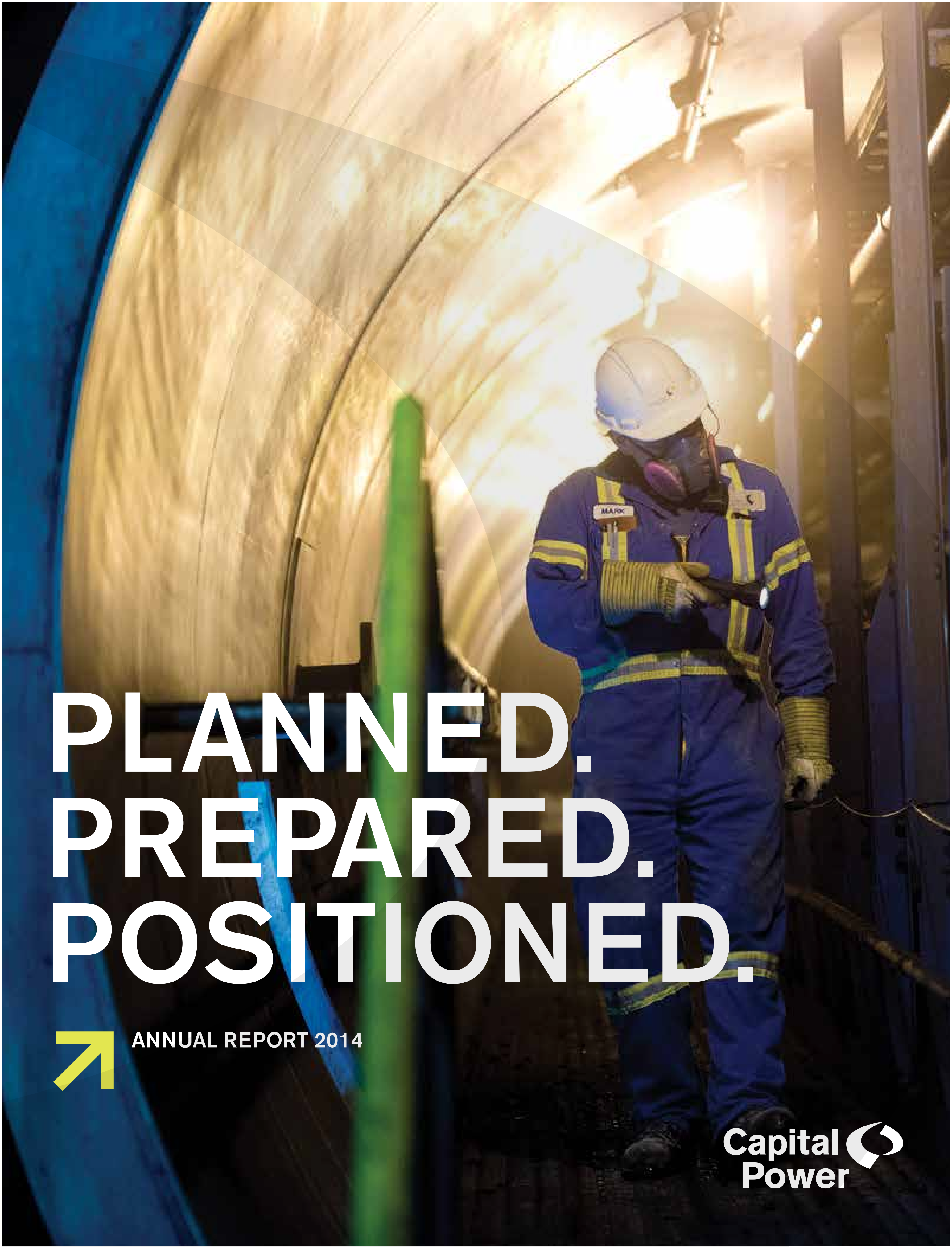


PLANNED. PREPARED. POSITIONED.

ANNUAL REPORT 2014

Capital Power

Capital Power's vision is to be recognized as one of North America's most respected, reliable and competitive power generators.

OUR VALUES

- We are passionate about our business and safety
- We act with integrity
- We work together
- We are accountable
- We create and enhance shareholder value

OUR PURPOSE

Capital Power creates and enhances shareholder value by delivering on our strategy of generating power from well-maintained and efficiently-operated plants and investing in disciplined growth opportunities.

Forward-looking information: Forward-looking information or statements included in this Annual Report 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. Certain information in this Annual Report is forward-looking within the meaning of Canadian securities law, as it is related to anticipated financial performance, events or strategies. When used in this context, words such as "will," "anticipate," "believe," "plan," "intend," "target" and "expect" or similar words suggest future outcomes. By their nature, such statements are subject to significant risks, assumptions and uncertainties, which could cause Capital Power's actual results and experience to be materially different than the anticipated results. Readers are advised that all information in this Annual Report is provided subject to the cautionary statement regarding forward-looking information, which is found in management's discussion and analysis (MD&A) beginning at page15.

PRODUCING POWER

RELIABLY, COMPETITIVELY AND RESPONSIBLY

Capital Power (CPX: TSX) 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 2,700 megawatts of power generation capacity at 15 facilities across North America and owns 371 megawatts of capacity through a power purchase agreement. An additional 490 megawatts of owned generation capacity is under construction in Alberta and Ontario.

PLANNED. PREPARED. POSITIONED.

PLANT AVAILABILITY HAS AVERAGED

92%

IN THE PAST 5 YEARS

We continue to demonstrate operational excellence with high plant availability averaging 92% in the past 5 years. Our power generation fleet is well maintained and modern and we continue to pursue increased optimization based on plant output, costs, risk mitigation, and safety and environment.

OUR GENERATION PORTFOLIO

Our power generation fleet is well maintained, modern, and focused on three main energy sources: natural gas, coal and wind. Our young fleet (average age of 13 years) delivers high plant availability and reduces the risk of unplanned outages.

WIND

Quality Wind
Halkirk Wind
Kingsbridge 1 Wind
K2 Wind[1,2]
Port Dover & Nanticoke Wind
Macho Springs Wind

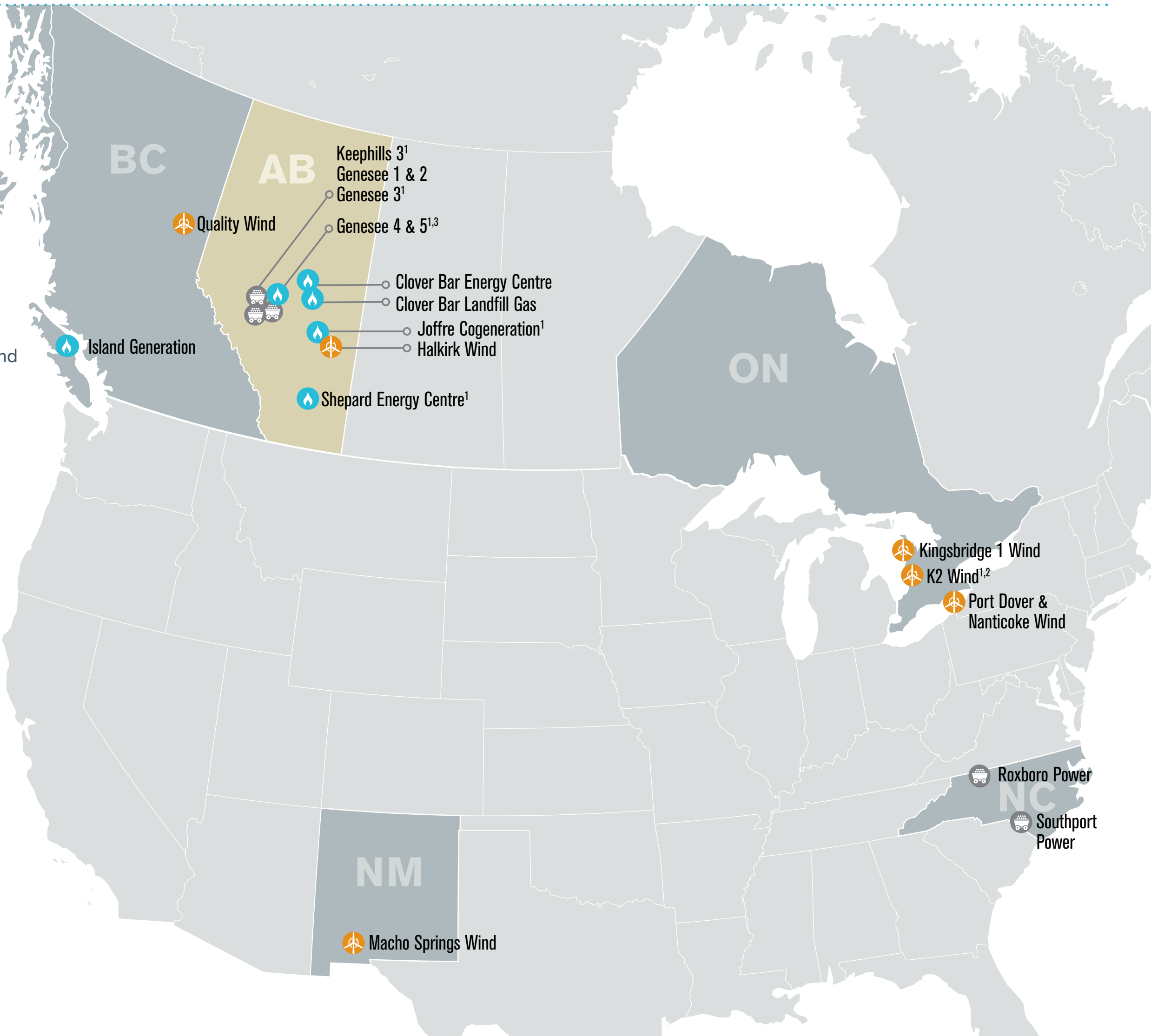
GAS

Clover Bar Energy Centre
Clover Bar Landfill Gas
Genesee 4 & 5[1,3]
Island Generation
Joffre Cogeneration[1]

COAL/ SOLID FUELS

Genesee 1 & 2
Genesee 3[1]
Keephills 3[1]
Roxboro Power
Shepard Energy Centre[1]
Southport Power

1 Joint arrangement. For ownership details see pages 124 to 125.
2 Under construction.
3 In development.



We are a leading Alberta power generation developer, with current investments in the Shepard Energy Centre and Genesee 4 & 5, a North American platform of contracted opportunities and proven development and construction expertise.

MESSAGE FROM THE

BOARD CHAIR

DONALD LOWRY

DEAR SHAREHOLDERS:

The Board appreciates that shareholders have a vested interest in how the company is operating and governed and as such we continually look at ways to improve dialogue with our shareholders.

In early 2015, Al Bellstedt, Chair of the Corporate Governance committee and I held meetings with a number of Capital Power's largest institutional shareholders as part of our first corporate governance roadshow. Although the management team is actively involved in communicating with institutional shareholders, the objective of these meetings was to provide an opportunity for our shareholders to meet directly with Board members and share feedback regarding Capital Power's governance.

Furthermore, as part of our commitment to shareholder engagement, all shareholders have the opportunity to vote on our third 'say on pay' advisory vote on executive compensation at the 2014 Annual Meeting. Despite receiving 98% approval from shareholders on 'say on pay' last year that strongly supported our approach to executive compensation, we believe it's important to continue receiving direct shareholder feedback on this matter.

July 2014 marked the fifth anniversary for Capital Power as a publicly-traded company. During this time, the Board has provided independent leadership and oversight in guiding the company's growth through acquisitions, divestitures and developments. This past year's results showed progress towards the goal of establishing Capital Power as one of North America's most respected, reliable and competitive power generators.

At this year's annual meeting, two shareholder-elected directors, Bill Bennett and Richard Cruickshank will not be standing for re-election as well as Hugh Bolton, a director nominated by EPCOR. This past fall Brian Bentz resigned from the Board of Directors for personal health reasons. All four individuals have been Board members since the initial public offering in 2009. I would like to thank Bill, Richard, Hugh and Brian for their insights and contributions over the past five and a half years.

I would also like to thank the employees of Capital Power for their hard work and achievements in 2014, and welcome our shareholders to the upcoming annual meeting. We look forward to meeting you, hearing your thoughts and speaking with you.

Sincerely,

Donald Lowry
BOARD CHAIR

MESSAGE FROM THE PRESIDENT & CEO

BRIAN VAASJO

TO OUR SHAREHOLDERS:

2014 was a busy year with the completion of many initiatives that position Capital Power for the future. Our strategy of preserving and growing shareholder value by providing shareholders with a stable and growing contracted cash flow base, with upside exposure to the Alberta power market, drives these initiatives.

PLANNED TO DELIVER ON STRATEGY

In the Alberta power market, we go through business cycles. As new generation is added, we expect to go through lower price periods followed by periods of price recovery with demand growth. This cycle has been consistent since Alberta's wholesale power market was deregulated in 1996, and we expect this will continue in the future.

In early 2015, the 800 megawatt (MW) Shepard Energy Centre (Shepard) started commercial operations, which is the main contributing factor that will cause a temporary excess supply of generation in the Alberta power market. Although annual Alberta power prices have averaged $65 per megawatt hour (MWh) in the past 14 years from 2001 to 2014, the excess supply is expected to cause low power prices in the near to medium term.

Capital Power has been planning for this expected oversupply in generation and we have made decisions over the past few years based on this view of 2015. We expected the excess supply of generation in the near term would be partially offset by the fact that Alberta was one of the fastest growing economies and power markets in North America. However, with the slower growth expected from lower crude oil prices, we expect it will take longer for the market to get back to balance. With increasing demand for electricity and the retirement of older coal-fired facilities, these strong market fundamentals will lead to higher power prices and new build opportunities over time, making Alberta an attractive long-term market to invest in.

This was the rationale behind our decision to invest in the Shepard project in 2012 after it was already under construction. At that time, the project was 100% owned by ENMAX Corporation (ENMAX). With an opportunity to increase our generation in Alberta as well as to significantly increase our contracted cash flow base, we entered into a joint venture agreement with ENMAX to purchase a 50 per cent interest in Shepard including agreements to construct and operate the facility.

PREPARED FOR THE POWER MARKET CYCLE

Addressing how we are positioned through the bottom of the Alberta power cycle is key to shareholder value. Our outlook for 2015 is what we have been expecting and, more importantly, what we have been preparing for. Our primary approaches have been to increase the contracted cash flow base and optimize our existing assets and costs. We've taken actions such as accelerating our reliability program back in 2012 and working on programs over the past few years that resulted in substantial reductions in operating, maintenance, and general and administration costs, particularly in 2013. The cost savings were evident in 2014 as we reduced corporate expenses by $37 million, representing a 31% reduction. Despite the cost savings, we continue to adhere to our high maintenance standards as reflected in our key performance indicator, plant availability. In 2014, we achieved a 95% average plant availability and have averaged 92% over the past five years.

When we structured the commercial arrangements for Shepard in 2012 with ENMAX, it included a 20-year contract for 50% of our capacity from 2015 to 2035. With the expectation of lower power prices in the short term, the commercial agreements expanded the contracted terms to 75% of our capacity output from 2015 to 2017. In addition, for 2015 we sold our remaining 25% of Shepard's on-peak power to ENMAX on fixed-price terms. Essentially, our output is 100% contracted/hedged in 2015 and 75% contracted in 2016 and 2017. Our commercial portfolio for 2015 is substantially hedged at prices that are above the current forward curves.

To fund our approximate $826 million capital cost investment for Shepard, we divested our three U.S. Northeast commercial plants in late 2013 through a successful sales process. The divestiture of these merchant facilities outside of Alberta is consistent with our strategy of focusing our merchant activities in Alberta and limiting our exposure to merchant markets.

Our actions over the past few years have contributed to our growing contracted cash flow base, which resulted in the Company's first dividend increase, a 7.9% increase in the annual dividend, announced last July. The decision to increase the dividend incorporated a low power price outlook for 2015 and was based on an ability to deliver consistent annual dividend growth.

POSITIONED FOR SOLID LONG-TERM GROWTH

Since 2012, we have constructed and now operate three contracted wind facilities to add nearly 400 MW to our fleet. When K2 Wind begins commercial operations in mid-2015, it will add another 90 MW of contracted cash flows. These wind projects have significantly helped expand our contracted cash flow base in conjunction with the contracted portion of Shepard.

Overall, our contracted cash flows are expected to increase 73% from 2012 to 2016 and to provide more than 100% coverage to meet our financial obligations and support dividend growth. In addition to the contracted cash flows, the Alberta merchant cash flows provide us with upside when power prices recover.

The significant expansion in contracted cash flows puts us in a strong financial position. Capital Power has a solid balance sheet with relatively low debt levels compared to our peers. We expect to strengthen our balance sheet even further as we expect 2015 funds from operations to increase approximately 8% and result in improved credit metrics through 2015. In 2014, approximately 38% of funds from operations were discretionary cash flow, after deducting dividend payments and sustaining capital expenditures, and this is expected to increase to 41% in 2015. The discretionary cash flow will allow us to fund or partially fund new growth opportunities.

In terms of growth, a significant 2014 accomplishment was advancing the development of the Genesee 4 & 5 project. The project has received all required major regulatory approvals from the Alberta Utilities Commission and the Alberta Environment and Sustainable Resource Development to proceed with construction and is best positioned to be the next large natural-gas-fired generation project built in Alberta near the end of the decade.

In December, we also completed the acquisition of Element Power US. The primary driver for the acquisition was to build a portfolio of development projects in strategic locations in the United States. The acquisition included 10 wind development sites, four solar development sites, and a 50 MW operating wind project in New Mexico that is fully contracted to the end of 2031.

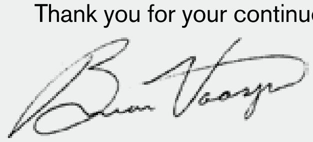
We are well positioned for the future with our pursuit of higher levels of operational excellence, our strong and growing cash flow base that is strengthening our balance sheet, an increasing dividend profile, and by owning the best assets in the best merchant market in North America.

LOOKING AHEAD

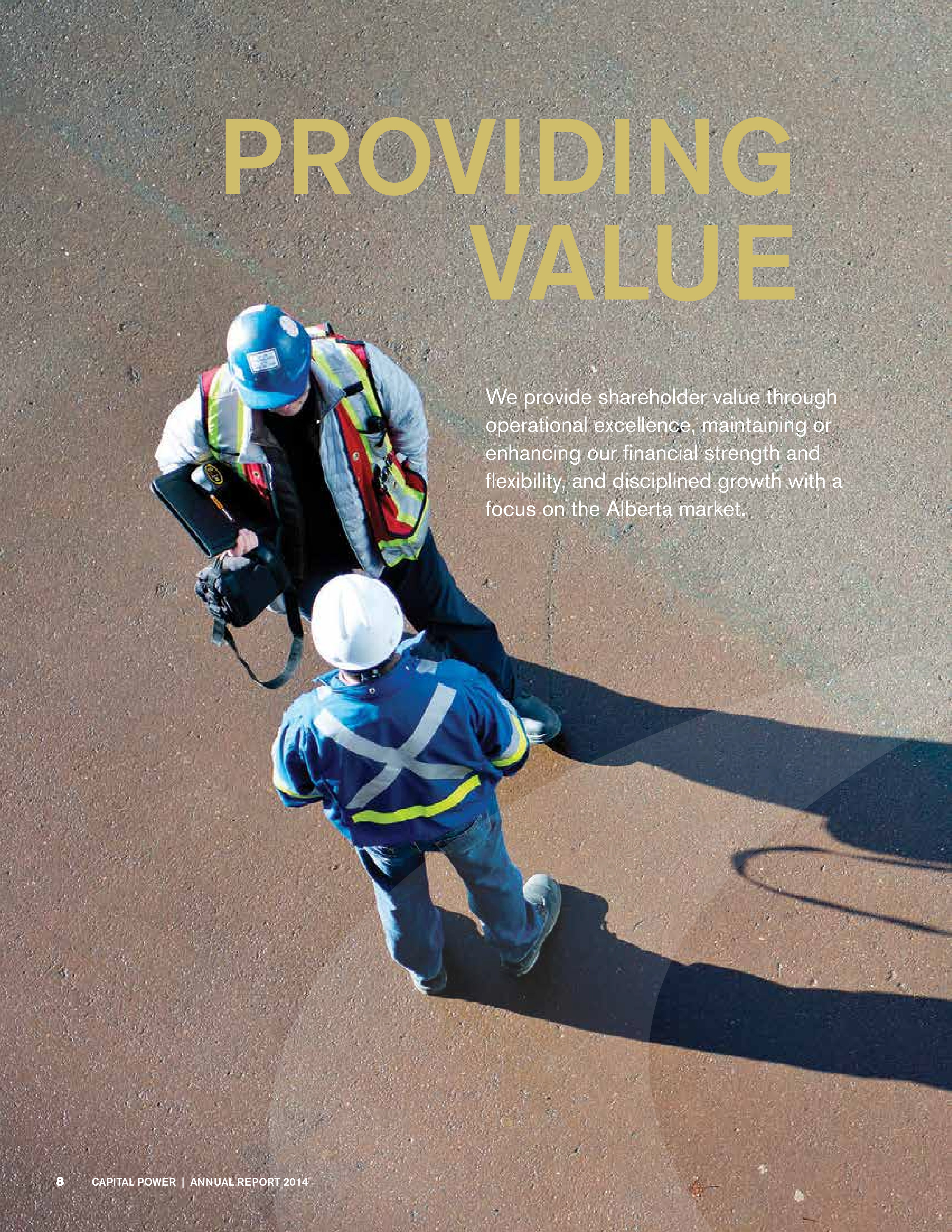
For 2015, management is focused on delivering strong operational performance from our generation fleet with a plant availability target of 94%, completing the construction of the K2 Wind project for operations in mid-2015, transitioning the Genesee 4 & 5 project from development to construction, and generating between $365 million to $415 million in funds from operations.

With the acquisition of Element Power US, we have established a substantial footprint in the United States for future wind and solar development that will help define the Capital Power of the future. Consistent with the theme of this year's annual report "Planned. Prepared. Positioned.", the planning and preparation that we have completed has us well positioned to maximize shareholder value by successfully addressing the opportunities and challenges that come our way.

Thank you for your continued support.



Brian Vaasjo
PRESIDENT AND CHIEF EXECUTIVE OFFICER



PROVIDING VALUE

We provide shareholder value through operational excellence, maintaining or enhancing our financial strength and flexibility, and disciplined growth with a focus on the Alberta market.

GROWTH

- Genesee 4 & 5 is best positioned to be the next large natural-gas-fired generation project to be built in Alberta
- Strong pipeline of contracted growth opportunities in North America

ALBERTA POWER MARKET UPSIDE

- Owns a young, well-maintained fleet with a significant presence in the Alberta market
- Well positioned to weather the bottom of the power market cycle with a significant percentage of merchant cash flows hedged in the near term

CONTRACTED CASH FLOW

- Substantial growth in contracted operating margins expected to fully cover financial obligations[1] and dividends in 2015 and beyond
- Supports consistent annual dividend growth

STRONG FINANCIAL POSITION

FOUNDATION

- Strong balance sheet and investment grade credit rating
- Generating approximately $200 million in free cash flow before growth capital expenditures at the bottom of the Alberta power market cycle to reinvest in the business

OPERATIONAL EXCELLENCE

FOUNDATION

- Excellent assets in good markets with solid operating performance
- Ongoing improvements to operating cost base, fleet availability and risks

1 Financial obligations include interest payments (including interest during construction), sustaining capital expenditures and general & administration expenses.

WELL POSITIONED

Capital Power is an independent power producer with proven operating, construction and trading performance.

The drive behind our strategy is preserving and growing shareholder value by:

OPTIMIZING OPERATIONS:
Assets, resources and capital are part of our optimization program to generate greater value.

BUILDING FOR THE FUTURE:

- Genesee 4 & 5 (AB), to be built by the end of the decade, is a high-efficiency combined-cycle natural-gas-fired generation facility with capacity of up to 1,060 MW.
- Acquisition of Element Power U.S. provides Capital Power with a portfolio of wind and solar energy development sites in the United States.

POSITIONING FOR THE ALBERTA POWER CYCLE:
Capital Power has been preparing for the current low point in the Alberta power market.
We have:

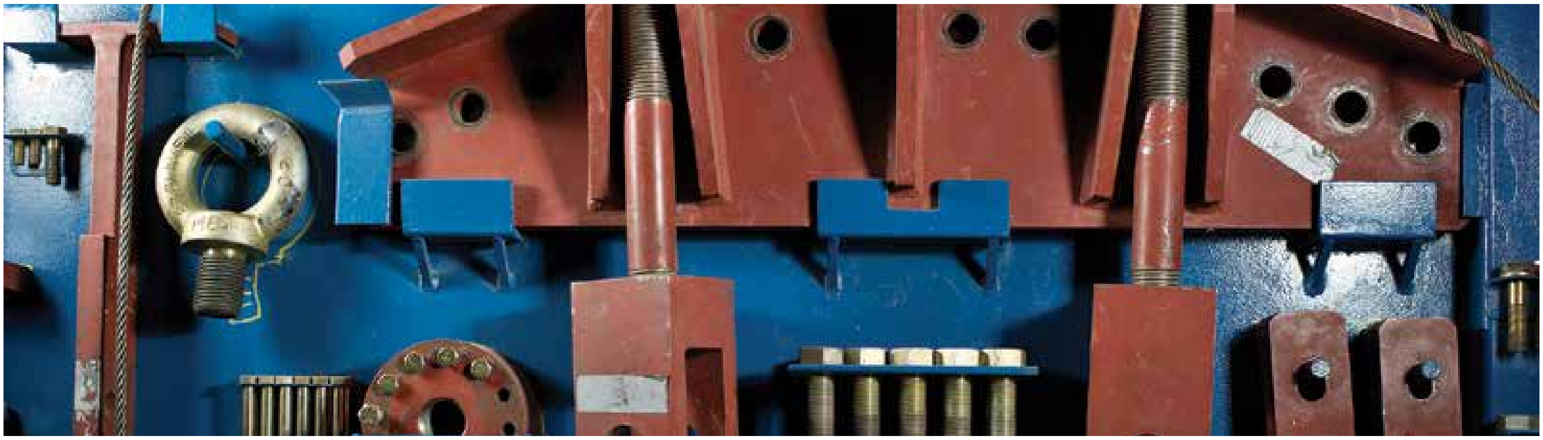
- accelerated our reliability program from 2012, which resulted in substantial 2013 cost reductions and the sale of the U.S. northeast assets.
- structured the joint ownership agreement with ENMAX for the combined-cycle 800 MW[1] natural-gas Shepard Energy Centre (AB) so that 100% of our output is contracted in 2015.
- incorporated a portfolio hedging strategy where we actively trade throughout various time periods to minimize portfolio risks, create incremental value and reduce volatility.

1 Maximum gross capacity of Shepard Energy Centre is 873 MW.

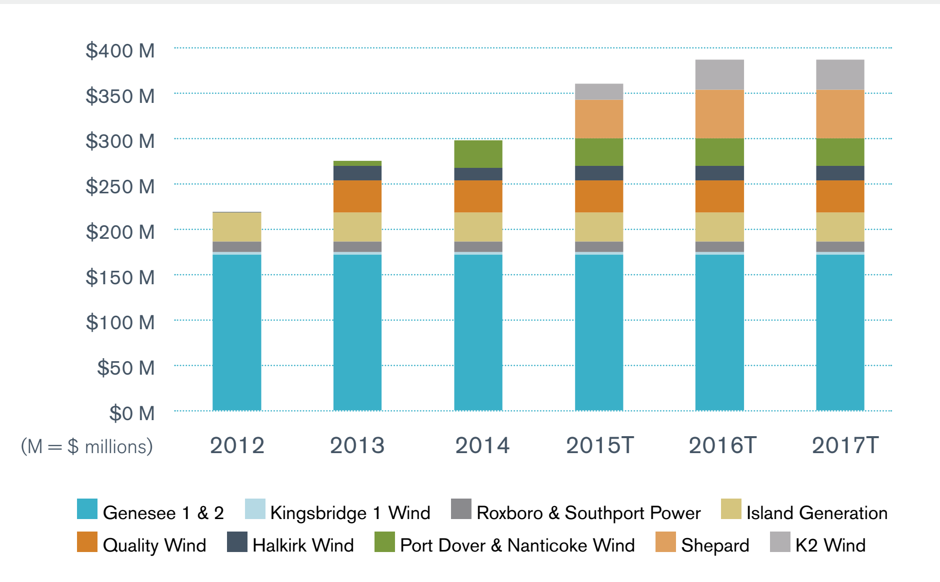
FINANCIAL & OPERATING PERFORMANCE

(unaudited, $ millions, except per share amounts)

	2014	2013	% CHANGE
Revenues	$1,228	$1,393	-12%
Adjusted EBITDA	$423	$509	-17%
Net income	$50	$228	-78%
Normalized earnings per share	$0.72	$1.74	-59%
Funds from operations	$362	$426	-15%
Plant availability average	95%	93%	



STRONG CASH FLOW GENERATION



Margins have been averaged over the periods except in the year of commissioning.
Only includes contracted portions of Halkirk (AB) and Shepard (AB) plants.

Power generation from the K2 Wind (ON) facility[1] and the Shepard Energy Centre[2] (AB) adds to our contracted cash flow in 2015 and 2016. We have methodically built our renewable portfolio and our long-term contracted facilities since 2012. As a result, our long-term contracted operating margin is expected to grow from $225 million in 2012 to $390 million in 2016–a 73% increase in long-term contracted cash flow.

1 Limited partnership with Samsung Renewable Energy Inc. and Pattern Renewable Holdings Canada ULC

2 Joint arrangement with ENMAX

FROM 2012-2016

73%

EXPECTED INCREASE IN CONTRACTED OPERATING MARGIN

Backed by expansion of contracted cash flow to fund growth, we work to create value through continued operational excellence, a commitment to consistent dividend growth, and disciplined execution of our strategy.

- Cash flow is expected to increase 8% in 2015.
- After dividend payments and sustaining capital expenditures, approximately 41% of funds from operations in 2015 are expected to be discretionary cash flow.

7.9%

DIVIDEND INCREASE IN 2014

Our growing contracted cash flow base contributed to the Company's first dividend increase of 7.9% in 2014.

GOVERNANCE

The Board ensures that management's plans and activities are consistent with our values and support our vision to be recognized as one of North America's most respected, reliable and competitive power producers.

Detailed information on the Board's mandate, its committees, Directors' biographies and highlights of the Board and committee work in 2014 can be found in the Management Proxy Circular on our website (www.capitalpower.com) or on SEDAR (www.sedar.com). Our corporate governance policy is also on our website (www.capitalpower.com).

As of December 31, 2014, Capital Power was governed by a Board of 10 directors, eight of whom are independent according to the standards of independence established under Canadian securities laws. Mr. Brian Bentz served as the eleventh member of the Board until his resignation effective September 14, 2014. Mr. Bentz was independent according to the standards of independence established under Canadian securities laws. As of February 17, 2015, Mr. Patrick Daniel was appointed to serve as a director until the end of the next annual meeting of shareholders. Mr. Daniel is independent according to the standards of independence established under Canadian securities laws.

HIGHLIGHTS

- Voting is by individual director; we have a majority voting policy and we disclose the voting results on all items of business within five business days of a shareholder meeting
- We maintain separate Chair and CEO positions so the Board can function independently and monitor management's decisions and actions and effectively oversee our affairs
- The majority of our Board (9 of 11 directors) is independent
- The Chair of the Board and the Chair of the Capital Power nominated directors (Chair of the non-EPCOR elect directors) are independent
- The Board has developed clear position descriptions for the Chair of the Board, chair of the non-EPCOR elect directors, each committee chair and the CEO
- Our Audit committee is 100% independent
- Four of the five members of our Corporate Governance, Compensation and Nominating committee are independent
- Directors must meet share ownership requirements within five years of joining the Board (three times their annual cash and equity retainer in Capital Power deferred share units and/or common shares); Capital Power's executive officers must also meet share ownership requirements
- Our Board has a formal, written mandate
- Directors meet regularly without management present (in-camera)
- We expect 100% attendance of our directors (the Corporate Governance, Compensation and Nominating committee reviews the attendance record to ensure directors have attended at least 80% of Board meetings and their respective committee meetings)
- The Board has adopted a Board Diversity Policy
- The Board has adopted a written code of business conduct and ethics and monitors our compliance with it
- The Board oversees strategic planning risk management, succession planning and leadership development
- We conduct an advisory vote on executive compensation and give shareholders a say on pay
- We adopted an incentive clawback policy and anti-hedging policy, which further aligns the interests of executives and shareholders
- We have orientation and continuing education programs for our directors
- We maintain a skills matrix to assist in planning, developing and managing the skills and competencies of the Board
- Board and committee director self-assessments are conducted every year, with regular individual director and peer review through an anonymous questionnaire and independent consultant interviews every second and third year, respectively

BOARD OF DIRECTORS

FRONT ROW (LEFT TO RIGHT)

Philip Lachambre
Peggy Mulligan
Donald Lowry
Brian Vaasjo
Albrecht Bellstedt
William Bennett

BACK ROW (LEFT TO RIGHT)

Richard Cruickshank
Hugh Bolton
Allister McPherson
Doyle Beneby
Brian Bentz
(resigned September 14, 2014)

2014 BOARD OF DIRECTORS AND COMMITTEE MEMBERSHIP

BOARD OF DIRECTORS[1]	AUDIT GOVERNANCE[2, 3]	CORPORATE GOVERNANCE, COMPENSATION AND NOMINATING COMMITTEE[5]	HEALTH, SAFETY AND ENVIRONMENT COMMITTEE[5]	INDEPENDENT	NOMINATED BY EPCOR
Donald Lowry[4] (Chair)	X	X	X	X	
Albrecht Bellstedt		CHAIR	X	X	
Doyle Beneby	X		CHAIR[6]	X	
William Bennett	CHAIR[7]		X	X	
Hugh Bolton		X		X	X
Richard Cruickshank	X				
Philip Lachambre	X[7]			X	X
Allister McPherson	X			X	X
Peggy Mulligan	X	X		X	
Brian Vaasjo					

1 All members of the Board, except Mr. Cruickshank and Mr. Vaasjo, are independent within the meaning of NI 58-101. Mr. Cruickshank is not considered independent as he is a partner of a law firm that provides legal advice and services to the company. Mr. Vaasjo is not considered independent as he is the President and CEO of the company.

2 Experience of the members of the Audit Committee that indicates an understanding of the accounting principles the company uses to prepare its financial statements is shown within the 'Audit Committee Report' in the Management Proxy Circular.

3 All Audit Committee members are independent and 'financially literate' within the meaning of NI 52-110.

4 As Chair of the Board, Mr. Lowry is an ex-officio, non-voting member of each committee.

5 Mr. Brian Bentz, who resigned from the Board effective September 14, 2014, chaired the Health, Safety & Environment Committee until his resignation and served on the Corporate Governance, Compensation and Nominating Committee until July 25, 2014.

6 Mr. Beneby served on the Health, Safety and Environment Committee throughout 2014 and was appointed chair of that committee on October 24, 2014.

7. Effective February 20, 2015, Mr. Bennett stepped down as Chair of the Audit Committee, and Mr. Lachambre was appointed Chair of the Audit Committee.

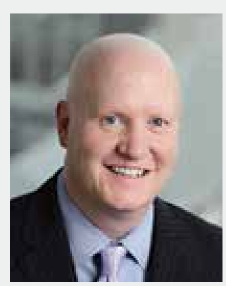
EXECUTIVE TEAM

Brian Vaasjo
PRESIDENT AND CHIEF EXECUTIVE OFFICER

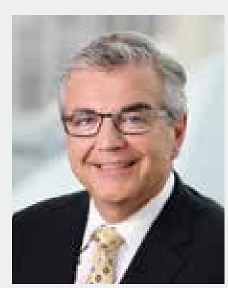
Kate Chisholm
SENIOR VICE PRESIDENT, LEGAL AND EXTERNAL RELATIONS

Bryan DeNeve
SENIOR VICE PRESIDENT, CORPORATE DEVELOPMENT AND COMMERCIAL SERVICES

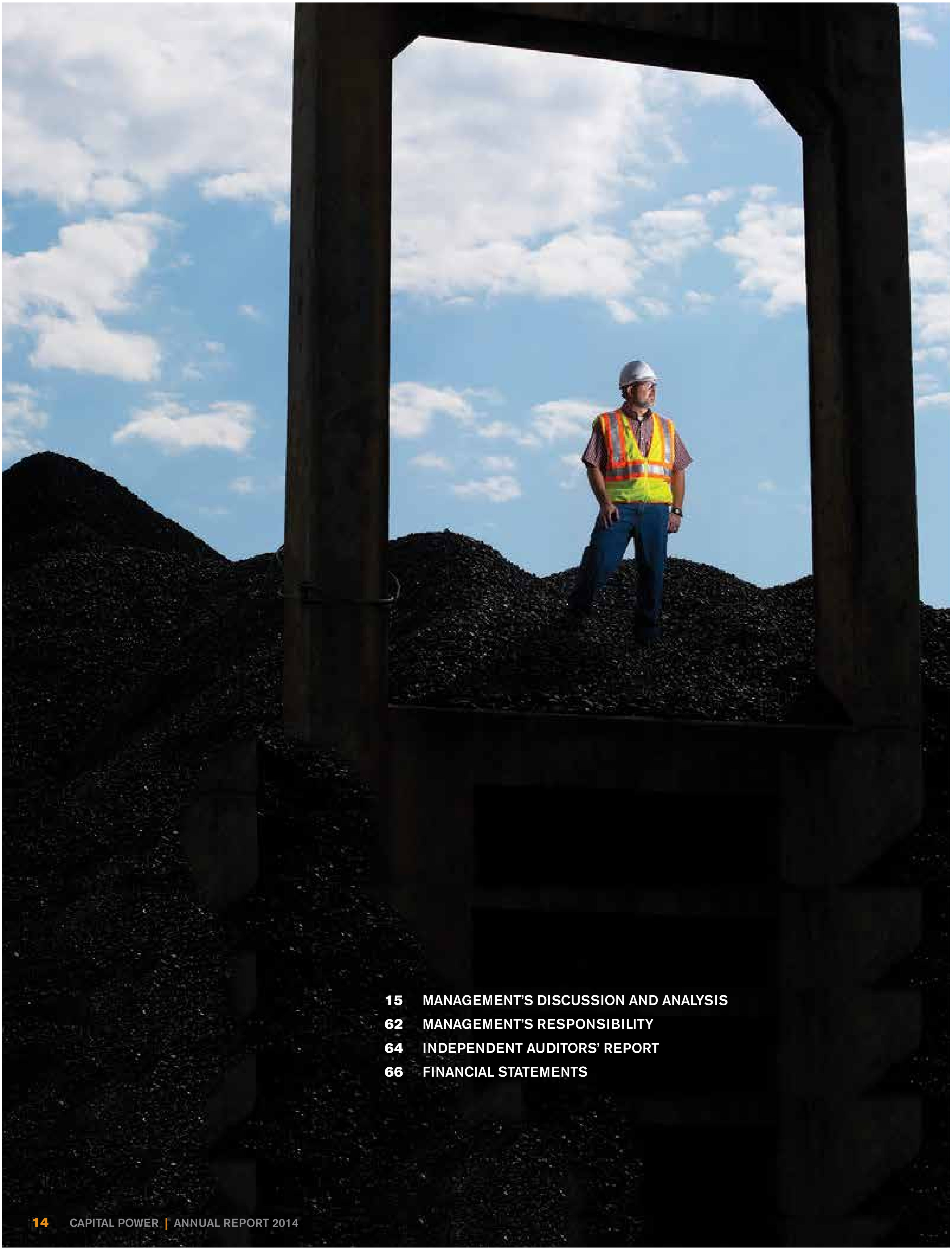
Todd Gilchrist
SENIOR VICE PRESIDENT, HUMAN RESOURCES AND HEALTH, SAFETY AND ENVIRONMENT



Stuart Lee
SENIOR VICE PRESIDENT, FINANCE AND CHIEF FINANCIAL OFFICER



Darcy Trufyn
SENIOR VICE PRESIDENT, OPERATIONS, ENGINEERING AND CONSTRUCTION



Management's Discussion and Analysis

This management's discussion and analysis (MD&A), prepared as of February 20, 2015, should be read in conjunction with the audited consolidated financial statements of Capital Power Corporation and its subsidiaries for the years ended December 31, 2014 and December 31, 2013, the annual information form of Capital Power Corporation for the year ended December 31, 2014 and the cautionary statements regarding forward-looking information which begin on page 16. 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, 2014, 2013 and 2012 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 20, 2015.

Contents

FORWARD-LOOKING INFORMATION

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

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

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

These statements are based on certain assumptions and analyses made by the Company in light of its experience and perception of historical trends, current conditions, expected future developments, and other factors it believes are appropriate. The material factors and assumptions used to develop these forward-looking statements relate to:

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

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

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

See Risks and Risk Management for further discussion of these and other risks.

Readers are cautioned not to place undue reliance on any such forward-looking statements, which speak only as of the date made. The Company does not undertake or accept any obligation or undertaking to release publicly any updates or revisions to any forward-looking statements to reflect any change in the Company's expectations or any change in events, conditions or circumstances on which any such statement is based, except as required by law.

OVERVIEW OF BUSINESS AND CORPORATE STRUCTURE

Capital Power is a growth-oriented North American power producer headquartered in Edmonton, Alberta. The Company develops, acquires, operates and optimizes power generation from a variety of energy sources. Capital Power owns more than 2,700 megawatts (MW) of power generation capacity at 15 facilities across North America and owns 371 MW of capacity through its interest in the acquired Sundance power purchase arrangement (acquired Sundance PPA). An additional 1,020 MW of owned generation capacity is under construction or in advanced stages of development in Alberta and Ontario.

The Company's power generation operations and assets are owned by Capital Power L.P. (CPLP), a subsidiary of the Company. As at December 31, 2014, the Company held 21.750 million general partnership units and 62.112 million common limited partnership units of CPLP which represented approximately 82% of CPLP's total partnership units. EPCOR (in this MD&A, EPCOR refers to EPCOR Utilities Inc. collectively with its subsidiaries) held 18.841 million exchangeable common limited partnership units of CPLP which represented approximately 18% of CPLP. CPLP's exchangeable common limited partnership units are exchangeable for common shares of Capital Power Corporation on a one-for-one basis.

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 business strategy that sets out how to become an increasingly competitive power producer and financial strategy that is 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 fossil fuel fired technologies supplemented by 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.

(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 the year ended December 31, 2014, the Company continued construction, with ENMAX Corporation (ENMAX), of the Shepard Energy Centre, commenced construction of K2 Wind, executed agreements with ENMAX to jointly develop, construct and operate the Genesee 4 and 5 power project (Genesee 4 and 5) and acquired a portfolio of wind and solar development sites in the U.S. (see Significant Events).

The Company is assessing a number of additional projects in various stages of development 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 plant 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. The measurement categories include corporate measures and measures specific to certain groups within the Company. The corporate measures are company-wide and include funds from operations and safety. The group-specific measures include plant operating margin and other operations measures, committed capital, construction and maintenance capital on budget and on schedule, and plant site safety.

Operational excellence

Performance measure	2014 target	2014 actual results
Plant availability average [1]	95% or greater	95%
Capital expenditures for plant maintenance, Genesee mine extension and other (sustaining capital expenditures)	$85 million	$75 million
Plant operating and maintenance expenses	$165 million to $185 million	$185 million

1 All plants excluding acquired Sundance PPA.

In 2014, the Company's plant availability averaged 95% which reflected the second quarter planned outage at Genesee 2 and several unplanned maintenance and forced outages of short-term duration. The most significant unplanned outage was at Genesee 1 which experienced a 10-day maintenance outage in the first quarter to perform valve repairs.

Capital expenditures for maintenance of the plants, Genesee mine extension and other for the year ended December 31, 2014 were less than target primarily due to lower spending on Genesee mine land purchases.

The plant operating and maintenance expenses target includes other raw materials and operating charges, staff costs and employee benefits expense and other administrative expenses for the Company's plants. The actual results for 2014 were consistent with the target range.

Disciplined growth

Performance measure	2014 target	Status as at December 31, 2014
K2 Wind	Commence construction and complete project financing	Construction commenced and project financing completed first quarter 2014 (see Significant Events)
Shepard Energy Centre	Complete construction with commercial operation date in early 2015	On track with target
Genesee 4 and 5	Continue on track for first quarter 2015 permitting approval	Permitting completed ahead of schedule (see Significant Events)

The first fire of the Shepard Energy Centre occurred in September 2014 which was delayed by one month from the previously expected timing. Plant construction is expected to be on time for expected commercial operation to commence in March 2015. The Company's expected capital costs for its share of the plant have increased to $826 million from its previous estimate of $821 million. The increased capital costs are primarily due to lower than expected commissioning revenues because of lower spot power prices and higher than expected capitalized interest because of the revised timing of completion.

Financial stability and strength

Performance measure	2014 target	2014 actual results
Funds from operations [1]	$360 million to $400 million	$362 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, 2014 reflected lower than expected cash flows from plant operations. This was largely due to an extended planned and other unplanned outages at the acquired Sundance PPA units, primarily in July 2014, when power prices for the month averaged $122 per megawatt-hour (MWh) and derates at Keephills 3 during the first half of 2014. In addition, results for the fourth quarter of 2014 were impacted by an unplanned outage at the Clover Bar Energy Centre, lower than expected wind generation from Halkirk and Quality Wind, and additional maintenance expenses. The actual results for the year ended December 31, 2014 include the $20 million arising from the amendment of the Genesee Coal Mine Agreements (see Significant Events) and the $8 million settlement of a claim with a turbine supplier. Capital expenditures for plant maintenance, Genesee mine extension and other (sustaining capital expenditures) were below target which partly offset the impact of the lower funds from operations.

OUTLOOK AND TARGETS FOR 2015

The following discussion should be read in conjunction with the Forward-looking Information section of this MD&A which identifies the material factors and assumptions used to develop forward-looking information and their material associated risk factors.

At its 2014 Investor Day held in December 2014, the Company provided financial guidance for 2015 funds from operations in the range of $365 million to $415 million. This was based on a forecasted 2015 Alberta spot power price average of $44 per MWh which was lower than market forward pricing at the time. Since then, Alberta power forward pricing for 2015 has declined to $35 per MWh. This is due to a combination of events including lower forward natural gas prices for 2015, expected lower economic growth in Alberta and its expected impact on Alberta power demand growth, and market reaction to low fourth quarter 2014 settled prices of $30 per MWh. Lower expected growth in the Alberta economy is largely the result of the significant decline in global oil prices.

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

Shepard Energy Centre and K2 Wind are both expected to commence commercial operations in 2015 and to have a positive impact on earnings and funds from operations. However, this impact will be partly offset by the lower forecast average Alberta power prices which are expected to result in lower realized prices on the economically unhedged portion of the portfolio. As a result, the Company now expects 2015 funds from operations to be at the lower end of its 2015 target range and moderately higher than 2014 funds from operations.

If 2015 Alberta power prices continue trending downward, this impact may be greater than expected and may be amplified by the supply and demand dynamics in the Alberta electricity market should demand decrease as a result of general economic conditions.

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

Portfolio position and contracted prices for 2014 (as at the beginning of the year) compared with 2015, 2016 and 2017 (all as at December 31, 2014) were:

Alberta commercial portfolio positions and power prices	**2014**	**2015**	**2016**	**2017**
Percentage of baseload generation sold forward [1]	100%	97%	48%	22%
Contracted price [2]	Mid-$50 per MWh	Mid-$50 per MWh	Low-$50 per MWh	Mid-$50 per MWh

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

[2] The forecast average contracted prices may differ significantly from the future average realized prices as the hedged and unhedged positions have a varying mix of differently priced blocks of power. This impact is accentuated in 2014 which includes one contract-for-differences for 300 MW for the full year that is sold forward for peak periods only.

The 2015 targets and forecasts are based on numerous assumptions including power and natural gas price forecasts. However, they do not include the effects of potential future acquisitions or development activities, or potential market and operational impacts relating to unplanned plant outages including outages at facilities of other market participants, and the related impacts on market power prices.

See Liquidity and Capital Resources for discussion of future cash requirements and expected sources of funding.

Performance measure targets for 2015

Performance measure	2015 target
Operational excellence	
Plant availability average	94% or greater
Capital expenditures for plant maintenance, Genesee mine extension and other (sustaining capital expenditures)	$65 million
Plant operating and maintenance expenses	$180 million to $200 million
Disciplined growth	
K2 Wind project	Complete construction for commercial operations date in mid-2015
Genesee 4 and 5	Transition from development to construction.
Financial stability and strength	
Funds from operations [1]	$365 million to $415 million

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

As indicated above, actual average Alberta power prices for the early part of 2015 and as reforecast for the remaining part of 2015 are lower than originally expected and may adversely affect results including funds from operations. The Company expects funds from operations will be at the low end of the $365 million to $415 million target range.

NON-GAAP FINANCIAL MEASURES

The Company uses (i) earnings before finance expense, income tax expense, depreciation and amortization, impairments, foreign exchange gains or losses, and gains on disposals (adjusted EBITDA), (ii) funds from operations, (iii) normalized earnings attributable to common shareholders, and (iv) normalized earnings per share as financial performance measures.

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

Adjusted EBITDA

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

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

(unaudited, $ millions)	**Year ended December 31**		**Three months ended**							
	2014	**2013**	**Dec 2014**	**Sep 2014**	**Jun 2014**	**Mar 2014**	**Dec 2013**	**Sep 2013**	**Jun 2013**	**Mar 2013**
Revenues	1,228	1,393	432	248	240	308	327	380	321	365
Energy purchases and fuel, other raw materials and operating charges, staff costs and employee benefits expense, and other administrative expense	(805)	(884)	(291)	(157)	(162)	(195)	(208)	(229)	(217)	(230)
Adjusted EBITDA	**423**	**509**	**141**	**91**	**78**	**113**	**119**	**151**	**104**	**135**
Depreciation and amortization	(189)	(222)	(49)	(47)	(47)	(46)	(52)	(54)	(58)	(58)
Impairments	-	(6)	-	-	-	-	-	(6)	-	-
Foreign exchange (loss) gain	(10)	(6)	(4)	(5)	3	(4)	(5)	(1)	-	-
Gains on disposals of subsidiaries	-	76	-	-	-	-	76	-	-	-
Finance expense	(55)	(78)	(16)	(15)	(11)	(13)	(18)	(18)	(20)	(22)
Income tax expense	(119)	(45)	(24)	(81)	(2)	(12)	(22)	(13)	(3)	(7)
Net income (loss)	**50**	**228**	**48**	**(57)**	**21**	**38**	**98**	**59**	**23**	**48**
Net income (loss) attributable to:										
Non-controlling interests	4	53	9	(12)	1	6	21	15	3	14
Shareholders of the Company	46	175	39	(45)	20	32	77	44	20	34
Net income (loss)	**50**	**228**	**48**	**(57)**	**21**	**38**	**98**	**59**	**23**	**48**

Funds from operations

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

Commencing with the Company's June 30, 2014 quarter-end, the reported funds from operations measure was changed consistent with the reclassification of Part VI.1 tax from operating activities to financing activities in the Company's statement of cash flows. All comparative funds from operations amounts for quarters prior to those ended on June 30, 2014 were revised.

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

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

(unaudited, $ millions)	**Year ended December 31**		**Three months ended December 31**	
	2014	**2013**	**2014**	**2013**
Net cash flows from operating activities per Consolidated Statements of Cash Flows	391	499	107	157
Add (deduct) items included in calculation of net cash flows from operating activities per Consolidated Statements of Cash Flows:				
Interest paid	45	67	16	18
Realized gain on the settlement of interest rate derivatives	(2)	(1)	(1)	(1)
Change in fair value of derivatives reflected as cash settlement	(17)	-	(17)	-
Miscellaneous financing charges paid and included in other items of non-cash adjustments to reconcile net income to net cash flows from operating activities	5	5	-	1
Income taxes recovered	(10)	(12)	(3)	(15)
Change in non-cash operating working capital	(1)	(71)	9	(36)
	20	(12)	4	(33)
Finance expense included in cash flows from operating activities excluding unrealized changes on interest rate derivative contracts and amortization and accretion charges	(48)	(72)	(9)	(15)
Current income tax (expense) recovery	(11)	4	(4)	(9)
Decrease in current income tax expense due to Part VI.1 tax	10	7	4	10
Funds from operations	362	426	102	110

Normalized earnings attributable to common shareholders and normalized earnings per share

The Company uses normalized earnings attributable to common shareholders and normalized earnings per share to measure performance by period on a comparable basis. Normalized earnings per share is based on earnings used in the calculation of earnings per share according to GAAP adjusted for items that are not reflective of performance in the period such as unrealized fair value changes, impairment charges, unusual tax adjustments, gains and losses on disposal of assets or unusual contracts, and foreign exchange gain or loss on the revaluation of U.S. dollar denominated debt. The adjustments 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**							
	2014	**2013**	**Dec 2014**	**Sep 2014**	**Jun 2014**	**Mar 2014**	**Dec 2013**	**Sep 2013**	**Jun 2013**	**Mar 2013**
Basic earnings (loss) per share ($)	**0.28**	**2.13**	**0.40**	**(0.62)**	**0.17**	**0.33**	**0.89**	**0.55**	**0.20**	**0.44**
Net income (loss) attributable to shareholders of the Company per Consolidated Statements of Income	**46**	**175**	**39**	**(45)**	**20**	**32**	**77**	**44**	**20**	**34**
Preferred share dividends	(23)	(20)	(6)	(6)	(6)	(5)	(6)	(5)	(6)	(3)
Earnings (loss) attributable to common shareholders	23	155	33	(51)	14	27	71	39	14	31
Write-down of U.S. deferred tax assets	59	-		59	-	-	-	-	-	-
Unrealized changes in fair value of derivatives	(21)	(13)	(21)	(3)	8	(5)	(9)	(1)	3	(6)
Amount received upon amendment of the Genesee Coal Mine Agreements	(14)	-	-	-	(14)	-	-	-	-	-
Unrealized foreign exchange (gain) loss on revaluation of U.S. dollar denominated debt	9	4	4	5	(3)	3	4	-	-	-
Genesee flood damage repair costs	2	-	-	-	1	1	-	-	-	-
Impact of change in non-controlling interest percentage on adjustments of previous quarters	1	-	1	-	-	-	-	-	-	-
Gain on sale of North East U.S. assets	-	(34)	-	-	-	-	(34)	-	-	-
Restructuring charges	-	7	-	-	-	-	1	4	2	-
Reduction of amount receivable related to Sundance force majeure claim	-	6	-	-	-	-	6	-	-	-
Impairment loss on North East U.S. assets	-	3	-	-	-	-	-	3	-	-
Obligation to EPCOR for Rossdale plant	-	(1)	-	-	-	-	(1)	-	-	-
Income tax expense (recovery) related to change in income tax rate applicable to North East U.S.	-	-	-	-	-	-	(6)	6	-	-
Normalized earnings attributable to common shareholders	**59**	**127**	**17**	**10**	**6**	**26**	**32**	**51**	**19**	**25**
Weighted average number of common shares outstanding (millions)	82.31	72.82	83.31	82.79	81.94	81.18	79.73	70.83	70.48	70.15
Normalized earnings per share ($)	**0.72**	**1.74**	**0.20**	**0.12**	**0.07**	**0.32**	**0.40**	**0.72**	**0.27**	**0.36**

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

FINANCIAL HIGHLIGHTS

(unaudited, $ millions, except per share amounts)	Year ended December 31		
	2014	2013	2012
Revenues	1,228	1,393	1,296
Adjusted EBITDA [1]	423	509	441
Net income	50	228	90
Net income attributable to shareholders of the Company	46	175	62
Normalized earnings attributable to common shareholders [1]	59	127	86
Basic earnings per share ($)	0.28	2.13	0.84
Diluted earnings per share ($) [2]	0.28	2.08	0.84
Normalized earnings per share ($) [1]	0.72	1.74	1.29
Funds from operations [1,3]	362	426	383
Purchase of property, plant and equipment and other assets	220	943	598
Dividends per common share, declared ($)	1.310	1.260	1.260
Dividends per Series 1 preferred share, declared ($)	1.150	1.150	1.150
Dividends per Series 3 preferred share, declared ($)	1.150	1.178	N/A
Dividends per Series 5 preferred share, declared ($)	1.125	0.895	N/A

	As at December 31		
	2014	2013	2012
Loans and borrowings including current portion	1,586	1,527	1,659
Total assets	5,420	5,219	5,134

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

[2] Diluted earnings per share was calculated after giving effect to outstanding share purchase options and the potential exchange of common limited partnership units of CPLP held by EPCOR which are exchangeable for common shares of Capital Power on a one-for-one basis.

[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 statement of cash flows. All comparative funds from operations amounts for 2013 and 2012 were revised.

Normalized earnings attributable to common shareholders and normalized earnings per share

Normalized earnings attributable to common shareholders were significantly lower in 2014 compared with 2013. See Consolidated Net Income and Results of Operations for discussion of the results for the quarter and year-to-date on a comparative basis. This decrease coupled with the increased number of common shares outstanding resulted in a decrease in normalized earnings per share from 2013 to 2014.

Funds from operations

Funds from operations for 2014 decreased in comparison to funds from operations for 2013 consistent with the lower adjusted EBITDA.

SIGNIFICANT EVENTS

Genesee 4 and 5

On April 24, 2014, Capital Power and ENMAX executed a purchase and sale agreement in support of a joint arrangement agreement to jointly develop, construct and operate Genesee 4 and 5. The joint arrangement agreement provides for, among other things, an agreement for ENMAX to purchase approximately 250 MW from Capital Power for eight years. The joint arrangement agreement closing occurred in July 2014.

On January 8, 2015, Capital Power and ENMAX announced that the project received all major regulatory approvals from the Alberta Utilities Commission and Alberta Environment and Sustainable Resource Development. They also announced the execution of agreements with Mitsubishi Hitachi Power Systems for the supply and maintenance of the world's most advanced J-Class natural gas turbine technology in commercial operation with a targeted completion date as early as 2018.

The capital cost for the project, excluding interest to fund construction and refundable transmission system contribution payments, is expected to be approximately $1.4 billion.

Acquisition of renewable development sites

On December 19, 2014, Capital Power acquired Element Power U.S., LLC (Element Power) for $18 million (US$15 million) net of cash acquired. The purchase also provides for contingent consideration of $12 million (US$10 million) which is payable upon reaching specified milestones in connection with the development sites acquired. Element Power provides Capital Power with a portfolio of wind and solar energy development sites in the United States. The development sites consist of 10 wind sites and 4 solar sites including a North Carolina site with a 15 MW solar contract with Duke Energy Progress, Inc. The acquisition also includes Macho Springs, a 50 MW wind project in New Mexico that has been operating since 2011 under a 20-year power purchase arrangement with Tucson Electric Power. The Federal Energy Regulatory Commission approved the transfer of Macho Springs on December 16, 2014.

Write-down of deferred tax assets

Capital Power's 2014 net income was negatively impacted by a non-cash write-down of deferred tax assets of $73 million in the third quarter. The write-down related to the accounting impact of U.S. income tax loss carryforwards that can no longer be recognized for accounting purposes based on the Company's current long-term forecast for U.S. taxable income. The forecast showed a decline in taxable income over the latter years of the forecast period. For income tax purposes, these U.S. net operating losses do not expire until the 2027 to 2033 period. Accordingly, they retain economic value and could result in the Company recording deferred tax assets in the future. The Company continues to pursue U.S. contracted power opportunities and the U.S. business development pipeline is active. Importantly, the write-down is a non-cash item and had no impact on operations or other key performance measures.

Dividend increase

On July 25, 2014, the Company announced that its Board of Directors approved a 7.9% increase in the annual dividend for holders of its common shares, from $1.26 per common share to $1.36 per common share. This increased common dividend commenced with the third quarter 2014 quarterly dividend payment paid on October 31, 2014 to shareholders of record at the close of business on September 30, 2014.

Genesee coal mine

Capital Power is a party to various agreements with Prairie Mines & Minerals Royalty Ltd. (PMRL) in relation to the operations of the Genesee coal mine (Genesee Coal Mine Agreements). Pursuant to the Genesee Coal Mine Agreements, PMRL operates the Genesee coal mine. In connection with the 2014 acquisition by Westmoreland Coal Company (Westmoreland) of PMRL and the 2014 acquisition by Altius Minerals Corporation (Altius) of the royalty assets of PMRL, the Genesee Coal Mine Agreements and certain related agreements were, among other things, amended to: (a) confirm the acquisitions by Westmoreland and Altius; (b) provide for certain amendments to the Genesee Coal Mine Agreements; and (c) provide for a payment to Capital Power of $20 million upon completion of the acquisitions; the payment was received in the second quarter of 2014.

Construction of K2 Wind Power Project commences

On March 24, 2014, construction of the K2 Wind Power Project (K2 Wind) commenced following the successful completion of an $850 million financing in the form of a construction loan that will convert to long-term project debt once K2 Wind starts commercial operations. K2 Wind is a 270 MW wind power project located in Goderich, Ontario that is under joint development by Samsung Renewable Energy, Inc., Pattern Energy Group LP and Capital Power with operations expected to commence in the second half of 2015. The total estimated project cost has been revised upward to $930 million from the previous upper end of range of $900 million primarily due to foreign exchange changes on U.S. contract deliverables. Capital Power's share is $310 million. As a higher portion of the project is expected to be financed with project debt than originally forecast, Capital Power expects higher equity returns on the project.

PLANTS AND PORTFOLIO OPTIMIZATION OPERATIONS

Plant category and plant	Type of generating plant	Year commissioned	Capacity (MW) Plant	Capacity (MW) Capital Power interest	Revenues based on	Contract expiry
Alberta commercial plants and acquired Sundance PPA						
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)	-
Halkirk	Wind turbine	2012	150	150	Merchant with Renewable Energy Credits (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	-
Acquired Sundance PPA	Coal-fired steam turbine	1978 (Unit 5) 1980 (Unit 6)	710	371	Merchant (plant capacity and output purchased under Alberta PPA)	2020
Alberta contracted plants						
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 plants						
Island Generation	Natural gas-fired combined cycle	2002	275	275	PPA with B.C. Hydro	2022
Kingsbridge 1	Wind turbine	2001 and 2006	40	40	Energy supply contracts with Ontario Power Authority	2027
Port Dover and Nanticoke	Wind turbine	2013	105	105	Energy supply contract with Ontario Power Authority	2033
Quality Wind	Wind turbine	2012	142	142	Electricity purchase agreement with B.C. Hydro	2036
U.S. contracted plants						
Roxboro, North Carolina	Solid fuels (wood residuals, tire-derived and coal)	1987	46	46	PPA with Duke Progress Energy	2021
Southport, North Carolina	Solid fuels (wood residuals, tire-derived and coal)	1987	88	88	PPA with Duke Progress Energy	2021
Macho Springs, New Mexico	Wind turbine	2011	50	50	PPA with Tucson Electric Power	2031
U.S. commercial plants (until 2013 fourth quarter disposal)						
Bridgeport, Connecticut	Natural gas-fired combined cycle	1999	540	540	Merchant	-
Rumford, Maine	Natural gas-fired combined cycle	2000	270	270	Merchant	-
Tiverton, Rhode Island	Natural gas-fired combined cycle	2000	279	279	Merchant	-

Plant category and plant	Type of generating plant	Year commissioned	Capacity (MW) Plant	Capacity (MW) Capital Power interest	Revenues based on	Contract expiry
Under construction or in advanced development						
Shepard Energy Centre	Natural gas-fired combined cycle	Expected 2015	800	400	Merchant with tolling agreement for 50% of owned capacity plus additional 25% contracted for 2015 to 2017	2035 (tolling agreement)
K2 Wind	Wind turbine	Expected 2015	270	90	PPA with Ontario Power Authority	2035
Genesee 4 and 5	Natural gas-fired combined cycle	As early as 2018	1,060	530	Merchant with approximately 250 MW contracted to ENMAX for initial term of 8 years	To be determined

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 plants, contracted plants with residual commodity exposure and acquired PPAs 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 plant 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 the year ended December 31, 2014 compared with the year ended December 31, 2013 are presented below followed by further discussion of these items.

(unaudited, $ millions)		
Consolidated net income for the year ended December 31, 2013		**228**
Increase (decrease) in adjusted EBITDA:		
Alberta commercial plants and portfolio optimization	(141)	
Alberta contracted plants	2	
Ontario and British Columbia contracted plants	25	
U.S. contracted plants	2	
U.S. commercial plants and portfolio optimization	(21)	
Corporate	37	
Change in unrealized net gains or losses related to the fair value of commodity derivatives and emission credits	10	(86)
Decrease in depreciation and amortization expense		33
Decrease in impairment expense		6
Increase in foreign exchange loss		(4)
Decrease in gain on disposal of subsidiaries		(76)
Decrease in finance expense including change in unrealized net gains or losses related to the fair value of interest rate derivatives		23
Decrease in income before tax		(104)
Increase in income tax expense		(74)
Decrease in net income		**(178)**
Consolidated net income for the year ended December 31, 2014		**50**

Results by Plant Category and Other

	Year ended December 31							
	2014	2013	2014	2013	2014	2013	2014	2013
	Electricity generation (GWh) [1]		Plant availability (%) [2]		Revenues (unaudited, $ millions)		Adjusted EBITDA (unaudited, $ millions) [3]	
Total electricity generation, average plant availability and plant revenues excluding acquired Sundance PPA	12,376	16,130	95	93	753	1,110		
Alberta commercial plants and acquired Sundance PPA								
Genesee 3	1,746	1,917	91	99	86	147		
Keephills 3	1,674	1,654	98	91	80	132		
Clover Bar Energy Centre 1, 2 and 3	296	347	95	96	44	85		
Joffre	324	414	93	92	39	66		
Halkirk	462	466	96	96	36	47		
Clover Bar Landfill Gas	14	16	78	88	-	2		
Alberta commercial plants – owned	4,516	4,814	94	95	285	479		
Acquired Sundance PPA	2,763	2,772	84	90	112	208		
Portfolio optimization [4]	N/A	N/A	N/A	N/A	229	55		
	7,279	7,586	90	93	626	742	211	352
Alberta contracted plants								
Genesee 1	3,160	2,950	95	89				
Genesee 2	3,075	3,134	91	94				
	6,235	6,084	93	91	266	246	161	159
Ontario and British Columbia contracted plants								
Island Generation	130	224	100	100	38	39		
Kingsbridge 1	105	108	95	96	7	7		
Port Dover and Nanticoke [5]	301	54	97	95	37	7		
Quality Wind	349	377	96	98	37	39		
	885	763	98	99	119	92	92	67
U.S. contracted plants								
Roxboro, North Carolina	244	249	97	94	24	23		
Southport, North Carolina	491	436	91	96	59	48		
Macho Springs, New Mexico [x]	5	N/A	99	N/A	-	N/A		
	740	685	93	95	83	71	7	5
U.S. commercial plants [6]								
Bridgeport, Connecticut	N/A	2,607	N/A	88	N/A	148		
Rumford, Maine	N/A	124	N/A	91	N/A	18		
Tiverton, Rhode Island	N/A	1,053	N/A	81	N/A	56		
Portfolio optimization	N/A	N/A	N/A	N/A	N/A	5		
	N/A	3,784	N/A	87	N/A	227	N/A	21
Corporate [7]					13	(13)	(84)	(121)
Unrealized changes in fair value of commodity derivatives and emission credits					121	28	36	26
Consolidated revenues and adjusted EBITDA					**1,228**	**1,393**	**423**	**509**

1 Electricity generation reflects the Company's share of plant output.

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

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

[4] The results of the previously reported other portfolio activities category were included in the Alberta commercial plants and acquired Sundance PPA category effective January 1, 2014. The results for the comparative 2013 year were reclassified.

[5] Port Dover and Nanticoke includes pre-commissioning output until its commissioning date of November 7, 2013. Revenues and expenses related to commissioning activities were capitalized as part of the cost of the facility in property, plant and equipment.

[6] The U.S. commercial plants were disposed of effective November 19, 2013.

[7] Corporate revenues were offset by interplant category eliminations.

Energy prices and hedged positions

		Year ended December 31	
Alberta	**Unit**	**2014**	**2013**
Hedged position [1]	Percentage sold forward at beginning of year (%)	100	45
Spot power price average	$ per MWh	49	80
Realized power price [2]	$ per MWh	58	78
Natural gas price (AECO) [3]	$ per gigajoule (Gj)	4.49	3.01

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

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

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

Alberta commercial plants, acquired Sundance PPA and portfolio optimization

Production decreased 307 GWh for 2014 compared with 2013 primarily due to lower production at Genesee 3 as a result of a planned outage that occurred in October 2014 and unplanned outages earlier in the year. In addition, the Clover Bar Energy Centre was not dispatched as often in 2014 and completed a one-month unplanned outage. Joffre completed planned outages and experienced lower production due to weaker prices. These decreases were partly offset by increased production at Keephills 3 primarily due to the planned turnaround in 2013. Overall availability for 2014 was 90% compared with 93% for 2013. This was primarily due to unplanned outages at the Sundance PPA units since the facility had on-going boiler leak repairs during the year.

The average Alberta spot power price of $49 per MWh for 2014 was significantly lower than the 2013 average spot power price of $80 per MWh. In 2014, Alberta spot prices reflected fewer unplanned outages, the return to market of two large coal units in the last quarter of 2013, stronger wind production, and greater imports. The significantly higher market prices in 2013 were driven by high volatility reflecting tighter supply due to several planned and unplanned outages in the Alberta market, lower imports, and lower than historical wind generation.

Lower revenues and adjusted EBITDA for 2014 compared with 2013 primarily reflected the weaker average spot prices and lower production. This was partly offset by forward sales that settled in the money. In addition, 2014 financial results for the Alberta commercial plants were significantly lower than 2013 primarily due to an extended planned outage and other unplanned outages at the acquired Sundance PPA units and derates at the Keephills 3 plant. The outages occurred primarily in July 2014 coinciding with high pricing volatility.

Lower adjusted EBITDA for 2014 also reflected the write-down of the investment in an emissions credit project of $5 million and net losses on North East U.S. natural gas and electricity trades that were wound down due to the 2013 strategic refocus. These were partly offset by decreased coal costs due to the reallocation of coal costs between Genesee 1 and 2 and Genesee 3, gains on Alberta natural gas trades, and a settlement of $8 million with a supplier relating to the 2008 Genesee 3 turbine failure.

Early in 2014, the Company elected to meet its 2013 Specified Gas Emitters Regulation (SGER) compliance requirements by paying the statutory rate of $15 per metric tonne of carbon dioxide (CO2) emissions above specified limits compared with using its lower cost inventory of CO2 credits. The decision resulted in an additional cash payment of $4 million for 2014.

Alberta contracted plants

Production and availability increased in 2014 compared with 2013 primarily due to the decreased duration of planned and unplanned outages. Genesee 2 was offline in 2014 for a planned outage of 25 days while Genesee 1 underwent a planned outage of 27 days in 2013.

Both revenues and adjusted EBITDA for 2014 increased compared to 2013 which reflected the lower availability penalties under the plants' PPA resulting from the decreased duration of outages and significantly lower rolling average prices in 2014 compared with 2013. These improved results were partly offset by increased coal costs due to the reallocation of coal costs between Genesee 1 and 2 and Genesee 3 and costs of $3 million incurred for flood damage repairs to the Genesee river water pumphouse and related infrastructure.

Ontario and British Columbia contracted plants

Production in 2014 increased compared with 2013 primarily due to the full year's operation of the Port Dover and Nanticoke wind farm which commenced operations in November 2013. This was partly offset by Island Generation's lower production since the plant was not dispatched as often in 2014 compared with 2013. Overall availability for 2014 was consistent with 2013.

Increased revenues and adjusted EBITDA primarily reflected a full year of operations of Port Dover and Nanticoke in 2014 compared with two months of operations in 2013.

The lower generation from Island Generation in 2014 compared with 2013 had little impact on revenues and adjusted EBITDA because, under the terms of the Island Generation agreement, revenues are based on deemed generation which is determined based on the plant's availability. Deemed generation for 2014 was consistent with 2013.

U.S. contracted plants

Production increased in 2014 compared with 2013 as the result of Southport's increased off-peak production. However, Southport's availability was lower in 2014 primarily due to a higher number of planned outage days than 2013.

Revenues for 2014 increased compared with 2013 due to the favourable impact of the decrease in the exchange rate of the Canadian dollar relative to the U.S. dollar, Southport's increased off-peak production and the increased sales of off-peak renewable energy certificates (RECs). Adjusted EBITDA for 2014 increased compared with 2013 primarily due to the increased production and sales of off-peak RECs partly offset by increased fuel costs related to the increased production.

The acquisition of Macho Springs wind farm in December 2014 did not materially impact 2014 results.

U.S. commercial plants and portfolio optimization

The U.S. commercial plants, all located in the North East, were sold effective November 19, 2013.

Corporate

Corporate includes (i) revenues for cost recoveries, (ii) the cost of support services such as treasury, finance, internal audit, legal, human resources, corporate risk management, asset management, and environment, health and safety, and (iii) business development expenses. The cost recovery revenues are primarily intercompany revenues which are offset by interplant category transactions.

The Corporate category's increased adjusted EBITDA for the year ended December 31, 2014 compared with the previous year was primarily due to lower staffing levels following the restructuring undertaken in the latter part of 2013. In addition, revenues and adjusted EBITDA for 2014 included the $20 million of revenues arising from the amendment of the Genesee Coal Mine Agreements (see Significant Events).

Unrealized changes in fair value of commodity derivatives and emission credits

(unaudited, $ millions)	Year ended December 31			
Unrealized changes in fair value of commodity derivatives and emission credits	**2014**	**2013**	**2014**	**2013**
	Revenues		**Adjusted EBITDA**	
Unrealized gains on Alberta energy derivatives	112	6	26	4
Unrealized gains on Bridgeport heat rate option	-	18	-	18
Unrealized (losses) gains on natural gas derivatives	(1)	6	(1)	4
Unrealized gains on emission credits held for trading	-	-	2	-
Unrealized gains on emission portfolio activities	8	-	8	-
Other	2	(2)	1	-
	121	**28**	**36**	**26**

[1] The financial results, except for adjusted EBITDA, were prepared in accordance with GAAP. See Non-GAAP Financial Measures.

The Company's financial results relating to its Alberta commercial plants and portfolio optimization, and U.S. commercial plants and portfolio optimization (until their disposal in the fourth quarter of 2013) include unrealized changes in the fair value of commodity and other derivatives.

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

Alberta portfolio activities for the year ended December 31, 2014 accounted for unrealized net gains of $26 million compared with unrealized net gains of $4 million for the year ended December 31, 2013. The net gains for both years primarily reflected the impact of decreasing Alberta forward power prices combined with the portfolio's net forward sales contracts. The net unrealized gains for the year ended December 31, 2013 were partly offset by the reversal of unrealized net gains on contracts, previously recorded in 2012, that settled during 2013.

On acquisition of the New England plants in the second quarter of 2011, the Company acquired heat rate options related to the Bridgeport facility. For the year ended December 31, 2013, the Company recognized unrealized net gains of $18 million primarily due to the reversal of prior year's unrealized net losses.

Natural gas portfolio activities for the year ended December 31, 2014 accounted for unrealized net losses of $1 million. These net losses primarily reflected the reversal of prior year's unrealized net gains on contracts that settled during the year. Unrealized net gains of $4 million were recognized for the year ended December 31, 2013 and primarily reflected the reversal of prior year's unrealized net losses on contracts that settled during 2013.

During the year ended December 31, 2014, the Company recognized unrealized net gains of $2 million on its emission credits held for trading. The unrealized net gains reflected the impact of valuing inventory at market prices higher than the initial cost.

Emission portfolio activities for the year ended December 31, 2014 accounted for unrealized net gains of $8 million. The unrealized net gains were primarily driven by net forward sales contracts priced at values in excess of forward prices.

Consolidated Other Expenses and Non-controlling Interests

(unaudited, $ millions)	Year ended December 31	
	2014	**2013**
Interest on borrowings less capitalized interest	(45)	(68)
Realized gain on settlement of interest rate derivatives	2	1
Other finance expense – sundry interest and guarantee and other fees	(5)	(5)
	(48)	(72)
Unrealized loss representing changes in the fair value of interest rate derivatives	-	(1)
Other finance expense - amortization and accretion charges	(5)	(5)
Other finance expense – finance charges incurred on repurchase of debt	(2)	-
Total finance expense	(55)	(78)
Depreciation and amortization	(189)	(222)
Impairments	-	(6)
Foreign exchange loss	(10)	(6)
Gain on disposal of subsidiaries	-	76
Income tax expense	(119)	(45)
Net (income) attributable to non-controlling interests	(4)	(53)

Finance expense

Lower finance expense for the year ended December 31, 2014 compared with the year ended December 31, 2013 was primarily due to decreased borrowings related to capital projects and increased capitalized interest.

Depreciation and amortization

Depreciation and amortization for the year ended December 31, 2014 decreased $33 million compared with the prior year primarily due to the disposal of the North East U.S. commercial assets in the fourth quarter of 2013.

Impairments

An asset impairment charge of $6 million related to the North East U.S. commercial assets was recognized in the third quarter of 2013 immediately before classifying those assets as held for sale and in advance of the final disposal of the U.S. subsidiaries.

Foreign exchange loss

As at December 31, 2014, the Company had outstanding U.S. dollar denominated debt payable totalling US$295 million. Approximately US$200 million is hedged for accounting purposes using foreign currency swaps. Foreign exchange loss consisted of the loss incurred on the revaluation of U.S. dollar denominated debt not hedged for accounting purposes. For the year ended December 31, 2014, the exchange rate of the Canadian dollar relative to the U.S. dollar decreased resulting in an unrealized loss of $10 million.

Gain on disposal of subsidiaries

In 2013, the Company recognized a pre-tax gain of $76 million on the sale of its North East U.S. commercial assets primarily consisting of foreign exchange gains which were recognized in other comprehensive income and deferred in accumulated other comprehensive income from the date of acquisition of these U.S. subsidiaries in 2011 until their disposal in the third quarter of 2013.

Income tax expense

In the third quarter of 2014, Capital Power recorded a write-down of its deferred tax assets in the amount of $73 million. This non-cash write-down related to the impact of U.S. income tax loss carryforwards that can no longer be recognized for accounting purposes based on the Company's latest long-term forecast for U.S. taxable income. These loss carryforwards expire between 2027 and 2033. Thus, the loss carryfowards retain economic value that could result in the future recording of deferred tax assets depending on future U.S. taxable income projections.

Non-controlling interests

For the year ended December 31, 2014, approximately 19% (year ended December 31, 2013 - 27%) of CPLP's net income was attributable to EPCOR which is reported as net income attributable to non-controlling interests. In 2014, EPCOR's interest was reduced to 18% from 19% following the issuance of common limited partnership units to Capital Power as settlement of certain indebtedness between Capital Power and CPLP. EPCOR's October 10, 2013 exchange of exchangeable common limited partnership units and subsequent sale of common shares of Capital Power reduced its interest in CPLP from 29% to 19% which reduced the proportion of net income attributable to non-controlling interests in periods subsequent to the exchange. Net income attributable to non-controlling interests also included the Genesee Coal Mine Assets (Coal Mine) partner's share of the consolidated net income of the Coal Mine.

COMPREHENSIVE INCOME

(unaudited, $ millions)	Year ended December 31	
	2014	2013
Net income	50	228
Other comprehensive income (loss):		
Net unrealized gains (losses) on commodity derivatives designated as cash flow hedges	44	(35)
Net realized (gains) losses and ineffective portion of unrealized losses on commodity derivatives designated as cash flow hedges reclassified to revenues and/or energy purchases and fuel	(18)	27
Unrealized foreign exchange gains on the translation of foreign operations	16	23
Foreign exchange gains realized in net income on disposal of foreign subsidiaries	-	(59)
Actuarial (losses) gains related to the company's defined benefit pension plan	(2)	2
	40	(42)
Comprehensive income	**90**	**186**

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 gains or losses are subsequently recognized in net income when the hedged transactions are completed and the foreign operations are disposed of or otherwise terminated. The actuarial gains or losses will not be subsequently recognized in net income.

FINANCIAL POSITION

(unaudited, $ millions)	As at December 31		Increase (decrease) due to		
	2014	2013	Acquisition of Element Power	Other	Primary other changes
Trade and other receivables	185	218	-	(33)	Lower trade receivables related to Alberta operations resulting from lower power prices and receipt of Sundance amount receivable.
Inventories	104	92	-	12	Increased coal fuel inventory and emission credits held for trading.
Net derivative financial instruments assets	113	26	-	87	Impact of decreased Alberta forward power prices on the fair value of forward sales contracts.
Intangible assets	350	310	36	4	Purchase of emission credits held for compliance.
Property, plant and equipment	3,701	3,525	103	73	Capital additions (most significantly, Shepard Energy Centre) partly offset by depreciation and amortization.
Trade and other payables	185	198	-	(13)	Decreased capital trade payables related to Port Dover and Nanticoke and decreased income tax payable.
Loans and borrowings (including current portion)	1,586	1,527	76	(17)	Repayment of loans and borrowings partly offset by foreign exchange increases on U.S. debt and increase in U.S. bank loans outstanding.
Provisions (including current portion)	220	175	3	42	Increased decommissioning provisions resulting from discount rate changes.
Net deferred tax liabilities	228	85	29	114	Write-down of deferred tax assets (see Significant Events), accelerated depreciation for income tax purposes on property, plant and equipment related to wind projects, and changes in derivative financial instruments balances.
Share capital	2,391	2,328	-	63	Shares issued under the Dividend Re-investment Plan and share purchase option plan.
Retained earnings	25	83	-	(58)	Common and preferred share dividends in excess of net income partly offset by the transfer between retained earnings and non-controlling interests due to the issuance of CPLP partnership units to Capital Power to settle certain indebtedness
Other reserves	35	6	-	29	Unrealized gains on cash flow hedges and investment in foreign operations included in other comprehensive income.
Non-controlling interests	552	587	-	(35)	Transfer between non-controlling interests and retained earnings due to the issuance of CPLP partnership units to Capital Power to settle certain indebtedness.

LIQUIDITY AND CAPITAL RESOURCES

(unaudited, $ millions)	Year ended December 31		
Cash inflows (outflows)	2014	2013	Increase (decrease)
Operating activities	391	499	(108)
Investing activities	(230)	(348)	118
Financing activities	(191)	(103)	(88)

Operating activities

Cash flows from operating activities for 2014 decreased compared with 2013 primarily due to decreased plant adjusted EBITDA and lower contributions from operating working capital.

Investing activities

Cash flows used in investing activities for the year ended December 31, 2014 were significantly lower than for the year ended December 31, 2013. The primary reason for the decline was that capital spending on the Shepard Energy Centre was much higher in 2013 and there were no new major growth capital projects in 2014. The year-over-year changes in cash flows used in investing activities also reflected a decrease in proceeds on disposal of assets since the North East U.S. assets were sold in 2013. The cash flows used in investing activities for the year ended December 31, 2014 included $220 million for purchases of property, plant and equipment and other assets and $18 million for the Element Power business acquisition.

Capital expenditures and investments

(unaudited, $ millions)	Pre-2013 Actual	Year ended December 31 2013 Actual	2014 Actual	2015 Estimated [1, 2]	Actual or Projected Total [2, 3]	Timing
Port Dover and Nanticoke	68	208	11	1	288	Completed 4th quarter 2013
K2 Wind [4]	3	13	28	1	310	Projected completion 2015
Shepard Energy Centre	50	634	127	15	826	Projected commercial operation 2015
Genesee 4 and 5 [5]	-	-	2	15	700	Targeted completion date as early as 2018
Other	-	3	-	-	-	
Subtotal growth projects		**858**	**168**			
Sustaining – plant maintenance excluding Genesee mine		58	54			
Sustaining – Genesee mine maintenance and lands [6]		16	8			
Sustaining – other		5	13			
Total capital expenditures [7]		**937**	**243**			
Emission credits held for compliance		27	16			
Capitalized interest		(21)	(39)			
Purchase of property, plant and equipment and other assets		**943**	**220**			
Business acquisition, net of acquired cash		**-**	**18**			

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

2 Costs for the Port Dover and Nanticoke project completed in 2013 include certain costs that were incurred subsequent to the date of commercial operations such as site remediation, vendor optimization, project clean-up and project close-out costs.

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

4 Capital Power entered into a limited partnership agreement to develop K2 Wind which is expected to be in operation by 2015. The actual 2014 expenditures for K2 Wind primarily consist of the Company's estimated equity contribution to the K2 Wind partnership. The projected total of $310 million is Capital Power's share of the K2 Wind partnership's expected capital expenditures including both debt and equity financed components.

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

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

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

Financing activities

The cash flows used in financing activities for the year ended December 31, 2014 primarily reflected the sum of distributions to non-controlling interests, common share dividends, and preferred share dividends paid of $115 million (2013 - $118 million), repayment of loans and borrowings of $65 million (2013 - $155 million) and interest paid that was capitalized of $39 million (2013 - $21 million). Unlike 2013, there were no requirements for external financing in the form of debt or equity in 2014.

The Company's credit facilities consisted of:

(unaudited, $ millions)		As at December 31, 2014			As at December 31, 2013		
	Maturity timing	**Total facilities**	**Credit facility utilization**	**Available**	**Total facilities**	**Credit facility utilization**	**Available**
CPLP committed credit facility	2018	1,200			1,200		
Letters of credit outstanding			122			160	
U.S. dollar bank loans outstanding			17			-	
		1,200	139	1,061	1,200	160	1,040
CPLP demand facility	N/A	20	-	20	20	-	20
Capital Power Corporation demand facility	N/A	5	-	5	5	-	5
		1,225	**139**	**1,086**	**1,225**	**160**	**1,065**

As at December 31, 2014, the committed credit facility utilization decreased $21 million compared with the utilization as at December 31, 2013 primarily due to decreased letters of credit outstanding. The committed credit facility includes an accordion feature that permits an increase to the facility size by $300 million in the future, subject to certain conditions including lender approval. The maturity date of CPLP's credit agreements is July 9, 2018.

The available credit facilities provide the Company with adequate funding for ongoing development projects.

CPLP has a corporate credit rating of BBB- with a stable outlook from Standard & Poor's (S&P). According to S&P, a BBB- corporate credit rating exhibits adequate capacity to meet financial commitments. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitments.

CPLP has a long-term debt credit rating of BBB from DBRS Limited (DBRS). The BBB rating assigned by DBRS is the fourth highest rating of DBRS' ten rating categories for long-term debt obligations. According to DBRS, long-term debt rated BBB is of adequate credit quality. The capacity of the payment of financial obligations is considered acceptable but the entity is vulnerable to future events.

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

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

Financial covenant	**Required at the end of each fiscal quarter**	**Actual as at December 31, 2014**
Senior debt to consolidated capitalization ratio [1]	Not more than 0.65 to 1.0	0.36
Consolidated EBITDA to consolidated interest expense [1, 2]	Not less than 2.5 to 1.0	3.2

[1] As defined in the relevant agreements.

[2] Only in the event that CPLP 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 2015 include:

- $249 million for medium-term note settlement and/or repayment,
- $102 million for capital expenditures excluding capitalized interest and emission credits held for compliance,
- $26 million for CPLP distributions to EPCOR (subject to approval by the Board of Directors of CPLP's general partner), and
- $116 million for common share dividends and $22 million for preferred share dividends (subject to approval by Capital Power Corporation's Board of Directors).

Capital Power Corporation has a Dividend Re-investment Plan (DRIP) where shareholders may elect to reinvest their quarterly cash dividends for additional shares of Capital Power Corporation as an alternative to receiving cash dividends. The participation rate in the DRIP was approximately 36% for 2014. Depending on the participation rate for 2015, cash requirements for common share dividends may differ from the above expectations.

The current portion of loans and borrowings on the December 31, 2014 statement of financial position included $334 million senior debt payable to EPCOR which was classified as current since the debt is callable and, therefore, potentially repayable in 2015 (see Transactions with Related Parties).

The Company expects to fund the construction of the Genesee 4 and 5, Shepard Energy Centre and K2 Wind projects using existing bank credit facilities and cash flows from operating activities. K2 Wind will be financed by non-recourse project debt issued by the K2 Wind limited partnership. 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 short form base shelf prospectuses to provide it with the ability, market conditions permitting, to obtain new debt and equity capital from external markets when required. Under the short-form base shelf prospectuses, Capital Power may raise up to $3 billion by issuing common shares, preferred shares, subscription receipts exchangeable for common shares and/or other securities of the Company and/or debt securities, and up to $1 billion by issuing medium-term notes with maturities of not less than one year. These prospectuses expire in January 2017.

Financial market stability remains an issue. If instability reoccurs in the Canadian and U.S. financial markets, Capital Power's ability to raise new capital, to meet its financial requirements, and to refinance indebtedness under existing credit facilities and debt agreements may be adversely affected. Capital Power has credit exposure relating to various agreements, particularly with respect to its PPA, trading and supplier counterparties. While Capital Power continues to monitor its exposure to its significant counterparties, there can be no assurance that all counterparties will be able to meet their commitments.

Off-statement of financial position arrangements

The Company has off-statement of financial position arrangements including operating leases and, as at December 31, 2014, $122 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	
	2014	**2013**
Loans and borrowings	1,586	1,527
Less cash and cash equivalents	71	100
Net debt	1,515	1,427
Share capital	2,391	2,328
Retained earnings and other reserves	60	89
Non-controlling interests	552	587
Total equity	3,003	3,004
Total capital	**4,518**	**4,431**

CONTRACTUAL OBLIGATIONS AND CONTINGENT LIABILITIES

(unaudited, $ millions)	Payments due by period						
	2015	**2016**	**2017**	**2018**	**2019**	**Thereafter**	**Total**
Loans and borrowings	599	11	11	25	258	692	1,596
Interest on loans and borrowings	86	54	51	51	44	86	372
Capital – growth projects [1]	31	62	200	259	141	49	742
Acquired PPA obligations – fixed [2]	33	37	35	38	39	41	223
Acquired PPA obligations – variable [2]	61	58	61	60	64	64	368
Decommissioning provisions [3]	2	2	2	2	2	292	302
Energy purchase and transportation contracts [4]	124	105	76	89	91	416	901
Operating and maintenance contracts	17	18	18	20	19	216	308
Operating leases	8	7	8	8	-	71	102
Environmental credits	13	8	7	1	1	-	30
Commodity and other derivatives liabilities net of financial assets	17	5	3	1	-	-	26
Total	**991**	**367**	**472**	**554**	**659**	**1,927**	**4,970**

[1] Capital Power's obligations for capital – growth projects include the Shepard Energy Centre, K2 Wind and Genesee 4 and 5 projects.

[2] Capital Power's obligation to make payments on a monthly basis for fixed and variable costs under the terms of its acquired PPAs will vary depending on generation volume and scheduled plant outages. Fixed costs include fixed operation and maintenance expenditures, fuel, depreciation, decommissioning, return on equity, and return on debt and working capital.

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

[4] Includes natural gas transportation contracts which are based on estimates subject to changes in regulated rates for transportation and have expiry terms ranging from 2015 to 2019.

Contingent liabilities

Capital Power is participating in a line loss factor proceeding underway before the Alberta Utilities Commission (AUC) regarding factors that form the basis for certain transmission charges paid by Alberta generators including Capital Power. This proceeding intends to address the factors to be applied for the years 2006 forward and is expected to be completed in three modules. In January 2015, the AUC issued its decision in Module A of the line loss factor proceeding that the AUC has the jurisdiction and authority to retrospectively change the line loss rule and related loss factors and that such changes as may be determined will be applied retroactively. Module B will address the replacement line loss factors and rules. Module C will address the compensation to be paid or received by the various parties. It is expected that a Module B decision will be issued no earlier than the third quarter of 2015 while the timing of a Module C decision is unknown. There are many variables and considerations that must be taken into account in establishing transmission line loss factors and new line loss factors have not been established nor has any mechanism for the sharing of any retrospective adjustments been established. Capital Power may incur material additional transmission charges on a retrospective and go-forward basis but a provision has not been recorded in the Company's financial statements since the outcome of the proceeding is not known.

The Company previously disclosed that it believed that any revised factors that would arise from these proceedings would be applied prospectively and that Module A would commence in April 2015. Capital Power has updated its position consistent with the ruling that the AUC has the jurisdiction and authority to retrospectively change the line loss rule and related loss factors. However, the Company continues to consider potential legal and other actions to mitigate any potential exposure. The timing of completion of Module A was moved forward by the AUC.

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

(unaudited, $ millions)		Year ended December 31	
	Note	2014	2013
EPCOR (shareholder)			
CPLP distributions paid	(a)	24	36
Purchase of distribution and transmission services	(b)	2	1
Purchase of other services	(b)	8	6
Power sales	(b)	11	6
Interest incurred on unsecured senior debt payable	(c)	21	22
Repayment of unsecured senior debt payable	(c)	8	14
The City of Edmonton (sole shareholder of EPCOR)			
Power sales	(b)	2	21

		As at December 31	
	Note	2014	2013
EPCOR (shareholder)			
Trade and other receivables	(b)	3	1
Trade and other payables	(b)	13	14
Provision for future maintenance costs associated with EPCOR's Rossdale plant	(d)	2	3
Loans and borrowings	(c)	334	341
The City of Edmonton (sole shareholder of EPCOR)			
Trade and other receivables	(b)	-	5

(a) As at December 31, 2014 and 2013, EPCOR owned 18.841 million exchangeable common limited partnership units of CPLP, (representing approximately 18% at December 31, 2014 and 19% at December 31, 2013 of CPLP), and 18.841 million accompanying special voting shares and one special limited voting share of Capital Power Corporation. In connection with EPCOR's unitholdings, CPLP paid distributions to EPCOR for the years ended December 31, 2014 and 2013.

(b) The power sales and purchase of 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. The Company has a lease agreement with EPCOR for office space that requires payment to EPCOR of $5 million per year through 2031.

(c) The Company's unsecured senior debt payable to EPCOR, at interest rates ranging from 5.80% to 9.00% per annum, matures between 2015 and 2018. As at December 31, 2014, since EPCOR owns less than 20% of the outstanding limited partnership units of CPLP, EPCOR may, by written notice, require repayment of all or any portion of the outstanding principal amount of this debt and accrued interest thereon. If the principal amount specified in such repayment is less than $200 million, then it and the accrued interest thereon shall be payable on or before 180 days after delivery of notice, and if it is $200 million or more, then it and the accrued interest thereon shall be payable on or before 365 days after delivery of notice.

(d) The Rossdale plant, which is owned by EPCOR, was taken out of service in January 2009 and was decommissioned. Certain structures at the plant site were designated as Provincial Historical Resources by the Province of Alberta and are thereby legally protected from demolition. These structures, and additional structures at the plant site, are also on the City of Edmonton's Register of Historic Resources. CPLP has an obligation to EPCOR to share in some of the costs for ongoing operations and maintenance of the Rossdale plant and related assets until 2019.

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 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 and govern the Company's decisions and policies associated with risk. The Board of Directors reviews the Company's risk profile on a semi-annual 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.

Subject to the oversight of the Board of Directors, risk management is carried out at several levels. 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, and the rest of the executive team provide general oversight and policy review and recommendation. They meet 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 the physical markets and the financial derivatives markets. The Vice President, 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 the policies and processes by performing periodic reviews and internal audits. He is also responsible for the leadership of the commodity risk management (middle office) function and the leadership of security and contingency planning. 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; it continually looks for ways to enhance the Company's risk management processes.

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:

Performance of assets of acquired PPA and joint arrangements risk

Some of Capital Power's assets are operated through an acquired PPA and 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 the Sundance power plants to produce or sell power or thermal energy for an extended period under the Sundance PPA would likely require Capital Power to replace the electricity at market prices prevailing at that time, although it would be relieved of the obligation to pay the unit capacity fee. Depending on market liquidity, these market prices could be significantly higher than the prices inherent in the Sundance PPA, thus increasing the cost of energy purchases to Capital Power. Similar factors could affect Capital Power's generation plants that are operated by third parties.

Strategies employed for managing acquired PPA and joint arrangements risk:

- Work with plant owner and/or operator to execute appropriate operating and maintenance practices to minimize the likelihood of prolonged unplanned down time.
- Measure performance against benchmarks.
- 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.

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, and operations. 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 operation activities could be impeded by stakeholder intervention. Changes in law and regulatory requirements, such as the Canadian Securities Administrators proposed Derivative Product Determination and Trade Repositories and Derivatives Data Reporting rules 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 liability for costs to investigate or remediate contamination. Compliance with new regulatory requirements may require Capital Power to incur significant capital expenditures or additional operating expenses, and 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, the transmission companies may not have sufficient incentive to invest in expansion of 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 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 potential 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 government with respect to tax policy development and proposed legislation.

Commodity price volatility

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 wholesale markets of Alberta, Ontario, and the U.S. Such transactions are settled at the spot market prices of the respective markets. Market electricity prices are dependent upon a number of factors including: the projected supply and demand of electricity, 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, and the acquired Sundance PPA plant, 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 which may result in lost opportunity costs. 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 plants under new or extended contracts to maintain a balance of contracted and non-contracted plants.
- Limit exposure to market price volatility by entering into long-term contracts such as those contracts for the Company's Genesee 1 and 2, Kingsbridge 1, Port Dover and Nanticoke, Quality Wind, Island Generation, Roxboro and Southport plants.
- 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 daily key risk measures in relation to applicable limits to the executive team with quarterly review by the Board of Directors.
- 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 plant 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 plant operations are susceptible to outages due to failure of generation equipment, transmission lines, pipelines or other equipment, which could make the impacted plant unavailable to provide service.

The inability of Capital Power's power plants 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 plant 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 plants and the acquired Sundance PPA provide appropriate incentives to plant owners to keep the plants 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 plants 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 third parties to deliver the wholesale power from its power generation plants 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 plant 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. Participate in a leased engine program for the LMS 100 units at CBEC to reduce down time by replacing a failed unit with a leased unit provided by the manufacturer.
- Execute appropriate operating and maintenance practices (reliability program) to minimize the likelihood of prolonged unplanned down time for the Company's plants.
- 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 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 CSU 52, which represents certain administrative, technical, professional, and information technology employees located in the Edmonton corporate office and Genesee power plant, expired December 13, 2014. All existing terms, conditions and wage rates in the expired collective agreement will continue in force and effect until a new collective agreement is concluded.

Strategies employed for managing human resources risk:

- Maintain good human resource programs and practices including monitoring developments and contingency plans.
- 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 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 electricity 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, 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.

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 support the indebtedness 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 plants may over time be unable to compete with newer more efficient plants utilizing improvements to existing power technologies and cost-efficient new technologies.

EPCOR ownership risk

For as long as EPCOR maintains a significant indirect equity and voting interest in the Company, EPCOR will have the ability to significantly influence the outcome of shareholder votes, including the ability to prevent certain fundamental transactions. As a result, EPCOR has the ability to influence many matters affecting the Company.

EPCOR's significant equity ownership may discourage transactions involving a change of control of the Company, including transactions in which a holder of common shares might otherwise receive a premium for its common shares over the then-current market price.

The interests of other common shareholders are protected by the Board structure which provides EPCOR the right, voting separately as a class, to nominate and elect two directors of the Company. There are currently 10 directors on Capital Power's Board of Directors.

EPCOR has no contractual obligation to retain any exchangeable common limited partnership units of CPLP or common shares of the Company. At December 31, 2014, EPCOR's interest in the Company was approximately 18%. EPCOR has advised the Company that it plans to eventually sell all or a substantial portion of the common shares underlying its exchangeable common limited partnership units, subject to market conditions, its requirement for capital and other circumstances that may arise in the future. Capital Power is entitled to defer such offerings of common shares requested by EPCOR in certain circumstances for a limited period. Any sale of substantial amounts of common shares in the public market by EPCOR or the Company, or the perception that such sales could occur, could adversely affect prevailing market prices for the common shares and impede the Company's ability to raise capital through the issuance of additional equity securities.

Strategies employed for managing EPCOR ownership risk:

- Maintain good relationship with EPCOR to ensure that EPCOR continues to act only as an investor in and not as a manager of the Company.

Energy supply risk

Capital Power requires energy from sources such as coal, natural gas, wind, wood waste and tire derived fuel 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.

Capital Power's wind power facilities are dependent on the availability and constancy of sufficient wind resources to meet generation capacity. Fluctuations in wind speed or duration 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.

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 rate on income before tax for 2014 and 2013 was 25%. 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. plant 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 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, 2014, the Company loaned $473 million to CPLP under subordinated debt agreements. The terms of this agreement 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 $161 million as at December 31, 2014 ($120 million as at December 31, 2013) for its generation plants and the Genesee coal mine as it is obliged to remove the facilities at the end of their useful lives and restore the plant and mine sites to their original condition. Decommissioning provisions for the coal mine are incurred over time as new areas are mined, and a portion of the liability is settled over time as areas are reclaimed prior to final pit reclamation.

The Company is obligated to purchase environmental credits totaling approximately $30 million in the current and future years and expects to mostly use these credits to comply with applicable environmental regulations.

USE OF JUDGEMENTS AND ESTIMATES

In preparing the consolidated financial statements, management made judgements, 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 judgements in applying accounting policies

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

Judgement	Management applies judgement to evaluate	Resulting conclusions
Cash generating units	What constitutes a cash generating unit 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.	Cash generating units were determined giving consideration to geographic proximity and shared risk exposure and risk management.
Asset impairment	Whether events or circumstances may indicate that an asset's carrying amount exceeds its recoverable amount.	In 2014, deferred tax assets related to U.S. income tax loss carryforwards were written down based on the Company's updated forecast of U.S. taxable income. The recoverability of goodwill and indefinite life intangibles is tested annually. No impairments were recognized in 2014 since expected recoverable amounts exceeded carrying amounts.
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** (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** (substantially all the risks and rewards remain with Capital Power) • Genesee 1 and 2 PPA • Island Generation PPA • Roxboro PPA
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 in each case, CPLP and Genesee Coal Mine are subsidiaries that are consolidated and have non-controlling interests.
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 Energy Centre 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.

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 • Share price at grant date • Expected volatility, option life and dividend yield • Risk-free interest rate • Exercise price • Expiry date
	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	Asset's useful life based on the life characteristics of common assets
Recognition of deferred tax assets and availability of future taxable income against which carryforward tax losses can be used.	Deferred tax assets and income tax provisions based on likelihood that tax losses will be recovered from future taxable income
Revenue recognition	Value of electricity and natural gas consumed by customers but not billed until after year-end based on data provided by the parties delivering the commodity

ACCOUNTING CHANGES

Effective January 1, 2014

The Company adopted a number of new accounting standards, together with the consequential amendments to other standards, as issued by the International Accounting Standards Board (IASB). The changes that are significant to Capital Power are:

Standard	Description	Impact to Capital Power
Recoverable amount disclosures for non-financial assets – amendments to IAS 36 Impairment of assets	In May 2013, the IASB issued amendments to IAS 36 which require disclosure of the recoverable amount of impaired assets and additional disclosures about the measurement of the impaired assets when the recoverable amount is based on fair value less costs of disposal, including the discount rate when a present value technique is used to measure the recoverable amount.	The amendments are effective for annual periods beginning on or after January 1, 2014. However, the Company early adopted the amendments, on a retrospective basis, with insignificant impact to the Company's financial statement note disclosures.

Future

The IASB issued the following new standards and amendments to existing standards that were not yet effective as of December 31, 2014 and which may significantly impact Capital Power:

Standard	Description	Impact to Capital Power	Effective Date
General hedge accounting (amendments to IFRS 9, IFRS 7, and IAS 39)	Potentially provides that hedge accounting may be applied to more hedge strategies, that some own use contracts may be fair valued, and to remove the bright line assessment of hedge effectiveness.	May be able to apply hedge accounting to more hedge strategies. Capital Power is currently analyzing the requirements to determine how best to apply them, determine system requirements, and develop the required disclosures.	These amendments do not have a mandatory effective date but are available for application under IFRS 9 or IFRS 39.
Acquisition of an interest in a joint operation (amendments to IFRS 11)	Provides guidance on how a joint operator accounts for the acquisition of an interest in a joint operation that is a business. It requires a joint operator to account for such an acquisition by applying IRFS 3 Business Combinations and other standards, and disclosing the relevant information specified in those IFRSs for business combinations.	No immediate impact but would affect applicable future transactions.	Effective for annual periods beginning on or after January 1, 2016; early application permitted.
Sale or contribution of assets between an investor and its associate or joint venture (amendments to IFRS 10 and IAS 28)	Provides that a full gain or loss will be recognized on the loss of control of a business (whether it is housed in a subsidiary or not) including cases in which the investor retains joint control of, or significant influence over, the investee.	No immediate impact but would affect applicable future transactions.	Effective for annual periods beginning on or after January 1, 2016; early application permitted.
Revenue from contracts with customers (IFRS 15)	New standard on revenue recognition consisting of a single and comprehensive framework for revenue recognition to ensure consistent treatment for all transactions in all industries and capital markets.	May change the timing of revenue recognized from any contracts with a number of discrete performance obligations (multiple-element arrangements), require separate line disclosure of credit losses, and require more extensive disclosures on annual and interim basis.	Effective for annual periods beginning on or after January 1, 2017; early application permitted and to be applied retrospectively.
Financial instruments (IFRS 9)	New standard, replacing IAS 39, which addresses requirements for classification and measurement, impairment, hedge accounting and derecognition of financial assets and liabilities.	May change the measurement of certain financial instruments and the recording of expected credit losses. Capital Power is currently analyzing the requirements to determine how best to apply them, determine system requirements, and develop the required disclosures.	Effective for annual periods beginning on or after January 1, 2018; early application permitted.

FINANCIAL INSTRUMENTS

The classification, carrying amounts and fair values of financial instruments held at December 31, 2014 and 2013 were as follows:

(unaudited, $ millions)			As at December 31			
			2014		2013	
	Classification	Fair value hierarchy level	Carrying amount	Fair value	Carrying amount	Fair value
Financial assets:						
Cash and cash equivalents	Loans and receivables	N/A	71	71	100	100
Trade and other receivables	Loans and receivables	N/A	177	177	218	218
Derivative financial instruments assets – current and non-current	Financial assets designated at fair value through income or loss	See below	187	187	67	67
Finance lease receivables	Loans and receivables	Level 2	708	726	711	647
Other financial assets	Loans and receivables	Level 2	16	17	34	34
Financial liabilities:						
Trade and other payables	Other financial liabilities	N/A	185	185	198	198
Derivative financial instruments liabilities – current and non-current	Financial liabilities designated at fair value through income or loss	See below	74	74	41	41
Loans and borrowings (including current portion)	Other financial liabilities	Level 2	1,586	1,670	1,527	1,561

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 statement 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 contract 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 stations and power purchased under PPAs 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, 2014 and 2013 and used for risk management purposes were measured at fair value and consisted of the following:

(unaudited, $ millions)		As at December 31, 2014				
	Fair value hierarchy level	**Commodity cash flow hedges**	**Commodity non-hedges**	**Foreign exchange hedges**	**Interest rate non-hedges**	**Total**
Derivative financial instruments assets	Level 1	-	-	-	-	-
	Level 2	53	109	21	4	187
	Level 3	-	-	-	-	-
		53	109	21	4	187
Derivative financial instruments liabilities	Level 1	-	-	-	-	-
	Level 2	(3)	(66)	-	(5)	(74)
	Level 3	-	-	-	-	-
		(3)	(66)	-	(5)	(74)
Net derivative financial instruments assets (liabilities)		**50**	**43**	**21**	**(1)**	**113**

(unaudited, $ millions)		As at December 31, 2013				
	Fair value hierarchy level	**Commodity cash flow hedges**	**Commodity non-hedges**	**Foreign exchange hedges**	**Interest rate non-hedges**	**Total**
Derivative financial instruments assets	Level 1	-	-	-	-	-
	Level 2	29	37	1	-	67
	Level 3	-	-	-	-	-
		29	37	1	-	67
Derivative financial instruments liabilities	Level 1	-	-	-	-	-
	Level 2	(11)	(28)	(1)	(1)	(41)
	Level 3	-	-	-	-	-
		(11)	(28)	(1)	(1)	(41)
Net derivative financial instruments assets (liabilities)		**18**	**9**	**-**	**(1)**	**26**

Commodity and foreign exchange derivatives designated as accounting hedges

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

Commodity and interest rate derivatives not designated as accounting hedges

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

Unrealized and realized losses on interest rate derivatives that are not designated as hedges for accounting purposes are recorded in net income as finance expense.

Fair value measurement

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. These fair values are partly based on the key unobservable inputs of volatilities and correlations of the relative price changes in underlying prices. These volatilities and correlations are estimated using an exponentially-weighted moving average based on historical forward prices. When required, sensitivity analysis for significant Level 3 financial instruments is performed.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

As at December 31, 2014, 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) that 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, 2014, 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 and the requirements of the Canadian Securities Administrators' National Instrument 52-109.

SUMMARY OF QUARTERLY RESULTS

(GWh)	Three months ended							
Electricity generation	**Dec 31 2014**	**Sep 30 2014**	**Jun 30 2014**	**Mar 31 2014**	**Dec 31 2013**	**Sep 30 2013**	**Jun 30 2013**	**Mar 31 2013**
Total generation excluding acquired Sundance PPA	3,204	3,220	2,711	3,241	3,925	4,317	3,746	4,142
Alberta commercial plants and acquired Sundance PPA								
Genesee 3	369	473	438	466	463	480	493	481
Keephills 3	433	461	381	399	418	483	296	457
Clover Bar Energy Centre 1, 2 and 3	45	77	66	108	60	45	157	85
Joffre	58	77	71	118	95	109	109	101
Halkirk	146	86	92	138	137	76	118	135
Clover Bar Landfill Gas	3	3	5	3	5	4	4	3
Alberta commercial plants – owned	1,054	1,177	1,053	1,232	1,178	1,197	1,177	1,262
Acquired Sundance PPA	819	673	521	750	710	659	712	691
	1,873	1,850	1,574	1,982	1,888	1,856	1,889	1,953
Alberta contracted plants								
Genesee 1	857	854	771	678	842	819	482	807
Genesee 2	856	841	546	832	802	840	704	788
	1,713	1,695	1,317	1,510	1,644	1,659	1,186	1,595
Ontario and British Columbia contracted plants								
Island Generation	9	6	-	115	210	14	-	-
Kingsbridge 1	35	14	22	34	37	12	22	37
Port Dover and Nanticoke	91	51	66	93	54	N/A	N/A	N/A
Quality Wind	101	71	80	97	113	68	88	108
	236	142	168	339	414	94	110	145
U.S. contracted plants								
Roxboro, North Carolina	74	73	58	39	70	69	57	53
Southport, North Carolina	122	133	115	121	128	117	97	94
Macho Springs, New Mexico	5	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	201	206	173	160	198	186	154	147
U.S. commercial plants								
Bridgeport, Connecticut	N/A	N/A	N/A	N/A	326	690	678	913
Rumford, Maine	N/A	N/A	N/A	N/A	10	57	32	25
Tiverton, Rhode Island	N/A	N/A	N/A	N/A	155	434	409	55
	N/A	N/A	N/A	N/A	491	1,181	1,119	993

(%)	Three months ended							
Plant availability	**Dec 31 2014**	**Sep 30 2014**	**Jun 30 2014**	**Mar 31 2014**	**Dec 31 2013**	**Sep 30 2013**	**Jun 30 2013**	**Mar 31 2013**
Total average plant availability excluding acquired Sundance PPA	94	97	92	94	93	97	86	94
Alberta commercial plants and acquired Sundance PPA								
Genesee 3	74	97	96	96	98	100	100	98
Keephills 3	92	100	100	100	99	100	65	98
Clover Bar Energy Centre 1, 2 and 3	90	97	98	97	91	93	99	99
Joffre	82	95	95	100	85	95	94	92
Halkirk	98	91	98	96	99	89	99	98
Clover Bar Landfill Gas	87	58	83	75	98	66	91	97
Alberta commercial plants – owned	87	96	97	98	94	96	91	97
Acquired Sundance PPA	96	85	67	89	89	83	93	97
	91	91	84	94	92	90	92	97
Alberta contracted plants								
Genesee 1	100	100	96	83	100	98	61	96
Genesee 2	100	99	66	93	95	100	86	94
	100	99	81	88	98	99	74	95
Ontario and British Columbia contracted plants								
Island Generation	100	99	100	100	99	100	100	100
Kingsbridge 1	96	93	97	95	94	95	96	99
Port Dover and Nanticoke	97	98	94	98	95	N/A	N/A	N/A
Quality Wind	98	93	99	95	98	100	98	99
	98	97	98	98	98	99	99	99
U.S. contracted plants								
Roxboro, North Carolina	100	100	96	90	98	97	88	94
Southport, North Carolina	88	85	93	99	91	99	94	96
Macho Springs, New Mexico	99	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	92	90	94	96	93	98	92	96
U.S. commercial plants								
Bridgeport, Connecticut	N/A	N/A	N/A	N/A	72	93	83	97
Rumford, Maine	N/A	N/A	N/A	N/A	91	100	77	97
Tiverton, Rhode Island	N/A	N/A	N/A	N/A	83	96	93	51
	N/A	N/A	N/A	N/A	79	95	84	86

Financial results

(unaudited, $ millions)	Three months ended							
	Dec 31 2014	**Sep 30 2014**	**Jun 30 2014**	**Mar 31 2014**	**Dec 31 2013**	**Sep 30 2013**	**Jun 30 2013**	**Mar 31 2013**
Revenues								
Alberta commercial plants, acquired Sundance PPA and portfolio optimization	189	119	130	188	173	202	198	169
Alberta contracted plants	69	76	58	63	70	80	27	69
Ontario and British Columbia contracted plants	36	21	25	37	33	16	18	25
U.S. contracted plants	22	22	22	17	19	20	17	15
U.S. commercial plants and portfolio optimization	-	-	-	-	23	63	63	78
Corporate [1]	(9)	2	18	2	(9)	(4)	2	(2)
Unrealized changes in fair value of commodity derivatives and emission credits	125	8	(13)	1	18	3	(4)	11
	432	**248**	**240**	**308**	**327**	**380**	**321**	**365**
Adjusted EBITDA								
Alberta commercial plants, acquired Sundance PPA and portfolio optimization	60	49	43	59	57	104	112	79
Alberta contracted plants	41	44	34	42	53	55	7	44
Ontario and British Columbia contracted plants	29	15	18	30	26	9	12	20
U.S. contracted plant	1	3	3	-	1	2	1	1
U.S. commercial plants and portfolio optimization	-	-	-	-	(1)	11	7	4
Corporate	(27)	(25)	(7)	(25)	(34)	(31)	(30)	(26)
Unrealized changes in fair value of commodity derivatives and emission credits	37	5	(13)	7	17	1	(5)	13
	141	**91**	**78**	**113**	**119**	**151**	**104**	**135**

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

Quarterly revenues, net income and cash flows from operating activities are affected by seasonal weather conditions, fluctuations in U.S. dollar exchange rates relative to the Canadian dollar, power and natural gas prices, and planned and unplanned plant outages and items outside the normal course of operations. Net income is also affected by changes in the fair value of the Company's power, natural gas, foreign exchange and interest rate derivative contracts.

Financial highlights

(unaudited, $ millions except per share amounts)	Three months ended							
	Dec 31 2014	Sep 30 2014	Jun 30 2014	Mar 31 2014	Dec 31 2013	Sep 30 2013	Jun 30 2013	Mar 31 2013
Revenues	432	248	240	308	327	380	321	365
Adjusted EBITDA [1]	141	91	78	113	119	151	104	135
Net income (loss)	48	(57)	21	38	98	59	23	48
Net income (loss) attributable to shareholders of the Company	39	(45)	20	32	77	44	20	34
Basic earnings (loss) per share ($)	0.40	(0.62)	0.17	0.33	0.89	0.55	0.20	0.44
Normalized earnings per share ($) [1]	0.20	0.12	0.07	0.32	0.40	0.72	0.27	0.36

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

	Three months ended							
Spot price averages	Dec 31 2014	Sep 30 2014	Jun 30 2014	Mar 31 2014	Dec 31 2013	Sep 30 2013	Jun 30 2013	Mar 31 2013
Alberta power ($ per MWh)	30	64	42	61	49	84	123	65
Alberta natural gas (AECO) ($ per Gj)	3.43	3.81	4.46	5.45	3.33	2.32	3.36	3.03
Capital Power's Alberta portfolio average realized power price ($ per MWh)	58	56	57	58	64	85	93	69

Factors impacting results for the fourth quarter of 2014

For the quarter ended December 31, 2014, the Company recorded net income attributable to shareholders of $39 million and normalized earnings per share of $0.20 which were significantly lower than the comparable amounts of $77 million and $0.40, respectively, in the fourth quarter of 2013. This decrease in net income attributable to shareholders was primarily due to the 2013 gain on disposal of the North East U.S. subsidiaries. This decrease was partly offset by the impact of increased net unrealized gains in the fair value of commodity derivatives. Comparative normalized earnings per share does not include the impact of the 2013 gain on disposal and the increased net unrealized gains in the fair value of commodity derivatives; thus, the decrease primarily reflects plant operating factors outlined below and a higher number of outstanding common shares in the fourth quarter of 2014.

For the three months ended December 31, 2014, Alberta commercial plants and acquired Sundance PPA electricity generation was consistent with the generation in the same quarter of 2013. This was primarily the result of offsetting plant outages. Genesee 3 experienced a major planned outage of in the fourth quarter of 2014 while the acquired Sundance PPA units underwent an outage in the fourth quarter of 2013. Revenues for the fourth quarter of 2014 increased compared with the same quarter of 2013 primarily due to increased portfolio optimization revenues. During the fourth quarter of 2014, the Company hedged a greater portion of its baseload generation and, therefore, entered more contracts resulting in greater revenues than for the same period of 2013. However, while captured prices realized through portfolio optimization were greater than spot prices during the fourth quarter of 2014, they were not as high as 2013. Lower Alberta commercial plant results were partly offset by the $8 million settlement of a claim with a turbine supplier relating to a component failure at Genesee 3 in 2008.

The Alberta contracted plants achieved strong availability of 100% and 98% in the fourth quarters of 2014 and 2013, respectively. Production increased 69 GWh since there were no outages in the fourth quarter of 2014 comparable to the 2013 fourth quarter maintenance outages at Genesee 2. The combination of increased production and lower prices resulted in consistent revenues for the 2014 and 2013 fourth quarters. However, lower costs were incurred in the fourth quarter of 2013 relating to contractual adjustments to the cost of coal between the three Genesee units, and higher costs were incurred in the fourth quarter of 2014 associated with the wind-up of the Genesee coal mine's defined benefit pension plan, leading to decreased adjusted EBITDA.

Ontario and British Columbia total generation for the fourth quarter of 2014 was lower than the same period in 2013. This was primarily due to Island Generation which was seldom required by B. C. Hydro to run during the quarter. However, Island Generation's revenues were not significantly impacted relative to the same period last year since they are based on deemed generation, as established under its contract with B.C. Hydro, which is tied to plant availability. The increase in revenues and adjusted EBITDA for the fourth quarter of 2014 compared to the fourth quarter of 2013 was primarily due to the additional contribution of the Port Dover and Nanticoke windfarm, which commenced operations in November 2013, partly offset by lower generation at Quality Wind.

During the fourth quarter of 2014, the Company recognized an additional income tax provision of $6 million related to 2014 U.S. tax losses. This adjustment arose from the Company's annual income tax review that determined that 2014 U.S. tax losses of $24 million could not be recognized for accounting purposes and therefore resulted in an effective tax rate significantly higher than the Canadian statutory rate in the fourth quarter of 2014. These additional tax charges contributed to lower net income and lower normalized earnings attributable to common shareholders for the quarter ended December 31, 2014 compared with the fourth quarter of 2013.

Factors impacting results for the previous quarters

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

Financial results for third quarter 2014 reflected the impact of an extended planned outage and other unplanned outages at the acquired Sundance PPA units and derates at the Keephills 3 plant. The outages occurred primarily in July 2014 coinciding with a period of pricing volatility with Alberta spot power prices in July averaging $122 per MWh compared with $45 per MWh in August 2014 and $24 per MWh in September 2014. With commercial production 100% sold forward in July 2014, the resulting short position was covered at the higher prices. Capital Power's third quarter 2014 net income was also negatively impacted by a non-cash write-down of deferred tax assets of $73 million. The write-down related to the accounting impact of U.S. income tax loss carryforwards that could no longer be recognized for accounting purposes based on the Company's long-term forecast for U.S. taxable income.

In the second quarter of 2014, the results for the Alberta commercial plants reflected seasonally low Alberta power prices, lower generation from the acquired Sundance PPA units, and lower generation at Genesee 3 caused by transmission constraints. However, the results for the Alberta contracted plants were positively impacted by lower rolling average pool prices which caused lower availability penalties on outages in the second quarter of 2014 compared with the same quarter in 2013. Capital Power recorded revenues of $20 million arising from the amendment of the Genesee Coal Mine Agreements. The Company announced a 7.9% increase in the annual dividend for holders of its common shares commencing with the third quarter 2014 quarterly dividend payment.

The 2014 first quarter included the first full quarter of operations and results for Capital Power's Port Dover and Nanticoke wind facility. The Alberta commercial plants' results were impacted by lower pricing experienced in this quarter compared with first quarter 2013. The impact of lower pricing on the significantly hedged portfolio also reduced portfolio optimization results. Additionally, the Company experienced higher costs of emissions compliance. The Genesee 1 unit within the Alberta contracted plants category experienced a 10-day unplanned outage which dampened results. Depreciation and amortization expense was reduced from prior quarters due to the disposal of the North East U.S. assets.

During the quarter ended December 31, 2013, commercial operations of the Port Dover and Nanticoke wind facility commenced while the sale of the North East U.S. assets was completed resulting in a net capacity decrease of 984 MW. The Company recognized a pre-tax gain of $76 million on the sale of the North East U.S. assets. The results for this quarter also included significant unrealized net gains related to the fair value of commodity derivatives and the impact of improved operating results for the Alberta commercial plants and the Ontario and British Columbia contracted plants.

Results of operations for the third quarter of 2013 were influenced by the Alberta spot power average price of $84 per MWh and unplanned plant maintenance outages in the Alberta market. In particular, the high Alberta power prices favourably impacted the Alberta contracted plants' results. The Company announced its agreement with Emera Inc. to sell its North East U.S. plants. This decision to exit North East U.S. market was accompanied by the Company's decision to refocus its merchant power business in Alberta. As a result, the Company recognized a pre-tax impairment loss of $6 million and incurred pre-tax restructuring costs of $9 million in the third quarter of 2013. The purchase of the second tranche of the Company's interest in Shepard Energy Centre was completed during the quarter.

In the second quarter of 2013, Alberta commercial plants had strong results as power prices were driven higher when the Alberta market experienced several planned and unplanned outages. These positive results were partly offset by the results for Alberta contracted plants since Genesee 1 experienced a planned outage and both Genesee 1 and 2 experienced unplanned outages. These outages decreased production and the significant availability penalties incurred reflected the quarter's higher Alberta power prices.

The 2013 first quarter included the first full quarter of operations and results for Capital Power's Quality Wind and Halkirk wind projects. All plants, with the exception of Tiverton in the North East U.S., had relatively strong performance and financial results. Tiverton experienced an outage during the quarter when the maintenance work that was originally scheduled to be performed in the last half of 2013 was completed. The purchase of the first tranche in the Company's interest in Shepard Energy Centre was completed during the quarter.

SHARE AND PARTNERSHIP UNIT INFORMATION

Quarterly common share trading information

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

	Three months ended							
	Dec 31 2014	**Sep 30 2014**	**Jun 30 2014**	**Mar 31 2014**	**Dec 31 2013**	**Sep 30 2013**	**Jun 30 2013**	**Mar 31 2013**
Share price ($/common share)								
High	28.17	28.71	26.49	25.81	21.95	22.22	22.55	23.53
Low	24.50	25.75	24.07	20.51	20.30	19.80	19.76	21.02
Close	26.00	26.75	26.36	25.72	21.30	21.26	20.58	21.20
Volume of shares traded (millions)	22.8	19.6	21.7	27.0	23.5	13.2	12.2	14.7

Outstanding share and partnership unit data

As at February 17, 2015, the Company had 83.878 million common shares outstanding, 18.841 million special voting shares outstanding, 5 million Cumulative Rate Reset Preference Shares, Series 1 outstanding, 6 million Cumulative Rate Reset Preference Shares, Series 3, 8 million Cumulative Rate Reset Preference Shares, Series 5, and one special limited voting share outstanding. Assuming full conversion of the outstanding and issuable share purchase options to common shares and the redemption of all outstanding special voting shares in relation to the conversion of all outstanding exchangeable common limited partnership units of CPLP to common shares and ignoring exercise prices, the outstanding and issuable common shares as at February 17, 2015 were 106.448 million. All of the outstanding special voting shares and the outstanding special limited voting share are held by EPCOR.

As at February 17, 2015, CPLP had 21.750 million general partnership units outstanding, 62.112 million common limited partnership units outstanding and 18.841 million exchangeable common limited partnership units outstanding, which are exchangeable for 18.841 million common shares of the Company. All of the outstanding general partnership units and the outstanding common limited partnership units are held, indirectly, by the Company. All of the outstanding exchangeable common limited partnership units are held by EPCOR.

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, 2014 and 2013

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 20, 2015. Financial information presented elsewhere in this 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 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

Stuart Lee
Senior Vice President, Finance and
Chief Financial Officer

February 20, 2015

CAPITAL POWER CORPORATION

Consolidated Financial Statements

Years ended December 31, 2014 and 2013

KPMG LLP
Chartered Accountants
10125 – 102 Street
Edmonton AB T5J 3V8
Canada

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Fax (780) 429-7379
Internet 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 statement of financial position as at December 31, 2014 and December 31, 2013, 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, 2014 and December 31, 2013, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards**.**

KPMG LLP

February 20, 2015
Edmonton, Canada

CAPITAL POWER CORPORATION

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

Years ended December 31

	2014	2013
Revenues (note 4)	$ 1,228	$ 1,393
Energy purchases and fuel	(511)	(560)
Gross margin	717	833
Other raw materials and operating charges	(83)	(89)
Staff costs and employee benefits expense (note 5)	(123)	(147)
Depreciation and amortization (note 5)	(189)	(222)
Impairments (note 11)	-	(6)
Other administrative expense (note 5)	(88)	(88)
Foreign exchange loss	(10)	(6)
Operating income	224	275
Gain on disposal of subsidiaries (note 9)	-	76
Finance expense (note 6)	(55)	(78)
Income before tax	169	273
Income tax expense (note 7)	(119)	(45)
Net income	$ 50	$ 228
Attributable to:		
Non-controlling interests (note 33)	$ 4	$ 53
Shareholders of the Company	$ 46	$ 175

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

Basic (note 8)	$ 0.28	$ 2.13
Diluted (note 8)	$ 0.28	$ 2.08

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

	2014	2013
Net income	$ 50	$ 228
Other comprehensive income (loss):		
Items that will not be reclassified subsequently to net income:		
Defined benefit plans:		
Actuarial (losses) gains[1]	(2)	2
Items that are or may be reclassified subsequently to net income:		
Cash flow hedges:		
Unrealized gains (losses) on derivative instruments [2]	59	(35)
Unrealized losses on derivative instruments – joint venture (note 34) [3]	(15)	-
Reclassification of (gains) losses on derivative instruments to income for the year [4]	(18)	27
Net investment in foreign subsidiaries:		
Unrealized gain [5]	16	23
Gain realized in net income on disposal of foreign subsidiary (note 9)	-	(59)
Total items that are or may be reclassified subsequently to net income, net of tax	42	(44)
Total other comprehensive income (loss), net of tax	40	(42)
Total comprehensive income	$ 90	$ 186
Attributable to:		
Non-controlling interests (note 33)	$ 14	$ 41
Shareholders of the Company	$ 76	$ 145

[1] For the year ended December 31, 2014, net of income tax recovery of $1. For the year ended December 31, 2013, net of income tax expense of $1.

[2] For the year ended December 31, 2014, net of income tax expense of $14. For the year ended December 31, 2013, net of income tax recovery of $9.

[3] For the year ended December 31, 2014, net of income tax recovery of $5. For the year ended December 31, 2013, net of income tax of nil.

[4] For the year ended December 31, 2014, net of reclassification of income tax expense of $4. For the year ended December 31, 2013, net of reclassification of income tax recovery of $6.

[5] For the years ended December 31, 2014 and December 31, 2013, net of income tax of nil.

See accompanying notes to the consolidated financial statements

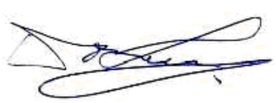
CAPITAL POWER CORPORATION

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

As at December 31

	2014	2013
Assets		
Current assets:		
Cash and cash equivalents (note 12)	$ 71	$ 100
Trade and other receivables (note 13)	185	218
Inventories (note 14)	104	92
Derivative financial instruments assets (note 15)	132	31
	492	441
Non-current assets:		
Other assets	28	27
Derivative financial instruments assets (note 15)	55	36
Finance lease receivables (note 16)	708	711
Other financial assets (note 17)	18	36
Deferred tax assets (note 18)	21	95
Equity-accounted investment (note 34)	22	15
Intangible assets (note 19)	350	310
Property, plant and equipment (note 20)	3,701	3,525
Goodwill (note 21)	25	23
Total assets	$ 5,420	$ 5,219

Approved on behalf of the Board:



Donald Lowry
Director and Chairman of the Board

Philip Lachambre
Director and Chairman of the Audit Committee

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

	2014	2013
Liabilities and equity		
Current liabilities:		
Trade and other payables (note 22)	$ 185	$ 198
Derivative financial instruments liabilities (note 15)	64	31
Loans and borrowings (note 23)	599	346
Deferred revenue and other liabilities	5	5
Provisions (note 24)	22	27
	875	607
Non-current liabilities:		
Derivative financial instruments liabilities (note 15)	10	10
Loans and borrowings (note 23)	987	1,181
Deferred revenue and other liabilities	98	89
Deferred tax liabilities (note 18)	249	180
Provisions (note 24)	198	148
	1,542	1,608
Equity:		
Equity attributable to shareholders of the Company		
Share capital (note 25)	2,391	2,328
Retained earnings	25	83
Other reserves (note 26)	35	6
Retained earnings and other reserves	60	89
	2,451	2,417
Non-controlling interests (note 33)	552	587
Total equity	3,003	3,004
Total liabilities and equity	$ 5,420	$ 5,219

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 25)	Cash flow hedges [1]	Cumulative translation account [1]	Defined benefit plan actuarial losses [1]	Employee benefits reserve	Retained earnings	Equity attributable to shareholders of the Company	Non-controlling interests (note 33)	Total
Equity as at January 1, 2014	$ 2,328	$ 21	$ (14)	$ (11)	$ 10	$ 83	$ 2,417	$ 587	$ 3,004
Net income	-	-	-	-	-	46	46	4	50
Other comprehensive (loss) income:									
Defined benefit plan actuarial losses	-	-	-	(3)	-	-	(3)	-	(3)
Cash flow derivative hedge gains	-	73	-	-	-	-	73	-	73
Cash flow derivative hedge losses – joint venture	-	(20)	-	-	-	-	(20)	-	(20)
Reclassification of gains to income	-	(22)	-	-	-	-	(22)	-	(22)
Unrealized gain on foreign currency translation	-	-	16	-	-	-	16	-	16
Tax on items recognized directly in equity	-	(5)	-	1	-	-	(4)	-	(4)
Attributed to non-controlling interests (note 33)	-	(7)	(3)	-	-	-	(10)	10	-
Other comprehensive income (loss)	$ -	$ 19	$ 13	$ (2)	$ -	$ -	$ 30	$ 10	$ 40
Total comprehensive income (loss)	-	19	13	(2)	-	46	76	14	90
Distributions to non-controlling interests	-	-	-	-	-	-	-	(25)	(25)
Net additional investment by non-controlling interests	-	-	-	-	-	-	-	5	5
Change in non-controlling interests ownership (note 33)	-	-	-	-	-	29	29	(29)	-
Tax on change in non-controlling interests ownership	-	-	-	-	-	(2)	(2)	-	(2)
Common share dividends (note 25)	-	-	-	-	-	(108)	(108)	-	(108)
Preferred share dividends (note 25)	-	-	-	-	-	(22)	(22)	-	(22)
Tax on preferred share dividends	-	-	-	-	-	(1)	(1)	-	(1)
Dividends reinvested	37	-	-	-	-	-	37	-	37
Share options exercised	26	-	-	-	(2)	-	24	-	24
Share-based payment	-	-	-	-	1	-	1	-	1
Equity as at December 31, 2014	$ 2,391	$ 40	$ (1)	$ (13)	$ 9	$ 25	$ 2,451	$ 552	$ 3,003

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

See accompanying notes to the consolidated financial statements

CAPITAL POWER CORPORATION

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

	Share capital (note 25)	Cash flow hedges [1]	Cumulative translation account [1]	Defined benefit plan actuarial gains (losses) [1]	Employee benefits reserve	Retained earnings (deficit)	Equity attributable to shareholders of the Company	Non-controlling interests (note 33)	Total
Equity as at January 1, 2013	$ 1,903	$ 15	$ 10	$ (13)	$ 9	$ (1)	$ 1,923	$ 829	$ 2,752
Net income	-	-	-	-	-	175	175	53	228
Other comprehensive (loss) income:									
Defined benefit plan actuarial gains	-	-	-	3	-	-	3	-	3
Cash flow derivative hedge losses	-	(44)	-	-	-	-	(44)	-	(44)
Reclassification of losses to income	-	33	-	-	-	-	33	-	33
Unrealized gain on foreign currency translation	-	-	23	-	-	-	23	-	23
Gain realized on disposal of subsidiaries (note 9)	-	-	(59)	-	-	-	(59)	-	(59)
Tax on items recognized directly in equity	-	3	-	(1)	-	-	2	-	2
Attributed to non-controlling interests (note 33)	-	3	9	-	-	-	12	(12)	-
Other comprehensive (loss) income	$ -	$ (5)	$ (27)	$ 2	$ -	$ -	$ (30)	$ (12)	$ (42)
Total comprehensive (loss) income	-	(5)	(27)	2	-	175	145	41	186
Issue of share capital	402	11	3	-	-	42	458	(258)	200
Share issue costs	(6)	-	-	-	-	-	(6)	-	(6)
Deferred taxes	2	-	-	-	-	(21)	(19)	-	(19)
Distributions to non-controlling interests	-	-	-	-	-	-	-	(33)	(33)
Net additional investment by non-controlling interests	-	-	-	-	-	-	-	8	8
Common share dividends (note 25)	-	-	-	-	-	(92)	(92)	-	(92)
Preferred share dividends (note 25)	-	-	-	-	-	(20)	(20)	-	(20)
Dividends reinvested	27	-	-	-	-	-	27	-	27
Share-based compensation	-	-	-	-	1	-	1	-	1
Equity as at December 31, 2013	$ 2,328	$ 21	$ (14)	$ (11)	$ 10	$ 83	$ 2,417	$ 587	$ 3,004

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

See accompanying notes to the consolidated financial statements

CAPITAL POWER CORPORATION

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

Years ended December 31

	2014	2013
Cash flows from operating activities:		
Net income	$ 50	$ 228
Non-cash adjustments to reconcile net income to net cash flows from operating activities:		
Depreciation and amortization (note 5)	189	222
Gain on disposal (note 9)	-	(76)
Impairments (note 11)	-	6
Finance expense (note 6)	55	78
Fair value changes on commodity derivative instruments and emission credits held for trading	(36)	(26)
Foreign exchange loss	10	6
Income tax expense (note 7)	119	45
Other items	21	(14)
Finance lease receivable collected	17	14
Interest paid [1]	(45)	(67)
Income taxes recovered [2]	10	12
Change in non-cash operating working capital (note 27)	1	71
Net cash flows from operating activities	391	499
Cash flows used in investing activities:		
Purchase of property, plant and equipment and other assets	(220)	(943)
Proceeds on disposal of assets	-	570
Business acquisition, net of acquired cash (note 10)	(18)	-
Other cash flows from investing activities	8	25
Net cash flows used in investing activities	(230)	(348)
Cash flows used in financing activities:		
Proceeds from issue of loans and borrowings	17	-
Repayment of loans and borrowings	(65)	(155)
Issue costs on loans and borrowings	-	(1)
Proceeds from exercise of share options (note 25)	24	-
Proceeds from issue of preferred shares (note 25)	-	200
Share issue costs (note 25)	-	(6)
Distributions paid to non-controlling interests (note 28)	(24)	(36)
Common share dividends paid (note 25)	(68)	(62)
Preferred share dividends paid (note 25)	(22)	(20)
Interest paid [1]	(39)	(21)
Income taxes paid [2]	(14)	(2)
Net cash flows used in financing activities	(191)	(103)
Foreign exchange gain (loss) on cash held in a foreign currency	1	(1)
Net (decrease) increase in cash and cash equivalents	(29)	47
Cash and cash equivalents, beginning of year	100	53
Cash and cash equivalents, end of year	$ 71	$ 100

[1] Total interest paid.
[2] Total income taxes recovered (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 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 20, 2015.

(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 an approximate 82% interest in Capital Power L.P. (CPLP) (December 31, 2013 – 81%). Based on an assessment of the relationship between Capital Power and CPLP as disclosed in note 33, Capital Power controls CPLP and therefore CPLP is treated as a subsidiary of Capital Power. EPCOR Utilities Inc. (EPCOR) holds a non-controlling interest in CPLP as described in note 33.

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:

The Company adopted the following new accounting standard, together with the consequential amendments to other IFRSs effective January 1, 2014:

- IFRIC 21 – Levies

The adoption of this standard did not have a significant impact on the Company’s financial statements and note disclosures thereto.

The Company also early adopted the amendments to IAS 36 – Impairment of Assets, on a retrospective basis during the year ended December 31, 2013. The adoption did not have a significant impact on the Company’s note disclosure.

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(o)).

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.

Investments in joint ventures

The Company, along with two third 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:

Investments in joint ventures, continued

The Company's investment in this joint venture is accounted for under the equity method, and was recognized initially at cost. The accounting policies of the joint venture are aligned with the accounting policies of the Company.

(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 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 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 income as part of translation gains and losses.

(g) 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 (PPAs) as described in note 2(h). 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.

Derivative instruments

Revenues also include 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 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.

2. Significant accounting policies, continued:

(g) Revenue recognition, continued:

Deferred revenues, continued

Monetary contributions received from third parties used to either connect a customer to a network or to provide the customer 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.

(h) 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. Such types of 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. The Company has not entered into any finance lease arrangements as a lessee.

(i) 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.

2. Significant accounting policies, continued:

(i) Non-derivative financial instruments, continued:

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 and trade and other receivables. Non-current loans and other long-term receivables comprise 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 2015 and 2020.

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 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 or cancelled or expire.

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.

As a result of the acquisition of Element Power U.S., LLC (Element) as described in note 10, the Company now 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 have 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 the Macho Springs project, 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 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 is 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.

(j) 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

2. Significant accounting policies, continued:

(j) Derivative instruments and hedging activities, continued:

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 or energy purchases and fuel and realized gains and losses on foreign exchange derivatives are recorded in revenues or foreign exchange gains and losses, as appropriate, while unrealized gains and losses are recorded in other comprehensive income. If hedge accounting requirements are not met, unrealized and realized gains and losses on financial energy derivatives are recorded in revenues or energy purchases and fuel as appropriate, unrealized and realized gains and losses on financial foreign exchange derivatives are recorded in revenues or foreign exchange gains and losses and such gains and losses on financial interest rate derivatives are recorded in 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.

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.

2. Significant accounting policies, continued:

(j) Derivative instruments and hedging activities, continued:

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 income, while the ineffective portion is recognized in energy revenues or energy purchases or fuel, as appropriate. The amounts recognized in other comprehensive 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 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 income are recognized in net income in the same period as the corresponding gains or losses on the hedged item. 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 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.

(k) Property, plant and equipment:

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

2. Significant accounting policies, continued:

(k) Property, plant and equipment, continued:

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 53 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.

(l) 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 19 for additional discussion on intangible assets.

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

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:

Alberta PPA	12 years
Contract rights	7 to 51 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.

2. Significant accounting policies, continued:

(m) Development costs:

Development activities involve a plan or design for the production of new or substantially improved products and processes. Development expenditures are capitalized only if development costs can be measured reliably, the product or process is technically and commercially feasible, 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 expenditures are recognized in income or loss as incurred.

Capitalized development expenditures are measured at cost less accumulated amortization and accumulated impairment losses.

(n) 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.

(o) 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 based on estimated market values based on actual market transactions, if available. When actual market transactions are not available, a valuation model is used.

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.

2. Significant accounting policies, continued:

(p) Impairment of financial assets:

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 taxes. Current and deferred tax is recognized in net income except to the extent that it relates to a business combination, or items recognized directly in equity or in other comprehensive income.

Current income taxes for the current period, including any adjustments to taxes payable in respect of previous years, are recognized and measured at the amount expected to be recovered from or payable to the taxation authorities based on the tax rates that are enacted or substantively enacted by the end of the reporting period.

Deferred income tax assets and liabilities are recognized for temporary differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases using the tax rates that are expected to apply in the period in which the deferred tax asset or liability is expected to settle, based on the laws that have been enacted or substantively enacted by the reporting date. Such deferred tax assets and liabilities are not recognized if the temporary difference arises from goodwill or from the initial recognition (other than in a business combination) of other assets and liabilities in a transaction that affects neither the taxable income nor the accounting income. Deferred tax assets are generally recognized for all deductible temporary differences to the extent that it is probable that taxable income will be available against which they can be utilized. Deferred tax assets are reviewed at each reporting date and reduced accordingly to the extent that it is no longer probable that they can be utilized.

Deferred tax liabilities are recognized for taxable temporary differences associated with investments in subsidiaries, and interests in joint ventures, except where the Company is able to control the reversal of the temporary difference and it is probable that the temporary difference will not reverse in the foreseeable future. Deferred tax assets arising from deductible temporary differences associated with such investments and interests are only recognized to the extent that it is probable that there will be sufficient taxable income against which to utilize the benefits of the temporary differences and they are expected to reverse in the foreseeable future.

The Company records deferred income tax provisions related to its economic interest in CPLP and records current income taxes pursuant to the contractual provision in the CPLP Limited Partnership Agreement.

2. Significant accounting policies, continued:

(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. The fair values of the Company's emission credits fall within Level 2 of the Company's fair value hierarchy described in note 3. 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) Government assistance:

Government assistance is recognized when there is reasonable assurance that the Company will comply with the conditions attached to the government assistance and the grants will be received. Such assistance is recorded either as a reduction to the related expense or, where related to an asset, as deferred revenue and amortized over the useful life of the related asset.

(u) 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.

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 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.

(v) 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

2. Significant accounting policies, continued:

(v) Share-based payments, continued:

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.

(w) 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.

(x) Future accounting changes:

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 are effective for annual periods beginning on or after January 1, 2016. Early application is permitted.

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, 2017 and is to be applied retrospectively.

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 the above future accounting changes on the Company's consolidated financial statements.

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.

3. Use of judgments and estimates, continued:

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.

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(h), 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 16.

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 33.

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 34.

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 of 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.

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.

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

- Note 10 – Purchase price allocation;
- Note 11 – Impairment testing;
- Note 14 – Inventories - emissions credits;
- Notes 15 and 30 – Financial instruments;
- Note 24 – Decommissioning and other provisions; and
- Note 29 – 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.

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 18.

Revenue recognition

As noted in note 2(g), 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.

4. Revenues:

Capital Power is a party to various agreements with Prairie Mines & Minerals Royalty Ltd. (PMRL) in relation to the operations of the Genesee Coal Mine (Genesee Coal Mine Agreements). Pursuant to the Genesee Coal Mine Agreements, PMRL operates the Genesee Coal Mine. In connection with the 2014 acquisition by Westmoreland Coal Company (Westmoreland) of PMRL and the 2014 acquisition by Altius Minerals Corporation (Altius) of the royalty assets of PMRL, the Genesee Coal Mine Agreements and certain related agreements were, among other things, amended to: (a) confirm the acquisitions by Westmoreland and Altius; (b) provide for certain amendments to the Genesee Coal Mine Agreements; and (c) provide for a payment to Capital Power of $20 million upon completion of the acquisitions, which was received in 2014 and recorded within revenues (year ended December 31, 2013 – nil).

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

5. Expenses:

	2014	2013
Included in other raw materials and operating charges		
Settlement of claim with turbine supplier	$ (8)	$ -
Included in staff costs and employee benefits expense		
Share-based payments (note 29)	8	4
Post-employment defined contribution plan expense	8	8
Post-employment defined benefit plan expense	4	5
Included in depreciation and amortization		
Depreciation of property, plant and equipment (note 20)	155	185
Amortization of intangible assets (note 19)	21	21
Losses on retirement of property, plant and equipment	3	7
Other	10	9
	189	222
Included in other administrative expenses		
Operating lease payments	8	5

6. Finance expense:

	2014	2013
Interest expense		
Interest on loans and borrowings	$ 84	$ 89
Capitalized interest	(39)	(21)
Total interest expense	45	68
Other finance expense		
Gain on interest rate non-hedges (note 15)	(2)	-
Charge on early debt extinguishment (note 23)	2	-
Unwinding of discount on decommissioning provisions (note 24)	3	4
Other	7	6
Finance expense	$ 55	$ 78

7. Income tax:

	2014	2013
Current income tax		
Current income tax expense (recovery)	$ 11	$ (4)
Deferred income tax		
Relating to origination and reversal of temporary differences	26	42
Relating to prior periods	(1)	(5)
Relating to write-downs of deferred tax assets	83	12
Total deferred income tax expense	108	49
Income tax expense	$ 119	$ 45

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

7. Income tax, continued:

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

	2014	2013
Income before tax	$ 169	$ 273
Income tax at the statutory rate of 25.0%	42	68
Increase (decrease) resulting from:		
Amounts attributable to non-controlling interests	(4)	(9)
Amounts relating to gain on disposal	-	10
Change in unrecognized tax benefits	83	(4)
Non-taxable amounts	(1)	(5)
Prior period tax adjustments	(1)	(5)
Statutory and other rate differences	(1)	(9)
Other	1	(1)
Income tax expense	$ 119	$ 45

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:

	2014	2013
Income for the period attributable to shareholders of the Company	$ 46	$ 175
Preferred share dividends of the Company [1]	(23)	(20)
Earnings used in the calculation of basic earnings per share	$ 23	$ 155

[1] Includes preferred share dividends declared for the years ended December 31, 2014 and 2013 respectively and related taxes.

	2014	2013
Weighted average number of common shares used in the calculation of basic earnings per share	82,309,777	72,818,513

Diluted earnings per share

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

	2014	2013
Earnings used in the calculation of basic earnings per share	$ 23	$ 155
Effect of exchangeable limited partnership units issued to EPCOR for common shares [2]	-	51
Earnings used in the calculation of diluted earnings per share	$ 23	$ 206

[2] The exchangeable limited partnership units issued to EPCOR may be exchanged for common shares of Capital Power on a one-for-one basis. For the year ended December 31, 2014, the potential exchange of such units for common shares of the Company was not included in the calculation of diluted earnings per share as it was antidilutive. For the year ended December 31, 2013, the potential exchange of such units for common shares of the Company had a dilutive impact as the potential exchange would remove the attribution of net income to non-controlling interests related to CPLP of $65 million. Additionally, the income tax provision of the Company would need to be adjusted to reflect the non-controlling interest's share of CPLP income tax expenses of $14 million.

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

8. Earnings per share, continued:

Diluted earnings per share, continued

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:

	2014	2013
Weighted average number of common shares used in the calculation of basic earnings per share	82,309,777	72,818,513
Effect of dilutive share purchase options [1]	233,777	-
Effect of exchangeable limited partnership units issued to EPCOR for common shares	-	26,047,575
Weighted average number of common shares used in the calculation of diluted earnings per share	82,543,554	98,866,088

[1] For the year ended December 31, 2014, the average market price of the Company's common shares exceeded the exercise price of all granted share purchase options described in note 29, but had a neutral effect on earnings per share. For the year ended December 31, 2013, the average market price of the Company's common shares was below the exercise price of all granted share purchase options described in note 29 and as a result none of the share purchase options had a dilutive effect on earnings per share.

9. Disposal of subsidiaries:

On November 19, 2013, the Company completed the sale to a third party of one hundred percent of Capital Power's equity interests in Bridgeport Energy, LLC, Tiverton Power, LLC, and Rumford Power Inc. (the North East U.S. assets) for gross proceeds of $577 million (US$550 million) less transaction costs of $8 million (US$8 million). The gross proceeds at the close of the transaction included $9 million (US$9 million) of working capital adjustments. The carrying amount of net assets disposed of was $551 million.

Prior to the close of the transaction, accumulated foreign currency translation gains of $59 million relating to the North East U.S. assets were included in the accumulated other comprehensive income within other reserves on the consolidated statements of financial position. These amounts were reclassified to net income, within the gain on disposal, upon close of the transaction.

The gain recognized on disposal of the subsidiaries was as follows:

	2014	2013
Gain on disposal of North East U.S. assets	$ -	$ 76

10. Business combination:

On December 19, 2014, the Company acquired one hundred per cent of the equity interest in Element which included a portfolio of wind and solar energy development sites in the U.S. and Macho Springs, a 50 megawatts (MW) wind farm in New Mexico that has been operating since 2011 under a 20-year PPA.

The total fair value of consideration was $37 million (US$32 million) which consisted of $21 million (US$18 million) in base purchase price, preliminary normal working capital adjustments of $4 million (US$4 million), and contingent consideration of $12 million (US$10 million) payable upon reaching specified milestones in connection with the development sites acquired. Contingent consideration is recorded in non-current other liabilities as at December 31, 2014. The valuation model for contingent consideration is based on the present value of 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.

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

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

10. Business combination, continued:

	December 19, 2014
Cash	$ 3
Other assets	3
Intangibles[1]	36
Property, plant and equipment	103
Loans and borrowings	(76)
Provisions	(3)
Deferred tax liabilities	(29)
Fair value of net assets acquired	$ 37

[1] Intangibles acquired consisted of land leases, permits and interconnection agreements which are recorded to work in progress until such time that the assets are constructed and commissioned for service or development is discontinued.

Measurement of fair values

The fair value measurement of material assets acquired is categorized in Level 3 of the fair value hierarchy as described in note 3. The valuation techniques used for measuring the fair values were as follows:

Property, plant and equipment

The Company used the cost approach in determining the fair value of the property, plant and equipment acquired. The valuation considered the current replacement cost for the assets acquired. The replacement cost was used as the basis to calculate depreciated replacement cost, which reflects adjustments for physical deterioration as well as functional and economic obsolescence.

Intangible assets

The Company used the market comparison and cost approaches, where appropriate, in determining the fair value of the intangible assets acquired. For projects that used the market comparison approach, the valuation model considered quoted market prices for similar development opportunities. For other development projects, the cost approach was applied given the lack of availability of relevant market data for a market approach and a lack of cash flow data for an income approach. The cost approach considers the cost incurred to date in developing the sites, and applies multiples ranging from two times to three times based on the degree of advancement of the project as well as the likelihood of success.

Due to the timing of the transaction's close date, information required to finalize the purchase price allocation is outstanding. As a result, the estimated fair values allocated to the acquired assets and assumed liabilities above are preliminary and are subject to change. The Company expects to finalize the purchase price allocation in 2015.

The results of Macho Spring's operations are included in the Company's consolidated statements of income and statements of changes in equity from the date of acquisition. In addition, the related assets and liabilities as at December 31, 2014 are included in the consolidated statement of financial position.

Amounts included in the consolidated statement of income for the year ended December 31, 2014, since the date of acquisition were immaterial. Had the acquisition occurred at January 1, 2014, the Company would have recorded consolidated revenues of $1,240 million and consolidated net income of $47 million for the year ended December 31, 2014.

In conjunction with the above acquisition, the Company incurred immaterial acquisition costs which have been recorded on the Company's statement of income as other administrative expenses for the year ended December 31, 2014.

11. Impairment testing:

The Company reviews its CGUs that contain goodwill on an annual basis, generally in the third quarter, to determine whether any impairments should be recognized. As a result, the Company's Southport CGU was tested for impairment during the third quarter of 2014. The carrying amount of the Southport CGU was within the range of its estimated recoverable amount and as such, no impairment was required. During the year ended December 31, 2013, the Company tested its North East U.S. CGU for impairment immediately prior to classifying those assets as held for sale and recorded pre-tax impairments of $6 million.

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

11. Impairment testing, continued:

Impairments recognized in the years ended December 31, 2014 and 2013, respectively, were as follows:

	2014	2013
Property, plant and equipment (note 20)	$ -	$ 6
Total impairments	$ -	$ 6

Key assumptions used in calculating recoverable amounts

The recoverable amount of the Southport CGU was determined based on its fair value less costs to sell, estimated using discounted cash flows. The fair value measurement of the Southport CGU is categorized in Level 3 of the fair value hierarchy, as described in note 3, 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 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:

	2014	2013
Discount rate – currently contracted period	7.9%	7.9%
Discount rate – post current contract period	9.9%	9.9%
Growth rate	2.0%	2.0%

Other key cash flow assumptions

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

The Company has assumed the Southport power purchase agreement will be extended for 10 years following the expiry of the current agreement at rates consistent with current pricing, adjusted for 1% inflation. The Company has also assumed that the Southport facility will optimize its fuel mix at 50% wood waste and 50% tire-derived fuel (TDF), and will execute long-term contracts 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.

12. Cash and cash equivalents:

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 $18 million (December 31, 2013 - $30 million).

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

13. Trade and other receivables:

	December 31, 2014	December 31, 2013
Accrued revenues	$ 124	$ 143
Trade receivables	33	29
Receivables from related parties (note 28)	3	6
Finance lease receivable (note 16)	20	21
Allowance for doubtful accounts (note 31)	(5)	-
Net trade receivables	175	199
Income taxes recoverable	1	12
Prepayments	9	7
	$ 185	$ 218

Details of the aging of trade receivables and analysis of the movement on the allowance for doubtful accounts are provided in note 31.

14. Inventories:

	December 31, 2014	December 31, 2013
Parts and other consumables	$ 53	$ 50
Coal	19	19
Emission credits	32	23
	$ 104	$ 92

Inventories expensed upon usage for the year ended December 31, 2014 of $163 million (year ended December 31, 2013 - $133 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 15. Write-downs of $1 million in inventories were recognized in the year ended December 31, 2014 (year ended December 31, 2013 - nil). There were no reversals of previous write downs recognized in the year ended December 31, 2014 (year ended December 31, 2013 - nil). As at December 31, 2014, no inventories were pledged as security for liabilities (December 31, 2013 - nil).

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

15. 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 31 consist of the following:

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

	December 31, 2013				
	Energy		Foreign exchange	Interest rate	
	cash flow hedges	non-hedges	cash flow hedges	non-hedges	Total
Derivative instruments assets:					
Current	$ 7	$ 24	$ -	$ -	$ 31
Non-current	22	13	1	-	36
Derivative instruments liabilities:					
Current	(6)	(23)	(1)	(1)	(31)
Non-current	(5)	(5)	-	-	(10)
Net fair value	$ 18	$ 9	$ -	$ (1)	$ 26
Net notional buys (sells):					
Megawatt hours of electricity (millions)	(10)	(4)			
Gigajoules of natural gas (millions)	-	1			
Cross currency swaps and interest rate swaps (millions of U.S. dollars)			$ 195	$ 100	
Range of remaining contract terms in years	0.1 to 5.0	0.1 to 5.0	7.5 to 12.5	7.5	

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

15. Derivative financial instruments and hedge accounting, continued:

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.

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

	2014		2013	
	Unrealized gains	Realized gains	Unrealized (losses) gains	Realized (losses) gains
Energy cash flow hedges	$ 49	$ 22	$ (11)	$ (34)
Energy and emission non-hedges	34	43	26	152
Foreign exchange cash flow hedges[1]	2	-	-	-
Foreign exchange non-hedges	-	-	-	(1)
Interest rate non-hedges	-	2	(1)	1

[1] For the year ended December 31, 2014, unrealized gains of $19 million (year ended December 31, 2013 – nil) related to foreign exchange cash flow hedges were reclassified from other comprehensive income to net income to offset the impact of unrealized foreign exchange losses from the revaluation of U.S. dollar denominated loans and borrowings.

Realized and unrealized gains and losses relate only to derivative financial instruments. The following realized and unrealized gains and losses are included in the Company's statements of income for the years ended December 31, 2014 and 2013:

	2014	2013
Revenues	$ 311	$ 214
Energy purchases and fuel	(212)	(70)
Foreign exchange loss	19	(1)
Finance expense	2	-

The Company has elected to apply hedge accounting on certain derivatives it uses to manage commodity price risk relating to electricity and natural gas prices and certain derivatives it uses to manage currency risk relating to U.S. dollar denominated loans and borrowings. For the year ended December 31, 2014, the changes in the fair value of the ineffective portion of hedging derivatives required to be recognized in the statement of income was nil (year ended December 31, 2013 - nil).

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

15. Derivative financial instruments and hedge accounting, continued:

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

	December 31, 2014
Within one year	$ 29
Between one and five years	21
After five years	-
	$ 50

The Company's cash flow hedges extend to 2018 for energy cash flow hedges and to 2026 for foreign exchange cash flow hedges.

16. Leases:

Finance lease receivables

	Minimum lease payments		Present value of minimum lease payments	
	December 31, 2014	December 31, 2013	December 31, 2014	December 31, 2013
Amounts receivable under finance leases:				
Less than one year	$ 57	$ 57	$ 20	$ 18
Between one and five years	229	229	89	82
More than five years	925	981	619	632
Unearned finance income	(483)	(535)	-	-
Lease payment receivable	728	732	728	732
Less current portion: (included within trade and other receivables (note 13)	20	21	20	21
	$ 708	$ 711	$ 708	$ 711

The PPAs pertaining to the Company's wind generation facilities located in Ontario (Kingsbridge 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%, 6.21% 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 30.

Finance income of $43 million was recognized in revenues during the year ended December 31, 2014 (year ended December 31, 2013 - $20 million).

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, 2014, the cost of such property, plant and equipment was $1,211 million (December 31, 2013 - $1,188 million), less accumulated depreciation of $268 million (December 31, 2013 - $224 million).

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

	December 31, 2014
Within one year	$ 61
Between one and five years	248
After five years	81
	$ 390

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

17. Other financial assets:

	December 31, 2014	December 31, 2013
Other financial assets – non-current:		
Loans and other long-term receivables	$ 16	$ 34
Available for sale - portfolio investments	2	2
	$ 18	$ 36

18. Deferred tax:

Deferred tax assets and liabilities are attributable to the following as at December 31, 2014 and 2013:

	Assets		Liabilities		Net	
	2014	2013	2014	2013	2014	2013
Losses carried forward	$ 21	$ 84	$ -	$ -	$ 21	$ 84
Difference in accounting and tax basis of property, plant and equipment	-	6	(153)	(87)	(153)	(81)
Difference in accounting and tax basis of intangible assets	18	42	(6)	(22)	12	20
Deferred partnership income	-	4	(1)	-	(1)	4
Derivative financial instruments	25	11	(50)	(16)	(25)	(5)
Share issue costs and deferred financing charges	2	5	-	-	2	5
Equity-accounted investment	5	-	-	-	5	-
Deferred revenue and other liabilities	23	20	-	-	23	20
Finance lease receivables	-	-	(149)	(148)	(149)	(148)
Decommissioning provisions	37	27	-	-	37	27
Goodwill	-	-	(8)	(8)	(8)	(8)
Prepaid reclamation amounts	-	-	(14)	(14)	(14)	(14)
Other provisions	11	9	-	-	11	9
Loans and borrowings	7	-	(1)	(1)	6	(1)
Trade and other receivables	1	-	-	-	1	-
Other assets	4	3	-	-	4	3
Deferred tax assets (liabilities)	$ 154	$ 211	$ (382)	$ (296)	$ (228)	$ (85)
Set off of tax	(133)	(116)	133	116	-	-
Net deferred tax assets (liabilities)	$ 21	$ 95	$ (249)	$ (180)	$ (228)	$ (85)

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

18. Deferred tax, continued:

Movement in temporary differences during the year ended December 31, 2014:

	As at January 1, 2014	Recognized in net income	Recognized directly in other comprehensive income	Amounts relating to acquisitions and disposals	Recognized directly in equity	Reclassified from equity to net income	As at December 31, 2014
Losses carried forward	$ 84	$ (65)	$ 3	$ -	$ 7	$ (8)	$ 21
Difference in accounting and tax basis of property, plant and equipment	(81)	(40)	-	(32)	-	-	(153)
Difference in accounting and tax basis of intangible assets	20	-	-	(8)	-	-	12
Deferred partnership income	4	(5)	-	-	-	-	(1)
Derivative financial instruments	(5)	(10)	(10)	-	-	-	(25)
Share issue costs and deferred financing charges	5	-	-	-	-	(3)	2
Equity-accounted investment	-	-	5	-	-	-	5
Deferred revenue and other liabilities	20	(1)	-	4	-	-	23
Finance lease receivables	(148)	1	-	(2)	-	-	(149)
Decommissioning provisions	27	7	1	2	-	-	37
Goodwill	(8)	1	(1)	-	-	-	(8)
Prepaid reclamation amounts	(14)	-	-	-	-	-	(14)
Other provisions	9	2	-	-	-	-	11
Loans and borrowings	(1)	-	-	7	-	-	6
Trade and other receivables	-	1	-	-	-	-	1
Other assets	3	1	-	-	-	-	4
	$ (85)	$ (108)	$ (2)	$ (29)	$ 7	$ (11)	$ (228)

Movement in temporary differences during the year ended December 31, 2013:

	As at January 1, 2013	Recognized in net income	Recognized directly in other comprehensive income	Amounts relating to acquisitions and disposals	Recognized directly in equity	Reclassified from equity to net income	As at December 31, 2013
Losses carried forward	$ 59	$ 22	$ 4	$ -	$ 7	$ (8)	$ 84
Difference in accounting and tax basis of property, plant and equipment	(110)	6	(2)	25	-	-	(81)
Difference in accounting and tax basis of intangible assets	15	19	-	(14)	-	-	20
Deferred partnership income	18	(14)	-	-	-	-	4
Derivative financial instruments	2	(8)	3	(2)	-	-	(5)
Share issue costs and deferred financing charges	7	(4)	-	-	2	-	5
Other financial assets	(4)	5	-	(1)	-	-	-
Deferred revenue and other liabilities	18	-	-	2	-	-	20
Finance lease receivables	(84)	(52)	-	(12)	-	-	(148)
Decommissioning provisions	43	(21)	2	3	-	-	27
Goodwill	(8)	-	-	-	-	-	(8)
Prepaid reclamation amounts	(12)	-	-	(2)	-	-	(14)
Other provisions	11	(1)	(1)	-	-	-	9
Loans and borrowings	-	(1)	-	-	-	-	(1)
Other assets	3	-	-	-	-	-	3
	$ (42)	$ (49)	$ 6	(1)	$ 9	$ (8)	$ (85)

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

18. Deferred tax, continued:

The deferred tax assets presented on the consolidated statements of financial position are recoverable based on estimated future earnings and the reversal of taxable temporary differences. The assumptions used in the estimate of future earnings are based on the Company's cash flow projections, which include estimates described in note 11.

During the year ended December 31, 2014, the Company reversed previously recognized deferred tax assets of $73 million (US$66 million) relating to non-capital losses of $216 million (US$186 million) from U.S. subsidiaries that will expire between 2027 and 2033. At December 31, 2014, the Company has not recognized deferred tax assets on temporary differences of $177 million (December 31, 2013 - $155 million) and non-capital losses from U.S. subsidiaries totaling $281 million (US$242 million) (December 31, 2013: $38 million - US$36 million).

As at December 31, 2014, the Company has non-capital losses carried forward of $365 million (December 31, 2013 - $294 million), of which $281 million (US$242 million) (December 31, 2013: $236 million - US$222 million) relates to U.S. subsidiaries. These losses expire between 2027 and 2034.

19. Intangible assets:

	Intangible work in progress	PPAs	Contract rights	Other rights	Emission credits	Software	Total
Cost							
As at January 1, 2013	$ 12	$ 140	$ 35	$ 114	$ 33	$ 26	$ 360
Additions from separate acquisition	39	-	-	2	27	3	71
Additions into service	(13)	-	-	-	-	13	-
Disposal of North East U.S. assets	-	-	-	-	(15)	-	(15)
Other disposals	-	-	-	-	(7)	-	(7)
Transfers to finance lease receivables	(8)	-	-	(7)	-	-	(15)
Transfers to inventory	-	-	-	-	(9)	-	(9)
As at December 31, 2013	$ 30	$ 140	$ 35	$ 109	$ 29	$ 42	$ 385
Additions from separate acquisition	10	-	-	6	16	-	32
Additions into service	(5)	-	-	1	-	4	-
Acquisition through business combination (note 10)	36	-	-	-	-	-	36
Other disposals	-	-	-	-	(1)	(1)	(2)
Transfers to finance lease receivables	(5)	-	-	-	-	-	(5)
As at December 31, 2014	$ 66	$ 140	$ 35	$ 116	$ 44	$ 45	$ 446
Accumulated amortization							
At January 1, 2013	$ -	$ (43)	$ (1)	$ (5)	$ -	$ (5)	$ (54)
Amortization	-	(12)	(2)	(2)	-	(5)	(21)
As at December 31, 2013	$ -	$ (55)	$ (3)	$ (7)	$ -	$ (10)	$ (75)
Amortization	-	(12)	(2)	(2)	-	(5)	(21)
As at December 31, 2014	$ -	$ (67)	$ (5)	$ (9)	$ -	$ (15)	$ (96)
Net book value							
As at January 1, 2013	$ 12	$ 97	$ 34	$ 109	$ 33	$ 21	$ 306
As at December 31, 2013	$ 30	$ 85	$ 32	$ 102	$ 29	$ 32	$ 310
As at December 31, 2014	$ 66	$ 73	$ 30	$ 107	$ 44	$ 30	$ 350

Acquired PPAs are recorded at the cost of acquisition. Under the terms of the Company's Sundance and Joffre PPAs, the Company is obligated to make fixed and variable payments to the owners of the underlying generation units over their respective terms. Such amounts are recorded as operating expenses as incurred.

The Sundance PPA is owned under an equity syndication agreement with an equity syndicate. Under the terms of the agreement, the syndicate members receive their proportionate share of the committed generating capacity in exchange for their proportionate share of the price paid for the Sundance PPA and all payments to the generation unit owners.

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

19. Intangible assets, continued:

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

Other rights include the cost of land lease agreements for use in wind and solar power projects in Alberta, British Columbia, and Ontario, 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, 2014 (year ended December 31, 2013 - nil). No previous impairments of intangible assets were reversed during the year ended December 31, 2014 (year ended December 31, 2013 - nil).

Capitalized borrowing costs

Borrowing costs were not capitalized on intangible assets during the years ended December 31, 2014 or 2013.

Restrictions on assets

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

20. Property, plant and equipment:

	Construction work in progress	Land	Plant and equipment	Total
Cost				
As at January 1, 2013	$ 91	$ 104	$ 3,932	$ 4,127
Additions	932	-	5	937
Additions into service	(91)	10	81	-
Disposal of North East U.S. assets	-	(7)	(747)	(754)
Retirements and other disposals	-	-	(1)	(1)
Transfers to finance lease receivables	(256)	-	-	(256)
Revisions to decommissioning costs	-	-	(38)	(38)
Foreign currency translation adjustments	-	-	51	51
As at December 31, 2013	$ 676	$ 107	$ 3,283	$ 4,066
Additions	201	-	-	201
Additions into service	(69)	4	65	-
Acquisitions through business combination (note 10)	-	-	103	103
Retirements and other disposals	-	(3)	(37)	(40)
Transfers to finance lease receivables	(1)	-	(7)	(8)
Revisions to decommissioning costs	-	-	32	32
Foreign currency translation adjustments	-	-	12	12
As at December 31, 2014	$ 807	$ 108	$ 3,451	$ 4,366
Accumulated depreciation				
At January 1, 2013	$ -	$ -	$ (499)	$ (499)
Depreciation	-	-	(185)	(185)
Disposal of North East U.S. assets	-	-	162	162
Retirements and other disposals	-	-	1	1
Foreign currency translation adjustments	-	-	(14)	(14)
Impairments (note 11)	-	-	(6)	(6)
As at December 31, 2013	$ -	$ -	$ (541)	$ (541)
Depreciation	-	-	(155)	(155)
Retirements and other disposals	-	-	37	37
Foreign currency translation adjustments	-	-	(6)	(6)
As at December 31, 2014	$ -	$ -	$ (665)	$ (665)
Net book value				
As at January 1, 2013	$ 91	$ 104	$ 3,433	$ 3,628
As at December 31, 2013	$ 676	$ 107	$ 2,742	$ 3,525
As at December 31, 2014	$ 807	$ 108	$ 2,786	$ 3,701

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

20. Property, plant and equipment, continued:

Impairments

No impairments of property, plant and equipment were recognized during the year ended December 31, 2014 (year ended December 31, 2013 - $6 million) as described in note 11. No reversals of impairments on property, plant and equipment were recognized during the year ended December 31, 2014 (year ended December 31, 2013 - 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 5.26% (year ended December 31, 2013 – 5.26%) for projects financed using general borrowings. For the years ended December 31, 2014 and December 31, 2013, 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 23.

21. Goodwill:

	2014	2013
Cost		
As at January 1	$ 23	$ 46
Disposal of North East U.S. assets	-	(24)
Foreign currency translation adjustments	2	1
As at December 31	$ 25	$ 23
Accumulated impairments		
As at January 1	$ -	$ (24)
Disposal of North East U.S. assets	-	24
As at December 31	$ -	$ -
Net book value		
As at January 1	$ 23	$ 22
As at December 31	$ 25	$ 23

The aggregate carrying amounts of goodwill allocated to the Company's CGUs at December 31, 2014 and December 31, 2013 are substantially all related to the Company's Southport CGU.

Impairments

No impairments of goodwill were recorded in the consolidated statement of income for the year ended December 31, 2014 (year ended December 31, 2013 – nil).

22. Trade and other payables:

	December 31, 2014	December 31, 2013
Operating accruals	$ 99	$ 110
Trade payables	34	36
Dividends and distributions payable	35	31
Accrued interest	15	15
Income taxes payable	2	6
	$ 185	$ 198

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

23. Loans and borrowings:

	Effective interest rate	December 31, 2014	December 31, 2013
CPLP unsecured senior debt payable to EPCOR			
Due in 2016 at 6.75%	6.16%	$ 130	$ 130
Due in 2018 at 5.80%	5.63%	164	164
Due between 2015 and 2018 at 9.00%	7.41%	40	47
Total CPLP debt payable to EPCOR		334	341
Less: current portion		334	341
		-	-
CPLP debt payable to non-related parties			
Unsecured senior medium-term notes, at 4.60% payable semi-annually, due in 2015	4.69%	249	300
Unsecured senior medium-term notes, at 4.85% payable semi-annually, due in 2019	4.96%	250	250
Unsecured senior medium-term notes, at 5.28% payable semi-annually, due in 2020	5.34%	300	300
Unsecured senior notes (US$230), at 5.21% payable semi-annually, due in 2021	5.29%	267	245
Unsecured senior notes (US$65), at 5.61% payable semi-annually, due in 2026	5.67%	75	69
Revolving extendible credit facilities (US$30), at floating rates, due in 2018	2.89%	17	-
Non-recourse financing:			
Joffre Cogeneration Project, at 8.59% payable quarterly, due in 2020	8.31%	29	34
Macho Springs, at 6.90% payable quarterly, due in 2031	6.9%	59	-
Tax-equity financing:			
Macho Springs, at 13.85% payable quarterly	13.85%	16	-
Total CPLP debt payable to non-related parties		1,262	1,198
Less: current portion		265	5
		997	1,193
Less: deferred debt issue costs		10	12
		$ 987	$ 1,181

Unsecured senior debt payable to EPCOR

The unsecured senior debt payable to EPCOR matures between 2015 and 2018. As at December 31, 2014 and 2013, 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. As a result, as at December 31, 2014 and 2013, all of the unsecured senior debt payable to EPCOR has been classified as current loans and borrowings.

Unsecured senior medium-term notes

During the year ended December 31, 2014, the Company repurchased $51 million of its 4.60% unsecured medium-term notes due in 2015 (year ended December 31, 2013 - nil) and incurred $2 million in finance charges associated with the early extinguishment of the debt (note 6).

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

23. Loans and borrowings, continued:

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 $66 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 $103 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 2017.

CPLP revolving extendible credit facilities

Unsecured credit facilities of $700 million committed to 2018 and uncommitted amounts of $20 million, are available to CPLP. As at December 31, 2014, the Company had U.S. LIBOR loans of $17 million (US$14 million) outstanding under these facilities (December 31, 2013 – nil). Additional uncommitted amounts of $5 million are available to the Company and are undrawn at December 31, 2014 (December 31, 2013 – $5 million).

The Company also has unsecured credit facilities of $500 million available through its CPLP subsidiary. These facilities have a maturity date of July 9, 2018. As at December 31, 2014, no amounts have been drawn on these facilities (December 31, 2013 – nil), and letters of credit of $122 million (December 31, 2013 – $160 million) have been issued as described in note 36.

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.

24. Provisions:

	December 31, 2014	December 31, 2013
Decommissioning	$ 161	$ 120
Employee benefits [1]	56	50
Other	3	5
	220	175
Less: current portion	22	27
	$ 198	$ 148

[1] Included in the employee benefits provision is $13 million pertaining to the share-based payment obligations described in note 29, of which $13 million is vested at December 31, 2014 (December 31, 2013 - $8 million total share based payment obligation, $8 million vested).

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

24. Provisions, continued:

	Decommissioning	Employee benefits	Other	Total
As at January 1, 2013	$ 173	$ 52	$ 13	$ 238
Additional liabilities incurred	16	31	-	47
Liabilities settled	(1)	(29)	-	(30)
Amounts reversed unused	-	(4)	(8)	(12)
Foreign currency translation adjustments	3	-	-	3
Revisions to decommissioning costs (note 20)	(38)	-	-	(38)
Unwinding of the discount (note 6)	4	-	-	4
Settlement on disposal North East U.S. assets	(37)	-	-	(37)
As at December 31, 2013	$ 120	$ 50	$ 5	$ 175
Additional liabilities incurred	2	22	(1)	23
Additional liabilities acquired in business combination (note10)	3	-	-	3
Liabilities settled	(1)	(15)	-	(16)
Amounts reversed unused	1	(1)	(1)	(1)
Foreign currency translation adjustments	1	-	-	1
Revisions to decommissioning costs (note 20)	32	-	-	32
Unwinding of the discount (note 6)	3	-	-	3
As at December 31, 2014	$ 161	$ 56	$ 3	$ 220

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, 2014, the Company estimates the undiscounted amount of cash flow required to settle its decommissioning obligations is approximately $302 million, calculated using an inflation rate of 2%. The expected timing for settlement of the obligations is between 2015 and 2061, 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 2033 and 2061 for the power generation facilities and between 2015 and 2020 for the un-reclaimed sections of the Genesee coal mine. Discount rates used to calculate the carrying amount of the obligations range from 0.99% to 2.34%. 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.

Other provisions

The Company holds retail and commercial natural gas customer contracts in Alberta. The future unavoidable costs of meeting the terms of these contracts are expected to exceed the economic benefits to be received under these contracts. As a result, a provision has been recorded on the consolidated statement of financial position to reflect the estimated present value of the loss on these contracts. The expected timing of settlement of these contracts range from 2015 to 2046 and the costs were discounted using risk free rates between 1.01% and 2.48%. The timing and amount of settlement of the obligation is dependent on expectations of renewal of the contracts and expectations over the forward price of natural gas.

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

25. Share capital:

Authorized shares

	Number of shares authorized
Common shares	unlimited
Preference shares, issuable in series	unlimited
Special voting shares	unlimited
Special limited voting share	one

Issued and fully paid shares

	Common shares		Preference shares		Special voting shares	
	Number of shares	Amount	Number of shares	Amount	Number of shares	Amount
As at January 1, 2013	69,955,693	$ 1,635	11,000,000	$ 268	28,441,000	$ -
Shares issued	-	-	8,000,000	200	-	-
Share issue costs	-	-	-	(6)	-	-
Deferred taxes on share issue costs	-	-	-	2	-	-
Shares exchanged [1]	9,600,000	202	-	-	(9,600,000)	-
Share purchase options exercised (note 29)	1,757	-	-	-	-	-
Dividend reinvestment plan	1,332,428	27	-	-	-	-
As at December 31, 2013	80,889,878	$ 1,864	19,000,000	$ 464	18,841,000	$ -
Share purchase options exercised (note 29)	1,028,778	26	-	-	-	-
Dividend reinvestment plan	1,542,240	37	-	-	-	-
As at December 31, 2014	83,460,896	$ 1,927	19,000,000	$ 464	18,841,000	$ -

[1] During the year ended December 31, 2013, EPCOR exchanged 9,600,000 of its exchangeable limited partnership units in CPLP on a one-for-one basis for common shares of Capital Power and subsequently entered into an agreement for a secondary offering of 9,600,000 common shares of Capital Power at an offering price of $21.00 per common share. There were no exchanges that occurred during the year ended December 31, 2014.

There were no transactions in respect of the special voting limited share during the years ended 2014 and 2013.

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. The Rights Plan will continue in force until the end of the annual meeting of shareholders in 2016 subject to any changes in applicable securities law requirements.

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

25. Share capital, continued:

Cumulative rate reset preference shares

Preferred shares	Dividend per share per annum[1]	Dividend rate reset	Redemption terms	Conversion terms[2]
Series 1	$1.15	Dividend rate will be reset on December 31, 2015 and 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, 2015 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, 2015 and on December 31 of every fifth year thereafter.
Series 3	$1.15	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%.	The 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.

[1] Holders of Series 1, Series 3, and Series 5 shares will be entitled to receive fixed cumulative quarterly dividends that yield 4.60%, 4.60%, and 4.50%, 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.

[2] Holders of Series 2, Series 4, and Series 6 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% and 3.15%, respectively, as and when declared by the board of directors of Capital Power.

Special voting shares

The special voting shares and special limited voting shares were issued to a related party, EPCOR. The special limited voting share entitles holders the right to vote as a class on any matter that would: (i) change the location of Capital Power's head office to a place other than the City of Edmonton in the Province of Alberta; (ii) amend the articles of Capital Power to, or result in a transaction that would, in each case, impact the location of the head office or its meaning as defined in Capital Power's articles; or (iii) amend the rights attaching to the special limited voting share.

The special voting shareholders are entitled to nominate and elect four Directors to the Company's Board of Directors, provided that they own not less than 20% of the aggregate number of outstanding Capital Power common shares and CPLP exchangeable LP units (exchangeable for Capital Power common shares). The special voting shareholders are entitled to nominate and elect two Directors to the Company's Board of Directors, provided that they own less than 20% but not less than 10% of the aggregate number of outstanding Capital Power common shares and CPLP exchangeable LP units.

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

25. Share capital, continued:

The common and preferred share dividends declared and paid by the Company for the years ended December 31, 2014 and December 31, 2013 are summarized as follows:

	Dividends declared				Dividends paid			
	2014		2013		2014		2013	
	Per share	Total	Per share	Total	Per share	Total	Per share	Total
Common [1,2]	$ 1.3100	$ 108	$ 1.2600	$ 92	$ 1.2850	$ 105	$ 1.2600	$ 89
Preference, Series 1	1.1500	6	1.1500	6	1.1500	6	1.1500	6
Preference, Series 3	1.1500	7	1.1776	7	1.1500	7	1.1776	7
Preference, Series 5	1.125	9	0.8954	7	1.125	9	0.8954	7

[1] On July 25, 2014, the Company's Board of Directors approved an increase of 7.9% in the quarterly dividend to $1.36 per common share effective for the third quarter of 2014.

[2] For the year ended December 31, 2014, dividends paid on common shares consist of $68 million paid in cash and $37 million paid through the Company's dividend reinvestment plan as common shares issued. For the year ended December 31, 2013, dividends paid on common shares consist of $62 million paid in cash and $27 million paid through the Company's dividend reinvestment plan as common shares issued.

26. Other reserves:

Components of other comprehensive 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 is reclassified to net income or loss only when the hedged transaction affects the net income or loss, or is included as a basis adjustment to the non-financial hedged item, consistent with the relevant accounting policy.

Cumulative translation account

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 29.

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

27. Change in non-cash operating working capital:

	2014	2013
Trade and other receivables	$ 25	$ 108
Inventories	(13)	(10)
Trade and other payables	(6)	(31)
Deferred revenue and other liabilities	(1)	-
Provisions	(4)	4
	$ 1	$ 71

28. Related party balances and transactions:

Nature of transactions

Sales and purchases between the Company and its subsidiaries, or between subsidiaries of the Company, are made at normal market prices. Transactions between the Company and its subsidiaries and transactions between subsidiaries are eliminated on consolidation.

As described in note 34, the Company is party to a number of joint arrangements, primarily for the construction and operation of power generation 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.

Transactions and balances

The following transactions took place during the years ended December 31, 2014 and December 31, 2013 between the Company and its related parties:

	2014	2013
Revenues – energy sales:		
EPCOR and City of Edmonton [1]	$ 13	$ 27
Energy purchases and fuel:		
EPCOR [2]	2	1
Purchase of raw materials and other services:		
EPCOR	8	6
Finance expense:		
EPCOR [3]	13	18

[1] Energy sales of $11 million (year ended December 31, 2013 - $6 million) to EPCOR, and $2 million (year ended December 31, 2013 - $21 million) to the City of Edmonton.

[2] Energy purchases and fuel include energy distribution and transmission charges from EPCOR, net of charges flowed through to the City of Edmonton.

[3] Net finance expenses on loans and borrowings owed to EPCOR.

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

28. Related party balances and transactions, continued:

	December 31, 2014	December 31, 2013
Trade and other receivables from related parties:		
EPCOR and City of Edmonton [1]	$ 3	$ 6
Intangible assets:		
EPCOR [2]	4	4
Property, plant and equipment:		
EPCOR [3]	8	4
Trade and other payables to related parties:		
EPCOR [4]	13	14
Current provisions:		
EPCOR [5]	-	1
Non-current provisions:		
EPCOR [5]	2	2
Loans and borrowings from related parties (including current portion):		
EPCOR (note 23)	334	341
Share capital:		
EPCOR (note 25)	-	-

[1] Trade and other receivables includes $3 million (December 31, 2013 - $1 million) relating to energy sales to EPCOR, and nil (December 31, 2013 - $5 million) related to energy sales to the City of Edmonton.

[2] Contributions made to EPCOR for the construction of aerial and underground transmission lines.

[3] Interest on loans and borrowings from EPCOR capitalized to property, plant and equipment during the period.

[4] Trade and other payables includes interest accrued on the loans and borrowings owed to EPCOR of $6 million (December 31, 2013 - $6 million) and distributions payable to EPCOR of $7 million (December 31, 2013 - $6 million).

[5] The provision amounts represent an obligation to EPCOR for future maintenance costs associated with EPCOR's Rossdale plant through 2019.

In addition to the transactions disclosed above, the Company's subsidiary CPLP has recorded total distributions of $25 million to EPCOR for the year ended December 31, 2014 (year ended December 31, 2013 - $33 million). CPLP paid distributions of $24 million to EPCOR in the year ended December 31, 2014 (year ended December 31, 2013 - $36 million).

No provisions for doubtful debts have been established against the trade and other receivables balances for any related party. No bad debt expense was recognized in relation to any transaction with a related party that occurred during the year (2013 - nil).

Details of any commitments between Capital Power and its related parties are disclosed in note 35.

Compensation of key management personnel

	2014	2013
Short-term employee benefits	$ 5	$ 5
Termination benefits	-	-
Share-based payments	4	2
	$ 9	$ 7

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

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

29. 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 2014, the Company granted 725,571 share purchase options with one third vesting on March 12 of each of 2015, 2016 and 2017. The fair values of these options at grant date were $1.83, $1.90 and $1.96 per option for the 2015, 2016 and 2017 tranches respectively. Granted options may be exercised within 7 years of the grant date at a price of $24.80 per share.

In March 2013, the Company granted 740,304 share purchase options with one third vesting on March 14 of each of 2014, 2015 and 2016. The fair values of these options at grant date were $1.28, $1.31 and $1.34 per option for the 2014, 2015 and 2016 tranches respectively. Granted options may be exercised within 7 years of the grant date at a price of $21.76 per share.

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

	Share purchase options issued in: 2014	2013
Share price at grant date	$ 24.80	$ 21.76
Expected volatility [1]	15.2%	14.4%
Expected option life [2]	4.5 years	4.5 years
Expected dividend yield	5.08%	5.79%
Risk-free interest rate [3]	1.85%	1.25%
Exercise price	$ 24.80	$ 21.76
Expiry date	March 12, 2021	March 14, 2020

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

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

[3] Based on the Government of Canada zero-coupon yield curve. Represents the weighted 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, 2014 and 2013:

	2014		2013	
	Number of options	Weighted average exercise price	Number of options	Weighted average exercise price
Options outstanding, as at January 1	4,210,458	$ 23.44	4,385,712	$ 23.75
Granted	725,571	24.80	740,304	21.76
Exercised [4]	(1,028,778)	23.41	(1,757)	22.50
Forfeited	(149,802)	23.37	(913,801)	23.55
Options outstanding, as at December 31	3,757,449	$ 23.72	4,210,458	$ 23.44
Vested options outstanding, as at December 31	2,319,938	$ 23.65	2,558,124	$ 23.48

[4] The weighted average share price at the date of exercise was $26.10 (2013 - $23.23).

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

29. Share-based payments, continued:

Share purchase options, continued

During the year ended December 31, 2014, the Company recorded compensation expenses of $1 million related to share purchase options in staff costs and employee benefits expense (year ended December 31, 2013 - $1 million).

The weighted average remaining contractual life of the Company's outstanding share purchase options as at December 31, 2014 is 4.0 years (December 31, 2013 – 4.2 years). The exercise prices of share purchase options outstanding as at December 31, 2014 range from $21.76 to $24.90 (December 31, 2013 - $21.76 to $24.90).

Performance share units

Capital Power grants performance share units (PSUs) to certain employees, which entitles 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. 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 percent to 200 percent times the market price of the PSU at the release date.

	2014	2013
PSUs outstanding, as at January 1	378,436	356,933
Granted [1]	105,777	202,083
Released [2]	(76,613)	(75,002)
Dividends reinvested	35,737	26,825
Forfeited	(85,043)	(132,403)
PSUs outstanding, as at December 31	358,294	378,436

[1] The fair value of the PSUs at the grant date was $23.48 (2013 - $23.16).

[2] The weighted average share price at the date of release was $22.45 (2013 - $22.24).

During the year ended December 31, 2014, the Company recorded compensation expenses of $5 million (year ended December 31, 2013 - $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 entitles 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 based on the prevailing market price of Capital Power common shares at the time of payment.

	2014
RSUs outstanding, as at January 1	-
Granted [1]	89,368
Released [2]	(1,544)
Dividends reinvested	3,195
Forfeited	(6,838)
RSUs outstanding, as at December 31	84,181

[1] The fair value of the RSUs at the grant date was $23.48 (2013 – nil).

[2] The weighted average share price at the date of release was $25.96 (2013 – nil).

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

29. Share-based payments, continued:

Restricted share units, continued

During the year ended December 31, 2014, the Company recorded compensation expenses of $1 million (year ended December 31, 2013 – nil) related to the outstanding RSUs in staff costs and employee benefits expense.

Deferred stock units

The Company has approved a deferred stock unit (DSU) plan pursuant to which non-employee directors of the Company 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, 2014, the Company recorded compensation expenses of $1 million (year ended December 31, 2013 – $1 million) related to the outstanding DSUs in staff costs and employee benefits expense.

30. 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.

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

		December 31, 2014		December 31, 2013	
	Fair value hierarchy level	Carrying amount	Fair value	Carrying amount	Fair value
Other financial assets – non-current (note 17)					
Loans and receivables	Level 2	$ 16	$ 17	$ 34	$ 34
Finance lease receivable (note 16)					
Loans and receivables	Level 2	708	726	711	647
Loans and borrowings (note 23)					
Other financial liabilities (includes current portion)	Level 2	1,586	1,670	1,527	1,561

Loans and receivables

The fair values of the Company's finance lease receivables 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, 2014 and December 31, 2013.

Loans and borrowings

The fair value of the Company's loans and borrowings is based on determining a current yield for the Company's loans and borrowings as at December 31, 2014 and December 31, 2013. 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.

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

30. Financial instruments, continued:

Fair value hierarchy

The following tables present the Company's financial instruments measured at fair value on a recurring basis in the consolidated statement of financial position, classified using the fair value hierarchy:

	December 31, 2014			
	Level 1	Level 2	Level 3	Total
Derivative financial instruments assets				
Commodity derivatives	$ -	$ 162	$ -	$ 162
Foreign exchange derivatives	-	21	-	21
Interest rate derivatives	-	4	-	4
	$ -	$ 187	$ -	$ 187
Derivative financial instruments liabilities				
Commodity derivatives	-	(69)	-	(69)
Interest rate derivatives	-	(5)	-	(5)
	$ -	$ (74)	$ -	$ (74)

	December 31, 2013			
	Level 1	Level 2	Level 3	Total
Derivative financial instruments assets				
Commodity derivatives	$ -	$ 66	$ -	$ 66
Foreign exchange derivatives	-	1	-	1
	$ -	$ 67	$ -	$ 67
Derivative financial instruments liabilities				
Commodity derivatives	-	(39)	-	(39)
Foreign exchange derivatives	-	(1)	-	(1)
Interest rate derivatives	-	(1)	-	(1)
	$ -	$ (41)	$ -	$ (41)

There were no significant transfers between levels in the fair value hierarchy for the years ended December 31, 2014 and 2013.

Details of the fair values of the Company's derivative instruments and the valuation techniques used in determination of the fair values are described in note 15.

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. As at December 31, 2014 and 2013, the Company did not classify any financial instruments in Level 3 of the hierarchy. Derivative instruments previously classified as Level 3 were disposed of as part of the North East U.S. assets in the third quarter of 2013.

The following table summarizes the changes in the fair value of financial instruments classified in Level 3:

	2014	2013
As at January 1 [1]	$ -	$ (16)
Unrealized and realized gains included in net income [2]	-	26
Settlements	-	(10)
As at December 31	$ -	$ -
Total unrealized gains for the year included in net income	$ -	$ 16

[1] The fair value of derivative instruments is presented on a net basis.

[2] Gains and losses are recorded in revenues or energy purchases and fuel, as appropriate.

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

30. Financial instruments, continued:

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.

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

As at December 31, 2014

				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	$ 230	$ (10)	$ 220	$ (55)	$ (2)	$ 163

[1] The net amounts of commodity trading assets presented in the statement of financial position include current derivative instruments assets of $107 million, non-current derivative instruments assets of $55 million and trade and other receivables of $58 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, 2014

				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 [4]	Net amount
Commodity trading liabilities	$ 109	$ (10)	$ 99	$ (57)	$ (10)	$ 32

[3] The net amounts of commodity trading liabilities presented in the statement of financial position include current derivative instruments liabilities of $59 million, non-current derivative instruments liabilities of $10 million and trade and other payables of $30 million.

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

30. Financial instruments, continued:

Offsetting of financial assets and liabilities, continued

[4] Collateral pledged against the net financial liabilities disclosed above consists of $9 million in cash collateral and $1 million in letters of credit issued.

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

As at December 31, 2013

				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	$ 139	$ (9)	$ 130	$ (21)	$ (2)	$ 107

[1] The net amounts of commodity trading assets presented in the statement of financial position include current derivative instruments assets of $31 million, non-current derivative instruments assets of $35 million and trade and other receivables of $64 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, 2013

				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 [4]	Net amount
Commodity trading liabilities	$ 86	$ (9)	$ 77	$ (28)	$ (4)	$ 45

[3] The net amounts of commodity trading liabilities presented in the statement of financial position include current derivative instruments liabilities of $29 million, non-current derivative instruments liabilities of $10 million and trade and other payables of $38 million.

[4] Collateral pledged against the net financial liabilities disclosed above consists of $3 million in cash collateral and $1 million in letters of credit issued.

31. 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 a senior management group.

31. Risk management, continued:

Risk management overview, continued

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, liquidity risk, and the associated credit 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.

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.

31. Risk management, continued:

Market risk, continued

Commodity price risk, continued

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, 2014, that are required to be measured at fair value with the respective changes in fair value recognized in net income are disclosed in note 15.

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.

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 and reported to the executive team on a daily basis. The portfolios are stress tested regularly to observe the effects of plausible scenarios taking into account historical maximum volatilities and maximum observed price movements. Based on the commodity portfolio as at December 31, 2014, 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.

31. Risk management, continued:

Market risk, continued

Foreign exchange risk, continued

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, 2014, the Company held foreign exchange derivatives as disclosed in note 15.

As at December 31, 2014, 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 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, 2014, the proportion of fixed rate loans and borrowings was approximately 99% of total loans and borrowings outstanding (December 31, 2013 - 100%). The Company may also use derivative instruments to manage interest rate risk. At December 31, 2014, the Company held interest rate derivatives as disclosed in note 15 which have effectively reduced the proportion of fixed rate loans and borrowing disclosed above to 86%.

Assuming that the amount and mix of fixed and floating rate loans and borrowings, net loans and borrowings and derivative instruments used to manage interest rate risk remains unchanged from that held as at December 31, 2014, a 100 basis point decrease or increase to interest rates would decrease or increase full year net income attributable to common shareholders by $12 million and would have no direct impact on other comprehensive 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.

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

31. Risk management, continued:

Credit risk, continued

Maximum credit risk exposure

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

	December 31, 2014	December 31, 2013
Cash and cash equivalents	$ 71	$ 100
Trade and other receivables [1]	185	218
Derivative financial instruments assets [1]	187	67
Loans and other long-term receivables	16	34
Finance lease receivables	708	711
	$ 1,167	$ 1,130

[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 $98 million (December 31, 2013 - $140 million) for generation counterparties and $274 million (December 31, 2013 - $145 million) for wholesale counterparties at December 31, 2014.

This table does not take into account collateral held. As at December 31, 2014, the Company held cash deposits of nil (December 31, 2013 - nil) as security for certain counterparty trade and other receivables and derivative contracts. The Company is not permitted to sell or re-pledge collateral in the absence of default of the collateral providers. As at December 31, 2014, the Company also held other forms of credit enhancement in the forms of letters of credit of $55 million (December 31, 2013 - $4 million), property registrations valued at $12 million (December 31, 2013 - $19 million) and parental guarantees of $1,254 million (December 31, 2013 - $1,278 million) related to the financial assets noted above. As at December 31, 2014 and December 31, 2013, 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.

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 and interest rate 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, 2014, loans and long-term financing consists primarily of notes receivable attributable to two Alberta PPA syndicate members. The Company is exposed to credit risk in the event of non-performance by the syndicate members, but does not anticipate such non-performance. Although the syndicate members are not investment grade, the notes receivable are secured by security interests in the syndicate members' respective shares of the power syndicate agreement.

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

31. Risk management, continued:

Credit risk, continued

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

The aging of trade and other receivables as at December 31, 2014 was:

	Gross trade and other receivables	Allowance for doubtful accounts	Net trade and other receivables
Current [1]	$ 185	$ -	$ 185
Outstanding 30 - 60 days	-	-	-
Outstanding 60 - 90 days	-	-	-
Outstanding greater than 90 days	5	(5)	-
	$ 190	$ (5)	$ 185

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

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

31. Risk management, continued:

Credit risk, continued

Trade and other receivables and allowance for doubtful accounts, continued

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

	2014	2013
As at January 1	$ -	$ 2
Amounts reversed unused	-	(2)
New allowance	5	-
As at December 31	$ 5	$ -

Bad debt expenses (net of recoveries) of $5 million and nil were recognized in the years ended December 31, 2014 and 2013 respectively.

As at December 31, 2014, the Company held no customer deposits for the purpose of mitigating the credit risk associated with accounts receivable from customers (December 31, 2013 - nil).

As at December 31, 2014 and December 31, 2013, 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 a long-term debt rating of BBB- (Outlook Stable), assigned by Standard & Poor's (S&P) and a preferred share rating of P-3 and Pfd-3(low) assigned by S&P and DBRS Limited (DBRS) respectively. CPLP has long-term debt ratings of BBB- (Outlook Stable) and BBB/stable outlook, assigned by S&P and DBRS respectively.

As at December 31, 2014, the Company had undrawn bank credit facilities and operating lines of credit and demand facilities, totaling $1,086 million (December 31, 2013 - $1,065 million), of which $1,061 million is committed for at least 3 years (December 31, 2013 - $1,040 million committed for at least four years).

In addition to the facilities noted above, the Company, through its own facilities and those of its subsidiary, CPLP, has shelf prospectuses under which it may raise funds in the form of debt or equity. As at December 31, 2014, Capital Power has a Canadian shelf prospectus, which expires in January 2017, 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, 2014, the amounts available on the shelf prospectus are $3 billion (as at December 31, 2013 - $1,218 million). As at December 31, 2014, the Company's subsidiary, CPLP, has a Canadian shelf prospectus, which expires in January 2017, under which it may raise up to $1 billion in medium term notes of CPLP. As at December 31, 2014, CPLP has not drawn on the shelf prospectus (December 31, 2013 – nil).

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

31. Risk management, continued:

Liquidity risk, continued

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, 2014:

	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	$ 599	$ 11	$ 11	$ 25	$ 258	$ 692	$ 1,596
Interest payments on loans and borrowings	86	54	51	51	44	86	372
Trade and other payables [1]	170	-	-	-	-	-	170
Other current liabilities and deferred revenue	5	-	-	-	-	-	5
Derivative financial liabilities:							
Net commodity contracts for differences	12	5	3	1	-	-	21
Interest rate derivatives	5	-	-	-	-	-	5
Total	$ 877	$ 70	$ 65	$ 77	$ 302	$ 778	$ 2,169

[1] Excluding accrued interest on loans and borrowings of $15 million.

32. 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).

The following table represents the total capital of the Company:

	2014	2013
Loans and borrowings (note 23)	$ 1,586	$ 1,527
Cash and cash equivalents (note 12)	(71)	(100)
Net debt	1,515	1,427
Non-controlling interests (note 33)	552	587
Share capital (note 25)	2,391	2,328
Retained earnings and other reserves	60	89
Total equity	3,003	3,004
	$ 4,518	$ 4,431

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

32. Capital management, continued:

The Company, through its subsidiary CPLP, 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 0.8 to 1.0;
- Maintenance of 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 CPLP is assigned a rating of less than BBB- by S&P and BBB (Low) by DBRS, CPLP would also be required to maintain a ratio of net income before interest, income taxes, depreciation and amortization to finance expense, as defined in the debt agreements, of not less than 2.5 to 1.0.

For the year ended December 31, 2014, the Company and its subsidiaries 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, issue new CPLP units, repay existing loans and borrowings or adjust dividends paid to its shareholders.

33. 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, 2014:

	Place of business	Percentage of ownership interest held by the Company	Percentage of ownership interest held by the NCI	Principal activities
CPLP [1]	Canadian partnership with Canadian and U.S. subsidiaries	82%	18%	Power generation
Genesee Coal Mine Assets (Coal Mine) [2]	Canada	50%	50%	Coal production for use in power generation

[1] EPCOR owns 18.841 million (December 31, 2013 – 18.841 million) exchangeable limited partnership units of CPLP (exchangeable for common shares of Capital Power on a one-for-one basis) which represents approximately 18% of CPLP (December 31, 2013 – 19%). Each exchangeable limited partnership unit is accompanied by a special voting share in the capital of Capital Power which entitles the holder to a vote at Capital Power shareholder meetings, subject to the restriction that such special voting shares must at all times represent not more than 49% of the votes attached to all Capital Power common shares and special voting shares, taken together. The special voting shares also entitle EPCOR, voting separately as a class, to nominate and elect a maximum of two (December 31, 2013 – two) directors of Capital Power of the current ten (December 31, 2013 – eleven) directors on Capital Power's board of directors. Although EPCOR, through its ownership of the special voting shares described above, is the largest single shareholder, its representation on the board of directors does not represent a controlling vote. Capital Power is the general partner of, and holds an 82% partnership interest in, CPLP (December 31, 2013 – 81%). During the year ended December 31, 2014, CPLP issued 5.813 million common limited partnership units to Capital Power to settle indebtedness owed by CPLP. There were no issuances that occurred during the year ended December 31, 2013. Through this interest, Capital Power has rights to variable returns from its involvement with CPLP and has the ability to affect those returns through its power over CPLP. As a result Capital Power has control over CPLP and, on that basis, the operations of CPLP are consolidated by Capital Power for financial statement purposes.

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

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

[2] The Company holds a 50% interest in the Coal Mine while the other 50% is held by a third 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 third 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 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 a subsidiary's assets that relate to the subsidiaries above, other than those described in note 32.

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

	December 31, 2014		December 31, 2013	
Consolidated statements of financial position	CPLP	Coal Mine	CPLP	Coal Mine
Current assets	$ 487	$ -	$ 429	$ -
Non-current assets	4,956	142	4,808	156
Current liabilities	(877)	-	(687)	-
Non-current liabilities	(1,732)	-	(1,856)	-
Non-controlling interests - Genesee Coal Mine	(72)	-	(78)	-
Non-controlling interests - other	(19)	-	(22)	-
Net assets	$ 2,743	$ 142	$ 2,594	$ 156

	2014		2013	
Consolidated statements of income	CPLP	Coal Mine	CPLP	Coal Mine
Revenues	$ 1,220	$ -	$ 1,383	$ -
Net income attributable to partners	73	(22)	240	(24)
Other comprehensive income attributable to partners	52	-	(47)	-
Total comprehensive income attributable to partners	$ 125	$ (22)	$ 193	$ (24)

	2014		2013	
Consolidated statements of cash flows	CPLP	Coal Mine	CPLP	Coal Mine
Net cash flows from operating activities	$ 336	$ -	$ 470	$ -
Net cash flows used in investing activities	(227)	(8)	(341)	(15)
Net cash flows (used in) from financing activities	(141)	8	(81)	15
Foreign exchange gains (losses) on cash held in a foreign currency	1	-	(1)	-
Net (decrease) increase in cash and cash equivalents	(31)	-	47	-
Cash and cash equivalents at beginning of year	100	-	53	-
Cash and cash equivalents at end of year	$ 69	$ -	$ 100	$ -

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

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

Non-controlling interests reflected on the consolidated balance sheet are comprised of:

	December 31, 2014	December 31, 2013
Non-controlling interest in CPLP, beginning of year	$ 509	$ 747
Net income attributable to non-controlling interest	15	65
Other comprehensive income (loss) attributable to non-controlling interest	10	(12)
Distributions to non-controlling interest (note 28)	(25)	(33)
Change in non-controlling interest ownership	(29)	-
Exchange of CPLP units for Capital Power shares (note 25)	-	(258)
Non-controlling interest in CPLP, end of year	480	509
Non-controlling interest in Genesee Coal Mine, beginning of year	78	82
Net loss attributable to non-controlling interest	(11)	(12)
Net additional investment by non-controlling interest	5	8
Non-controlling interest in Genesee Coal Mine, end of year	72	78
	$ 552	$ 587

34. Interests in joint arrangements:

Joint operations

The Company holds interests in the following joint operations as at December 31, 2014:

	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 516MW coal-fired generating facility and is a 50/50 joint arrangement between Capital Power and a third party, with Capital Power acting as the manager and operator. Both parties independently dispatch and market their share of the electrical output through the Alberta Power Pool.

[2] K3 is a 516MW coal-fired generating facility and is a 50/50 joint arrangement between Capital Power and a third party with the third party responsible for operations. Both parties independently dispatch and market their share of the facility's electrical output.

[3] Joffre Cogeneration Project is a 480MW gas-fired combined cycle cogeneration facility in which Capital Power holds a 40% interest with third 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 800MW gas-fired generating facility and is a 50/50 joint arrangement between Capital Power and a third party with the third party responsible for operations. Shepard is currently under construction as described in note 35(b).

[5] Genesee 4 and 5 is a 1,060MW gas-fired generating project and is a 50/50 joint arrangement between Capital Power and a third 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 35(c).

There are no significant restrictions pertaining to the joint operations described above, other than those described in note 23 pertaining to the charges on the Joffre Cogeneration project assets.

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

34. Interests in joint arrangements, continued:

Joint ventures

The Company holds an interest in the following joint venture as at December 31, 2014:

	Place of business	Measurement Method
K2 Wind Power Project[1]	Canada	Equity method

[1] The K2 Wind Power Project (K2 Wind) is a 270MW wind power project currently under development and construction. Capital Power has entered into agreements with two third parties for the development, construction and operation of K2 Wind. Capital Power and each of the third parties will hold an equal 33.33% ownership interest in K2 Wind. 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.

The summarized financial information of K2 Wind is as follows:

Statements of Financial Position	December 31, 2014	December 31, 2013
Cash and cash equivalents	$ 1	$ 3
Other current assets[2]	40	1
Non-current assets [2]	756	70
Current financial liabilities	-	(5)
Other current liabilities	(76)	(25)
Other non-current liabilities	(656)	-
Net assets	$ 65	$ 44

[2] K2 Wind has restricted cash of $28 million included in other current and non-current assets above (December 31, 2013 - $5 million in non-current assets) which represents security for a standby line of credit with a third party.

Statements of Loss and Comprehensive Loss	2014	2013
Revenues	$ -	$ -
Depreciation and amortization	-	-
Finance expense	-	-
Income tax expense	-	-
Net loss	(1)	(2)
Other comprehensive loss:		
Unrealized losses on derivative instruments	(60)	-
Total comprehensive loss	$ (61)	$ (2)

The Company's recorded equity investment in K2 Wind of $22 million (December 31, 2013 - $15 million) reconciles to the Company's 33.33% share of the net assets of K2 Wind.

35. Commitments and contingencies:

(a) Under the terms of the Sundance PPA, the Company is obligated to make monthly payments for fixed and variable costs. The estimated annual total of these payments for 2015 is $94 million. It is expected that the annual payments over the remaining term of the Sundance PPA, as described in note 19, will range from $94 million to $105 million, adjusted for inflation, other than in the event of a forced outage. The actual amounts for future years may vary from estimates depending on generation volume, scheduled outages, and force majeure events.

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

35. Commitments and contingencies, continued:

(b) The Company entered into a series of agreements with a third party to purchase a 50% interest in the 800 MW Shepard Energy Centre in southern Alberta. The Company expects to invest approximately $826 million, including capitalized borrowing costs, into Shepard, which is expected to commence commercial operations in early 2015. The two parties will build, own and operate Shepard under a joint arrangement. In conjunction with the joint arrangement, the parties will be subject to various commercial agreements, including a 20 year tolling agreement. Under the tolling agreement, 75% of Capital Power's share of the output will be sold at a fixed capacity charge to the other party to the joint arrangement for the years 2015 through 2017 decreasing to 50% of the output for the years 2018 to 2035. As at December 31, 2014, the estimated total remaining capital cost to be incurred is $15 million.

(c) The Company is party to a series of agreements with a third 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 is expected to commence commercial operations between 2018 and 2020. The expected investment includes a commitment to purchase a power island to be delivered in 2015. The two parties will build, own and operate Genesee 4 and 5 under a joint arrangement. In conjunction with the joint arrangement, the parties will 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 starting in 2021.

(d) The K2 wind joint venture, in which the Company holds a 33% interest as described in note 34, will develop, construct and operate the 270 MW K2 power project in southern Ontario. K2 has an expected capital cost of $930 million, which will be shared by each of the three venturers equally through their equity interests in the joint venture. As at December 31, 2014 the estimated total remaining capital cost for the Company's share of the project is $61 million of which a portion will be financed within the joint venture. Energy generated by K2 will be sold under a PPA to a third party. K2 is expected to commence commercial operations in 2015.

(e) 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 [1]
Within one year	$ 124	$ 17	$ 13	$ 8
Between one and five years	361	75	17	23
After five years	416	216	-	71
	$ 901	$ 308	$ 30	$ 102

[1] Operating lease amounts include $5 million per year through 2031 for head office lease costs payable to EPCOR.

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

35. Commitments and contingencies, continued:

(f) The Company is participating in a line loss factor proceeding underway before the Alberta Utilities Commission (AUC) regarding factors that form the basis for certain transmission charges paid by Alberta generators including the Company. This proceeding intends to address the factors to be applied for the years 2006 forward and is expected to be completed in three modules. In January 2015, the AUC issued its decision in Module A of the line loss factor proceeding that the AUC has the jurisdiction and authority to retrospectively change the line loss rule and related loss factors. Module B will address the replacement line loss rule which would apply prospectively but which may also form the basis for retroactive adjustments that are to be considered in Module C. It is expected that a Module B decision will be no earlier than the third quarter of 2015 while the timing of a Module C decision is unknown. There are many variables and considerations that must be taken into account in establishing transmission line loss factors and new line loss factors have not been established nor has any mechanism for the sharing of any retrospective adjustments been established. The Company may incur additional payments for transmission charges on a retrospective and go-forward basis but a provision has not been recorded in the Company's financial statements since the outcome of the proceeding is not known.

(g) Contingent consideration payable by the Company in connection with the acquisition of Element is described in note 10.

(h) 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.

36. Guarantees:

The Company, through its subsidiary CPLP, has issued letters of credit of $122 million (December 31, 2013 - $160 million) to meet the credit requirements of energy market participants, to meet conditions of certain service agreements, and to satisfy legislated reclamation requirements.

37. Segment information:

The Company operates in one reportable business segment involved in the operation of electrical generation facilities within Canada (Alberta, British Columbia and Ontario) and in the U.S. (North Carolina and New Mexico), as this is how management assesses performance and determines resource allocations. The Company also holds a portfolio of wind and solar development sites in the U.S. The Company had operations in Connecticut, Maine and Rhode Island within the U.S. up until the fourth quarter for 2013 when the Company disposed of its North East U.S. assets.

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

	Year ended December 31, 2014				Year ended December 31, 2013			
	Canada	U.S.	Inter-area eliminations	Total	Canada	U.S.	Inter-area eliminations	Total
Revenues - external	$ 1,061	$ 167	$ -	$1,228	$1,048	$ 345	$ -	$1,393
Revenues - inter-area	17	1	(18)	-	43	(2)	(41)	-
Total revenues	$ 1,078	$ 168	$ (18)	$1,228	$1,091	$ 343	$ (41)	$1,393

	As at December 31, 2014			As at December 31, 2013		
	Canada	U.S.	Total	Canada	U.S.	Total
Property, plant and equipment	$ 3,511	$ 190	$ 3,701	$ 3,441	$ 84	$ 3,525
Intangible assets	313	37	350	309	1	310
Goodwill	-	25	25	-	23	23
Other assets	28	-	28	27	-	27
	$ 3,852	$ 252	$ 4,104	$ 3,777	$ 108	$ 3,885

38. Comparative figures:

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

5-YEAR OPERATIONAL AND FINANCIAL HIGHLIGHTS

(millions of dollars except per share and operational amounts) (unaudited)

	2014	2013	2012	2011	2010
OPERATIONAL					
Number of facilities at year-end[1]	15	14	16	16	32
Electricity generation[1] (GWh)	12,376	16,130	16,455	13,659	9,205
Plant availability average[1] (%)	95%	93%	91%	92%	90%
FINANCIAL POSITION (as at December 31)					
Total assets	$5,420	$5,219	$5,134	$4,743	$5,296
Loans and borrowings including current portion	$1,586	$1,527	$1,659	$1,480	$1,869
INCOME AND CASH FLOW					
Revenues[2]	$1,228	$1,393	$1,296	$1,736	$1,762
Adjusted EBITDA[3]	$423	$509	$441	$485	$418
Net income	$50	$228	$90	$188	$77
Net income attributable to shareholders	$46	$175	$62	$77	$17
Normalized earnings attributable to common shareholders[3]	$59	$127	$86	$55	$32
Basic earnings per share	$0.28	$2.13	$0.84	$1.60	$0.77
Diluted earnings per share[4]	$0.28	$2.08	$0.84	$1.59	$0.69
Normalized earnings per share[3]	$0.72	$1.74	$1.29	$1.24	$1.40
Funds from operations[3,5,6]	$362	$426	$383	$352	$277
Purchase of property, plant and equipment and other assets	$220	$943	$598	$493	$329
DIVIDEND					
Dividends declared per common share	$1.31	$1.26	$1.26	$1.26	$1.26
COMMON SHARE INFORMATION (CPX: TSX)					
High	$28.71	$23.53	$25.72	$28.00	$24.84
Low	$20.51	$19.76	$20.75	$21.50	$20.97
Close	$26.00	$21.30	$22.73	$25.12	$23.65
TSX volume (millions)	58.3	42.8	39.7	36.6	17.8

(1) In November 2011, the Capital Power Income L.P. (CPILP) plants excluding Roxboro and Southport were disposed of as part of the Atlantic Power acquisition of the CPILP partnership units. Electricity generation and plant availability average excludes CPILP plants in 2010 and 2011 and excludes the acquired Sundance PPA in all five years.

(2) Revenues for 2011 and 2012 have been restated to correspond to 2013 basis of presentation. Revenues for 2010 have not been restated.

(3) 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 in the Management's Discussion and Analysis.

(4) Diluted earnings per share was calculated after giving effect to share purchase options and the potential exchange of common limited partnership units of CPLP held by EPCOR which are exchangeable for common shares of Capital Power on a one-for-one basis.

(5) Excluding non-controlling interests in CPILP (applicable to 2010 and 2011).

(6) The 2013 and 2012 funds from operations amounts were revised consistent with the change in the measure due to the reclassification of Part VI.1 tax from operating activities to financing activities.

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STOCK EXCHANGE AND INDEX MEMBERSHIP

Toronto Stock Exchange (TSX)

Member of:
- S&P/TSX Composite Index
- S&P/TSX SmallCap Index

TRADING SYMBOLS

Common shares
CPX

Preferred shares
Series 1 - CPX.PR.A
Series 3 - CPX.PR.C
Series 5 - CPX.PR.E

TOTAL OUTSTANDING COMMON SHARES AS OF DECEMBER 31, 2014

Public Float: 83,460,896
Total (fully diluted): 102,301,896
Market capitalization (fully diluted) $2.7 billion

DIVIDEND REINVESTMENT PLAN (DRIP)

Current quarterly dividend of $0.34 per share ($1.36 per year). Eligible Capital Power common shareholders can take advantage of our automatic dividend reinvestment plan to acquire additional shares at 97 percent of the average market price without brokerage commissions or service charges.

For details regarding the DRIP, please visit www.capitalpower.com/DRIP or contact Computershare for information and enrollment forms.

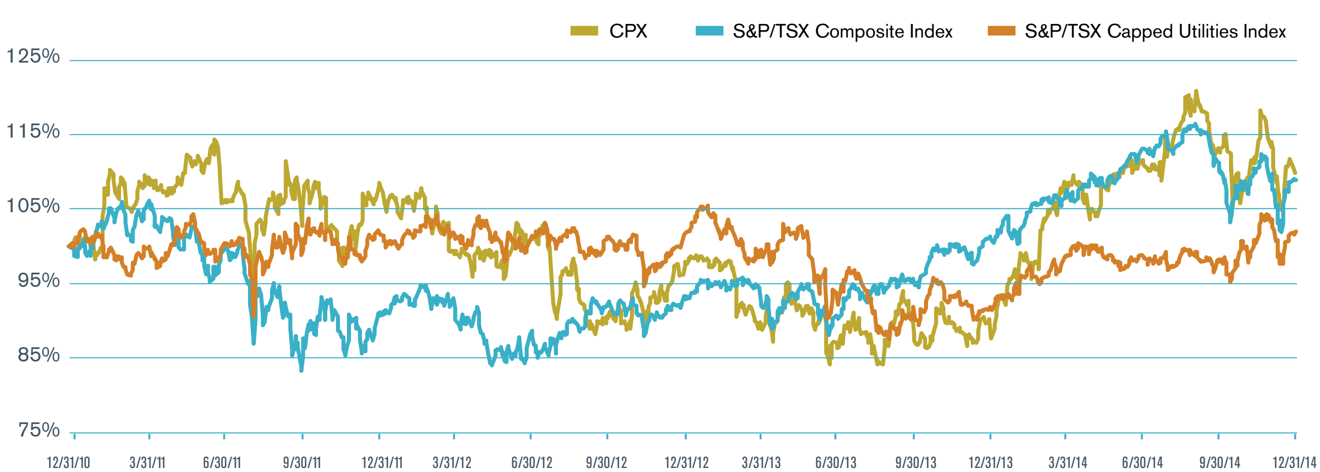
2015 EXPECTED COMMON SHARE DIVIDEND DATES

	EX-DIVIDEND DATE	RECORD DATE	PAYMENT DATE
Quarter 1	March 27	March 31	April 30
Quarter 2	June 26	June 30	July 31
Quarter 3	September 28	September 30	October 30
Quarter 4	December 29	December 31	January 29, 2016

2015 EXPECTED PREFERRED SHARES DIVIDEND DATES

	EX-DIVIDEND DATE	RECORD DATE	PAYMENT DATE
Quarter 1	March 16	March 18	March 31
Quarter 2	June 15	June 17	June 30
Quarter 3	September 15	September 17	September 30
Quarter 4	December 14	December 16	December 31

CAPITAL POWER COMMON SHARE (CPX) PRICE PERFORMANCE



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