PSU Plan, RSU Plan and the DSU Plan, which are settled in cash, are recognized as expenses with corresponding increases in liabilities, over the period that the employees/directors unconditionally become entitled to payments. The grant date fair values are determined using a binomial lattice valuation based on a five-day weighted average price of the Company's shares immediately prior to the grant, adjusted for estimated forfeitures and discounted using the risk-free interest rate. The liability is re-measured to fair value at each reporting date and at the settlement date. Any changes in the fair value of the liability are recognized in income or loss.

(v) Earnings per share:

Basic earnings per share is calculated by dividing income available to common shareholders by the weighted average number of common shares outstanding during the period.

Diluted earnings per share is calculated on the treasury stock method, by dividing income available to common shareholders, adjusted for the effects of dilutive securities, by the weighted average number of common shares outstanding during the period and all additional common shares that would have been outstanding had all potential dilutive common shares been issued.

(w) Future accounting changes:

IAS 7 – Statement of Cash Flows (Amendment) – The objective of the amendment issued 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 amendments to IAS 7 are effective for annual periods beginning on or after January 1, 2017 and will result in additional disclosure by the Company around cash and non-cash debt transactions.

2. Significant accounting policies, continued:

(w) Future accounting changes, continued:

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 is currently assessing the applicability of this new standard on the Company's various contracts and system requirements and expects to provide more detailed information in its 2017 interim consolidated financial statements.

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 is intended 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 is currently assessing the impact of this new standard on the Company's consolidated financial statements and expects to provide more detailed information in its 2017 interim 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.

3. Use of judgments and estimates:

The preparation of the Company's consolidated financial statements in accordance with IFRS requires management to make estimates, judgments and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses in the consolidated financial statements and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements. The Company reviews its estimates and assumptions on an ongoing basis and uses the most current information available and exercises careful judgment in making these estimates and assumptions.

Critical judgments in applying accounting policies

The main judgments that were used in preparing the Company's consolidated financial statements relate to:

Non-financial assets

The determination of CGUs was based on management's judgment, giving consideration to geographic proximity and shared risk exposure and risk management.

During the fourth quarter of 2016, management reviewed the grouping of its assets into the Alberta Contracted and Alberta Commercial CGUs. Given that the contracted period of the Alberta Contracted assets will be completed in 2020, the majority of the remaining useful lives of these assets and the resulting future cash flows are now commercial in nature. As a result, effective for the fourth quarter of 2016, the Alberta Contracted and Alberta Commercial CGUs have been combined into one Alberta CGU for impairment testing purposes.

Identifying events or changes in circumstances that may indicate or cause an asset's carrying amount to exceed its recoverable amount requires judgment in assessing what events or circumstances would have such an impact.

Classification of arrangements which contain a lease

As noted in note 2(i), the Company has exercised judgment in determining whether the risks and rewards of its generation assets which are subject to a PPA are transferred to the contracted purchaser under the PPA, in determining whether a lease exists and if so, whether the lease should be treated as a finance or operating lease. Details of those PPAs which contain either finance or operating leases are provided in note 14.

3. Use of judgments and estimates, continued:

Critical judgments in applying accounting policies, continued

Consolidation of subsidiaries that are less than wholly owned

The Company has exercised judgment in determining certain subsidiaries are controlled by the Company even though the subsidiaries are less than wholly owned as described in note 32.

Classification of joint arrangements structured through a separate vehicle

The Company has exercised judgment in determining the classification of joint arrangements structured through separate vehicles as described in note 33.

Operating segments

As noted in note 36, the Company operates in one reportable business segment. The Company has aggregated its operating segments into one reportable business segment as its operating segments have similar products, production processes, types of customers, product distribution methods, regulatory environments and economic characteristics. Each operating segment is involved with the generation and sale of electricity, which includes the process of turning various fuel sources into electricity and managing the revenues and costs of such electricity, including engaging in trading activities. The Company's customers tend to be large industrial and commercial customers, independent system operators and government owned or sponsored entities. Given the similar size and credit profiles of these counterparties, they are deemed to be similar types of customers. The method of distributing electricity is the same across all facilities, and none of the Company's entities are rate-regulated.

Key sources of estimation uncertainty

The main sources of estimation uncertainty in preparing the Company's consolidated financial statements relate to:

Measurement of fair values

A number of the Company's accounting policies and disclosures require the measurement of fair values, for both financial and non-financial assets and liabilities. Fair value represents the Company's estimate of the price that could be agreed on 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. 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 following levels were established for each input:

- Level 1: Fair value is based on quoted prices (unadjusted) in active markets for identical instruments. Assets or liabilities classified in Level 1 include highly liquid short-term investments, and traded commodities obtained from active exchanges such as the New York Mercantile Exchange (NYMEX) whereby the Company can obtain quoted prices for identically traded commodities.
- Level 2: Fair value is based on other than unadjusted quoted prices included in Level 1, which are either directly or indirectly observable at the reporting date. Level 2 includes those assets or liabilities that are valued using commonly used valuation techniques, such as a discounted cash flow model or the Black-Scholes option pricing model. Valuation models use inputs such as quoted prices for similar instruments in active markets, quoted prices for identical or similar instruments in markets that are not active but observable, and other observable inputs that are principally derived from or corroborated by observable market data for substantially the full term of the instrument.
- Level 3: Fair value is based on unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the instrument. Level 3 includes assets or liabilities that are also valued using commonly used valuation techniques described in Level 2. However, some inputs used in the models may not be based on observable market data, but rather are based on the Company's best estimate from the perspective of a market participant.

3. Use of judgments and estimates, continued:

Key sources of estimation uncertainty, continued

Measurement of fair values, continued

The fair value measurement of an asset or liability is included in only one of the three levels, the determination of which is based upon the lowest level input that is significant to the derivation of the fair value. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment which will affect the placement within the fair value hierarchy levels. As at December 31, 2016, the Company classified $9 million of derivative financial instruments assets (2015 – $11 million) and $19 million of derivative financial instruments liabilities (2015 – nil) in Level 3 of the hierarchy.

The Company's policy is to recognize transfers between levels as of the date of the event of change in circumstances that caused the transfer. There were no significant transfers between levels in the fair value hierarchy for the years ended December 31, 2016 and 2015.

Further information about the significant assumptions made in measuring fair values is included in the following notes:

- Note 9 – Impairment testing;
- Note 12 – Inventories - emissions credits;
- Notes 13 and 29 – Financial instruments;
- Note 23 – Provisions; and
- Note 28 – Share-based payments.

Depreciation and amortization

Depreciation and amortization allocate the cost of assets and their components over their estimated useful lives on a systematic and rational basis. Estimating the appropriate useful lives of assets requires significant judgment and is generally based on estimates of the life characteristics of common assets. During the fourth quarter of 2016, the Company revised the estimated useful lives for the major components of its coal-fired generation facilities and equipment as a result of the 2030 phase-out of coal-fired generation and the expectation of converting those facilities to natural gas facilities, see notes 2(l) and 9. The revision of these estimated useful lives increased depreciation expense by $2 million for 2016.

Income taxes

Income taxes are determined based on estimates of the Company's current income taxes and estimates of deferred income taxes resulting from temporary tax differences. Deferred income tax assets are assessed to determine the likelihood that they will be realized from future taxable income. Details of tax losses expected to be utilized and the basis of utilization are provided in note 16.

Revenue recognition

As noted in note 2(h), estimates of the value of electricity and natural gas consumed by customers but not billed until after the reporting period-end are based on contracted prices and volume data provided by the parties responsible for delivering the commodity.

Actual results may differ from these estimates. Adjustments to previous estimates, which may be material, will be recorded in the period they become known.

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

4. Expenses:

Year ended December 31	2016	2015
Included in energy purchases and fuel		
Recovery of flow-through expenses related to the Genesee 1 and 2 PPA's [1]	$ (17)	$ (10)
Included in staff costs and employee benefits expense		
Share-based payments (recoveries) (note 28)	11	(1)
Post-employment defined contribution plan expense	7	8
Post-employment defined benefit plan expense	3	4
Recovery of flow-through expenses related to the Genesee 1 and 2 PPAs [1]	(1)	-
Included in depreciation and amortization		
Depreciation of property, plant and equipment (note 18)	198	186
Amortization of intangible assets (note 17)	16	24
Losses on retirement of property, plant and equipment	1	2
Other	1	3
Depreciation and amortization	$ 216	$ 215
Included in other administrative expenses		
Operating lease payments	8	8

[1] These recoveries are based on $18 million of expenses (2015 – $10 million) included in energy purchases and fuel and staff costs and employee benefits expense.

5. Losses on termination of power purchase arrangement:

Year ended December 31	2016	2015
Loss on de-recognition of the Sundance PPA	$ 53	$ -
Settlement of Sundance PPA legal action	20	-
	$ 73	-

On March 24, 2016, Capital Power notified the Balancing Pool of the Company's decision to terminate its role as Buyer of the Sundance C Power Purchase Arrangement (Sundance PPA). The Company recorded a pre-tax non-cash loss of $53 million ($46 million post-tax) with respect to the de-recognition of the Sundance PPA intangible asset. Effective March 24, 2016, the Company also de-designated certain energy cash flow hedges related to forecasted transactions no longer expected to occur as a result of the Sundance PPA termination, which resulted in the reclassification of unrealized gains of $5 million ($4 million post-tax) from other comprehensive (loss) income to net income. No hedge ineffectiveness resulted from the de-designation of the cash flow hedges.

During the third quarter of 2016, the Government of Alberta commenced legal action that sought to retroactively amend and restate certain power purchase arrangements, including the Sundance PPA, and prevent the Balancing Pool from accepting Capital Power's termination of its role as Buyer of the Sundance PPA. On November 24, 2016, the Government of Alberta agreed to discontinue its legal action against Capital Power and to arrange for the Balancing Pool to accept Capital Power's termination of its role as a Buyer of the Sundance PPA in accordance with the terms of the Sundance PPA. In consideration of these actions, Capital Power and its syndicate partners agreed to pay the Balancing Pool $39 million, of which Capital Power's portion was $20 million ($15 million post-tax).

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

6. Net finance expense:

Year ended December 31	2016	2015
Interest expense		
Interest on loans and borrowings	$ 77	$ 89
Capitalized interest	(3)	(9)
Total interest expense	74	80
Other finance expense		
(Gain) loss on interest rate non-hedges (note 13)	(8)	2
Termination of interest rate non-hedges (note 13)	11	-
Charge on early debt extinguishment	-	1
Unwinding of discount on decommissioning provisions (note 23)	3	4
Accretion on deferred government grant revenue	2	-
Interest on long-term government grant receivable	(2)	-
Other	6	7
Net finance expense	$ 86	$ 94

7. Income tax expense:

Year ended December 31	2016	2015
Current income tax		
Current income tax expense	$ 13	$ 10
Adjustments for prior periods	2	-
Total current income tax expense	15	10
Deferred income tax		
Origination and reversal of temporary differences	43	37
Change in statutory tax rate	-	19
Adjustments for prior periods	-	1
Recognition of previously unrecognized tax benefits	(37)	(6)
Write-downs of deferred tax assets	9	5
Total deferred income tax expense	15	56
Income tax expense	$ 30	$ 66

Reconciliation of effective income tax rate

Year ended December 31	2016	2015
Income before tax	$ 132	$ 152
Income tax at the statutory rate of 27.0%[1] (2015 - 26.0%)	36	40
Increase (decrease) resulting from:		
Amounts attributable to non-controlling interests	2	3
Change in unrecognized tax benefits	(26)	(1)
Non-deductible amounts	2	1
Adjustments for prior periods	-	1
Statutory and other rate differences	(2)	20
Deferred income tax expense related to temporary difference on investment in subsidiary	13	-
Other	5	2
Income tax expense	$ 30	$ 66

[1] The statutory rate increased to 27.0% from 25.0% on July 1, 2015 due to legislative changes. This increase resulted in $19 million of deferred income tax expense in 2015, which is included in the statutory and other rate differences line above.

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

8. 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:

Year ended December 31	2016	2015
Income for the period attributable to shareholders of the Company	$ 111	$ 90
Preferred share dividends of the Company [1]	(23)	(23)
Earnings used in the calculation of basic earnings per share	$ 88	$ 67

[1] Includes preferred share dividends declared for the years ended December 31, 2016 and 2015 respectively and related taxes.

Year ended December 31	2016	2015
Weighted average number of common shares used in the calculation of basic earnings per share	96,214,420	96,393,165

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 years ended December 31, 2016 and 2015. 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:

Year ended December 31	2016	2015
Weighted average number of common shares used in the calculation of basic earnings per share	96,214,420	96,393,165
Effect of dilutive share purchase options [2]	64,826	-
Weighted average number of common shares used in the calculation of diluted earnings per share	96,279,246	96,393,165

[2] For the year ended December 31, 2016, the average market price of the Company's common shares was above the exercise price of certain granted share purchase options described in note 28, but had a neutral impact on earnings per share. For the year ended December 31, 2015, 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.

9. Impairment testing:

Property, plant and equipment and definite life intangible assets

During the fourth quarter of 2015, the Government of Alberta announced its Climate Leadership Plan (CLP). The CLP was not in itself a triggering event for purposes of assessing potential asset impairment. However, the uncertainties created by the CLP combined with the impact of low Alberta power prices and general negative market reaction to Alberta's economic conditions led to a substantial decline in the Company's market capitalization, particularly in the last quarter of 2015. This led to impairment testing being completed in the fourth quarter of 2015, with no resulting impairment to the Alberta Contracted and Alberta Commercial CGUs.

On November 24, 2016, the Company announced details of the agreement reached with the Government of Alberta related to the impact of the 2030 phase-out of coal-fired generation on the Company's coal-fired generation facilities and the resulting compensation as described in note 15. On November 23, 2016, the Government of Alberta announced the transition of Alberta's electricity market from an energy-only market to a capacity market, for which the framework is expected to be in place by 2021. These announcements are additional components of the CLP.

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

9. Impairment testing, continued:

Property, plant and equipment and definite life intangible assets, continued

The Company's market capitalization has recovered since the last quarter of 2015, particularly in the period after the announcements in November 2016. However, the 2015 impairment testing was based on the assumption that the coal-fired generation facilities would continue to operate until the end of their previous useful lives, as a proxy for fair compensation being received from the Province for the post 2030 period. As a result of the announcement of compensation details and the transition to a capacity market, the Company determined that a triggering event had occurred for the Company's Alberta CGU (see note 3) which was tested for impairment during the fourth quarter of 2016. The Company determined that no other CGUs were affected by the triggering event, since they operate in geographic regions that are not directly impacted by the events in Alberta.

The carrying amount of the Alberta CGU was within the range of its estimated recoverable amount and as such, no impairment was required.

Key assumptions – property, plant and equipment and definite life intangible assets recoverable amounts

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

Discount rates

The after-tax discount rates used within the CGU give consideration to the risks specific to each stream of cash flows within the CGU and reflect either a market weighted average cost of capital (WACC) using a capital asset pricing model approach, or in the case of coal phase-out compensation, the borrowing rate associated with an equivalent cash flow guaranteed by the Province. The method and assumptions used to calculate the WACC rate are consistent with the Company's past experience and with previous valuations performed by the Company.

The discount rates used by the Company in the calculation of the recoverable amount for the Alberta CGU were as follows:

	2016	2015
Commercial	9.0% to 10.0%	9.0% to 10.0%
Contracted	6.0% to 7.0%	6.5% to 7.5%
Coal phase-out compensation (note 15)	2.8%	

Other key cash flow assumptions

The Company's cash flow projections incorporate estimates of annual facility revenues, expenses and capital expenditures to the end of each facility's useful life. These estimates incorporate past experience and the Company's current view of future generating capacity and natural gas forward pricing. The average forecasted Alberta power price is also a significant assumption used in determining the cash flows for any generation from the Alberta CGU that is not already sold forward at a contracted price as of the testing date including generation for the post-PPA period for the currently contracted generating units within the Alberta CGU. The PPA for the contracted cash flows within the Alberta CGU ends in 2020. Consideration is given to externally available information related to future pricing of electricity and natural gas inputs when developing certain pricing assumptions. Such external information is also used to validate the Company's current view of future pricing. These external sources of information include market information from the Alberta Electric System Operator (AESO) and information from third party advisory and research firms serving the industry.

The impact of the new carbon pricing under the proposed Carbon Competitiveness Regulation has been incorporated into the cash flows. The Company assumed that the carbon pricing after 2018 will escalate at a rate of the Consumer Price Index to the end of the current estimated useful lives of the facilities.

The tax impact of the future compensation stream related to the 2030 phase-out of the Company's coal-fired generation (see note 15) is assumed to be based on the tax position of an arms-length buyer subject to a tax rate of 27%.

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

9. Impairment testing, continued:

Other key cash flow assumptions, continued

Based on management's analysis of its options for coal-fired generation facilities in 2030, management now expects to convert each of those facilities to natural gas generation facilities by the end of 2030, thereby extending the useful lives and the future cash flows of those assets until 2045.

Goodwill and indefinite life intangible assets

The Company reviews its CGUs that contain goodwill on an annual basis, generally in the third quarter, to determine whether any impairment should be recognized. As a result, the Company's Southport CGU was tested for impairment during the third quarter of 2016. The carrying amount of the Southport CGU was at the high-end of the range of its estimated recoverable amounts and as such, a pre-tax impairment of $6 million was recorded against goodwill (2015 – nil) to reduce the carrying amount of the Southport CGU to the estimated recoverable amount.

Key assumptions – goodwill and indefinite life intangible assets recoverable amounts

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

Discount rates and growth rates

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

The Company has projected cash flows for a period of ten years and used a growth rate to extrapolate the cash flow projections beyond the ten-year period through to the end of the useful life of the Southport CGU. The growth rate reflects past experience and is consistent with industry practice.

The discount and growth rates used by the Company in the calculation of the recoverable amount for the Southport CGU were as follows:

	2016	2015
Discount rate – currently contracted period	6.6%	6.8%
Discount rate – post current contract period	8.6%	8.8%
Growth rate	2.0%	2.0%

Other key cash flow assumptions

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

The Company has assumed the Southport power purchase agreement will be extended for 10 years following the expiry of the current agreement in 2021 at rates consistent with current pricing, adjusted for 1% inflation. The Company has also assumed that the Southport facility will optimize its fuel mix at 55% wood waste, 35% tire-derived fuel (TDF), and 10% coal, and that long-term contracts will be executed with wood waste and TDF suppliers at prices consistent with current rates, adjusted for inflation.

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

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

10. Cash and cash equivalents:

As at December 31	2016	2015
Cash on deposit	$ 20	$ 72
Cash equivalents	78	8
	$ 98	$ 80

Cash and cash equivalents includes $4 million (2015 - $65 million) related to margin posted with an exchange counterparty as a result of the Company's commodity trading activity. As part of its collateral requirements, the exchange counterparty updates its bank margin accounts daily, by recording fair value changes on unsettled derivative financial instruments outstanding with the Company.

Included in the Company's cash and cash equivalents is its proportionate share of its rights to cash and cash equivalents, which are restricted to use within its joint operations of $15 million (2015 - $10 million).

11. Trade and other receivables:

As at December 31	2016	2015
Accrued revenues	$ 106	$ 121
Trade receivables	33	41
Finance lease receivable (note 14)	22	21
Allowance for doubtful accounts (note 30)	-	(5)
Net trade receivables	161	178
Government grant receivable (note 15)	52	-
Income taxes recoverable	1	2
Prepayments	9	10
	$ 223	$ 190

Details of the aging of trade receivables and analysis of the movement on the allowance for doubtful accounts are provided in note 30.

12. Inventories:

As at December 31	2016	2015
Parts and other consumables	$ 74	$ 60
Coal	15	19
Emission credits	29	20
	$ 118	$ 99

Inventories expensed upon usage for the year ended December 31, 2016 of $158 million (2015 - $144 million) were charged to energy purchases and fuel, and other raw materials and operating charges. Emission credits held for trading are carried at fair value as estimated by quoted market prices available as of the valuation date. Details of the valuation techniques used in determining the fair values are described in note 13. No write-downs in inventories were recognized in the year ended December 31, 2016 (2015 – nil). There were no reversals of previous write-downs recognized in the year ended December 31, 2016 (2015 - nil). As at December 31, 2016, no inventories were pledged as security for liabilities (2015 - nil).

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

13. 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 as described in note 30 consist of the following:

	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 swaps and interest rate swaps (U.S. dollars)			$ 195	
Range of remaining contract terms in years [1]	0.1 to 10.5	0.0 to 8.4	4.5 to 9.5	

[1] 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.

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

13. Derivative financial instruments and hedge accounting, continued:

	December 31, 2015				
	Energy and emission allowances		Foreign exchange	Interest rate	
	cash flow hedges	non-hedges	cash flow hedges	non-hedges	Total
Derivative instruments assets:					
Current	$ 42	$ 51	$ -	$ -	$ 93
Non-current	22	32	68	5	127
Derivative instruments liabilities:					
Current	(2)	(25)	-	-	(27)
Non-current	(2)	(13)	-	(11)	(26)
Net fair value	$ 60	$ 45	$ 68	$ (6)	$ 167
Net notional buys (sells) (millions):					
Megawatt hours of electricity	(8)	(3)			
Gigajoules of natural gas		19			
Metric tons of emission allowances		2			
Number of renewable energy credits		(2)			
Cross currency swaps and interest rate swaps (U.S. dollars)			$ 195	$ 100	
Interest rate swaps (Canadian dollars)				$ 200	
Range of remaining contract terms in years [2]	0.1 to 4.0	0.1 to 5.3	5.5 to 10.5	4.4 to 7.4	

[2] Terms of certain foreign exchange cash flow hedge contracts and interest rate non-hedge contracts require settlement in 2.5 years and 4.4 years respectively. The remaining years of the underlying derivatives of these contracts are reflected in the table above.

Fair values of derivative instruments are determined, when possible, using exchange or over-the-counter price quotations by reference to quoted bid, ask or closing market prices dependent on which is most representative of fair value in the circumstances, in the principal market for that instrument. The extent to which fair values of derivative instruments are based on observable market data is determined by the extent to which the market for the underlying commodity is judged to be active. When traded markets are not considered to be sufficiently active or do not exist, the Company uses appropriate valuation and price modeling techniques commonly used by market participants to estimate fair value. The Company may also rely on price forecasts prepared by third party market experts to estimate fair value when there are limited observable prices available. Fair values determined using valuation models require the use of assumptions concerning the amounts and timing of future cash flows. Fair value amounts reflect management's best estimates and maximize, when available, the use of external readily observable market data including future prices, interest rate yield curves, foreign exchange rates, quoted Canadian dollar swap rates, counterparty credit risk, the Company's own credit risk and volatility. When a valuation technique utilizes unobservable market data, no inception gains or losses are recognized, until inputs become observable. It is possible that the assumptions used in establishing fair value amounts will differ from future outcomes and the impact of such variations could be material. As at December 31, 2016 and, 2015, the Company classified financial instruments under Level 2 and Level 3 of the fair value hierarchy described in note 3.

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

13. Derivative financial instruments and hedge accounting, continued:

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

	2016		2015	
	Unrealized (losses) gains	Realized gains (losses)	Unrealized gains (losses)	Realized gains
Energy cash flow hedges	$ (23)	$ 114	$ 20	$ 81
Energy and emission allowances non-hedges	2	141	-	51
Foreign exchange cash flow hedges [3]	(3)	2	-	2
Interest rate non-hedges	6	(9)	(5)	3

[3] For the year ended December 31, 2016, unrealized losses of $8 million (2015 – unrealized gains of $47 million) related to foreign exchange cash flow hedges were reclassified from other comprehensive (loss) income to net income to offset the impact of unrealized foreign exchange gains (losses) from the revaluation of U.S. dollar denominated loans and borrowings.

Realized and unrealized gains and losses relate only to derivative financial instruments. The following realized and unrealized gains and losses are included in the Company's statements of income for the years ended December 31, 2016 and 2015:

	2016	2015
Revenues and other income	$ 393	$ 234
Energy purchases and fuel	(136)	(102)
Foreign exchange (loss) gain	(5)	49
Net finance expense	(3)	(2)

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 year ended December 31, 2016, 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 recorded to foreign exchange gain (loss) (2015 - nil).

During the fourth quarter ending December 31, 2016, the Company elected to terminate its interest rate non-hedge contracts resulting in realized losses of $11 million (2015 - nil) recorded to net finance expense.

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

As at December 31	2016
Within one year	$ 37
Between one and five years	12
After five years	(4)
	$ 45

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

14. Leases:

Finance lease receivables

	Minimum lease payments		Present value of minimum lease payments	
As at December 31	2016	2015	2016	2015
Amounts receivable under finance leases:				
Less than one year	$ 57	$ 57	$ 22	$ 21
Between one and five years	229	229	99	94
More than five years	811	868	568	595
Unearned finance income	(408)	(444)	-	-
Lease payments receivable	689	710	689	710
Less current portion: (included within trade and other receivables (note 11)	22	21	22	21
	$ 667	$ 689	$ 667	$ 689

The PPAs pertaining to the Company's wind generation facilities located in Ontario (Kingsbridge 1 and Port Dover and Nanticoke) and British Columbia (Quality Wind) are finance leases and expire in 2026, 2033 and 2037 respectively and have effective rates inherent in the leases of 3.21%, 6.16% and 4.86% respectively. The lease receivables contain unguaranteed residual values of $13 million, $44 million and nil for the Kingsbridge, Port Dover and Nanticoke and Quality Wind facilities respectively.

Details of the fair value of the finance lease receivables are provided in note 29.

Finance income of $36 million was recognized in revenues and other income during the year ended December 31, 2016 (2015 - $37 million).

Finance lease obligation

	Minimum lease payments		Present value of minimum lease payments	
As at December 31	2016	2015	2016	2015
Amounts payable under finance leases:				
Less than one year	$ 2	$ 2	$ 1	$ 1
Between one and five years	7	8	4	5
More than five years	17	19	15	16
Interest costs	(6)	(7)	-	-
Lease obligation	20	22	20	22
Less current portion: (included within trade and other payables (note 20))	1	1	1	1
	$ 19	$ 21	$ 19	$ 21

During the year ended December 31, 2015 the Company sold its Beaufort solar generating facility (Beaufort Solar) and immediately leased the facility back under a finance lease which expires in 2025 and has an effective rate inherent in the lease of 4.50%. Details of the assets under finance lease are provided in note 18.

Details of the fair value of the finance lease obligation are provided in note 29.

Interest expense of $1 million was recognized in net finance expense during the year ended December 31, 2016 (2015 - nil).

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

14. Leases, continued:

Facilities under operating leases

Certain power generation facilities owned by the Company operate under PPAs that convey the right to the holder of the agreement to use the related property, plant and equipment. Consequently, the Roxboro, Genesee units 1 and 2, and Island Generation power generation facilities are accounted for as assets under operating leases.

As at December 31, 2016, the cost of such property, plant and equipment was $1,228 million (2015 - $1,230 million), less accumulated depreciation of $350 million (2015 - $312 million).

The minimum future rental payments to be received on these PPAs are:

As at December 31	2016
Within one year	$ 62
Between one and five years	206
After five years	4
	$ 272

15. Government compensation:

On November 24, 2016, the Company announced details of the agreement reached with the Government of Alberta related to the 2030 phase-out of coal-fired generation. As compensation for the capital that the Company invested in coal generating assets that will be stranded effective December 31, 2030, the Company will receive cash payments from the Province of $52 million annually for 14 years, commencing July 31, 2017, for a total of $734 million. This future compensation stream has been recognized as a government grant, recorded within deferred revenue and other liabilities and will be recognized into net income through 2030. Additionally, the compensation to be received has been recognized as a government grant receivable which will be drawn down as cash payments are received. The conditions on the government grant include the Company agreeing to cease coal-fired emissions on or before December 31, 2030 and the Company continuing to participate in and make a minimum annual investment of $1 million in the Alberta electricity market, with a minimum total investment in the Alberta electricity market of $70 million by the end of 2030. Additional conditions include the Company supporting the local communities surrounding the coal facilities through 2030, and fulfilling its pension and other commitments to employees.

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

16. Deferred tax:

Movement of deferred tax balances

	As at January 1, 2016	Recognized in net income	Recognized directly in other compre-hensive income	Amounts relating to acquisitions and disposals	Recog-nized directly in loans and borrowings	Recognized directly in equity	Reclassified from equity to net income	As at December 31, 2016	Deferred tax assets	Deferred tax liabilities
Losses carried forward	$ 30	$ (2)	$ -	$ -	$ -	$ 9	$ (11)	$ 26	$ 26	$ -
Property, plant and equipment	(246)	(44)	-	-	-	2	-	(288)	-	(288)
Intangible assets	15	29	-	-	-	-	-	44	53	(9)
Deferred partnership income	(7)	16	-	-	-	-	-	9	9	-
Derivative financial instruments	(44)	(4)	7	-	-	-	-	(41)	31	(72)
Share issue costs and deferred financing charges	1	(1)	-	-	-	2	-	2	2	-
Equity-accounted investment	(4)	(18)	-	-	-	-	-	(22)	-	(22)
Deferred revenue and other liabilities	32	159	-	-	-	-	-	191	191	-
Finance lease receivables	(192)	6	-	-	-	-	-	(186)	-	(186)
Other financial assets	-	(160)	-	-	-	-	-	(160)	-	(160)
Decommissioning provisions	52	2	-	-	-	1	-	55	55	-
Goodwill	(10)	2	-	-	-	-	-	(8)	-	(8)
Prepaid reclamation amounts	(19)	-	-	-	-	-	-	(19)	-	(19)
Other provisions	9	2		-	-	-	-	11	11	-
Loans and borrowings	19	(3)	-	-		-	-	16	16	-
Other assets	6	1	-	-	-	-	-	7	7	-
Deferred tax assets (liabilities)	$ (358)	$ (15)	$ 7	$ -	$ -	$ 14	$ (11)	$ (363)	$ 401	$ (764)
Set-off of tax								-	(385)	385
Net deferred tax assets (liabilities)								$ (363)	$ 16	$ (379)

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

16. Deferred tax, continued:

Movement of deferred tax balances, continued

	As at January 1, 2015	Recognized in net income	Recognized directly in other compre-hensive income	Amounts relating to acquisitions and disposals	Recog-nized directly in loans and borrowings	Recognized directly in equity	Reclassified from equity to net income	As at December 31, 2015	Deferred tax assets	Deferred tax liabilities
Losses carried forward	$ 21	$ 10	$ -	$ -	$ -	$ 8	$ (9)	$ 30	$ 30	$ -
Property, plant and equipment	(153)	(57)	(4)	(32)	-	-	-	(246)	-	(246)
Intangible assets	12	(1)	(1)	5	-	-	-	15	19	(4)
Deferred partnership income	(1)	(6)	-	-	-	-	-	(7)	-	(7)
Derivative financial instruments	(25)	(9)	(7)	(3)	-	-	-	(44)	26	(70)
Share issue costs and deferred financing charges	2	(2)	-	-	-	1	-	1	1	-
Equity-accounted investment	5	(12)	3	-	-	-	-	(4)	-	(4)
Deferred revenue and other liabilities	23	4	1	4	-	-	-	32	32	-
Finance lease receivables	(149)	(7)	-	(36)	-	-	-	(192)	-	(192)
Decommissioning provisions	37	7	2	6	-	-	-	52	52	-
Goodwill	(8)	-	(2)	-	-	-	-	(10)	-	(10)
Prepaid reclamation amounts	(14)	(2)	-	(3)	-	-	-	(19)	-	(19)
Other provisions	11	(1)	(1)	-	-	-	-	9	9	-
Loans and borrowings	6	19	-	(2)	(4)	-	-	19	19	-
Other assets	5	1	-	-	-	-	-	6	6	-
Deferred tax assets (liabilities)	$ (228)	$ (56)	$ (9)	$ (61)	$ (4)	$ 9	$ (9)	$ (358)	$ 194	$ (552)
Set-off of tax								-	(176)	176
Net deferred tax assets (liabilities)								$ (358)	$ 18	$ (376)

Unrecognized deferred tax assets

Deferred tax assets have not been recognized on the following items as it is not probable the future taxable income will be available against which the Company can use the benefits therefrom.

As at December 31	2016	2015
Non-capital losses	$ 356	$ 341
Deductible temporary differences with no expiry	70	199
	$ 426	$ 540

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

16. Deferred tax, continued:

Tax losses carried forward

	2016		2015	
	Tax losses	Expiry dates	Tax losses	Expiry dates
Unrecognized tax losses carried forward	$ 356	2027-2036	$ 341	2027-2035

As at December 31, 2016, the Company has non-capital losses carried forward of $424 million (2015 - $455 million), of which $321 million (US$239 million) (2015 - $328 million (US$237 million)) relates to U.S. subsidiaries.

The deferred tax assets presented on the consolidated statements of financial position are recoverable based on estimated future net income and the reversal of taxable temporary differences. The assumptions used in the estimate of future net income are based on the Company's cash flow projections, which include the estimates described in note 9.

17. Intangible assets:

	Intangible work in progress	PPAs	Contract rights	Other rights	Emission credits	Software	Total
Cost							
As at January 1, 2015	$ 66	$ 140	$ 35	$ 111	$ 44	$ 45	$ 441
Additions	4	-	-	-	11	-	15
Additions into service	(45)	-	2	37	-	6	-
Disposal through sale and leaseback	(2)	-	-	-	-	-	(2)
Retirements and other disposals	-	-	-	-	(9)	-	(9)
Transfers from property, plant and equipment (note 18)	-	-	-	4	-	-	4
Foreign currency translation adjustments	4	-	-	3	-	-	7
As at December 31, 2015	$ 27	$ 140	$ 37	$ 155	$ 46	$ 51	$ 456
Additions	9	-	-	-	29	-	38
Additions into service	(6)	-	-	4	-	2	-
Retirements and other disposals	-	-	-	-	(2)	-	(2)
Termination of Sundance PPA (note 5)	-	(129)	-	-	-	-	(129)
Transfers from property, plant and equipment (note 18)	-	-	4	5	-	-	9
Transfers to held for sale	-	-	-	-	(12)	-	(12)
Foreign currency translation adjustments	(1)	-	-	-	-	-	(1)
As at December 31, 2016	$ 29	$ 11	$ 41	$ 164	$ 61	$ 53	$ 359
Accumulated amortization							
As at January 1, 2015	$ -	$ (67)	$ (5)	$ (9)	$ -	$ (15)	$ (96)
Amortization (note 4)	-	(12)	(2)	(4)	-	(6)	(24)
As at December 31, 2015	$ -	$ (79)	$ (7)	$ (13)	$ -	$ (21)	$ (120)
Amortization (note 4)	-	(4)	(2)	(5)	-	(5)	(16)
Termination of Sundance PPA (note 5)	-	76	-	-	-	-	76
As at December 31, 2016	$ -	$ (7)	$ (9)	$ (18)	$ -	$ (26)	$ (60)
Net book value							
As at January 1, 2015	$ 66	$ 73	$ 30	$ 102	$ 44	$ 30	$ 345
As at December 31, 2015	$ 27	$ 61	$ 30	$ 142	$ 46	$ 30	$ 336
As at December 31, 2016	$ 29	$ 4	$ 32	$ 146	$ 61	$ 27	$ 299

Contract rights include the cost of acquired management and operations agreements and a 20-year agreement whereby the Company will sell Renewable Energy Credits (RECs) produced by the Halkirk Wind Project to a third party.

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

17. Intangible assets, continued:

Other rights include the cost of land lease agreements for use in wind power projects in Alberta and Ontario, solar power projects in the United States, and coal supply access rights relating to the Keephills 3 Project.

Impairments

No impairments of intangible assets were recognized during the year ended December 31, 2016 (2015 - nil). No previous impairments of intangible assets were reversed during the year ended December 31, 2016 (2015 - nil).

Capitalized borrowing costs

Borrowing costs were not capitalized on intangible assets during the years ended December 31, 2016 or 2015.

Restrictions on assets

There are no charges over the Company's intangible assets.

18. Property, plant and equipment:

	Construction work in progress	Land	Plant and equipment	Total
Cost				
As at January 1, 2015	$ 807	$ 108	$ 3,449	$ 4,364
Additions	142	-	-	142
Additions into service	(878)	9	869	-
Additions through finance lease	-	-	22	22
Disposal through sale and leaseback	(39)	-	-	(39)
Retirements and other disposals	(2)	(1)	(22)	(25)
Transfers to intangible assets (note 17)	(4)	-	-	(4)
Transfers to finance lease receivables	-	-	(1)	(1)
Revisions to decommissioning costs (note 23)	-	-	12	12
Foreign currency translation adjustments	1	-	51	52
As at December 31, 2015	$ 27	$ 116	$ 4,380	$ 4,523
Additions	305	-	-	305
Additions into service	(82)	-	82	-
Retirements and other disposals	-	-	(50)	(50)
Transfers to intangible assets (note 17)	-	-	(9)	(9)
Revisions to decommissioning costs (note 23)	-	-	(8)	(8)
Foreign currency translation adjustments	3	-	(10)	(7)
As at December 31, 2016	$ 253	$ 116	$ 4,385	$ 4,754
Accumulated depreciation				
At January 1, 2015	$ -	$ -	$ (665)	$ (665)
Depreciation (note 4)	-	-	(186)	(186)
Retirements and other disposals	-	-	21	21
Foreign currency translation adjustments	-	-	(16)	(16)
As at December 31, 2015	$ -	$ -	$ (846)	$ (846)
Depreciation (note 4)	-	-	(198)	(198)
Retirements and other disposals	-	-	51	51
Foreign currency translation adjustments	-	-	3	3
As at December 31, 2016	$ -	$ -	$ (990)	$ (990)
Net book value				
As at January 1, 2015	$ 807	$ 108	$ 2,784	$ 3,699
As at December 31, 2015	$ 27	$ 116	$ 3,536	$ 3,677
As at December 31, 2016	$ 253	$ 116	$ 3,395	$ 3,764

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

18. Property, plant and equipment, continued:

Assets under finance lease

During the year ended December 31, 2015, the Company sold Beaufort Solar, which consisted of property, plant and equipment and intangible assets, for gross proceeds of $46 million (US$34 million) and immediately leased the facility back under a finance lease agreement described in note 14. The Company recorded a gain of $5 million (US$4 million) for the year ended December 31, 2015 to deferred revenue which will be amortized over the lease term. As at December 31, 2016, the asset under finance lease had a net book value of $20 million (2015 – $22 million) and the Company recorded depreciation expense of $2 million during the year ended December 31, 2016 (2015 – nil).

Impairments

No impairments of property, plant and equipment were recognized during the year ended December 31, 2016 (2015 - nil) as described in note 9. No reversals of impairments on property, plant and equipment were recognized during the year ended December 31, 2016 (2015 - nil).

Capitalized borrowing costs

Details of borrowing costs capitalized as part of property, plant and equipment are provided in note 6. The average borrowing rate used to capitalize interest during the year was 4.79% (2015 – 4.87%) for projects financed using general borrowings. For the years ended December 31, 2016 and 2015, there were no projects financed using specific borrowings that were included as part of property, plant and equipment.

Restrictions on assets

Details of charges over land, plant and equipment are provided in note 21.

19. Goodwill:

	2016	2015
Cost and net book value		
As at January 1	$ 30	$ 25
Foreign currency translation adjustments	(1)	5
Impairment (note 9)	(6)	-
As at December 31	$ 23	$ 30

The aggregate carrying amounts of goodwill as at December 31, 2016 and 2015 are substantially all related to the Company's Southport CGU.

Impairments

A pre-tax impairment of $6 million was recorded against goodwill (2015 – nil) to reduce the carrying amount of the Southport CGU to the estimated recoverable amount.

20. Trade and other payables:

As at December 31	2016	2015
Operating accruals	$ 90	$ 95
Trade payables	70	33
Dividends and distributions payable	37	36
Accrued interest	13	14
Finance lease obligation (note 14)	1	1
Taxes payable	6	2
	$ 217	$ 181

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

21. Loans and borrowings:

	Effective interest rate	December 31, 2016	December 31, 2015
Unsecured senior medium-term notes, payable semi-annually			
Issued by CPC, at 4.85% due in 2019	4.96%	$ 250	$ 250
Issued by CPC, at 5.28% due in 2020	5.34%	300	300
		550	550
CPC private placement, payable semi-annually			
Issued by CPC, at 3.85% due in 2026	3.85%	160	-
		160	-
CPLP unsecured senior debt, payable annually to EPCOR			
At 6.75% repaid in 2016	6.16%	-	130
At 5.80% due in 2018	5.63%	163	164
At 9.00% due between 2017 and 2018	7.41%	21	31
		184	325
CPLP unsecured senior notes, payable semi-annually			
US$230, at 5.21% due in 2021	5.29%	310	318
US$65, at 5.61% due in 2026	5.67%	87	90
		397	408
CPLP non-recourse financing, payable quarterly			
Joffre Cogeneration Project, at 8.59%, due in 2020	8.31%	18	24
Macho Springs, US$50 at 6.90%, due in 2031	7.00%	64	69
		82	93
CPLP tax-equity financing, payable quarterly			
Macho Springs, US$3 at 13.85%	13.85%	5	10
Revolving extendible credit facilities			
CPLP US$100, at floating rates, due in 2021	2.13%	134	27
CPLP at floating rates, due in 2021	2.30%	-	212
Joffre Cogeneration Project at floating rates, due in 2017	3.91%	4	-
		143	239
Total debt payable		1,516	1,625
Less: current portion		200	339
		1,316	1,286
Less: deferred debt issue costs		8	10
		$ 1,308	$ 1,276

Unsecured senior debt payable to EPCOR

The unsecured senior debt payable to EPCOR matures between 2017 and 2018. As at December 31, 2016, since EPCOR does not own any of the outstanding limited partnership units of CPLP (2015 – nil), EPCOR may, by written notice, require repayment of all or any portion of the outstanding principal amount of this debt and accrued interest thereon. As a result, as at December 31, 2016 and 2015, all of the unsecured senior debt payable to EPCOR has been classified as current loans and borrowings.

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

21. Loans and borrowings, continued:

$160 million private placement debt financing

On September 13, 2016, the Company issued a $160 million, 10-year unsecured senior note with an annual interest rate of 3.85%, payable semi-annually, and principal due upon maturity in September 2026.

Non-recourse financing

Joffre Cogeneration Project financing represents the Company's share of syndicated loans for the project. The debt is secured by a charge against project assets which have a carrying amount of $56 million.

Macho Springs financing represents loans for the project. The debt is secured by a charge against project assets which have a carrying amount of $95 million.

Tax-equity financing

Macho Springs tax-equity financing represents the initial equity investment made by the project investor adjusted for earnings, tax benefits and cash distributions paid to date. The maturity date of this obligation is subject to change and is driven by the date on which the project investor reaches the agreed upon target rate of return. The Company anticipates the maturity date will occur in the first quarter of 2018.

CPLP revolving extendible credit facilities

Unsecured credit facilities include a $755 million syndicated credit facility of which $700 million is committed to July 9, 2021 and $55 million is committed to July 9, 2020. In addition, CPLP has an unsecured club credit facility of $300 million committed to July 9, 2021. In July of 2016, the Company utilized the accordion feature of the committed credit facilities to increase the facility size by $55 million. As at December 31, 2016, the Company had bankers' acceptances of nil (2015 – $212 million), U.S. prime loans of $134 million (US$100 million) (2015 - $27 million (US$20 million)) and letters of credit of $58 million (2015 - $15 million) outstanding under these facilities as described in note 35.

Additional bilateral unsecured demand credit facilities are available to CPLP and include $200 million for the issuance of letters of credit and a further $20 million general facility. As at December 31, 2016, no amounts have been drawn on these facilities (2015 – nil), and letters of credit of $114 million (2015 – $110 million) have been issued as described in note 35.

The Company has a bilateral unsecured $5 million demand facility available which is undrawn at December 31, 2016 (2015 – nil).

Under the terms of the extendible facilities, the Company's subsidiary, CPLP, may obtain advances by way of Canadian or U.S. prime loans, U.S. base rate loans, U.S. LIBOR loans and bankers' acceptances. Amounts drawn by way of prime or base rate loans each bear interest at the prevailing Canadian Prime, U.S. Prime, or U.S. base rate respectively, plus a spread ranging from nil to 1.25%, depending on CPLP's credit rating. Amounts drawn by way of U.S. LIBOR loans or bankers' acceptances bear interest at the prevailing LIBOR rate or applicable bankers' acceptance rate plus a spread ranging from 1.00% to 2.25%, depending on CPLP's credit rating.

22. Deferred revenue and other liabilities

As at December 31	2016	2015
Deferred government grant revenue (note 15)	$ 589	$ -
Other deferred revenue and liabilities	100	99
	689	99
Less current portions:		
Deferred government grant revenue	51	-
Other deferred revenue and liabilities	6	2
Total current deferred revenue and other liabilities	57	2
	$ 632	$ 97

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

23. Provisions:

As at December 31	2016	2015
Decommissioning	$ 195	$ 184
Employee benefits [1]	57	46
Other	5	2
	257	232
Less: current portion	26	22
	$ 231	$ 210

[1] Included in the employee benefits provision is $13 million pertaining to the share-based payment obligations described in note 28, of which $13 million is vested at December 31, 2016 (2015 - $6 million total share-based payment obligation, $6 million vested).

	Decommissioning	Employee benefits	Other	Total
As at January 1, 2015	$ 161	$ 56	$ 3	$ 220
Additional liabilities incurred	3	10	-	13
Liabilities settled	(1)	(18)	-	(19)
Amounts reversed unused	-	(2)	(1)	(3)
Foreign currency translation adjustments	5	-	-	5
Revisions to decommissioning costs (note 18)	12	-	-	12
Unwinding of the discount (note 6)	4	-	-	4
As at December 31, 2015	$ 184	$ 46	$ 2	$ 232
Additional liabilities incurred	21	26	4	51
Liabilities settled	(3)	(15)	-	(18)
Amounts reversed unused	(1)	-	(1)	(2)
Foreign currency translation adjustments	(1)	-	-	(1)
Revisions to decommissioning costs (note 18)	(8)	-	-	(8)
Unwinding of the discount (note 6)	3	-	-	3
As at December 31, 2016	$ 195	$ 57	$ 5	$ 257

Decommissioning provisions

The Company has recorded decommissioning provisions for its power generation facilities and the Genesee coal mine as it is obliged to remove the facilities at the end of their useful lives and restore the power facilities 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.

At December 31, 2016, the Company's estimate of the undiscounted cash flow required to settle its decommissioning obligations is approximately $327 million (2015 - $318 million), calculated using an inflation rate of 2% (2015 – 2%). The expected timing for settlement of the obligations is between 2017 and 2055, which reflects the anticipated useful lives of the different power facilities. The majority of the payments to settle the obligations are expected to occur between 2030 and 2045 for the power generation facilities and between 2017 and 2025 for the un-reclaimed sections of the Genesee coal mine. Discount rates used to calculate the carrying amount of the obligations range from 1.31% to 3.05%. The actual timing and costs to settle decommissioning obligations may vary from estimates as a result of changes to contractor rates required to perform the decommissioning.

No assets have been legally restricted for settlement of these liabilities.

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

24. Share capital:

Authorized shares

	Number of shares authorized
Common shares	unlimited
Unlimited preference shares, issuable in series:	
Series 1 and 2	5 million
Series 3 and 4	6 million
Series 5 and 6	8 million
Series 7 and 8	8 million
Special limited voting share	one

Issued and fully paid shares

	Common shares		Preference shares		Special voting shares [1]	
	Number of shares	Amount	Number of shares	Amount	Number of shares	Amount
As at January 1, 2015	83,460,896	$ 1,927	19,000,000	$ 464	18,841,000	$ -
Shares exchanged [2]	18,841,000	449	-	-	(18,841,000)	-
Deferred taxes on share issue costs (note 16)	-	1	-	-	-	-
Share purchase options exercised (note 28)	76,580	2	-	-	-	-
Dividend reinvestment plan [3]	882,103	22	-	-	-	-
Common shares purchased [4]	(5,880,736)	(121)	-	-	-	-
As at December 31, 2015	97,379,843	$ 2,280	19,000,000	$ 464	-	$ -
Shares issued	-	-	8,000,000	200	-	-
Share issue costs	-	-	-	(6)	-	-
Deferred taxes on share issue costs (note 16)	-	-	-	2	-	-
Share purchase options exercised (note 28)	18,173	-	-	-	-	-
Common shares purchased [4]	(1,245,600)	(22)	-	-	-	-
As at December 31, 2016	96,152,416	$ 2,258	27,000,000	$ 660	-	$ -

[1] At the Company's Annual Meeting of Shareholders held on April 22, 2016, the Company's shareholders passed a special resolution approving the amendment of the articles of the Company in order to remove the Special Voting Shares and the rights, privileges, restrictions and conditions attached thereto from the articles of the Company, and to remove all references to such shares from the articles of the Company, such that the Company would be authorized to issue an unlimited number of Common Shares, one Special Limited Voting Share and an unlimited number of Preference Shares, issuable in series, the terms of each series to be determined by the Board at its discretion (including such series already created by the Board). On May 4, 2016, a Certificate of Amendment was issued in respect of those amendments to the Company's articles, and the Special Voting Shares ceased to exist as part of the Company's authorized capital.

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

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

24. Share capital, continued:

Issued and fully paid shares, continued

[4] On March 25, 2015, the Toronto Stock Exchange (TSX) approved Capital Power's normal course issuer bid (NCIB) to purchase and cancel up to 5,000,000 of its outstanding common shares during the one-year period from April 7, 2015 to April 6, 2016. On November 27, 2015, the TSX approved an amendment to Capital Power's NCIB to increase the number of shares to purchase and cancel up to 8,369,838 of its outstanding common shares during the same one-year period. During the year ended December 31, 2016, the Company purchased and canceled 1,245,600 of its outstanding common shares (2015 – 5,880,736).

On October 4, 2016, the Company issued 8 million Cumulative Minimum Rate Reset Preference Shares, Series 7 (Series 7 Shares) priced at $25.00 per share for gross proceeds of $200 million less issue costs of $6 million. The preferred shares will pay fixed cumulative dividends of $1.50 per share per annum, yielding 6.00% per annum, payable on the last business day of March, June, September and December of each year, as and when declared by the Board of Directors of Capital Power, for the initial period ending December 31, 2021. The dividend rate will be reset on December 31, 2021 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 5.26%, provided that, in any event, such rate shall not be less than 6.00%. The Series 7 Shares are redeemable by Capital Power, at its option on December 31, 2021 and every five years thereafter at a value of $25.00 per share.

Holders of the Series 7 Shares will have the right to convert all or any part of their shares into Cumulative Floating Rate Preference Shares, Series 8 (Series 8 Shares), subject to certain conditions, on December 31, 2021 and every five years thereafter. Holders of the Series 8 Shares will be entitled to receive a cumulative quarterly floating dividend at a rate equal to the sum of the then 90-day Government of Canada Treasury Bill yield plus 5.26%, as and when declared by the Board of Directors of Capital Power. The Series 8 Shares would be redeemable by Capital Power, at its option, on December 31, 2026 and December 31 of every fifth year thereafter at a value of $25.00 per share. The Series 8 shares would also be redeemable by Capital Power, at its option, on any date after December 31, 2021, excluding December 31 of every fifth year, at a value of $25.50 per share.

The Company's shares are subject to a Shareholder Rights Plan (Rights Plan). The objective of the Rights Plan is to ensure, to the extent possible, the fair treatment of all shareholders in connection with any take-over bid for the securities of the Company, and to provide the Board with sufficient time to evaluate unsolicited take-over bids and to explore and develop alternatives to maximize shareholder value. Shareholders approved the continuation, amendment and restatement of the Rights Plan at the annual meeting of shareholders on April 22, 2016. The Rights Plan will continue in force until the end of the annual meeting of shareholders in 2019 subject to any changes in applicable securities law requirements.

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

24. Share capital, continued:

Cumulative rate reset preference shares

Preferred shares	Dividend per share per annum [5]	Dividend rate reset	Redemption terms	Conversion terms [6]
Series 1	$0.765	Dividend rate was reset from $1.150 per annum to $0.765 per annum effective December 31, 2015 for the March 31, 2016 dividend payment and will be reset every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 2.17%.	Series 1 shares are redeemable by Capital Power, at its option, on December 31, 2020 and on December 31 of every fifth year thereafter.	Right to convert all or any part of shares into Series 2 Cumulative Floating Rate Preference Shares, subject to certain conditions, on December 31, 2020 and on December 31 of every fifth year thereafter.
Series 3	$1.150	Dividend rate will be reset on December 31, 2018 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 3.23%.	Series 3 shares are redeemable by Capital Power, at its option, on December 31, 2018 and on December 31 of every fifth year thereafter.	Right to convert all or any part of their shares into Series 4 Cumulative Floating Rate Preference Shares, subject to certain conditions, on December 31, 2018 and on December 31 of every fifth year thereafter.
Series 5	$1.125	Dividend rate will be reset on June 30, 2018 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 3.15%.	Series 5 shares are redeemable by Capital Power, at its option, on June 30, 2018 and on June 30 of every fifth year thereafter.	Right to convert all or any part of their shares into Series 6 Cumulative Floating Rate Preference Shares, subject to certain conditions, on June 30, 2018 and on June 30 of every fifth year thereafter.
Series 7	$1.500	The dividend rate will be reset on December 31, 2021 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 5.26%, provided that, in any event, such rate shall not be less than 6.00%.	Series 7 Shares would be redeemable by Capital Power, at its option, on December 31, 2026 and December 31 of every fifth year thereafter.	Right to convert all or any part of their shares into Cumulative Floating Rate Preference Shares, Series 8 (Series 8 Shares), subject to certain conditions, on December 31, 2021 and every five years thereafter.

[5] Holders of Series 1, Series 3, Series 5, and Series 7 shares will be entitled to receive fixed cumulative quarterly dividends that yield 3.06%, 4.60%, 4.50%, and 6.00% respectively, per annum payable on the last business day of March, June, September, and December of each year, as and when declared by the board of directors of Capital Power.

[6] Holders of Series 2, Series 4, Series 6, and Series 8 shares will be entitled to receive a cumulative quarterly floating dividend at a rate equal to the sum of the then 90-day Government of Canada Treasury Bill yield plus 2.17%, 3.23%, 3.15%, and 5.26% respectively, as and when declared by the board of directors of Capital Power.

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

24. Share capital, continued:

The common and preferred share dividends declared and paid by the Company for the years ended December 31, 2016 and 2015 are summarized as follows:

	Dividends declared				Dividends paid			
	2016		2015		2016		2015	
	Per share	Total	Per share	Total	Per share	Total	Per share	Total
Common [7,8]	$ 1.5100	$ 145	$ 1.4100	$135	$ 1.4850	$143	$ 1.3850	$128
Preference, Series 1	0.7650	4	1.1500	6	0.7650	4	1.1500	6
Preference, Series 3	1.1500	7	1.1500	7	1.1500	7	1.1500	7
Preference, Series 5	1.1250	9	1.1250	9	1.1250	9	1.1250	9
Preference, Series 7	0.3616	3	-	-	0.3616	3	-	-

[7] On July 25, 2016, the Company's Board of Directors approved an increase of 6.8% in the annual dividend to $1.56 per common share effective for the third quarter of 2016.

[8] For the year ended December 31, 2016, dividends paid on common shares were paid in cash. For the year ended December 31, 2015, dividends paid on common shares consist of $106 million paid in cash and $22 million paid through the Company's dividend reinvestment plan as common shares issued.

25. Other reserves:

Components of other comprehensive (loss) income and other reserves are established as follows:

Cash flow hedges

The cash flow hedging reserve represents the cumulative portion of gains and losses on hedging instruments deemed effective in cash flow hedges. The cumulative deferred gains or losses on the hedging instrument are reclassified to net income or loss only when the hedged transaction affects the net income or loss, or are included as a basis adjustment to the non-financial hedged item, consistent with the relevant accounting policy.

Cumulative translation reserve

The cumulative translation reserve for foreign operations represents the cumulative portion of gains and losses on retranslation of foreign operations that have a functional currency other than Canadian dollars. The cumulative deferred gain or loss on the foreign operation is reclassified to net income or loss only on disposal of the foreign operation.

Defined benefit plan actuarial gains and losses

The defined benefit plan actuarial gains and losses represent the cumulative differences between actual and expected experience and from changes in actuarial assumptions used to determine the accrued benefit obligation.

Employee benefits reserve

The equity-settled employee benefits reserve reflects share options granted to employees under the employee share option plan. Information about share-based payments to employees is disclosed in note 28.

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

26. Other cash items and change in non-cash operating working capital:

Other cash items

Year ended December 31	2016	2015
Settlement and termination of interest rate non-hedge contracts [1] (note 13)	$ (9)	$ 3
Fees related to the completion of contract for wind facility	(5)	-
Miscellaneous financing fees paid	(4)	(5)
Reclamation costs	(3)	(1)
Other	(4)	(2)
	$ (25)	$ (5)

[1] Includes a net realized loss of $11 million as described in note 13 related to the termination of the Company's interest rate non-hedges and periodic settlements of those non-hedges in 2016 prior to termination.

Change in non-cash operating working capital

Year ended December 31	2016	2015
Trade and other receivables	$ 17	$ 11
Inventories	5	13
Trade and other payables	(7)	(5)
Deferred revenue and other liabilities	-	(1)
Provisions	5	(7)
	$ 20	$ 11

27. Related party balances and transactions:

Nature of transactions

As described in note 33, the Company is party to a number of joint arrangements, primarily for the construction and operation of power generating facilities. The joint arrangements provide energy to the Company and the Company provides management and operation services to the joint arrangements. Transactions with joint arrangements are eliminated to the extent of the Company's interest in the joint arrangement.

The Company provides electricity to EPCOR's residential customers and EPCOR provides distribution and transmission services to the Company along with various other services pursuant to service agreements arranged with EPCOR.

EPCOR was a related party of Capital Power until April 2, 2015, following the secondary offering and exchange of exchangeable common limited partnership units, as described in note 24, which decreased EPCOR's interest in the Company to nil. The City of Edmonton, as the sole shareholder of EPCOR, was also a related party of Capital Power until April 2, 2015.

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

27. Related party balances and transactions, continued:

Transactions and balances

The following transactions took place during the period from January 1, 2015 to April 2, 2015 between the Company and its related parties:

	Period from January 1, 2015 to April 2, 2015
Revenues – energy sales:	
EPCOR and City of Edmonton [1]	$ 5
Purchase of raw materials and other services:	
EPCOR	2
Finance expense:	
EPCOR	5

[1] Energy sales of $5 million to EPCOR, and nil to the City of Edmonton.

In addition to the transactions described above, the Company's subsidiary CPLP has recorded total distributions of $6 million to EPCOR for the year ended December 31, 2015. CPLP paid distributions of $13 million to EPCOR in the year ended December 31, 2015.

Compensation of key management personnel

Year ended December 31	2016	2015
Short-term employee benefits	$ 4	$ 5
Share-based payments	4	-
	$ 8	$ 5

Key management personnel include certain executive officers of the Company in addition to the Directors of the Company.

28. Share-based payments:

Share purchase options

Under the Company's long-term incentive plan, the Company provides share purchase options to certain employees to purchase common shares, provided that the number of shares reserved for issuance will not exceed 10% of the common shares to be outstanding at closing and that the aggregate number of shares issued by the Company under this plan will not exceed 7,094,506 common shares.

In March 2016, the Company granted 977,624 share purchase options with one third vesting on March 1 of each of 2017, 2018 and 2019. The fair values of these options at grant date were $0.96, $0.97 and $0.96 per option for the 2017, 2018 and 2019 tranches respectively. Granted options may be exercised within 7 years of the grant date at a price of $17.33 per share.

In March 2015, the Company granted 671,804 share purchase options with one third vesting on March 4 of each of 2016, 2017 and 2018. The fair values of these options at grant date were $1.73, $1.79 and $1.80 per option for the 2016, 2017 and 2018 tranches respectively. Granted options may be exercised within 7 years of the grant date at a price of $24.88 per share.

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

28. Share-based payments, continued:

Share purchase options, continued

The following assumptions were used in estimating the fair value of the granted share purchase options:

	Share purchase options issued in: 2016	2015
Share price at grant date	$ 17.33	$ 24.88
Expected volatility [1]	16.50%	15.33%
Expected option life [2]	4.5 years	4.5 years
Expected dividend yield	8.14%	5.27%
Risk-free interest rate [3]	0.73%	1.29%
Exercise price	$ 17.33	$ 24.88
Expiry date	March 1, 2023	March 4, 2022

1 Volatility was estimated based on the historical volatility in the share prices of the Company's peer group.

2 Represents the average expected life of the three tranches for each grant date.

3 Based on the Government of Canada zero-coupon yield curve. Represents the average risk-free rate of the three tranches for each grant date.

The following illustrates the movements on share purchase options during the years ended December 31, 2016 and 2015:

	2016		2015	
	Number of options	Weighted average exercise price	Number of options	Weighted average exercise price
Options outstanding, as at January 1	3,708,838	$ 23.90	3,757,449	$ 23.72
Granted	977,624	17.33	671,804	24.88
Exercised [4]	(18,173)	22.36	(76,580)	23.09
Forfeited	(59,083)	22.86	(611,349)	23.88
Expired	(482,294)	23.08	(32,486)	24.80
Options outstanding, as at December 31	4,126,912	$ 22.46	3,708,838	$ 23.90
Vested options outstanding, as at December 31	2,610,490	$ 23.86	2,604,377	$ 23.69

4 The weighted average share price at the date of exercise was $23.78 (2015 - $24.67).

During the year ended December 31, 2016, the Company recorded compensation expense of $1 million related to share purchase options in staff costs and employee benefits expense (year ended December 31, 2015 – nil).

The weighted average remaining contractual life of the Company's outstanding share purchase options as at December 31, 2016 is 3.61 years (2015 – 3.42 years). The exercise prices of share purchase options outstanding as at December 31, 2016 range from $17.33 to $24.90 (2015 - $21.76 to $24.90).

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

28. Share-based payments, continued:

Performance share units

Capital Power grants performance share units (PSUs) to certain employees, which entitle those employees to receive payments based on an equivalent number of common shares at a specified release date for an amount based on the prevailing market price of such number of common shares on the release date. PSUs are paid out three years from the grant date and vest as service is rendered over that three-year period. Participants receive payments based on the number of units vested including dividend equivalents with an ending value based on the prevailing market price at the time of payment. PSUs will be paid in cash based on the Company's share performance relative to a group of peer organizations ranging from 0% to 200% times the market price of the PSU at the release date.

	2016	2015
PSUs outstanding, as at January 1	319,972	358,294
Granted [5]	146,644	100,770
Released [6]	(74,479)	(88,750)
Dividends reinvested	26,190	21,372
Forfeited	(86,468)	(71,714)
PSUs outstanding, as at December 31	331,859	319,972

[5] The fair value of the PSUs at the grant date was $17.62 (2015 - $25.97).

[6] The weighted average share price at the date of release was $16.97 (2015 - $25.93).

During the year ended December 31, 2016, the Company recorded a compensation expense of $4 million (2015 – recovery of $2 million) related to the outstanding PSUs in staff costs and employee benefits expense.

Restricted share units

Capital Power grants restricted share units (RSUs) to certain employees, which entitle those employees to receive payments based on an equivalent number of common shares at a specified release date for an amount equal to the market price of such number of common shares on the release date. RSUs are paid out three years from the grant date and vest as service is rendered over that three-year period. RSUs will be paid out to participants in cash based on the number of units vested including dividend equivalents with an ending value equal to the prevailing market price of Capital Power common shares at the time of payment.

	2016	2015
RSUs outstanding, as at January 1	173,200	84,181
Granted [7]	136,023	85,982
Released [8]	(6,916)	(2,206)
Dividends reinvested	21,725	9,158
Forfeited	(13,464)	(3,915)
RSUs outstanding, as at December 31	310,568	173,200

[7] The fair value of the RSUs at the grant date was $17.62 (2015 – $25.97).

[8] The weighted average share price at the date of release was $19.56 (2015 – $21.30).

During the year ended December 31, 2016, the Company recorded compensation expense of $3 million (2015 – $1 million) related to the outstanding RSUs in staff costs and employee benefits expense.

Deferred share units

The Company has approved a deferred share unit (DSU) plan pursuant to which non-employee directors of the Company may receive their annual equity retainer in the form of DSUs. Directors are entitled to elect to receive their annual retainer, committee retainer, and/or committee chair retainer in full or partial DSUs. Directors will receive additional DSUs in respect of dividends payable on common shares of the Company based on the value of a DSU at that time. DSUs vest immediately and are redeemed for cash six months after a director's resignation from the Board, using the average closing price of the Company's common shares on the TSX for the five trading days immediately before the redemption date. During the year ended December 31, 2016, the Company recorded compensation expense of $3 million (2015 – nil) related to the outstanding DSUs in staff costs and employee benefits expense.

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

29. Financial instruments:

Fair values

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

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

Details of the Company's derivative instruments are described in note 13.

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

		December 31, 2016		December 31, 2015	
	Fair value hierarchy level	Carrying amount	Fair value	Carrying amount	Fair value
Other financial assets					
Loans and receivables	Level 2	$ 4	$ 4	$ 12	$ 12
Finance lease receivable (note 14)					
Loans and receivables (includes current portion)	Level 2	689	762	710	807
Government grant receivable (note 15)					
Loans and receivables (includes current portion)	Level 2	594	594	-	-
Loans and borrowings (note 21)					
Other financial liabilities (includes current portion)	Level 2	1,508	1,540	1,615	1,623
Finance lease obligation (note 14)					
Other financial liabilities (includes current portion)	Level 2	20	20	22	22

Fair value hierarchy

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 note 3.

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

	December 31, 2015			
	Level 1	Level 2	Level 3	Total
Derivative financial instruments assets	$ -	$ 209	$ 11	$ 220
Derivative financial instruments liabilities	-	(53)	-	(53)

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

29. Financial instruments, continued:

Fair value hierarchy, continued

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 (Bloom Wind) 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 December 31, 2016 and December 31, 2015, the Company holds a contract for the sale of 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:

As at December 31	2016	2015
REC pricing (per certificate)	$0.54 to $0.58	$0.39 to $0.45
Power pricing (per megawatt hour)	$22.67 to $44.44	n/a

Valuation process applied to Level 3

The valuation model used to calculate the fair value of the derivative financial instruments assets and liabilities within Level 3 is reviewed by the Company's commodity risk group and the calculation is reviewed 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:

As at December 31	2016	2015
REC pricing [1]	$ 1	$ 2
Power pricing [1]	8	n/a

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

Continuity of Level 3 balances

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

	2016	2015
As at January 1 [1]	$ 11	$ 11
Unrealized and realized gains included in net income [2]	1	2
Unrealized and realized losses included in other comprehensive (loss) income	(19)	-
Settlements [3]	(3)	(2)
As at end of period	$ (10)	$ 11
Total unrealized losses for the period included in other comprehensive (loss) income	$ (19)	$ -
Total unrealized losses for the period included in net income [2]	$ (2)	$ -

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

[2] Gains are recorded in revenues and other income.

[3] Relates to settlement of financial derivative instruments.

29. Financial instruments, continued:

Fair value hierarchy, continued

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

Loans and receivables

The fair values of the Company's finance lease receivables, government grant receivable and other loans and receivables are estimated by discounting the expected future cash flows of these instruments at current market interest rates for comparable instruments with similar terms, plus an estimated credit spread based on the counterparty credit risk as at December 31, 2016 and 2015.

Other financial liabilities

The fair values of the Company's loans and borrowings and finance lease obligation are based on determining a current yield for the Company's loans and borrowings as at December 31, 2016 and 2015. This yield is based on an estimated credit spread for the Company over the yields of long-term Government of Canada and U.S. Government bonds that have similar maturities to the Company's loans and borrowings. The estimated credit spread is based on the Company's indicative spread as published by independent financial institutions.

Offsetting of financial assets and liabilities

The Company's commodity trading transactions are typically transacted on an exchange or under International Swap Dealers Association (ISDA) Master Agreements or similar master agreements. In general, under the Company's trading agreements the amounts owed by each counterparty that are due on a single day in respect of all transactions outstanding in the same currency under the agreement are aggregated into a single net amount being payable by one party to the other. Such amounts meet the criteria for offsetting and are presented as such on the Company's statements of financial position. In certain circumstances, including when a credit event such as a default occurs, generally all outstanding transactions under the agreement are terminated, the termination value is assessed and only a single net amount is payable by one party to the other in settlement of all transactions. Amounts that may only be offset in these circumstances do not meet the criteria for offsetting on the Company's statements of financial position.

The Company also has an agreement in place with one of its energy trading counterparties that conveys to the counterparty the right to set-off amounts receivable and amounts payable between the Company and the counterparty in certain circumstances, including when a credit event such as a default occurs on the part of the Company. Such amounts do not meet the criteria for offsetting on the Company's statements of financial position.

The Company issues and accepts collateral in the form of cash and letters of credit in respect of its commodity trading transactions. Such collateral is generally subject to standard industry terms. The terms generally also give each counterparty the right to terminate the related transactions upon the other counterparty's failure to post collateral.

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

29. Financial instruments, continued:

Offsetting of financial assets and liabilities, continued

Financial assets subject to offsetting, enforceable master netting arrangements or similar arrangements

As at December 31, 2016

				Related amounts not offset in the statement of financial position		
Types of financial assets	Gross amounts of recognized financial assets	Gross amounts of recognized financial liabilities offset in the statement of financial position	Net amounts of financial assets presented in the statement of financial position [1]	Financial instruments	Collateral received [2]	Net amount
Commodity trading assets	$ 256	$ (8)	$ 248	$ (56)	$ (45)	$ 147

[1] The net amounts of commodity trading assets presented in the statement of financial position include current derivative instruments assets of $113 million, non-current derivative instruments assets of $98 million and trade and other receivables of $37 million.

[2] Collateral received relating to the net financial assets disclosed above is in the form of letters of credit received from the Company's counterparties.

Financial liabilities subject to offsetting, enforceable master netting arrangements or similar arrangements

As at December 31, 2016

				Related amounts not offset in the statement of financial position		
Types of financial liabilities	Gross amounts of recognized financial liabilities	Gross amounts of recognized financial assets offset in the statement of financial position	Net amounts of financial liabilities presented in the statement of financial position [3]	Financial instruments	Collateral pledged	Net amount
Commodity trading liabilities	$ 113	$ (8)	$ 105	$ (56)	$ (18)	$ 31

[3] The net amounts of commodity trading liabilities presented in the statement of financial position include current derivative instruments liabilities of $48 million, non-current derivative instruments liabilities of $44 million and trade and other payables of $13 million.

Financial assets subject to offsetting, enforceable master netting arrangements or similar arrangements

As at December 31, 2015

				Related amounts not offset in the statement of financial position		
Types of financial assets	Gross amounts of recognized financial assets	Gross amounts of recognized financial liabilities offset in the statement of financial position	Net amounts of financial assets presented in the statement of financial position [4]	Financial instruments	Collateral received [5]	Net amount
Commodity trading assets	$ 204	$ (9)	$ 195	$ (22)	$ (19)	$ 154

[4] The net amounts of commodity trading assets presented in the statement of financial position include current derivative instruments assets of $93 million, non-current derivative instruments assets of $54 million and trade and other receivables of $48 million.

[5] Collateral received relating to the net financial assets disclosed above is in the form of letters of credit received from the Company's counterparties.

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

29. Financial instruments, continued:

Offsetting of financial assets and liabilities, continued

Financial liabilities subject to offsetting, enforceable master netting arrangements or similar arrangements

As at December 31, 2015

				Related amounts not offset in the statement of financial position		
Types of financial liabilities	Gross amounts of recognized financial liabilities	Gross amounts of recognized financial assets offset in the statement of financial position	Net amounts of financial liabilities presented in the statement of financial position [6]	Financial instruments	Collateral pledged	Net amount
Commodity trading liabilities	$ 71	$ (3)	$ 68	$ (28)	$ -	$ 40

[6] The net amounts of commodity trading liabilities presented in the statement of financial position include current derivative instruments liabilities of $27 million, non-current derivative instruments liabilities of $15 million and trade and other payables of $26 million.

30. Risk management:

Risk management overview

The Company is exposed to a number of different financial risks, arising from business activities and its use of financial instruments, including market risk, credit risk and liquidity risk. The Company's overall risk management process is designed to identify, manage and mitigate business risk which includes, among other risks, financial risk. Risk management is overseen by the Company's executive team according to objectives, targets, and policies approved by the Capital Power Board of Directors. The executive team is comprised of the most senior management group within the Company.

Risk management strategies, policies, and limits are designed to help ensure the risk exposures are managed within the Company's business objectives and risk tolerance. The Company's financial risk management objective is to protect and limit the volatility in income and cash flow.

Commodity price risk management and the associated credit risk management are carried out in accordance with the respective commodity, credit, and financial exposures risk management policies, as approved by the executive team and the Board of Directors. Financial risk management including foreign exchange risk, interest rate risk, and liquidity risk is carried out by a centralized Treasury function, also in accordance with a financial risk management policy approved by the executive team and the Board of Directors. Capital Power's Audit Committee of the Board of Directors, in its oversight role, monitors the assessment of financial risk management controls and procedures to ensure compliance with applicable policies.

Market risk

Market risk is the risk of loss that results from changes in market factors such as commodity prices, foreign currency exchange rates, interest rates and equity prices. The level of market risk to which the Company is exposed at any point in time varies depending on market conditions, expectations of future price or market rate movements and the composition of the Company's financial assets and liabilities held, non-trading physical asset and contract portfolios, and trading portfolios.

To manage the exposure related to changes in market risk, the Company uses various risk management techniques including derivative instruments. Derivative instruments may include forward contracts, fixed-for-floating swaps (or contracts-for-differences), and option contracts. Such derivative instruments may be used to establish a fixed price for an energy commodity, an interest-bearing obligation or an obligation denominated in a foreign currency. Commodity risk exposures are monitored daily against approved risk limits, and control processes are in place to monitor that only authorized activities are undertaken.

30. Risk management, continued:

Market risk, continued

The sensitivities provided in each of the following risk discussions disclose the effect of reasonably possible changes in relevant prices and rates on net income at the reporting date. The sensitivities are hypothetical and should not be considered to be predictive of future performance or indicative of income on these contracts. The Company's actual exposure to market risks is constantly changing as the Company's portfolio of debt, foreign currency and commodity contracts changes. Changes in fair values or cash flows based on market variable fluctuations cannot be extrapolated since the relationship between the change in the market variable and the change in fair value or cash flows may not be linear. In addition, the effect of a change in a particular market variable on fair values or cash flows is calculated without considering interrelationships between the various market rates or mitigating actions that would be taken by the Company.

Commodity price risk

The Company is exposed to commodity price risk as part of its normal business operations, including energy procurement activities in Alberta and the U.S. The Company's energy procurement activities consist of power generation, non-market traded and market traded electricity, natural gas purchase and sales contracts, and derivative contracts. The Company is primarily exposed to changes in the prices of electricity, and to a lesser extent is exposed to changes in the prices of natural gas and coal. The Company actively manages commodity price risk by optimizing its asset and contract portfolios utilizing the following methods:

- The Company reduces its exposure to the volatility of commodity prices related to electricity sales by entering into offsetting contracts such as contracts-for-differences and firm price physical contracts for periods of varying duration.
- The Company enters into fixed-price energy sales contracts and power purchase arrangements which limit the exposure to electricity prices. The Company has entered into long-term tolling arrangements whereby variable changes linked to the price of natural gas and coal are assumed by the counterparty.
- The Company enters into back-to-back electricity and natural gas physical and financial contracts in order to lock in a margin.

The Company also engages in taking market risk positions within authorized limits approved by Capital Power's executive team and Board of Directors. The trading portfolio consists of electricity and natural gas physical and financial derivative contracts which are transacted with the intent of benefiting from short-term actual or expected differences between their buying and selling prices or to lock in arbitrage opportunities.

The fair value of the Company's energy related derivatives as at December 31, 2016, that are required to be measured at fair value with the respective changes in fair value recognized in net income are disclosed in note 13.

The Company employs specific volumetric limits and a Value-at-Risk (VaR) methodology to manage risk exposures to commodity prices on a consolidated basis. VaR measures the estimated potential loss in a portfolio of positions associated with the movement of a commodity price for a specified time or holding period and a given confidence level. Capital Power's current period VaR uses a statistical confidence interval of 99% over a five business day holding period. This measure reflects a 1% probability that, over the five-day period commencing with the point in time that the VaR is measured, the fair value of the overall commodity portfolio could decrease by an amount in excess of the VaR amount. The VaR methodology is a statistically-defined, probability-based approach that takes into consideration market volatilities and risk diversification by recognizing offsetting positions and correlations between products and markets. This technique makes use of historical data and makes an assessment of the market risk arising from possible future changes in commodity prices over the holding period.

VaR should be interpreted in light of the limitations of the methodologies used. These limitations include the following:

- VaR calculated based on a holding period may not fully capture the market risk of positions that cannot be liquidated or hedged within the holding period.
- The Company computes VaR of the portfolios at the close of business and positions may change substantially during the course of the day.
- VaR, at a 99% confidence level, does not reflect the extent of potential losses beyond that percentile. Losses on the other 1% of occasions could be substantially greater than the estimated VaR.

30. Risk management, continued:

Market risk, continued

Commodity price risk, continued

These limitations and the nature of the VaR measurements mean that the Company can neither guarantee that losses will not exceed the VaR amounts or that losses in excess of the VaR amounts will not occur more frequently than 1% of the time. As VaR is not a perfect predictor of risk, the Company undertakes back testing and periodically calibrates the VaR calculation to a 99% confidence level.

The estimation of VaR takes into account positions from all wholly-owned subsidiaries and subsidiaries in which the Company has a controlling interest, and reflects the Company's aggregate commodity positions from its trading and asset portfolios. Capital Power's Board of Directors has approved the methodology for the ongoing determination of commodity risk limits, under their commodity risk management policy. Commodity risk is monitored on a daily basis and reported to the executive team on a monthly basis at a minimum and more frequently if exceptions and/or material changes are identified. The portfolios are stress tested regularly to observe the effects of plausible scenarios taking into account historical price movements and certain hypothetical extreme events. Based on the commodity portfolio as at December 31, 2016 there is a 99% probability that unfavourable daily market variations would not reduce the fair value of the trading portfolio.

Foreign exchange risk

The Company is exposed to foreign exchange risk on foreign currency denominated forecasted transactions, firm commitments, and monetary assets and liabilities denominated in a foreign currency and on its net investments in foreign operations. The Company's operations expose it to foreign exchange risk arising from transactions denominated in foreign currencies. The Company's foreign exchange risk arises primarily with respect to the U.S. dollar but it is potentially exposed to changes in other currencies if and when it transacts in other currencies.

The risk is that the functional currency value of cash flows will vary as a result of the movements in exchange rates.

The Company's foreign exchange management policy is to limit economic and material transactional exposures arising from movements in the Canadian dollar relative to the U.S. dollar or other foreign currencies. The Company's exposure to foreign exchange risk arises from future anticipated cash flows from its U.S. operations, debt service obligations on U.S. dollar borrowings, and from certain capital expenditure commitments denominated in U.S. dollars or other foreign currencies. The Company co-ordinates and manages foreign exchange risk centrally, by identifying opportunities for naturally-occurring opposite movements and then dealing with any material residual foreign exchange risks; these are hereinafter referred to as being economically hedged. The Company may also use derivative instruments to manage foreign exchange risk. At December 31, 2016, the Company held foreign exchange derivatives as disclosed in note 13.

As at December 31, 2016, holding all other variables constant, a $0.10 strengthening or weakening of the Canadian dollar against the U.S. dollar would have increased or decreased net income attributable to shareholders by $6 million. There would be no impact to other comprehensive (loss) income.

This sensitivity analysis excludes translation risk associated with the translation of subsidiaries that have a different functional currency to the functional currency of the Company and financial instruments denominated in the functional currency in which they are transacted and measured.

Interest rate risk

The Company is exposed to changes in interest rates on its cash and cash equivalents, and floating rate current and non-current loans and borrowings. The Company is exposed to interest rate risk from the possibility that changes in interest rates will affect future cash flows or the fair values of its financial instruments. In some circumstances, floating rate funding may be used for current borrowings and other liquidity requirements. As at December 31, 2016, the proportion of fixed rate loans and borrowings was approximately 91% of total loans and borrowings outstanding (2015 - 85%). The Company may also use derivative instruments to manage interest rate risk. At December 31, 2016, the Company did not hold interest rate derivatives as disclosed in note 13 and therefore, the proportion of fixed rate loans and borrowing disclosed above remained at 91% (2015 – 67%).

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

30. Risk management, continued:

Market risk, continued

Interest rate risk, continued

Assuming that the amount and mix of fixed and floating rate loans and borrowings and net loans and borrowings remains unchanged from that held as at December 31, 2016, a 100 basis point decrease or increase to interest rates would decrease or increase full year net income attributable to common shareholders by $1 million and would have no direct impact on other comprehensive (loss) income.

The effect on net income does not consider the effect of an overall change in economic activity that would accompany such an increase or decrease in interest rates.

Credit risk

Credit risk is the possible financial loss associated with the inability of counterparties to satisfy their contractual obligations to the Company. The Company's counterparty credit risk management policy is established by the executive team and approved by the Board of Directors. The associated procedures and practices are designed to manage the credit risks associated with the various business activities throughout the Company. Credit risk management procedures and practices generally include assessment of individual counterparty creditworthiness and establishment of exposure limits prior to entering into any agreements or transactions with the counterparty. Credit exposures and concentrations are subsequently monitored and are regularly reported to management on an ongoing basis. Counterparty creditworthiness also continues to be evaluated on an ongoing basis after transactions have been initiated.

Credit risk is managed and mitigated through a number of risk mitigation practices such as securing parent company guarantees to enhance counterparty credit quality, negotiating and obtaining security (such as cash, letters of credit or property) to offset potential losses, utilization of credit derivatives to reduce credit risk and margining to limit credit risk where applicable.

Maximum credit risk exposure

The Company's maximum credit exposure was represented by the following financial assets:

As at December 31	2016	2015
Cash and cash equivalents	$ 98	$ 80
Trade and other receivables [1]	223	190
Derivative financial instruments assets [1]	269	220
Loans and other long-term receivables	4	12
Finance lease receivables	667	689
Government grant receivable (note 15)	542	-
	$ 1,803	$ 1,191

[1] The Company's maximum credit exposures related to trade and other receivables and derivative financial instruments assets by major credit concentration are comprised of maximum exposures of $236 million (2015 - $195 million) for wholesale counterparties and $256 million (2015 - $215 million) for generation and other counterparties and at December 31, 2016.

The Company is not permitted to sell or re-pledge collateral in the absence of default of the collateral providers. As at December 31, 2016, the Company also held other forms of credit enhancement in the forms of letters of credit of $109 million (2015 - $71 million) and parental guarantees of $1,389 million (2015 - $1,301 million) related to the financial assets noted above. As at December 31, 2016 and 2015, the Company also held parental guarantees which do not have a defined amount or limit, but which provide full support on any outstanding positions related to certain development projects and counterparty performance for power purchase arrangements.

30. Risk management, continued:

Credit risk, continued

Credit quality and concentrations

The Company is exposed to credit risk on outstanding trade and other receivables associated with its generation and optimization activities including power purchase arrangements, agreements with independent system operators, power and steam sales contracts, energy supply agreements with government sponsored entities, wholesale customers, and trading counterparties. The Company is also exposed to credit risk related to its cash and cash equivalents (which include short-term investments), financial and non-financial derivative instruments assets and long-term financing arrangements.

The credit quality and concentrations of the Company's trade and other receivables and other financial assets, by major credit concentrations are the following:

Cash and cash equivalents

The Company has significant credit and performance exposures to financial institutions as they provide committed credit lines and cash deposit facilities, are the primary counterparty of the Company's foreign exchange derivative instruments, and facilitate letters of credit to mitigate the Company's exposure to certain counterparties. The Company manages its credit risk on cash and cash equivalents, and short-term investments by dealing with investment grade rated banks and financial institutions and reviewing each investment vehicle to ensure the underlying credit risk is known.

Loans and long-term financing

As at December 31, 2016, loans and long-term financing consists primarily of a note receivable attributable to one counterparty and is supported by a letter of credit.

Trade and other receivables and financial derivative instruments

Trade and other receivables are substantially made up of receivables related to the generation and sale of electricity to customers including industrial and commercial customers, independent system operators from various regions and government-owned or sponsored entities and the settlement of financial derivative instruments related to merchant price risk mitigation and trading activities. The Company manages its credit risk on these financial assets through its credit adjudication process, dealing with creditworthy counterparties and utilizing the credit risk mitigation practices noted above.

Generation credit risk

Credit risk exposure from PPAs, agreements with independent system operators, power and steam sales contracts, and certain energy supply agreements is predominantly restricted to trade and other receivables and contract default. In certain cases, the Company relies on a single or small number of customers to purchase all or a significant portion of a facility's output. The failure of any one of these counterparties to fulfill its contractual obligations could negatively impact the Company's financial results. Financial loss resulting from events of default by counterparties in certain PPAs and steam purchase arrangements may not be recovered since the contracts may not be replaceable on similar terms under current market conditions. Consequently, the Company's financial performance depends on the continued performance by customers and suppliers of their obligations under these long-term agreements. Credit risk exposure is mitigated by dealing with creditworthy counterparties that are determined to be investment grade based on the Company's internally assigned ratings or employing mitigation strategies as noted above, netting amounts by legally enforceable set-off rights, and, when appropriate, taking security from the counterparty. Credit risk with counterparties in this asset class that are government-owned or sponsored entities and regulated public utility distributors is generally considered low.

Wholesale and merchant credit risk

Credit risk exposure for wholesale and merchant trading counterparties is measured by calculating the costs (or proceeds) of replacing the commodity position (physical and derivative contracts), adjusting for settlement amounts due to or due from the counterparty and, if permitted, netting amounts by legally enforceable set-off rights. Financial loss on wholesale contracts could include, but is not limited to, the cost of replacing the obligation, amounts owing from the counterparty or any loss incurred on liability settlements. Wholesale and merchant credit risk exposure is mitigated by trading with investment grade and creditworthy counterparties, portfolio diversification, monitoring of

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

30. Risk management, continued:

Credit risk, continued

Wholesale and merchant credit risk, continued

credit exposure limits, margining to reduce energy trading risks, obtaining parent company guarantees, and when appropriate, taking security from counterparties.

Trade and other receivables and allowance for doubtful accounts

Trade and other receivables consist primarily of amounts due from customers including industrial and commercial customers, independent system operators from various regions, government-owned or sponsored entities, and other counterparties. Larger commercial and industrial customer contracts and contract-for-differences provide for performance assurances including letters of credit if deemed appropriate. The Company also has credit exposures to large suppliers of electricity and natural gas. The Company mitigates these exposures by dealing with creditworthy counterparties and, when appropriate, taking appropriate security from the supplier.

The aging of trade and other receivables as at December 31, 2016 was:

	Gross trade and other receivables	Allowance for doubtful accounts	Net trade and other receivables
Current [2]	$ 223	$ -	$ 223
Outstanding 30 - 60 days	-	-	-
Outstanding 60 - 90 days	-	-	-
Outstanding greater than 90 days	-	-	-
	$ 223	$ -	$ 223

[2] Current amounts represent trade and other receivables outstanding zero to 30 days. Amounts outstanding more than 30 days are considered past due.

The changes in the allowance for doubtful accounts were as follows:

Year ended December 31	2016	2015
As at January 1	$ 5	$ 5
Amounts reversed unused	(5)	-
As at December 31	$ -	$ 5

No bad debt expenses were recognized in the year (2015 - nil).

As at December 31, 2016, the Company held no customer deposits for the purpose of mitigating the credit risk associated with accounts receivable from customers (2015 - nil).

As at December 31, 2016 and 2015, there were no provisions for credit losses associated with trade and other receivables from treasury, trading and energy procurement counterparties as all balances were considered to be fully collectible.

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The Company's liquidity is managed centrally by the Treasury function. The Company manages liquidity risk through regular monitoring of cash and currency requirements by preparing short-term and long-term cash flow forecasts and also by matching the maturity profiles of financial assets and liabilities to identify financing requirements. The financing requirements are addressed through a combination of committed and demand revolving credit facilities, financings in public and private capital debt markets and equity offerings by the Company or its CPLP subsidiary.

Capital Power has senior unsecured long-term debt ratings of BBB- (stable outlook) and BBB (negative trend) assigned by Standard & Poor's (S&P) and DBRS Limited (DBRS) respectively. Capital Power has preferred share ratings of P-3 and Pfd-3(low) assigned by S&P and DBRS respectively.

As at December 31, 2016, the Company had undrawn bank credit facilities and operating lines of credit and demand facilities, totaling $974 million (2015 - $861 million), of which $808 million is committed to 2021 and $55 million committed to 2020 (2015 - $745 million committed to 2020).

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

30. Risk management, continued:

Liquidity risk, continued

In addition to the facilities noted above, the Company has a shelf prospectus under which it may raise funds in the form of debt or equity. As at December 31, 2016, Capital Power has a Canadian shelf prospectus, which expires in June 2018, under which it may raise up to $3 billion collectively in common shares of the Company, preference shares of the Company, subscription receipts exchangeable for common shares and/or other securities of the Company, and debt securities of the Company. As at December 31, 2016, the amounts available on the shelf prospectus are $2,800 million (2015 - $2,775 million).

The following are the undiscounted cash flow requirements and contractual maturities of the Company's financial liabilities, including interest payments, and where applicable, net of financial assets that generate cash inflows to meet cash outflows on financial liabilities as at December 31, 2016:

	Due within 1 year	Due between 1 and 2 years	2 and 3 years	3 and 4 years	4 and 5 years	Due after more than 5 years	Total contractual cash flows
Non-derivative financial liabilities:							
Loans and borrowings (note 21)	$ 26	$ 185	$ 259	$ 306	$ 446	$ 294	$ 1,516
Interest payments on loans and borrowings	76	70	57	51	25	69	348
Trade and other payables [3] (note 20)	196	-	-	-	-	-	196
Finance lease obligation	1	1	1	2	2	13	20
Other current deferred revenue and liabilities (note 22)	6	-	-	-	-	-	6
Derivative financial liabilities:							
Net commodity contracts for differences	9	9	9	5	3	6	41
Total	$ 314	$ 265	$ 326	$ 364	$ 476	$ 382	$ 2,127

[3] Excluding accrued interest on loans and borrowings of $13 million and current portion of finance lease obligation of $1 million.

31. Capital management:

The Company's primary objectives when managing capital are to safeguard the Company's ability to continue as a going concern, pay regular dividends to its shareholders, maintain a suitable credit rating, and to facilitate the acquisition or development of projects in Canada and the U.S. consistent with the growth strategy of the Company. The Company manages its capital structure in a manner consistent with the risk characteristics of the underlying assets.

The Company manages capital through regular monitoring of cash and currency requirements by preparing short-term and long-term cash flow forecasts and reviewing monthly financial results. The Company matches the maturity profiles of financial assets and liabilities to identify financing requirements to help ensure an adequate amount of liquidity.

The Company considers its capital structure to consist of loans and borrowings net of cash and cash equivalents and equity (which includes non-controlling interests).

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

31. Capital management, continued:

The following table represents the total capital of the Company:

As at December 31	2016	2015
Loans and borrowings (note 21)	$ 1,508	$ 1,615
Finance lease obligation (note 14)	20	22
Cash and cash equivalents (note 10)	(98)	(80)
Net debt	1,430	1,557
Non-controlling interests (note 32)	58	68
Share capital (note 24)	2,918	2,744
Deficit and other reserves	(75)	4
Total equity	2,901	2,816
	$ 4,331	$ 4,373

Capital Power has the following externally imposed requirements on its capital as a result of its credit facilities and certain debt covenants, as defined in the respective agreements:

- Maintenance of modified consolidated net tangible assets to consolidated net tangible assets ratio, as defined in the debt agreements, of not less than 0.80 to 1.0;
- Maintenance of consolidated senior debt to consolidated capitalization ratio, as defined in the debt agreements, of not more than 0.65 to 1.0;
- Limitation on debt issued by subsidiaries; and
- In the event that Capital Power is assigned a rating of less than BBB- from S&P and BBB (Low) from DBRS (in each case with a stable outlook), Capital Power would also be required to maintain a ratio of consolidated earnings before interest, income taxes, depreciation and amortization to consolidated interest expense, as defined in the debt agreements, of not less than 2.5 to 1.0.

Effective January 2016, amendments made to the loan credit agreements will require Capital Power to meet the financial covenants referenced above in place of CPLP. For the year ended December 31, 2016, Capital Power complied with all externally imposed capital restrictions. For the year ended December 31, 2015, CPLP complied with all externally imposed capital restrictions.

To manage or adjust its capital structure, the Company can issue new loans and borrowings, issue common or preferred shares, buy back common shares, redeem preferred shares, repay existing loans and borrowings or adjust dividends paid to its shareholders.

32. Investments in subsidiaries that have non-controlling interests:

Set out below are the Company's principal subsidiaries that have non-controlling interests (NCI) at December 31, 2016:

	Place of business	Percentage of ownership interest held by the Company	Percentage of ownership interest held by the NCI	Principal activities
Genesee Coal Mine Assets (Coal Mine)	Canada	50%	50%	Coal production for use in power generation

The Company holds a 50% interest in the Coal Mine while the other 50% is held by an external party. The decisions about the relevant activities of the coal mine are made based on majority vote by the Management Committee. The Management Committee is comprised of three members appointed by each of the Company and the external party. Based on the terms of the agreement surrounding the operations of the Coal Mine, it is noted that under the circumstance where the two parties are in a deadlock with respect to a decision that would affect the relevant activities of the Coal Mine, Capital Power holds the deciding vote. Given Capital Power's voting rights, Capital Power has control to affect the variability in its returns. Based on an assessment of the relationship between Capital

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

32. Investments in subsidiaries that have non-controlling interests, continued:

Power and the Coal Mine, Capital Power controls the Coal Mine and therefore the Coal Mine is treated as a subsidiary of Capital Power.

There are no significant restrictions on access to the subsidiary's assets noted above.

The summarized financial information of the Coal Mine is as follows:

Consolidated statements of financial position and loss and other comprehensive loss	2016	2015
Non-current assets	$ 117	$ 136
Net loss and comprehensive loss attributable to partners	$ (18)	$ (19)

Consolidated statements of cash flows	2016	2015
Net cash flows from (used in) investing activities	$ 2	$ (13)
Net cash flows (used in) from financing activities	(2)	13
Net increase (decrease) in cash and cash equivalents	-	-
Cash and cash equivalents at beginning of year	-	-
Cash and cash equivalents at end of year	$ -	$ -

Non-controlling interest reflected on the consolidated balance sheet is comprised of:

Year ended December 31	2016	2015
Non-controlling interest in the Coal Mine, beginning of year	$ 68	$ 72
Net loss attributable to non-controlling interest	(9)	(10)
Net (reduction in) additional investment by non-controlling interest	(1)	6
Non-controlling interest in the Coal Mine, end of year	$ 58	$ 68

Up to April 2, 2015, EPCOR held an ownership interest in CPLP. On that date, EPCOR exchanged all 18.841 million of its exchangeable limited partnership units of CPLP on a one-for-one basis for common shares of Capital Power in accordance with the terms of the exchangeable common limited partnership units. As a result of that exchange, EPCOR's ownership interest in CPLP was reduced to nil and Capital Power's interest in CPLP increased to 100%. The summarized financial information of CPLP for the period corresponding to an NCI being held in CPLP is as follows:

Consolidated statements of financial position	As at April 2, 2015
Current assets	$ 539
Non-current assets	5,032
Current liabilities	(869)
Non-current liabilities	(1,787)
Non-controlling interests – Coal Mine	(73)
Non-controlling interests – other	(20)
Net assets	$ 2,822

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

32. Investments in subsidiaries that have non-controlling interests, continued:

Consolidated statements of income	For the period ended April 2, 2015
Revenues and other income	$ 355
Net income attributable to partners	62
Other comprehensive income attributable to partners	52
Total comprehensive income attributable to partners	$ 114

Consolidated statements of cash flows	For the period ended April 2, 2015
Net cash flows from operating activities	$ 105
Net cash flows used in investing activities	(17)
Net cash flows used in financing activities	(80)
Foreign exchange gain on cash held in a foreign currency	3
Net increase in cash and cash equivalents	11
Cash and cash equivalents at beginning of year	69
Cash and cash equivalents	$ 80

NCI in CPLP reflected on the consolidated balance sheet is comprised of:

NCI in CPLP, January 1, 2015	$ 480
Net income attributable to non-controlling interest	6
Other comprehensive income attributable to non-controlling interest	2
Distributions to non-controlling interest (note 27)	(6)
Exchange of CPLP units for Capital Power shares	(482)
NCI in CPLP as at April 2, 2015	$ -

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

33. Interests in joint arrangements:

Joint operations

The Company holds interests in the following joint operations as at December 31, 2016:

	Place of business	% of ownership interest
Genesee (G3) Project [1]	Canada	50%
Keephills 3 (K3) Project [2]	Canada	50%
Joffre Cogeneration Project [3]	Canada	40%
Shepard Energy Centre (Shepard) [4]	Canada	50%
Genesee 4 and 5 [5]	Canada	50%

[1] G3 is a 516 megawatt (MW) coal-fired generating facility and is a 50/50 joint arrangement between Capital Power and an external party, with Capital Power acting as the manager and operator. Both parties independently dispatch and market their share of the electrical output through Alberta's competitive wholesale market.

[2] K3 is a 516 MW coal-fired generating facility and is a 50/50 joint arrangement between Capital Power and an external party with the external party responsible for operations. Both parties independently dispatch and market their share of the facility's electrical output through Alberta's competitive wholesale market.

[3] Joffre Cogeneration Project is a 480 MW gas-fired combined cycle cogeneration facility in which Capital Power holds a 40% interest with external parties holding 40% and 20% interests, respectively. The Company's investment in the Joffre Cogeneration Project joint arrangement, which is incorporated as a separate legal entity, has been determined to be a joint operation since the contractual arrangements governing the joint arrangement indicate that the parties to the arrangement are entitled to the assets of the joint arrangement and are exposed to the liabilities of the joint arrangement in proportion to their ownership interest.

[4] Shepard is an 800 MW gas-fired generating facility which is a 50/50 joint arrangement between Capital Power and an external party with the external party responsible for operations. Both parties independently dispatch and market their share of the electrical output through Alberta's competitive wholesale market.

[5] Genesee 4 and 5 is a 1,060 MW gas-fired generating project and is a 50/50 joint arrangement between Capital Power and an external party, with Capital Power responsible for construction and operations of the project. Regulatory approvals have been received. The Company's commitments associated with Genesee 4 and 5 are described in note 34(a).

There are no significant restrictions pertaining to the joint operations described above, other than those described in note 21 pertaining to the charges on the Joffre Cogeneration project assets.

Joint venture

The Company holds an interest in the following joint venture as at December 31, 2016:

	Place of business	Measurement Method
K2 Wind Power Project (K2 Wind) [6]	Canada	Equity method

[6] K2 Wind is a 270 MW wind facility in which Capital Power holds an equal 33.33% interest with two external parties. The Company's investment in K2 Wind, which consists of separate legal entities, has been determined to be a joint venture. The Company's obligations are limited to their capital contributions to the joint arrangement, and the Company's receipts of the economic benefits of the joint arrangement are limited to annual distributions. As a result, there is no indication that the Company has rights to the assets or obligations for the liabilities of the joint arrangement and the investment has been classified as a joint venture.

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

33. Interests in joint arrangements, continued:

Joint venture, continued

The summarized financial information of K2 Wind is as follows:

Statements of Financial Position	2016	2015
Cash and cash equivalents	$ 18	$ 39
Other current assets [7]	27	25
Non-current assets [7]	829	875
Financial current liabilities	(43)	(46)
Other current liabilities	(10)	(19)
Financial non-current liabilities	(821)	(850)
Other non-current liabilities	(15)	(16)
Net assets	$ (15)	$ 8

[7] K2 Wind has restricted cash of $8 million included in non-current assets above (2015 - $20 million in other current and non-current assets) which represents security for a standby line of credit with a third party.

Statements of Income and Comprehensive Income (Loss)	2016	2015
Revenues	$ 140	$ 75
Other raw materials and operating charges	(11)	(6)
Other administrative expense	(6)	(10)
Depreciation and amortization	(35)	(21)
Finance expense	(40)	(15)
Net income	48	23
Other comprehensive loss:		
Unrealized losses on derivative instruments	(15)	(32)
Reclassification of gains on derivative instruments to net income for the year	15	-
Total comprehensive income (loss)	$ 48	$ (9)

A reconciliation of the Company's recorded equity investment in K2 Wind is as follows:

As at December 31	2016	2015
Opening balance	$ 17	$ 29
Proportionate share of comprehensive income (loss) (33.33%)	16	(3)
Distributions received – return of capital	-	(8)
Distributions received – operating	(24)	(8)
Adjustments for differences in accounting policies	9	7
	$ 18	$ 17

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

34. Commitments and contingencies:

(a) The Company is party to a series of agreements with an external party to develop, build and own a 50% interest in Genesee 4 and 5 located in central Alberta. The Company expects to invest approximately $820 million, including capitalized borrowing costs, into Genesee 4 and 5, which are expected to commence commercial operations as additional electricity capacity is required, contingent on the implementation of a capacity market and other elements of the CLP not having adverse impacts to the economics of the facility and upon price signals from the capacity market. It is expected that the two parties will build, own and operate Genesee 4 and 5, which would operate as a joint arrangement. In conjunction with the joint arrangement, the parties would be subject to various commercial agreements, including an eight-year tolling agreement. Under the tolling agreement, 50% of Capital Power's share of the output will be sold to the other party to the joint arrangement when commercial operations begin.

(b) During the third quarter of 2016, the Company commenced construction of Bloom Wind. Bloom Wind is a 178 MW project in southwestern Kansas consisting of 54 3.3 MW turbines and is anticipated to cost $358 million (US$272 million). Commercial operation is expected in the third quarter of 2017.

(c) The Company is party to a number of long-term energy purchase and transportation contracts, operating and maintenance contracts, contracts to purchase environmental credits and operating leases for premises in the normal course of operations. Some of the energy purchase and transportation contracts are measured at their fair value and recorded on the consolidated statement of financial position as derivative financial instruments assets and liabilities as appropriate. The energy purchase and transportation contract amounts disclosed below are based on gross settlement amounts.

Approximate future payments under each group of contracts are as follows:

	Energy purchase and transportation contracts	Operating and maintenance contracts	Environmental credits	Operating leases
Within one year	$ 45	$ 25	$ 73	$ 8
Between one and five years	141	115	118	31
After five years	449	191	30	59
	$ 635	$ 331	$ 221	$ 98

(d) 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 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. The AESO has noted it expects to be able to produce prospective loss factors in March 2017 to be effective January 1, 2017. One party has subsequently 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.

34. Commitments and contingencies, continued:

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 Commission 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 is currently scheduled to conclude by May 2017 and an oral hearing, if determined to be required by the AUC, would commence in June 2017.

As at February 17, 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. It is unclear when retrospective loss factors will be made available, and the timing of a Module C decision remains unknown. 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 audited consolidated financial statements since the outcome of the LLR Proceeding is not known. 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 (see note 5), 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 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.

(e) The Company has contingent consideration payable upon reaching specified milestones in connection with the development sites acquired in connection with the its acquisition of Element Power US, LLC in 2014. As at December 31, 2016, contingent consideration of $12 million (US$9 million) is recorded in non-current other liabilities. The valuation model for contingent consideration is based on the present value of the expected payment discounted using a risk-adjusted discount rate of 8%. The expected payment is determined by considering the possible scenarios for the development sites reaching specified milestones, the amount to be paid under each scenario and the probability of each scenario.

(f) 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.

35. Guarantees:

The Company, through its subsidiary CPLP, has issued letters of credit of $172 million (2015 - $125 million) to meet the credit requirements of energy market participants, to meet conditions of certain service agreements, and to satisfy legislated reclamation requirements.

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

36. 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 and Kansas), 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:

	Year ended December 31, 2016				Year ended December 31, 2015			
	Canada	U.S.	Inter-area eliminations	Total	Canada	U.S.	Inter-area eliminations	Total
Revenues and other income								
External	$1,083	$ 131	$ -	$1,214	$1,115	$ 126	$ -	$1,241
Inter-area	3	(8)	5	-	9	12	(21)	-
	$1,086	$ 123	$ 5	$1,214	$1,124	$ 138	$ (21)	$1,241

	As at December 31, 2016			As at December 31, 2015		
	Canada	U.S.	Total	Canada	U.S.	Total
Property, plant and equipment	$ 3,355	$ 409	$ 3,764	$ 3,450	$ 227	$ 3,677
Intangible assets	249	50	299	295	41	336
Goodwill	-	23	23	-	30	30
Other assets	19	1	20	22	2	24
	$ 3,623	$ 483	$ 4,106	$ 3,767	$ 300	$ 4,067

37. Subsequent event:

Acquisition of thermal facilities

On February 21, 2017, the Company announced that it has entered into an agreement to acquire the thermal power business of Veresen Inc., consisting of two gas-fired and two waste-heat generation facilities.

Under the terms of the agreement, Capital Power will acquire 284 megawatts of generation from two natural gas-fired power facilities 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 will operate both facilities. Both East Windsor and York Energy are under long-term PPAs, with the A rated Ontario Independent Electricity System Operator, with original terms expiring in 2029 and 2032, respectively. Both facilities earn revenue through fixed capacity payments partly indexed to inflation and are compensated for operations and maintenance, and fuel (commodity and transportation) as well as start-up costs. Additionally, East Windsor is under a long-term steam supply agreement with a BBB rated third party.

The transaction also includes 10 MW of zero-emissions waste-heat generation from two facilities (5 MW each) located at Westcoast Energy's BC Gas Pipeline compressor stations in Savona and 150 Mile House, British Columbia. The waste heat facilities are under 20-year Electricity Purchase Agreements (EPAs), with AA rated BC Hydro, with original terms expiring in 2028. The EPAs provide for partial inflation indexation as well as premium pricing under peak load hours. A third party provides operations and maintenance services for the assets under a long-term agreement.

The purchase price for the acquisition is $225 million in total cash consideration, subject to working capital adjustments and other closing adjustments, and the assumption of $275 million of project level debt (on a proportionate basis). Capital Power expects to finance the transaction through existing cash and its credit facilities. The transaction is expected to close in the second quarter of 2017, subject to regulatory approvals and satisfaction of closing conditions.

38. Comparative figures:

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