Capital Power

OPTIMIZING TODAY FOR TOMORROW

2012 ANNUAL REPORT

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

OUR BUSINESS is the development, acquisition, construction, operation, and optimization of large-scale, fuel-diverse, cost-effective power generation facilities in North America.

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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 page 11.

AT A GLANCE

Capital Power (TSX: CPX) is a growth-oriented North American power producer headquartered in Edmonton, Alberta. The company develops, acquires, operates and optimizes power generation from a variety of energy sources. Capital Power owns more than 3,600 megawatts of power generation capacity at 16 facilities across North America. An additional 595 megawatts of owned generation capacity is under construction or in advanced development in Alberta and Ontario.

WHERE DO WE OPERATE?

BRITISH COLUMBIA
1 Island Generation
2 Quality Wind

ALBERTA
3 Keephills 3
4 Genesee 1
5 Genesee 2
6 Genesee 3
7 Capital Power Energy Centre
8 Clover Bar Energy Centre
9 Clover Bar Landfill Gas
10 Joffre
11 Halkirk Wind
12 Shepard Energy Centre

ONTARIO
13 Kingsbridge I
14 K2 Wind Ontario
15 Port Dover & Nanticoke

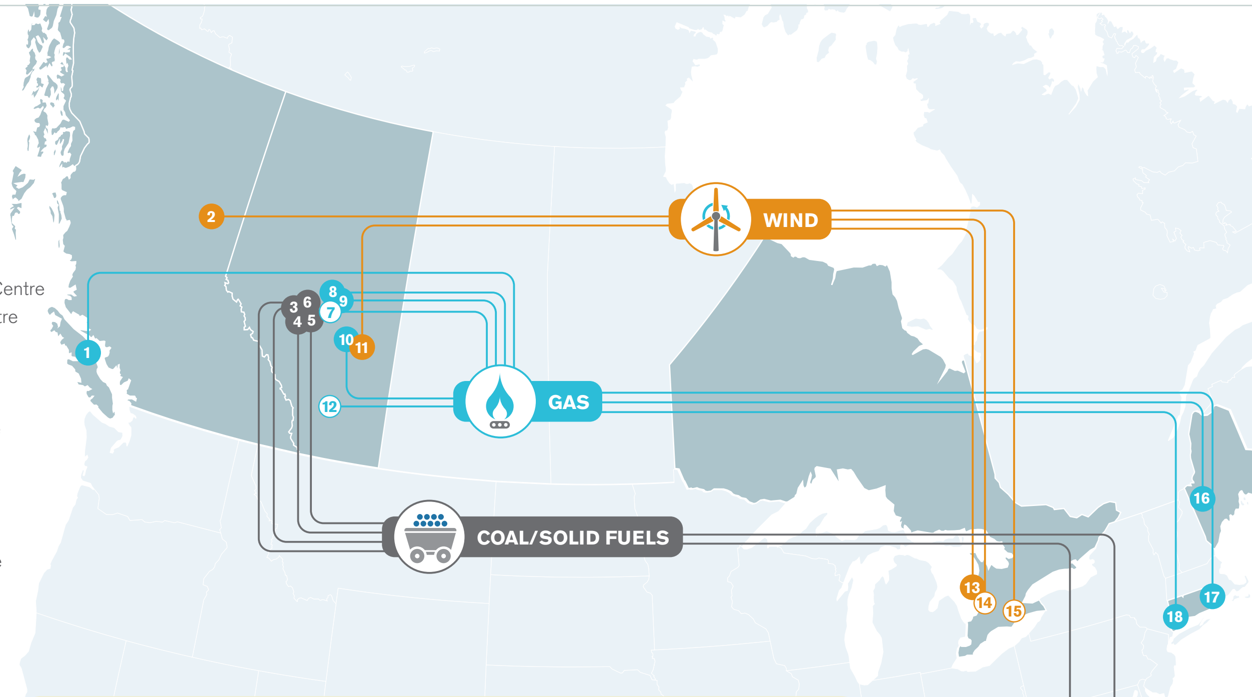
MAINE
16 Rumford

RHODE ISLAND
17 Tiverton

CONNECTICUT
18 Bridgeport

NORTH CAROLINA
19 Roxboro
20 Southport

Current
Under Construction/ Development



2012 PERFORMANCE

(unaudited, $ millions, except per share amounts)

	2012	2011	PERCENTAGE CHANGE
Revenues and other income ($M)	$1,331	$1,770	(25%)
Adjusted EBITDA ($M)	$441	$485	(9.1%)
Normalized earnings per share	$1.29	$1.24	4.0%
Funds from operations ($M)[1]	$381	$352	8.2%
Cash flow per share	$3.89	$3.89	
Plant availability average	91%	92%	

1 Excluding non-controlling interest in Capital Power Income L.P.

TO OUR SHAREHOLDERS

MESSAGE FROM THE PRESIDENT AND CEO

Throughout 2012, we remained focused on executing our strategy – a strategy that remains unchanged and designed to create value throughout the business cycle. Capital Power's corporate strengths continue to be the pillars that support our strategy and vision to be one of North America's most respected, reliable and competitive power producers.

MARKET FOCUS

We continue to be focused on our geographic footprint and target markets in North America. In our home market of Alberta, an energy only market, power prices are determined by supply and demand. The near-term outlook for power prices softened in the past year when an arbitration decision ordered TransAlta to restore their Sundance 1 and 2 units back to service. The addition of 560 megawatts (MWs) of supply from these two units expected in the fall of 2013 has reduced the forward view of Alberta power prices for the next few years. However, the excess supply of generation in the medium term is partially offset by the fact that Alberta remains one of the fastest growing economies and power markets in North America. With increasing demand for electricity and the retirement of older coal facilities, these strong market fundamentals will lead to higher power prices and new build opportunities over time, making it an attractive market to invest in.

For this reason, we announced major expansion plans late last year with two significant projects. First, we entered into a joint venture agreement with ENMAX Energy (ENMAX) for the construction and ownership of the Shepard Energy Centre, an 800 MW combined cycle natural gas power plant located in Calgary. Construction of the Shepard facility is more than 50% completed and is expected to begin commercial operations in early 2015. As part of the agreement, Capital Power has a 20-year tolling agreement with ENMAX, where we will receive fixed capacity payments for our portion of power output from the facility, with associated operations and maintenance costs flowing through to ENMAX. For the first three years, 75% of our generation from the Shepard facility will be contracted, which will drop to 50% for the balance of the 20 years. Overall, it is an excellent arrangement for Capital Power – it's a terrific asset in our home market and with the tolling agreement with ENMAX for a large portion of our output, it allows us to reposition our Alberta portfolio and significantly reduce our business risk by increasing our overall contracted position.

Second, we announced the Capital Power Energy Centre, a proposed facility with up to 900 MWs of generation capacity that will utilize General Electric's latest gas turbine technology. This facility would be operational in the 2017-20 timeframe when additional generation in the province will be required to meet growing demand and replace generation from the retirement of coal-fired units. Capital Power will strengthen its position as one of the dominant power producers in Alberta when these two large, efficient natural gas facilities are added to the fleet.

MODERN FLEET AND TECHNOLOGY FOCUS

During 2012, we completed the sale of our two remaining small hydro assets in British Columbia as the last step in sharpening our operational focus on four fuel types: natural gas, coal, wind and solar. We continued to demonstrate our construction expertise with the completion of the Quality Wind and Halkirk Wind projects on time and under budget. The two wind facilities added 292 MWs to our fleet, which has now grown to more than 3,600 MWs of owned generation – almost double the generation capacity compared to three years ago.

Our power generation fleet of 16 facilities continues to be both modern and relatively young with an average MW-weighted facility age of only 12 years. The age of our fleet helps keep plant availability high and reduces the risk of unplanned outages. With the future additions of the two Ontario wind facilities (Port Dover and Nanticoke and K2 Wind) and our 50% ownership of the Shepard Energy Centre, the fleet continues to operate with the latest technologies in power generation.

Capital Power has a history in utilizing leading technology in Alberta. We introduced super-critical coal technology to Alberta and North America, LMS100 peaking technology to Alberta and Canada, and when the Shepard facility begins commercial operations in 2015, it will be the most efficient combined cycle facility in Canada and will eventually be surpassed by the expected efficiency at the Capital Power Energy Centre when it is completed later in the decade. Capital Power does and will continue to own the best fleet of generation assets in one of the most attractive power markets in North America. It gives us the best peaking responsiveness, the best coal reliability, the lowest environmental impact and lowest cost, and the most competitive natural gas combined cycle facility in Alberta.

"Our strategy is to create shareholder value through operational excellence, maintaining or enhancing our financial strength and flexibility, and disciplined growth."

BRIAN VAASJO PRESIDENT AND CEO

OPERATIONAL EXCELLENCE

We have maintained high operating availability over a growing fleet and production volumes. Our average plant availability was 91% in 2012, and it has averaged 92% during the past four years – a period when our actual megawatt production has nearly doubled. In 2013, we are targeting a comparable 93% average plant availability.

INVESTMENT GRADE CREDIT RATING AND CONSISTENT ACCESS TO LOW COST CAPITAL

Our investment grade credit rating that provides access to low cost capital is a key component of our strategy, and we are firmly committed to maintaining the rating. Our long-term debt-to-capital ratio target of 40-50% provides a strong metric to support the credit rating. We continue to have strong access to the capital markets as noted by the successful $400 million of capital raised in 2012, through a $150 million preferred shares offering and a $250 million debt offering to fund our growth.

BALANCE OF CONTRACTED AND MERCHANT GENERATION

Maintaining a strong base of contracted cash flow from creditworthy counterparties is the cornerstone of Capital Power's ability to meet our fixed commitments and dividends through all business cycles. Looking ahead to 2015 when the two Ontario wind projects and the Shepard facility are completed, our contracted megawatts will increase to 47% of our portfolio compared to 42% today. Contracted cash flows provide Capital Power with a stable financial base, while the merchant cash flows provide upside with higher power prices.

With the Capital Power Energy Centre operating as a merchant facility when it begins operations later in the decade, our current focus is on contracted development projects in Canada and the US in order to maintain a balance of contracted and merchant assets in our portfolio.

FINANCIAL PERFORMANCE

Capital Power's financial performance in 2012 was mixed, with normalized earnings per share (EPS) falling significantly below target while cash flow performance met the target. Our financial targets, which we announced in December 2011, were based on an average Alberta power price forecast of $74 per megawatt hour (MWh) for 2012, which was used to set the target range of $1.50 to $1.70 for normalized EPS. Normalized EPS of $1.29 came in below target primarily due to a lower-than-expected average Alberta power price of $64/MWh, a one-time settlement loss on the heat rate option for the Bridgeport facility, and lower earnings from the North East U.S. plants primarily from an unplanned outage. Despite being below our earnings target, the company continues to generate strong cash flow with $381 million in funds from operations in 2012, which represented an 8.2% increase from the prior year and was within our target range.

LOOKING AHEAD

There's been a tremendous amount of change in our asset portfolio over the last four years. We have reduced our geographical footprint and our range of technologies to ensure that our growth remains focused and disciplined and reflects the competitive landscape for market opportunities. We have also divested our small interests so we could focus on significant investments.

For 2013, management is focused on delivering strong operational performance across the fleet, improving performance from our US assets, completing the Port Dover and Nanticoke wind project, continuing the development of K2 Wind Ontario project, and working with ENMAX on the construction of the Shepard facility for a successful completion in 2015.

Looking ahead, we continue to focus on developing our competitive advantages – our people, our market intelligence, the development and construction of generation facilities, and the optimization of our existing assets. With our investments in the Shepard facility and Capital Power Energy Centre, Capital Power will continue to be a dominant power producer in Alberta and will have the best fleet of power generation assets in the province. All of these initiatives are aligned with our strategy of being a competitive power producer and positions us to deliver shareholder value.

Thank you for your continued support.

BRIAN VAASJO PRESIDENT AND CEO

DEAR SHAREHOLDERS

MESSAGE FROM THE CHAIRMAN

Since Capital Power's initial public offering in July 2009, the Board has provided independent leadership and oversight in guiding the company's growth through acquisitions, divestitures and developments. This past year's results were mixed with the company facing a number of challenging headwinds but overall, progress was made towards the goal of establishing Capital Power as one of North America's most respected, reliable, and competitive power generators.

Each year, Capital Power's strategy is tested by the Board to ensure the company continues to be well positioned to deliver a stable long-term competitive shareholder return. This year's review confirmed the current strategy continues to be the right strategy for the company. Successful execution of this strategy was evident in 2012 as the company continued to provide safe reliable operations, completed successful offerings of debt and equity to fund growth, and developed the Quality Wind and Halkirk Wind projects on time and under budget.

A critical area of Board oversight is enterprise risk management. The Board is actively engaged with management in identifying, understanding and mitigating risks, particularly during uncertain economic conditions. Given the outlook for softer Alberta power prices in the medium term, a joint venture agreement for the development and ownership of ENMAX's Shepard Energy Centre was entered into last December. The transaction also included various commercial agreements that increased Capital Power's overall contracted position that significantly reduced its electricity price and volume risk.

The Board recognizes the climate of rising shareholder and stakeholder activism that exists today and continually looks at ways to improve dialogue with its shareholders. We appreciate that shareholders have a very legitimate interest in how the company is operating and governed.

As part of our commitment to shareholder engagement, shareholders have the opportunity to vote on our second 'say on pay' advisory vote on executive compensation at the 2013 annual meeting. Despite receiving 99% 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 feedback from our shareholders on this important matter.

Shareholders will also be voting on a Shareholder Rights Plan and the Advance Notice By-law. The primary objective of the Rights Plan is to ensure the fair treatment of all shareholders in the event that an unsolicited take-over bid for Capital Power is ever made and to provide the Board with sufficient time to evaluate the unsolicited bid and explore other options to maximize shareholder value. The Rights Plan was adopted by the Board last November; however, it must be ratified by our shareholders and filed with the Toronto Stock Exchange. If the Rights Plan is approved, it will remain in effect until the end of our 2016 annual meeting. The purpose of the Advance Notice By-law is to ensure all shareholders receive adequate notice and information about nominated directors, so that they can make informed voting decisions.

On behalf of the Board, I would like to thank all of the people of Capital Power for their work and achievements in 2012, and welcome our shareholders to the upcoming annual meeting.

We look forward to meeting you, hearing your thoughts and speaking with you.

DONALD LOWRY CHAIRMAN

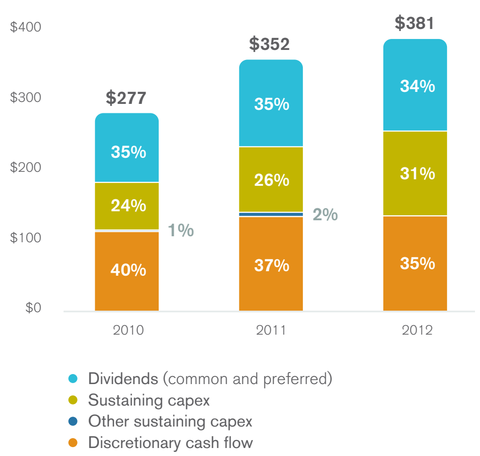
WHY INVEST

Invest in a Canadian independent power producer whose disciplined growth strategy is generating significant and growing cash flow from operations. Supported by our strong operations, quality assets and the strength of our financial position, Capital Power continues to invest in the future while paying a competitive dividend to investors.

STRONG CASH FLOW GENERATION

- Supports attractive dividend
- Funds sustaining capital expenditures
- Strong discretionary cash flow[1] used to fund growth

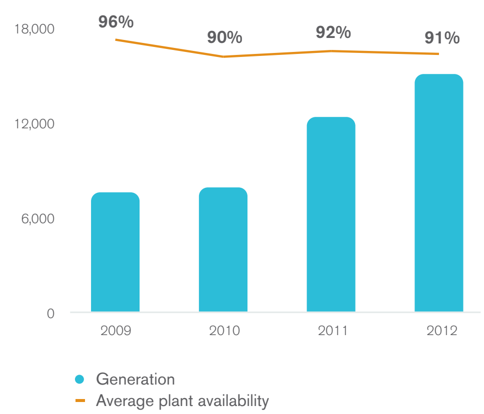
FUNDS FROM OPERATIONS (FFO)[1,2]
($millions)



EXCELLENT OPERATING HISTORY

- High plant availability maximizes value from our facilities
- Reduced costs associated with major outages

OPERATIONS
(GWh)



1 Discretionary cash flow and funds from operations are non-GAAP financial measures. See Management's Discussion and Analysis.
2 Excluding non-controlling interest in Capital Power Income L.P.

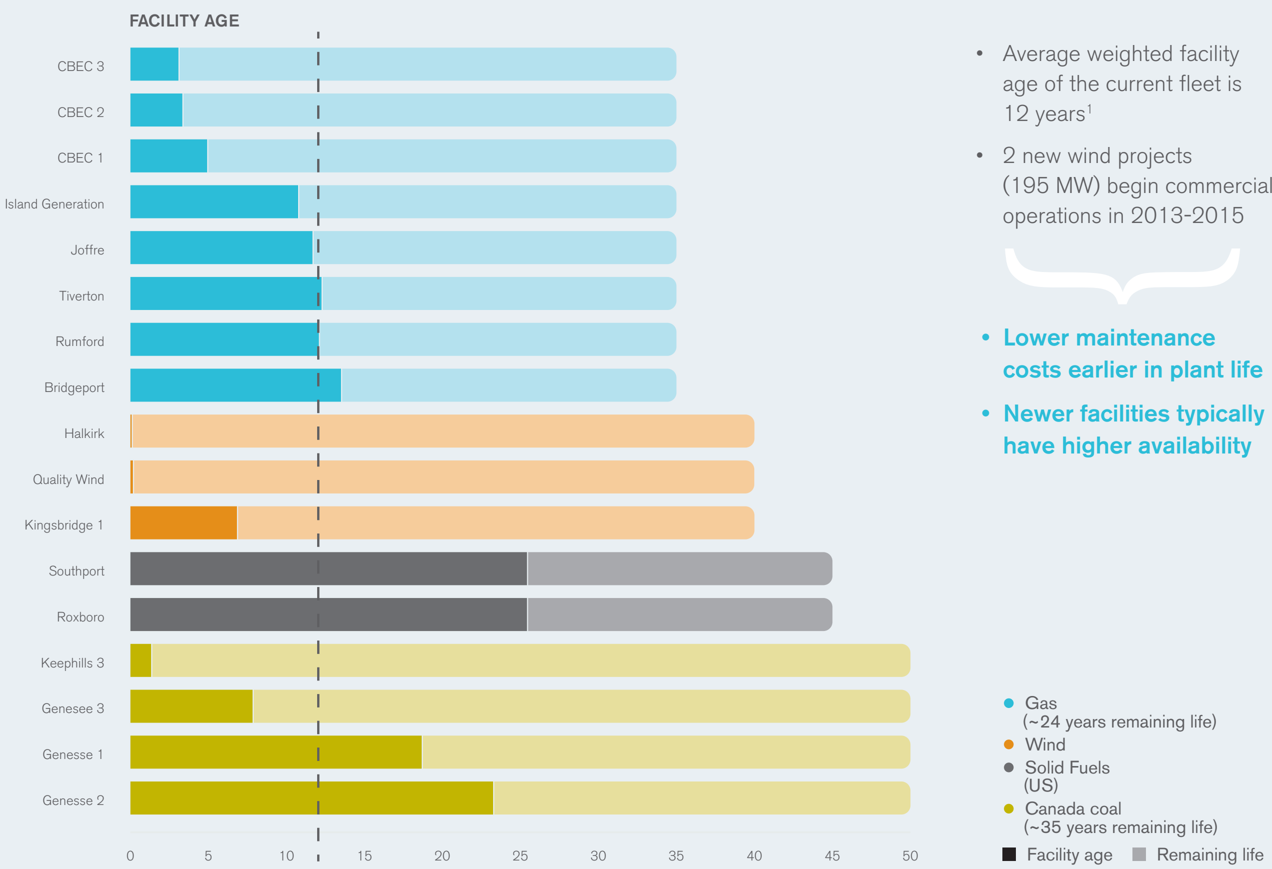
WHY INVEST

MODERN FLEET – UTILIZE LEADING TECHNOLOGY

- LMS100 peaking technology at our Clover Bar Energy Centre provides the best peaking responsiveness in Alberta
- Introduced super-critical coal technology to Alberta and North America with our jointly-owned Genesee 3 facility
- Our jointly-owned Keephills 3 generating facility is the most advanced coal-fired plant ever built in Canada
- Two new wind facilities (Quality Wind and Halkirk) built with modern wind technologies
- Six efficient, combined-cycle natural gas fired facilities with total of 1,556 MW

- **LMS100 units can fully ramp up in 10 minutes to capture upside from peak power prices and provides flexibility to manage Alberta power portfolio**
- **Lower environmental impact than older technologies**
- **Typically more efficient compared to older technologies**

YOUNG FLEET HELPS KEEP AVAILABILITY HIGH AND REDUCES RISK OF UNPLANNED OUTAGES



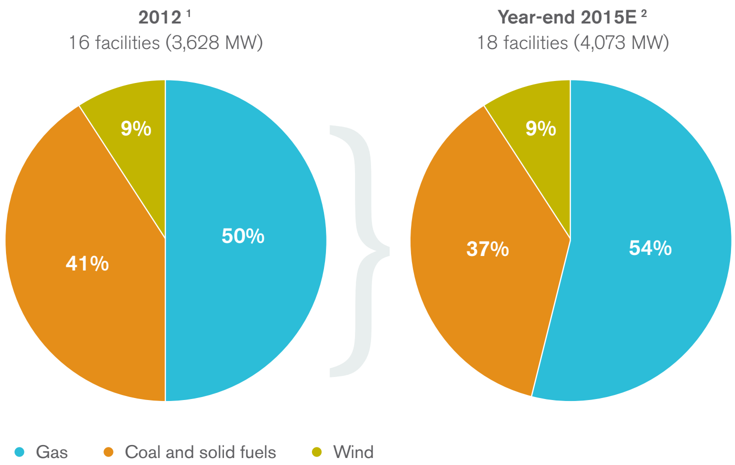
- Average weighted facility age of the current fleet is 12 years[1]
- 2 new wind projects (195 MW) begin commercial operations in 2013-2015

- **Lower maintenance costs earlier in plant life**
- **Newer facilities typically have higher availability**

1 Average facility age and remaining life weighted by owned capacity as of December 31, 2012.

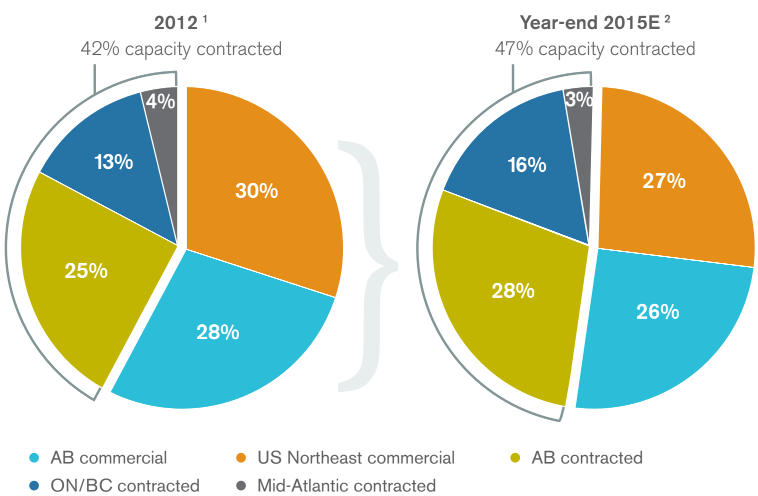
OPERATIONS AND GROWTH FOCUSED ON: NATURAL GAS, COAL, WIND AND SOLAR

- **Increased operating efficiencies, including refined operating and maintenance practices**
- **Greater economies of scale**



BALANCED PORTFOLIO OF MERCHANT AND CONTRACTED GENERATION

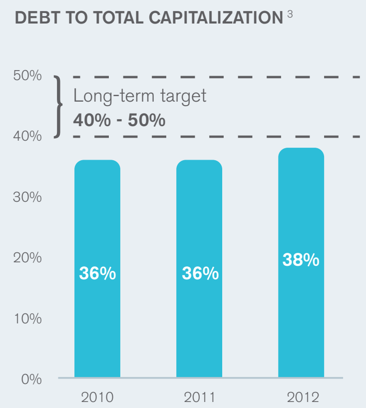
- **Long-term contracts help stabilize cash flows, support dividend and improve access to capital**
- **Cash flow from merchant assets help finance growth and provide upside**



1 Based on megawatts (MW) owned capacity; excludes the acquired Sundance PPA (371 MW).
2 Based on existing plants plus committed development projects.
3 Debt to total capitalization as of December 31 for each respective year. Capital Power Income L.P. accounted for on an equity basis in 2010.

FINANCIAL STRENGTH AND DISCIPLINE

- **Commitment to maintaining investment grade credit rating**
- **Well spread out debt maturities**
- **Current debt to capitalization lower than our target of 40%-50%**



BOARD OF DIRECTORS

Front row (left to right)
Richard Cruickshank
Philip Lachambre
Albrecht Bellstedt
Donald Lowry
Brian Vaasjo
Peggy Mulligan
William Bennett

Back row (left to right)
Robert Phillips
Allister McPherson
Doyle Beneby
Hugh Bolton
Brian Bentz

BOARD OF DIRECTORS AND COMMITTEE MEMBERSHIP

Board of Directors [1]	Audit Committee [2,3]	Corporate Governance, Compensation and Nominating Committee	Health, Safety and Environment Committee	Independent	Nominated by EPCOR
Don Lowry (Chair) [4]				✔	✔
Albrecht Bellstedt		Chair	✔	✔	
Doyle Beneby	✔		✔	✔	
William Bennett	Chair		✔	✔	
Brian Bentz			Chair	✔	
Hugh Bolton				✔	✔
Richard Cruickshank		✔			
Philip Lachambre	✔		✔	✔	
Robert Phillips		✔		✔	✔
Allister McPherson	✔			✔	✔
Peggy Mulligan	✔	✔		✔	
Brian Vaasjo					

1 All members, 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. Vassjo 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.

EXECUTIVE TEAM

BRIAN VAASJO President and Chief Executive Officer

PETER ARNOLD Senior Vice President, Human Resources & Health, Safety & Environment

KATE CHISHOLM Senior Vice President, Legal & External Relations

BRYAN DENEVE Senior Vice President, Corporate Development & Commercial Services

STUART LEE Senior Vice President, Finance & Chief Financial Officer

DARCY TRUFYN Senior Vice President, Operations, Construction & Engineering

GOVERNANCE

We believe that effective governance is a major contributor to long-term performance and investor confidence. Our corporate governance practices are consistent with the following, as adopted by the Canadian Securities Administrators:

National Policy 58-201 – Corporate Governance Guidelines (NP 58-201)
National Instrument 58-101 – Disclosure of Corporate Governance Practices (NI 58-101)
National Instrument 52-110 – Audit Committees (NI 52-110)
National Instrument 52-109 – Certification of Disclosure in Issuers' Annual and Interim Filings (CSox)
Form 58-101F1 – Corporate Governance Disclosure (58-101F1)

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 (83%) 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 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 DSUs and/or common shares)

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 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, giving shareholders a say on pay

We adopted an incentive clawback policy and anti-hedging policy, further aligning 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, committee and individual director assessments are conducted every year

You can find a copy of our corporate governance policy on our website (www.capitalpower.com). In addition, detailed information on the Board's mandate, its committees, Directors' biographies and highlights of the Board and committee work in 2012 can be found in the Management Proxy Circular, which can also be found on our website (www.capitalpower.com) or on SEDAR (www.sedar.com).

CAPITAL POWER CORPORATION

Management's Discussion and Analysis

This management's discussion and analysis (MD&A), dated March 1, 2013, should be read in conjunction with the audited consolidated financial statements of Capital Power Corporation and its subsidiaries for the years ended December 31, 2012 and December 31, 2011, the annual information form of Capital Power Corporation for the year ended December 31, 2012 and the cautionary statements regarding forward-looking information which begins on page 3. 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, 2012, 2011 and 2010 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 has approved this MD&A as of March 1, 2013.

Contents

The Business and Corporate Structure

Capital Power is a growth-oriented North American independent power producer headquartered in Edmonton, Alberta. The Company develops, acquires, operates and optimizes power generation from a variety of energy sources. Capital Power owns more than 3,600 megawatts (MW) of power generation capacity at 16 facilities across North America and has rights to 371 MW through its interest in the acquired Sundance power purchase arrangement (acquired Sundance PPA). An additional 595 MW of owned generation capacity is under construction or in advanced 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, 2012, the Company directly and indirectly held approximately 21.750 million general partnership units and 46.699 million common limited partnership units of CPLP which represented approximately 71% of CPLP's total partnership units. EPCOR (in this MD&A, EPCOR refers to EPCOR Utilities Inc. collectively with its subsidiaries) held 28.441 million exchangeable common limited partnership units of CPLP representing approximately 29% of CPLP. CPLP's exchangeable common limited partnership units are exchangeable for common shares of Capital Power Corporation on a one-for-one basis. The general partner of CPLP is wholly-owned by Capital Power Corporation and EPCOR's representation on the Board of Directors does not represent a controlling vote. Accordingly, Capital Power Corporation controls CPLP and the operations of CPLP have been consolidated for financial statement purposes.

Corporate Strategy

Capital Power's corporate strategy seeks to balance a strong financial position with targeted growth. The Company is committed to maintaining a stable dividend, an investment-grade credit rating supported by contracted cash flows, and a prudent expansion strategy.

The key components of Capital Power's corporate strategy are as follows:

Continued focus on operational excellence and environmental and safety leadership

Capital Power's operational strategy is to safely manage, operate and maintain its power generation facilities in a manner that maximizes efficiency, productivity and reliability, and minimizes costs while reducing environmental impact. Capital Power is committed to maintaining its facilities' record of strong operational performance by continuing to plan and monitor maintenance requirements in order to ensure high levels of fleet availability. The Company also remains committed to a safety culture of zero injury and occupational illness incidents.

Financial discipline

Capital Power is committed to a policy of financial discipline founded upon operational success, contracted generation assets and targeted growth while maintaining an investment-grade credit rating. Capital Power strives to maintain a strong financial position with an appropriate dividend yield on its common shares so that it will remain well positioned to access the capital markets to finance acquisitions or strategic development opportunities. To help achieve these objectives, Capital Power expects to continue to sell forward a significant portion of its generation output and capacity under long-term contracts.

Sustainable growth

In 2012, the Company completed construction of its Quality Wind project in British Columbia and its Halkirk wind project in Alberta which commenced commercial operations on November 6, 2012 and December 1, 2012, respectively. These wind projects provide incremental combined capacity of 292 MW. See Significant Events. In 2011, the Company acquired three natural gas-fired combined cycle power generating facilities in the New England states with a combined capacity of 1,089 MW. It also acquired two mixed fuel generating plants in North Carolina with a combined capacity of 134 MW that were previously owned by its former subsidiary, Capital Power Income L.P. (CPILP).The Company's wind power projects under development are Port Dover & Nanticoke Wind (Port Dover & Nanticoke) in Ontario (105 MW) and K2 Wind Power Project (K2) in Ontario (270 MW with Capital Power's ownership interest being 90 MW).

On December 6, 2012, Capital Power announced the signing of a joint venture agreement for the construction, ownership and operations of the 800 MW Shepard natural gas-fired combined cycle power generation facility located in Alberta. Capital Power has a 50% ownership position of 400 MW. The facility is currently under construction and is approximately half complete with an expected commercial operation date in the first quarter of 2015.

The Company also plans to develop the new Capital Power Energy Centre (CPEC), a natural gas combined cycle power generation facility in Alberta. CPEC's capacity is expected to be up to 900 MW with targeted commercial operations in the 2017 to 2020 timeframe.

The Company has a number of other projects in various stages of development and it continues to evaluate acquisition prospects, primarily in the U.S., to strengthen its regional footprint and existing portfolio. To help ensure that the Company's financial condition is not compromised by its growth strategy, it has set internal rates of return targets for acquisition and development project opportunities. As part of the Company's growth strategy through developing and building new assets, the Company has chosen to make construction a core competency.

Regional footprint

Capital Power intends to confine its regional footprint to Canada and the U.S. and seeks to enhance its regional diversification by focusing on a select group of target markets across Canada and the U.S. Capital Power uses a disciplined approach to select target regions with a preference for markets with favourable long-term fundamentals and spark spreads, including regulatory frameworks conducive to competitive power generation, sufficient scale to support the establishment of a networked hub of power facilities, and liquid trading markets. Spark spread means the theoretical difference between the price of electricity as the output and its energy cost of production.

Networked hub strategy

The Company's networked hub strategy is to manage power generation assets at the hub level rather than by individual facility in order to be a cost-effective provider of electricity in the Company's markets. The foundation of this strategy is to establish generation hubs by acquiring larger-scale, fossil-fuel based power plants supplemented by renewable facilities, in the Company's markets. In order to reduce purchasing, warehousing, inventory and other costs, the Company seeks to standardize these plants by fuel type and technology. The Company then seeks to enter into a mix of unit specific and non-unit specific contracts to provide it with flexibility in deploying its generation assets. The availability of physical generation from multiple sources in a market area provides the Company with the flexibility to optimize its portfolio of assets in the networked hub in response to changes in commodity prices. The Company believes that its approach of managing assets at the hub level improves efficiency and reduces risk through portfolio diversification.

Capital Power intends to maintain its existing strong position in Alberta and focus on developing additional hubs in the following three regions: Mid-Atlantic U.S., including the PJM (Pennsylvania, New Jersey and Maryland) Interconnection and the Virginia-Carolinas; the North East U.S., including the New York Independent System Operator and the New England Power Pool (NEPOOL); and the South West U.S., including the California Independent System Operator and Desert South West (Arizona, New Mexico and Nevada). In addition, other North American markets, especially where Capital Power has existing operations, are considered on a case-by-case basis if opportunities arise for the development of contracted facilities.

Technology preference

In its selection of future power generation technologies, Capital Power plans to capture economies of scale, accommodate emerging market supply and demand trends, and further develop distinctive competencies. The Company expects to focus primarily on larger-scale, fossil fuel-fired technologies, supplemented by renewable wind facilities that are economically attractive and supportive of the Company's long-term contracting position. Fossil fuel-fired facilities will remain a core component of the Company's portfolio. However, given the emerging opportunities in the Company's target markets, the Company is pursuing development and acquisition opportunities for solar power.

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 information with respect to: (i) expectations related to future earnings and funds from operations, (ii) expectations regarding the future pricing of electricity and market fundamentals in existing and target markets, (iii) expectations regarding fuel supply and pricing, (iv) expectations related to the Company's future cash requirements including interest and principal repayments, capital expenditures and dividends, (v) expectations for the Company's sources of funding, adequacy and availability of committed bank credit facilities and future borrowings, (vi) expectations regarding future growth and emerging opportunities in the Company's target markets including the focus on certain technologies, (vii) expectations regarding the timing of, funding of, and costs for existing, planned and potential development projects and acquisitions, (viii) expectations regarding plant availability, and (ix) expectations regarding 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 and expected future developments, and other factors it believes are appropriate. The material factors and assumptions used to develop these forward-looking statements relate to: (i) electricity and other energy prices, (ii) performance, (iii) business prospects and opportunities including expected growth and capital projects, (iv) status of and impact of policy, legislation and regulations, (v) effective tax rates, and (vi) other matters discussed under the Performance Overview and Outlook sections.

Whether actual results, performance or achievements will conform to the Company's expectations and predictions is subject to a number of known and unknown risks and uncertainties which could cause actual results and experience to differ materially from the Company's expectations. Such material risks and uncertainties are: (i) changes in electricity prices in markets in which the Company operates, (ii) changes in energy commodity market prices and use of derivatives, (iii) regulatory and political environments including changes to environmental, financial reporting and tax legislation, (iv) power plant availability and performance including maintenance expenditures, (v) ability to fund current and future capital and working capital needs, (vi) acquisitions and developments including timing and costs of regulatory approvals and construction, (vii) changes in market prices and availability of fuel, and (viii) changes in general economic and competitive conditions. See Risks and Risk Management 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.

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 core measures. The corporate measures are company-wide and include funds from operations and safety. The core measures are specific to certain groups of the Company and 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	2012 target	2012 actual results
Plant availability average	91% or greater	91%
Capital expenditures for plant maintenance and other (excludes capital expenditures for Genesee mine lands)	$108 million or lower	$102 million
Maintenance and operating expenses	$215 million to $235 million	$208 million

In 2012, the Company's plant availability averaged 91% which achieved target. In the fourth quarter of 2012, Genesee 3 experienced a planned outage that was extended for an additional 9 days. The availability of the North East U.S. plants was lower than expected due to several pre-emptive outage days at Bridgeport and Tiverton in consideration of Hurricane Sandy. These unfavourable plant availabilities were partly offset by the favourable availability of the contracted plants in Alberta, Ontario and British Columbia. Strong 2012 third quarter performance of the Alberta commercial plants was offset by the impact of an unscheduled outage for Genesee 1 in the third quarter of 2012. In the second quarter, planned outages for Genesee 2, Bridgeport, Rumford, Tiverton and the North Carolina U.S. plants occurred. An unscheduled outage for Bridgeport due to a condenser leak impacted availability in the middle two quarters of 2012. In the first quarter, strong performances of Genesee 1 and 2, Keephills 3 and Joffre were partly offset by the Genesee 3 outage which continued from November 11, 2011 until January 15, 2012.

Capital expenditures for 2012 for plant and other maintenance were consistent with target reflecting capital expenditures for plant maintenance and shutdowns and the major information technology systems that were substantially implemented by December 31, 2012.

The maintenance and operating 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 2012 were slightly better than target.

Financial stability and strength

Performance measure	2012 target	2012 actual results
Normalized earnings per share [(1)]	$1.50 to $1.70	$1.29
Funds from operations [(1)]	$380 million to $420 million	$381 million
Cash flow per share [(1)]	$3.90 to $4.30	$3.89

(1) Normalized earnings per share, funds from operations, and cash flow per share are non-GAAP measures. See Non-GAAP Financial Measures.

Actual financial results achieved in 2012 compared with the 2012 financial targets reflected the overall impact of lower than expected power prices and the results of portfolio optimization activities. The most significant variances from the targets were losses upon settlement of Bridgeport heat rate option contracts, lower than expected wind volumes at Quality Wind, and lower than expected adjusted EBITDA[(2)] for the North East U.S. plants primarily due to the second quarter unplanned outage at Bridgeport, lower than expected spark spreads and lower than expected trading results. The results for North Carolina U.S. plants were also under target primarily due to higher than expected maintenance costs incurred during planned outages and higher fuel costs. These unfavourable variances from target were partly offset by the fourth quarter increase in adjusted EBITDA due to a change in the estimate of Genesee coal mine inventory.

(2) Earnings before finance expense, income tax expense, depreciation and amortization, impairments, foreign exchange losses and gains on disposals (adjusted EBITDA) is a non-GAAP financial measure. See Non-GAAP Financial Measures.

Net pre-tax losses of $10 million related to the North East U.S. plants were incurred in the fourth quarter of 2012. A heat rate option that was in place on the Bridgeport facility at the time of acquisition in 2011 settled at a loss for November and December 2012 due to a significant shift in the underlying locational basis risk associated with the option. The basis risk existed because the plant delivers power to and procures gas from locations differing from those referenced in the heat rate option. The correlation between the locations has historically been very high for both power and natural gas. However, in November and December 2012, there was a spike in North East U.S. natural gas demand combined with supply constraints resulting in a significant shift in North East U.S. gas fundamentals. These factors led to a significant widening of the price spread between the Bridgeport plant's natural gas consumption point and the heat rate option location resulting in the loss. This Bridgeport heat rate option expires at the end of 2013 and this gas price differential risk has been fully mitigated for 2013. In addition, December 2012 physical natural gas consumption for Bridgeport was locked-in at prices higher than actual prices resulting in an additional loss. These losses were partly offset by gains realized on a financial hedge executed to reduce the locational basis risk. These trades were implemented to limit the exposure to the natural gas basis risk associated with the heat rate option.

Wind volumes at the Quality Wind facility, which began operations in early November 2012, were lower than expected. Based on historical wind data, the period from November to January typically has the strongest wind regime and Capital Power's forecast accordingly assumed an average capacity factor of 47% for this three-month period. The actual capacity factor for November and December averaged 27% and resulted in lower than forecasted operating margins of approximately $6 million in the fourth quarter of 2012. The actual capacity factor for January and February 2013 was in line with expectations.

Revenues and adjusted EBITDA for 2012 were unfavourably impacted by an unplanned outage at the Bridgeport facility which was offline from May 2, 2012 to June 11, 2012 due to a condenser leak. The Company incurred $2 million in maintenance costs and lost an estimated $4 million in revenues as a result of this outage. Lower market spark spreads reflected the impact of lower natural gas prices resulting primarily from an oversupply of natural gas. Other trading results for the North East U.S. portfolio were under target by $10 million for full year 2012

These unexpected events were partly offset by the favourable pre-tax adjustment of $9 million recorded in the fourth quarter of 2012 related to a change in estimate for the Genesee mine coal inventory which primarily impacted the Alberta contracted plants.

Enhancing shareholders' value

Performance measure	2012 target	Status at December 31, 2012
Halkirk wind project	Continue on budget of $357 million and on time with commercial operation date in the fourth quarter of 2012	Achieved commercial operation date on December 1, 2012 with actual capital costs forecast to be from $325 to $335 million
Quality Wind project	Continue on budget of $455 million and on time with commercial operation date in the fourth quarter of 2012	Achieved commercial operation date on November 6, 2012 with actual capital costs forecast to be from $405 to $415 million
Port Dover & Nanticoke and K2 wind projects	Full notice to proceed in 2012	Limited notice to proceed received for Port Dover & Nanticoke Full notice to proceed for K2 revised to late 2013 or early 2014

The growth projects of Halkirk and Quality Wind were completed on time and under budget in the fourth quarter of 2012. During the year, the Company revised its expectation for the timing of full notice to proceed on the K2 wind project from 2012 to late 2013 or early 2014. Total project costs for Quality Wind were approximately 10% lower than budget. This decrease was attributed primarily to strong project management including the impact of up-front planning and project execution steps such as value engineering, constructability improvements and supply chain optimization. Total final forecast project costs for Halkirk are approximately 8% lower than budget due to similar reasons as for the Quality Wind project.

The previously expected commissioning timing for K2 in 2014 was revised to early 2015 as a result of delays in the anticipated timing of delivery of the turbines. Its total project costs remain unchanged. Environmental approvals for K2 are expected to be received in 2013 but full notice to proceed may be delayed until 2014. The Port Dover & Nanticoke wind project received its Renewable Energy Approval (REA) from the Government of Ontario on July 17, 2012 and construction has commenced. In January 2013, the Environmental Review Tribunal (ERT) dismissed appeals to the REA which had been filed by two groups. In its decision, the ERT made a number of non-binding recommendations that Capital Power will consider implementing. The impact of implementing any or all of the recommendations is not considered significant.

Targets for 2013

The following table provides the Company's performance measure targets for 2013:

Performance measure	2013 target
Operational	
Plant availability average	93% or greater
Capital expenditures for plant maintenance, Genesee mine extension, and other	$105 million or lower
Maintenance and operating expenses	$225 million to $245 million
Financial	
Normalized earnings per share (1)	$1.20 to $1.40
Funds from operations (1)	$385 million to $415 million
Cash flow per share (1)	$3.80 to $4.20
Construction / Development	
Port Dover & Nanticoke wind project	Continue on budget of $340 million and on time with commercial operation date in the fourth quarter of 2013
K2 wind project	Environmental approvals received in 2013
Shepard Energy Centre	Continue on budget of $860 million

(1) Normalized earnings per share, funds from operations, and cash flow per share are non-GAAP measures. See Non-GAAP Financial Measures.

Outlook

The following discussion should be read in conjunction with the Forward-looking Information section of this MD&A which identifies the material factors and assumptions used to develop forward-looking information and their material associated risk factors. Based upon a forecast average Alberta power price of approximately $58 per megawatt hour (MWh), normalized earnings per share and funds from operations for 2013 are expected to be in line with the levels achieved in 2012. Items impacting the year-over-year comparison are as follows:

The Company's forecast for average Alberta power prices in 2013 is lower than the average of $64 per MWh experienced in 2012. Thus, the Company expects lower realized prices on its economically unhedged position, profitability from the peaking facilities, and incentive revenues from Genesee 1 and 2. This is expected to be offset by the full year earnings from Halkirk and Quality Wind and stronger plant availability.

The forecast 2012 generation, at the beginning of 2012, from the baseload plants and acquired Sundance PPA in the Alberta commercial portfolio was 48% sold forward at an average price of high-$60 per MWh compared with the following portfolio positions for 2013, 2014 and 2015:

Alberta commercial portfolio positions and power prices	**2013**	**2014**	**2015**
Percentage sold forward	49%	37%	31%
Contracted price	Mid-$60 per MWh	Mid-$50 per MWh	Mid-$50 per MWh

Results for 2013 are expected to include a full year of operations from the Halkirk and Quality Wind facilities which both began commercial operation in the fourth quarter of 2012. See Significant Events.

In 2013, Capital Power's availability target of 93% reflects two major scheduled maintenance outages, one at Genesee 1 and one at Keephills 3, compared with the 2012 scheduled maintenance outages for Genesee 2 and Genesee 3.

The 2013 targets and normalized earnings per share 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 impacts from unplanned plant outages including outages at facilities of other market participants, and the related impacts on market power prices.

The Company's estimated 2013 capital expenditures in the following table only include expenditures for previously identified growth projects and exclude the cost of potential new development projects:

(unaudited, $millions) **Capital expenditures – growth**	**Commercial operation or target completion timing**	**2013 estimated**
Halkirk and Quality Wind post-commercial operations date completion	4th quarter 2012	7
Port Dover & Nanticoke	4th quarter 2013	272
K2 (1)	2015	21
Shepard Energy Centre	2015	335
		635

(1) Capital Power entered into a partnership agreement to develop K2 which is expected to be in operation by 2015. The 2013 capital expenditures estimated for the K2 project consist primarily of the Company's estimated contribution towards the partnership's equity.

(unaudited, $millions) **Capital expenditures – sustaining**	**2013 estimated**
Plant maintenance	75
Genesee mine maintenance (1)	7
Other	11
	93
Genesee mine lands	9
	102

(1) Capital expenditures for Genesee mine maintenance represent only those capital expenditures funded by the Company for the Genesee mine operation.

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

Non-GAAP Financial Measures

The Company uses (i) earnings before finance expense, income tax expense, depreciation and amortization, impairments, foreign exchange losses, and gains on disposals (adjusted EBITDA), (ii) funds from operations, (iii) funds from operations excluding non-controlling interests in CPILP, (iv) cash flow per share, (v) discretionary cash flow, (vi) normalized earnings attributable to common shareholders, and (vii) 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 are therefore unlikely to be comparable to similar measures used by other enterprises. These measures should not be considered alternatives to gross income, operating income, 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. For previously reported periods prior to the three months ended December 31, 2011, the Company defined EBITDA as earnings before finance expense, income tax expense and depreciation and amortization. Commencing with the Company's December 31, 2011 year-end, adjusted EBITDA was defined to also exclude impairments, foreign exchange losses and gains on disposals. Management believes that EBITDA, as a measure of plant operating performance, is more meaningful if results not related to plant operations such as impairments, foreign exchange losses and gains on disposals are excluded from the adjusted EBITDA measure. All comparative EBITDA amounts for quarters prior to those ended on December 31, 2011 were revised to reflect this change. A reconciliation of adjusted EBITDA to net income is as follows:

(unaudited, $millions)	**Year ended December 31**		**Three months ended**							
	2012	**2011**	**Dec 2012**	**Sep 2012**	**Jun 2012**	**Mar 2012**	**Dec 2011**	**Sep 2011**	**Jun 2011**	**Mar 2011**
Revenues	1,291	1,691	282	392	249	368	382	414	455	440
Other income	40	79	14	2	12	12	25	19	17	18
Energy purchases and fuel	(553)	(904)	(134)	(162)	(110)	(147)	(169)	(189)	(255)	(291)
Gross income	**778**	**866**	**162**	**232**	**151**	**233**	**238**	**244**	**217**	**167**
Other raw materials and operating charges	(132)	(149)	(37)	(29)	(36)	(30)	(40)	(43)	(37)	(29)
Staff costs and employee benefits expense	(143)	(155)	(34)	(39)	(34)	(36)	(34)	(40)	(42)	(39)
Other administrative expenses	(62)	(77)	(18)	(12)	(17)	(15)	(14)	(22)	(26)	(15)
Adjusted EBITDA	**441**	**485**	**73**	**152**	**64**	**152**	**150**	**139**	**112**	**84**
Depreciation and amortization	(221)	(229)	(62)	(52)	(53)	(54)	(62)	(45)	(64)	(58)
Impairments	(74)	(43)	-	-	(74)	-	-	-	(43)	-
Foreign exchange losses	-	(13)	-	-	-	-	-	(7)	(4)	(2)
Operating income (loss)	**146**	**200**	**11**	**100**	**(63)**	**98**	**88**	**87**	**1**	**24**
Gains on disposals	15	93	15	-	-	-	93	-	-	-
Finance expense	(75)	(105)	(21)	(19)	(17)	(18)	(29)	(32)	(35)	(9)
Income tax recovery (expense)	4	-	14	(18)	22	(14)	-	(11)	12	(1)
Net income (loss)	**90**	**188**	**19**	**63**	**(58)**	**66**	**152**	**44**	**(22)**	**14**
Net income (loss) attributable to:										
Non-controlling interests	28	111	4	24	(26)	26	68	29	3	11
Shareholders of the Company	62	77	15	39	(32)	40	84	15	(25)	3
Net income (loss)	**90**	**188**	**19**	**63**	**(58)**	**66**	**152**	**44**	**(22)**	**14**

Funds from operations and funds from operations excluding non-controlling interests in CPILP

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, including finance and current income tax expenses, and excluding changes in 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.

The Company divested its 29% indirect ownership of CPILP as of November 5, 2011. Prior to the sale, the Company used funds from operations excluding non-controlling interests in CPILP to provide a more meaningful measure of the Company's operating cash flows since the non-controlling interests in CPILP's funds from operations were approximately 71%.

A reconciliation of net cash flows from operating activities to (i) funds from operations and (ii) funds from operations excluding non-controlling interests in CPILP is as follows:

(unaudited, $millions)	Year ended December 31		Three months ended December 31	
	2012	**2011**	**2012**	**2011**
Net cash flows from operating activities per Consolidated Statements of Cash Flows	**242**	**461**	**29**	**151**
Add (deduct) items included in calculation of net cash flows from operating activities per Consolidated Statements of Cash Flows:				
Interest paid	59	88	22	44
Miscellaneous financing charges paid and realized loss on the settlement of forward bond contracts included in other items	15	15	2	1
Income taxes paid	7	14	1	1
Change in non-cash operating working capital	140	(42)	46	(69)
	221	75	71	(23)
Finance expense excluding unrealized changes on interest rate derivative contracts and amortization and accretion charges	(78)	(98)	(17)	(24)
Current income tax expense	(4)	(5)	-	(5)
Funds from operations	**381**	**433**	**83**	**99**
Less funds from operations due to non-controlling interests in CPILP	-	81	-	11
Funds from operations excluding non-controlling interests in CPILP	**381**	**352**	**83**	**88**

Cash flow per share

Cash flow per share is calculated using the weighted average common shares of Capital Power Corporation and exchangeable common limited partnership units of CPLP that were outstanding during the period. The CPLP exchangeable common limited partnership units are exchangeable for common shares of Capital Power Corporation on a one-for-one basis.

(unaudited)	Year ended December 31		Three months ended December 31	
	2012	**2011**	**2012**	**2011**
Funds from operations excluding non-controlling interests in CPILP ($millions)	**381**	**352**	**83**	**88**
Weighted average common shares outstanding (millions)	66.82	44.25	69.84	55.64
Weighted average exchangeable common limited partnership units of CPLP outstanding (millions)	31.00	46.13	28.44	42.32
Weighted average shares and partnership units outstanding (millions)	97.82	90.38	98.28	97.96
Cash flow per share ($)	**3.89**	**3.89**	**0.84**	**0.90**

Discretionary cash flow

Capital Power uses discretionary cash flow as a measure of the Company's ability to pay dividends to its shareholders and distributions to CPLP's exchangeable common limited partnership unitholders from funds it generates from operations. The measure is calculated as funds from operations excluding non-controlling interests in CPILP less sustaining capital expenditures.

(unaudited, $millions)	Year ended December 31		Three months ended December 31	
	2012	**2011**	**2012**	**2011**
Funds from operations excluding non-controlling interests in CPILP	**381**	**352**	**83**	**88**
Less sustaining capital expenditures	119	92	37	47
Less CPLP's share of CPILP sustaining capital expenditures	-	6	-	1
Adjusted funds from operations	262	254	46	40
Common share dividends declared	85	60	23	18
Distributions to exchangeable common limited partnership unitholders of CPLP declared	39	57	9	12
Preferred share dividends declared	6	6	2	2
Total dividends and distributions declared	130	123	34	32
Discretionary cash flow	**132**	**131**	**12**	**8**

Normalized earnings attributable to common shareholders and normalized earnings per share

The Company uses 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 fair value changes, impairment charges, unusual tax adjustments, gains and losses on disposal of assets or unusual contracts, and foreign exchange loss on the translation of U.S. dollar denominated debt. A reconciliation of net income (loss) attributable to shareholders to normalized earnings attributable to common shareholders, and basic earnings (loss) per share to normalized earnings per share is as follows:

(unaudited, $millions except basic earnings (loss) per share and number of common shares)	Year ended December 31		Three months ended							
	2012	2011	Dec 2012	Sep 2012	Jun 2012	Mar 2012	Dec 2011	Sep 2011	Jun 2011	Mar 2011
Basic earnings (loss) per share	**0.84**	**1.60**	**0.19**	**0.55**	**(0.50)**	**0.66**	**1.47**	**$0.29**	**(0.67)**	**0.06**
Net income (loss) attributable to shareholders of the Company per Consolidated Statements of Income	**62**	**77**	**15**	**39**	**(32)**	**40**	**84**	**15**	**(25)**	**3**
Preferred share dividends	(6)	(6)	(2)	(1)	(2)	(1)	(2)	(1)	(2)	(1)
Earnings (loss) attributable to common shareholders	56	71	13	38	(34)	39	82	14	(27)	2
Unrealized changes in fair value of CPLP's derivative instruments	-	15	12	(4)	4	(12)	2	2	2	9
Unrealized changes in fair value of CPILP's derivative instruments	-	1	-	-	-	-	(1)	2	-	-
Impairment loss on North East U.S. assets	37	-	-	-	37	-	-	-	-	-
Impairment loss on manager and operating contracts	-	30	-	-	-	-	-	-	30	-
Gain on sale of hydro facilities	(9)	-	(9)	-	-	-	-	-	-	-
Gain on sale of CPILP	-	(60)	-	-	-	-	(60)	-	-	-
Gain on settlement of pension expense from sale of CPILP	-	(3)	-	-	-	-	(3)	-	-	-
Gain on sale of Taylor Coulee Chute	-	(1)	-	-	-	-	(1)	-	-	-
Genesee 1 unplanned outage costs due to plant research and development project	4	-	-	4	-	-	-	-	-	-
Impact of change in non-controlling interest percentage on adjustments of previous quarters	(2)	2	-	-	(2)	-	1	1	-	-
Foreign exchange losses on translation of U.S. dollar debt	-	2	-	-	-	-	-	2	-	-
Income tax adjustments	-	(2)	-	-	-	-	-	-	(2)	-
Normalized earnings attributable to common shareholders	**86**	**55**	**16**	**38**	**5**	**27**	**20**	**21**	**3**	**11**
Weighted average number of common shares outstanding (millions)	66.82	44.25	69.84	69.52	68.51	59.18	55.64	48.33	40.42	32.32
Normalized earnings per share	**1.29**	**1.24**	**0.23**	**0.55**	**0.07**	**0.46**	**0.36**	**0.43**	**0.07**	**0.33**

Normalized earnings per share reflects the period-over-period change in normalized earnings 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		
	2012	2011	2010
Revenues and other income	1,331	1,770	1,762
Adjusted EBITDA [1]	441	485	418
Net income	90	188	77
Net income attributable to shareholders of the Company	62	77	17
Normalized earnings attributable to common shareholders [1]	86	55	32
Basic earnings per share ($)	0.84	1.60	0.77
Diluted earnings per share ($) [2]	0.84	1.59	0.69
Normalized earnings per share ($) [1]	1.29	1.24	1.40
Funds from operations [1]	381	433	374
Funds from operations excluding non-controlling interests in CPILP [1]	381	352	277
Cash flow per share ($) [1]	3.89	3.89	3.53
Capital expenditures	598	493	329
Discretionary cash flow [1]	132	131	110
Dividends per common share, declared ($)	1.26	1.26	1.26
Dividends per preferred share, declared ($)	1.15	1.19	n/a

	As at December 31		
	2012	2011	2010
Loans and borrowings including current portion	1,659	1,480	1,869
Total assets	5,134	4,743	5,296

(1) The consolidated financial highlights, except for adjusted EBITDA, normalized earnings attributable to common shareholders, normalized earnings per share, funds from operations, funds from operations excluding non-controlling interests in CPILP, cash flow per share, and discretionary cash flow, were prepared in accordance with GAAP. See Non-GAAP Financial Measures.

(2) Diluted earnings per share was calculated after giving effect to share purchase options and the 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.

Normalized earnings and normalized earnings per share

Refer to Results by Plant Category and Other and Consolidated Other Expenses and Non-Controlling Interests for detailed discussion of the results for the year on a comparative basis.

Normalized earnings and normalized earnings per share were determined by excluding the total of net unrealized changes in the fair value of derivative instruments (including forward bond contracts). Accordingly, these net unrealized changes reduced normalized earnings by $2 million for 2012 and by $55 million for 2011 before consideration of taxes and non-controlling interests.

Additional significant adjustments to determine normalized earnings and normalized earnings per share were the exclusion of the second quarter pre-tax impairment of $74 million related to the North East U.S. plants and the fourth quarter pre-tax gain of $15 million on the sale of the British Columbia hydro facilities. See Significant Events.

Funds from operations

Changes in funds from operations for 2012 compared with 2011 were consistent with the changes in net income attributable to shareholders of the Company.

Significant Events

$150 million offering of 4.60% Cumulative Rate Reset Preference Shares

On December 18, 2012, Capital Power Corporation issued 6 million Cumulative Rate Reset Preference Shares, Series 3 at $25 per share for aggregate gross proceeds of $150 million on a bought deal basis with a syndicate of underwriters.

The Series 3 Shares will pay fixed cumulative preferential dividends of $1.15 per share per annum, yielding 4.60% per annum, payable on the last business day of March, June, September and December each year, as and when declared by the Board of Directors of Capital Power Corporation, for the initial period ending December 31, 2018. The Series 3 Shares are subject to specified redemption, conversion and reset rights.

Standard & Poor's (a division of the McGraw Hill Companies, Inc.) (S&P) has assigned a rating of P-3 and DBRS Limited (DBRS) has assigned a rating of Pfd-3 (low) for these Series 3 Shares.

Announcement of major expansion plans

In December 2012, Capital Power announced expansion plans including its joint venture agreement with ENMAX Corporation (ENMAX) for the construction, ownership and operations of the Shepard Energy Centre with scheduled completion in early 2015 and its intention to develop the Capital Power Energy Centre, a large natural gas facility that is scheduled for completion in the 2017 to 2020 timeframe when additional generation in Alberta is required to meet growing demand and replace generation from the retirement of coal-fired units.

Completion and commercial operations commencement of wind projects

Capital Power completed construction of its 150 MW Halkirk facility located in central Alberta. The Alberta Electric System Operator declared Halkirk commercially operational on December 1, 2012. The facility was completed slightly ahead of scheduled timing and approximately 8% under budgeted cost of $357 million. Capital Power also completed construction of its 142 MW Quality Wind facility located in British Columbia with its commercial operation date being November 6, 2012. Construction was completed on time and approximately 10% below its $455 million budget.

Impairment of North East U.S. assets

During the second quarter of 2012, Capital Power recognized a pre-tax impairment charge of $74 million with respect to its North East U.S. plants which reduced the carrying amount of the related property, plant and equipment and goodwill. This impairment was based on reduced expected operating margins for the Bridgeport, Rumford and Tiverton plants largely as a result of weaker spark spreads in the North East U.S power markets. The reduction in spark spreads is attributable to market and other changes since the April 2011 acquisition of the North East U.S. assets; the fair value paid was consistent with other transactional values in the market at the time of acquisition. If expected operating margins strengthen, a portion of the impairment loss could be reversed. The impairment charge, after income taxes and non-controlling interests, was excluded from net income attributable to shareholders in determining normalized earnings per share. The impairment charge had no cash flow impact.

Sale of hydro facilities

On October 12, 2012, Capital Power completed the sale of its two British Columbia hydro facilities, Brown Lake and Miller Creek. The two facilities, which generate 40 MW into the British Columbia power grid, were sold to Innergex Renewable Energy Inc. (Innergex) for approximately $69 million and a pre-tax gain of $15 million was recorded in the Company's consolidated statement of income. The gain on disposal, after income taxes and non-controlling interests, was excluded from net income attributable to shareholders in determining normalized earnings per share. The gain on disposal had no cash flow impact.

Debt and equity base shelf prospectuses

On June 12, 2012, CPLP filed a Canadian base shelf prospectus, which expires in July 2014, under which it may offer and issue medium-term notes, due not less than one year from the date of issue, to the public in an aggregate principal amount not to exceed $1 billion.

On February 16, 2012, Capital Power filed a Canadian base shelf prospectus, which expires in March 2014, under which it may raise up to $2 billion collectively in common shares of the Company, preferred shares of the Company and subscription receipts exchangeable for common shares and/or other securities of the Company.

Secondary offering of Capital Power common shares by EPCOR

Effective April 5, 2012, EPCOR exchanged 9,775,000 of its exchangeable common limited partnership units in CPLP for common shares of Capital Power on a one-for-one basis and sold 9,775,000 common shares of Capital Power to the public pursuant to a secondary offering at $23.55 per common share. Capital Power did not receive any of the approximate $230 million of proceeds from EPCOR's sale of common shares. This transaction reduced EPCOR's ownership interest in CPLP to approximately 29% from its interest of approximately 39% at December 31, 2011. EPCOR has advised that it intends to sell all or a portion of its remaining interest in CPLP as its demands for capital require and market conditions permit.

$250 million debt issue

On February 21, 2012, CPLP completed a public offering of $250 million unsecured medium-term notes. The notes have a coupon rate of 4.85%, with interest payable semi-annually commencing on August 21, 2012, and mature on February 21, 2019. The net proceeds of the offering were used for repayment of amounts owing under credit facilities, financing on ongoing capital projects, working capital requirements, and general corporate purposes.

Sale of Atlantic Power shares

On February 10, 2012, the Company completed the sale of its shares in Atlantic Power, which were acquired in November 2011 as part of the Atlantic Power acquisition of CPILP, for proceeds of $52 million on a bought deal basis. These shares were initially recorded at $48 million and subsequently adjusted to their fair value of $53 million as of December 31, 2011 resulting in an unrealized gain of $5 million recognized in 2011. In the first quarter of 2012, the Company recognized a realized pre-tax gain of $4 million with income taxes estimated to be $1 million offset by the reversal of the unrealized gain of $5 million recognized in the previous year.

Subsequent Event

On February 28, 2013, the purchase of the first tranche of the Company's interest in Shepard closed. Upon close of this transaction, the Company paid $237 million and acquired a 25% interest in Shepard. The total amount incurred by the Company to the date of close was $287 million compared with the total anticipated capital cost of $860 million. The second tranche, expected to close in the first quarter of 2014, will result in the Company's acquisition of an additional 25% interest in Shepard bringing its total ownership interest to 50%. Subsequent to the close of the first tranche, and prior to the close of the second tranche, all decisions related to Shepard will require unanimous approval by the Company and ENMAX. As a result, the Company jointly controls Shepard with ENMAX upon close of the first tranche. Based on the terms of the Shepard agreements, the Company will account for the Shepard joint arrangement, under the new accounting standard for joint arrangements, as a joint operation.

Plant Summary

		Year ended December 31					
		2012	2011	2012	2011	2012	2011
	Energy source	Electricity generation (GWh) [1]		Plant availability (%) [2]		Plant revenues (unaudited, $ millions) [3]	
Total electricity generation, average plant availability and total plant revenues excluding acquired Sundance PPA and CPILP plants		16,374	13,659	91%	92%	975	867
Alberta commercial plants and acquired Sundance PPA							
Genesee 3 [4]	Coal	1,631	1,677	84%	85%	101	126
Keephills 3 [5]	Coal	1,795	871	99%	99%	118	50
Clover Bar Energy Centre 1, 2 and 3	Natural gas	471	391	97%	80%	71	75
Joffre	Natural gas	341	349	89%	92%	52	61
Halkirk [5]	Wind	44	n/a	95%	n/a	3	n/a
Taylor Coulee Chute [6]	Water flows	n/a	16	n/a	98%	n/a	2
Clover Bar Landfill Gas	Landfill gas	32	33	91%	86%	2	3
Alberta commercial plants – owned		4,314	3,337	92%	87%	347	317
Acquired Sundance PPA	Coal	2,610	2,600	89%	86%	161	181
		6,924	5,937	91%	87%	508	498
Alberta contracted plants							
Genesee 1	Coal	3,166	3,127	96%	93%		
Genesee 2	Coal	3,014	3,314	91%	100%		
		6,180	6,441	94%	97%	282	314
Ontario and British Columbia contracted plants							
Island Generation	Natural gas	77	108	100%	100%	39	38
Kingsbridge 1	Wind	109	102	99%	99%	7	7
Quality Wind [5]	Wind	70	n/a	99%	n/a	6	n/a
Brown Lake [7]	Water flows	47	51	99%	86%	3	4
Miller Creek [7]	Water flows	43	88	65%	87%	1	2
		346	349	98%	98%	56	51
North East U.S. commercial plants [8]							
Bridgeport	Natural gas	2,912	2,016	78%	81%	124	96
Rumford	Natural gas	364	321	91%	95%	26	22
Tiverton	Natural gas	1,611	1,100	91%	94%	69	53
		4,887	3,437	85%	88%	219	171
North Carolina U.S. contracted plants [9]							
Roxboro	Mixed [10]	230	36	91%	100%	21	5
Southport	Mixed [10]	417	59	93%	100%	50	9
		647	95	93%	100%	71	14
CPILP plants [11]	Various	n/a	4,015	n/a	93%	n/a	444

(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) In this summary, plant revenue represents revenue generated directly from plant activity and does not include portfolio or mark-to-market generated revenue.

(4) Genesee 3 returned to service on January 15, 2012 after an unscheduled outage which commenced on November 11, 2011.

(5) Keephills 3, Halkirk and Quality Wind include pre-commissioning output until commissioning dates of September 1, 2011, December 1, 2012 and November 6, 2012 respectively. Revenues and expenses related to commissioning activities were capitalized as part of the cost of the facility in property, plant and equipment.

(6) Taylor Coulee Chute was disposed of on November 1, 2011.

(7) Brown Lake and Miller Creek were disposed of on October 12, 2012.

(8) North East U.S. commercial plants include the Bridgeport and the Rumford and Tiverton facilities as of their dates of acquisition of April 28, 2011 and April 29, 2011, respectively.

(9) North Carolina U.S. contracted plants include the Roxboro and Southport plants acquired from CPILP as of their date of acquisition of November 5, 2011. Prior to that date, these plants were included in the CPILP plants category.

(10) The energy sources for the Roxboro and Southport plants are wood waste, tire-derived fuel and coal.

(11) In November 2011, the CPILP plants, excluding Roxboro and Southport, were disposed of as part of the Atlantic Power acquisition of CPILP partnership units.

The Alberta commercial plants and acquired Sundance PPA category is a networked hub. The Company’s owned Alberta commercial generation fleet includes two supercritical-coal facilities, two natural gas-fired facilities, one wind facility, and one landfill-gas facility with a total gross generating capacity of 1,889 MW (1,096 MW net ownership interest). In 2012, the Company completed construction of its 150 MW Halkirk wind facility with the commercial operation date being December 1, 2012. In 2011, construction on the Keephills 3 unit, under joint venture with TransAlta, was completed. Commercial production commenced on September 1, 2011 adding 247 MW of generating capacity to the Company’s existing fleet. In November 2011, the Company sold its interest in the 13 MW Taylor Coulee Chute hydro plant.

The Alberta commercial plants and acquired Sundance PPA category also includes the Company’s 52% ownership in the acquired Sundance PPA which has a committed capacity for Sundance Units 5 and 6 equal to 710 MW. This PPA was purchased in August 2000 and expires on December 31, 2020. In addition to earning pool receipt revenues and incurring its share of certain variable and fixed costs, the Company can earn penalty payment revenue or incur availability incentive payments which are a function of plant performance and a 30-day rolling average power price.

The Genesee 1 and 2 generation facilities are the Company’s Alberta contracted plants. Their capacity and output are sold under a long-term PPA with the Alberta Balancing Pool which expires at the end of 2020. Under the PPA, the Alberta Balancing Pool has the right to dispatch the output from the generation facilities and it pays capacity payments, consisting of fixed operating and maintenance charges, and pays incentive or receives penalty payments based on plant availability. The Company seeks to maximize earnings for contracted plants by achieving high availability and managing costs within the PPA terms.

The natural-gas fired Island Generation plant in British Columbia, the Quality Wind facility in British Columbia and the Kingsbridge 1 wind farm in Ontario are the Company’s Ontario and British Columbia contracted plants. In 2012, the Company completed construction of its 142 MW Quality Wind facility with commissioning of operations commencing November 6, 2012. The Brown Lake and Miller Creek hydro facilities were sold effective October 12, 2012. Under the terms of the Company’s PPA with BC Hydro, Island Generation earns revenue based on deemed generation. Deemed generation is based on deemed availability being the availability of the plant for dispatch. The actual dispatch strategy is determined by BC Hydro and does not affect the Company’s revenues. The plant’s maintenance costs are primarily based on equivalent operating hours and are a function of actual generation. The Kingsbridge 1 wind facility operates under the terms of two energy supply contracts with the Ontario Power Authority which expire in 2027 plus it receives wind power production incentive payments from the Government of Canada. The Quality Wind facility earns revenues under a 25-year electricity purchase agreement with B.C. Hydro.

North East U.S. commercial plants consist of generation facilities for which the Company has not contracted their power and capacity to third parties. This category is a networked hub and includes the Company’s directly-owned facilities located in New England, U.S. consisting of the Bridgeport, Rumford and Tiverton facilities acquired in April 2011. The output of the plants is sold by the Company to the New England Power Pool (NEPOOL).

North Carolina U.S contracted plants include the Roxboro and Southport facilities acquired in November 2011. Revenues from these plants are earned under PPAs with Progress Energy which expire in 2021. Under the PPAs, Progress Energy has the right to dispatch the output from the generation facilities and it pays capacity payments, consisting of fixed operating and maintenance charges, and pays incentive or receives penalty payments based on targeted availability. The Company seeks to maximize earnings for these contracted plants by achieving high availability of the plants and managing costs within the PPA terms.

In this MD&A, the CPILP facilities are discussed on a combined basis rather than individually unless otherwise stated. During the period that the Company indirectly owned CPILP, the CPILP fleet consisted of 20 facilities located in Canada and the U.S. with PPAs and fuel supply contracts that provided stable cash flows.

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 under its networked hub strategy. Capital Power sells and/or buys physical and/or financial forward contracts that are generally non-unit specific, reducing exposure to plant specific availabilities. Capital Power also takes specific and limited positions in the electricity, natural gas, and emission markets outside of the Alberta and U.S. Northeast regions to develop capability to support Capital Power's growth strategy and to generate trading profits.

Capital Power's commodity portfolio team performs the following functions:

- Manages price and volume risk in Capital Power's commodity portfolio;
- Sets the generation unit offer strategy for electricity, capacity and ancillary services in order to optimize returns while managing potential exposure arising from generation and transmission risks, including unplanned outages;
- Acquires and schedules deliveries of natural gas supplies used to generate electricity;
- Derives earnings from wholesale trading of electricity, natural gas and emissions products in deregulated North America markets;
- Ensures compliance with existing and emerging market-based environmental regulations such as the GHG offset investments and purchases that are designed to proactively manage potential compliance risks and costs associated with GHG regulations; and
- Explores and researches electricity, natural gas and emissions markets to ensure preparedness for effective commodity portfolio management of Capital Power's growing commodity portfolio.

Capital Power controls its trading activities by measuring and reporting portfolio risk, validating transactions, valuing the portfolio and managing and reporting credit exposures. Capital Power uses mark-to-market valuation and Value-at-Risk (VaR) techniques to assess the risk of its commodity portfolio. 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 utilizes historical data and back testing to assess market risk arising from possible future changes in commodity prices over the holding period. Capital Power actively manages the aggregate VaR exposure of its commodity portfolio within approved limits as set out in Capital Power's risk management policies.

North East U.S. portfolio optimization includes electricity trading in the eastern Canada and North East U.S. markets. Other portfolio activities include natural gas trading in North American markets and electricity trading in the Pacific North West U.S. markets. The Company also holds retail and commercial natural gas customer contracts in Alberta but is seeking opportunities to exit these natural gas contracts or allow them to expire as it no longer participates in the competitive natural gas retail market.

The significant positions and results of portfolio optimization activities were as follows:

	Unit	2012	2011
Alberta portfolio			
Hedged position [1]	Percentage sold forward at beginning of period (%)	48	73
Realized power price [2]	$/MWh	72	68
Spot power price averages	$/MWh	64	76
North East U.S portfolio [3]			
Hedged position	Approximate average percentage hedged at the beginning of the period (%)	46	55

(1) Hedged position is for the Alberta baseload plants and acquired Sundance PPA.

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

(3) The North East U.S. portfolio activities commenced upon the acquisition of the Bridgeport and the Rumford and Tiverton facilities on April 28 and April 29, 2011.

Consolidated Net Income

The primary factors contributing to the change in net income for 2012 compared with 2011 are presented below; detailed analysis of these items can be found in the Results by Plant Category and Other and the Consolidated Other Expenses and Non-controlling Interests sections.

(unaudited, $ millions)	
Consolidated net income for the year ended December 31, 2011	**188**
Decrease in adjusted EBITDA for CPILP plants	(148)
Increase in adjusted EBITDA for Alberta commercial plants and portfolio optimization	95
Decrease in gains on disposals	(78)
Decrease in net unrealized losses on fair value adjustments of derivative instruments and Atlantic Power shares	33
Increase in impairment losses	(31)
Decrease in adjusted EBITDA of Alberta contracted plants	(21)
Decrease in finance expense excluding bond forward contracts	15
Decrease in realized foreign exchange losses	13
Increase in net unrealized gains on forward bond contracts included in finance expense	10
Decrease in depreciation and amortization expense	8
Decrease in Corporate adjusted EBITDA	(8)
Decrease in realized losses on settled forward bond contracts included in finance expense	5
Other	5
Decrease in income before tax	(102)
Increase in income tax recovery	4
Decrease in net income	(98)
Consolidated net income for the year ended December 31, 2012	90

Results by Plant Category and Other

The Company reports results of operations in the following categories: (i) Alberta commercial plants, acquired Sundance PPA and portfolio optimization, (ii) Alberta contracted plants, (iii) Ontario and British Columbia contracted plants, (iv) North East U.S. commercial plants and portfolio optimization, (v) North Carolina U.S. contracted plants, (vi) CPILP plants, (vii) Other portfolio activities, and (viii) Corporate.

Financial results

(unaudited, $ millions)	Year ended December 31	
	2012	**2011**
Revenues and other income		
Alberta commercial plants, acquired Sundance PPA and portfolio optimization (1)	673	793
Alberta contracted plants	282	314
Ontario and British Columbia contracted plants (2)	56	51
North East U.S. commercial plants and portfolio optimization (3)	220	173
North Carolina U.S. contracted plants (4)	71	14
CPILP plants	-	447
Other portfolio activities	53	92
Corporate	26	22
Interplant category transaction eliminations	(37)	(64)
	1,344	1,842
Unrealized changes in fair value of CPLP's energy derivative instruments and Atlantic Power shares	(13)	(62)
Unrealized changes in fair value of CPILP's foreign exchange contracts	-	(10)
	(13)	(72)
	1,331	**1,770**
Adjusted EBITDA (5)		
Alberta commercial plants, acquired Sundance PPA and portfolio optimization (1)	319	224
Alberta contracted plants	169	190
Ontario and British Columbia contracted plants (2)	42	38
North East U.S. commercial plants and portfolio optimization (3)	25	26
North Carolina U.S. contracted plants (4)	4	4
CPILP plants	-	148
Other portfolio activities	10	8
Corporate	(113)	(105)
	456	533
Unrealized changes in fair value of CPLP's energy derivative instruments and Atlantic Power shares	(15)	(39)
Unrealized changes in fair value of CPILP's foreign exchange and natural gas contracts	-	(9)
	(15)	(48)
	441	**485**

(1) Alberta commercial plants, acquired Sundance PPA and portfolio optimization includes Halkirk and Keephills 3 as of their dates of commissioning of December 1, 2012 and September 1, 2011, respectively. Revenues and expenses related to commissioning activities, prior to the dates of commissioning, were capitalized as part of the cost of the facility.

(2) Ontario and British Columbia contracted plants include Quality Wind as of its date of commissioning of November 6, 2012. Revenues and expenses related to commissioning activities, prior to the dates of commissioning, were capitalized as part of the cost of the facility.

(3) North East U.S. commercial plants and portfolio optimization include Bridgeport and the Rumford and Tiverton facilities as of their dates of acquisition of April 28, 2011 and April 29, 2011, respectively.

(4) North Carolina U.S. contracted plants comprises the Roxboro and Southport plants acquired from CPILP as of their date of acquisition of November 5, 2011.

(5) The results by plant category and other, except for adjusted EBITDA, were prepared in accordance with GAAP. See Non-GAAP Financial Measures.

Spot price averages	Year ended December 31 2012	2011
Alberta power ($/MWh)	64	76
New England mass hub (US$/MWh)[(1)]	36	43
Alberta natural gas (AECO) ($/Gj)[(2)]	2.27	3.44

(1) The New England plants were acquired in April 2011.

(2) Gigajoule (Gj) AECO means a 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

Alberta commercial plants, acquired Sundance PPA and portfolio optimization [(1)]	Year ended December 31 2012	2011
Electricity generation (GWh)	6,924	5,937
Availability (%)	91	87
Revenues (unaudited, $ millions)	673	793
Adjusted EBITDA (unaudited, $ millions) [(2)]	319	224

(1) Alberta commercial plants, acquired Sundance PPA and portfolio optimization includes the Company's interest in the acquired Sundance PPA.

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

Alberta commercial plants, acquired Sundance PPA and portfolio optimization includes the Company's interests in Alberta merchant facilities, the Company's interest in the acquired Sundance PPA and trading activities in the Alberta market.

Production increased 987 GWh for full year 2012 compared with 2011 primarily due to the addition of Keephills 3, which commenced commercial operations in September 2011. Overall availability for 2012 was higher compared with 2011 primarily due to increased availability from the Clover Bar Energy Centre (CBEC) units. CBEC Unit 3 was offline from January 15, 2011 to June 17, 2011 due to blade damage in its high pressure compressor with no comparable outages in 2012.

The average Alberta spot power price of $64/MWh for 2012 was significantly lower than 2011 which had an average spot price of $76/MWh. In 2011, higher Alberta spot prices reflected higher price volatility compared with the current year periods due to a tighter supply demand balance primarily related to increased generation within Alberta as Keephills 3 was commissioned, generation plant outages, and more extreme temperatures in the winter and summer months.

Lower revenues for 2012 compared with 2011 reflected the impact of lower Alberta power prices on portfolio generation, the Genesee 3 outage in late 2011 and early 2012, the extended Genesee 3 planned outage in 2012, and lower rate regulated tariff sales to Alberta local distribution companies. Lower revenues in 2012 were partly offset by incremental revenues from Keephills 3 and Halkirk, which commenced commercial operations in December 2012.

The increase in adjusted EBITDA for 2012 compared with 2011 was primarily driven by the impact of lower average pool prices on the Company's position which influenced the portfolio optimization strategies employed by the Company.

Alberta contracted plants

Alberta contracted plants	Year ended December 31 2012	2011
Electricity generation (GWh)	6,180	6,441
Availability (%)	94	97
Revenues (unaudited, $ millions)	282	314
Adjusted EBITDA (unaudited, $ millions) (1)	169	190

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

Production and availability decreased slightly in 2012 compared with 2011 primarily due to a forced outage at Genesee 1 from September 20 to 27, 2012 resulting from a trial project intended to increase the marketability of the fly ash by-product. Production and availability in 2012 was further reduced compared to 2011 due to a 24-day planned outage at Genesee 2 from May 26 to June 18, 2012. In 2011, a 21-day planned outage at Genesee 1 from March 28 to April 18 occurred. Both planned outages were for scheduled maintenance.

Revenues and adjusted EBITDA for 2012 compared with the previous year reflected lower availability incentive revenues, capacity payments revenues and fly ash sales partly offset by higher energy payment revenues. Lower availability incentive revenues were the result of lower availability due to the forced outage at Genesee 1 in September 2012 and lower rolling average power prices driven by lower Alberta spot power prices. This Genesee 1 outage reduced revenues and adjusted EBITDA by approximately $7 million. The decrease in capacity payment revenues was due to the decrease in the asset base of the plants and lower rates on government bonds which are both inputs to the capacity payment calculation. Higher energy payment revenues reflected an increase in the Statistics Canada indices which are an input to the energy payment calculation. Adjusted EBITDA increased due to the fourth quarter change in the estimate of coal inventory which decreased energy purchases and fuel costs by approximately $7 million.

Ontario and British Columbia contracted plants

Ontario and British Columbia contracted plants	Year ended December 31 2012	2011
Electricity generation (GWh)	346	349
Availability (%)	98	98
Revenues (unaudited, $ millions)	56	51
Adjusted EBITDA (unaudited, $ millions) (1)	42	38

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

Production in 2012 decreased slightly compared with 2011 primarily due to the sale of the Miller Creek and Brown Lake facilities effective October 12, 2012 and lower generation from Island Generation, partly offset by the addition of Quality Wind which commenced commercial operations on November 6, 2012. Availability for 2012 was consistent with the prior year.

The addition of Quality Wind was offset by the sale of Brown Lake and Miller Creek resulting in 2012 revenues and adjusted EBITDA being relatively consistent with the prior year. Lower generation from Island Generation in 2012 compared with 2011 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 2012 was consistent with 2011.

North East U.S. commercial plants and portfolio optimization

North East U.S. commercial plants (1)	Year ended December 31	
	2012	2011
Electricity generation (GWh)	4,887	3,437
Availability (%)	85	88
Revenues (unaudited, $ millions)	220	173
Adjusted EBITDA (unaudited, $ millions) (2)	25	26

(1) North East U.S. commercial plants include the Bridgeport and the Rumford and Tiverton facilities as of their dates of acquisition of April 28, 2011 and April 29, 2011, respectively.

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

Revenues and adjusted EBITDA for 2012 were unfavourably impacted by an unplanned outage at the Bridgeport facility which was offline from May 2 to June 11, 2012 due to a condenser leak. The Company incurred $2 million in maintenance costs as a result of this outage. Lower market spark spreads reflected the impact of lower natural gas prices resulting primarily from an oversupply of natural gas. The year-over-year unfavourable impacts of lower market prices and unplanned outages were more than offset in 2012 with a full year of operations compared with 2011 which only reflected operations since the acquisition of the plants in late April 2011.

Apart from the plant operations, 2012 portfolio optimization activities included the fourth quarter net realized losses of $10 million on the Bridgeport heat rate option and locked-in prices on natural gas consumption and $2 million of other trading losses incurred during the full year.

North Carolina U.S. contracted plants

North Carolina U.S contracted plants (1)	Year ended December 31	
	2012	2011
Electricity generation (GWh)	647	95
Availability (%)	93	100
Revenues (unaudited, $ millions)	71	14
Adjusted EBITDA (unaudited, $ millions) (2)	4	4

(1) North Carolina U. S. contracted plants comprises the Roxboro and Southport facilities as of their date of acquisition of November 5, 2011.

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

The 2012 performance of the North Carolina U.S. contracted plants was lower than expected primarily due to lower energy margins based on lower than expected heat rates (3) and higher maintenance and fuel costs compared with the costs in the prior year when these plants were owned and operated by CPILP. Maintenance costs in 2012 reflected planned spring outages at both Southport and Roxboro. Both outages took longer than expected which resulted in higher than anticipated maintenance costs. Between the two facilities, fuel costs for 2012 included approximately $2 million for unanticipated adjustments related to physical fuel coal inventory and Roxboro's maintenance costs for the same period included $1 million for reclassification from capital to operating.

(3) Heat rate is a measure of the efficiency of the conversion of fuel into electricity.

CPILP plants

CPILP plants	Year ended December 31	
	2012	2011
Electricity generation (GWh)	n/a	4,015
Availability (%)	n/a	93
Revenues (unaudited, $ millions)	n/a	447
Adjusted EBITDA (unaudited, $ millions) (1)	n/a	148

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

The Company divested its limited partnership units of CPILP in November 2011.

Other portfolio activities

Other portfolio activities	Year ended December 31	
	2012	2011
Revenues (unaudited, $ millions)	53	92
Adjusted EBITDA (unaudited, $ millions) [(1)]	10	8

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

See Portfolio Optimization section for description of other portfolio activities.

Lower revenues for 2012 compared with 2011 were primarily due to the termination of the manager contracts associated with the Company's former interest in CPILP and lower natural gas sales partly offset by higher revenues related to emission trading in the California power market.

Adjusted EBITDA increased in 2012 primarily due to natural gas trading gains. The increase in adjusted EBITDA for 2012 compared with 2011 was further impacted by a gain related to a change in the provision for estimated future losses on certain natural gas retail contracts. The revised estimate for the provision was based on a decrease in forward natural gas prices in 2012. North American forward gas prices have been decreasing primarily due to decreased demand and oversupply. The increase in adjusted EBITDA for 2012 compared with 2011 was partly offset by increased emission credit costs in 2012.

Corporate

Corporate	Year ended December 31	
	2012	**2011**
Revenues (unaudited, $ millions)	26	22
Adjusted EBITDA (unaudited, $ millions) [(1)]	(113)	(105)

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

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 in the consolidated results.

Adjusted EBITDA for 2012 reflected increased compensation costs resulting from performance in relation to the Company's 2011 target performance metrics and recruitment for previously vacant positions and increased costs related to the Company's corporate head office move in September 2011. These increased costs were partly offset by an unfavourable pension adjustment in 2011 based on an actuarial valuation of the Company's supplemental pension plan obligation which incorporated refinements to estimates made at the time of the Company's spinoff from EPCOR. Corporate results for 2012 included the first quarter realized gain on the sale of Atlantic Power shares.

Unrealized changes in fair value of energy and foreign exchange derivative instruments and Atlantic Power shares

Unrealized changes in fair value of energy and foreign exchange derivative instruments and Atlantic Power shares	Year ended December 31	
	2012	**2011**
Revenues (unaudited, $ millions)	(13)	(72)
Adjusted EBITDA (unaudited, $ millions) [(1)]	(15)	(48)

(1) The financial results by plant category, 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, North East U.S. commercial plants and portfolio optimization, and other activities include unrealized changes in the fair value of energy and foreign exchange derivative instruments and, until its disposal in February 2012, the Company's investment in Atlantic Power.

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

($ millions)	Year ended December 31			
	2012	2011	2012	2011
Unrealized changes in fair value of energy and foreign exchange derivative instruments and Atlantic Power shares	**Revenues**		**Adjusted EBITDA**	
Unrealized gains (losses) on Alberta energy derivatives	12	(64)	8	(53)
Unrealized (losses) gains on Bridgeport heat rate option	(15)	9	(15)	9
Unrealized (losses) on natural gas derivatives	(6)	(12)	(4)	-
(Reversal) of unrealized gain and unrealized gain on Atlantic Power shares	(5)	5	(5)	5
Other	1	-	1	-
	(13)	(62)	(15)	(39)
Unrealized gains on CPILP natural gas contracts	n/a	-	n/a	1
Unrealized losses on CPILP foreign exchange contracts	n/a	(10)	n/a	(10)
	n/a	(10)	n/a	(9)
	(13)	**(72)**	**(15)**	**(48)**

Alberta desk electricity portfolio activities in 2012 accounted for an unrealized net gain of $8 million compared with an unrealized net loss of $53 million for 2011. The unrealized gain in 2012 primarily reflected the impact of decreases in Alberta forward power prices on the portfolio positions and the reversal of previously recognized unrealized net losses on contracts which settled in 2012. The unrealized net loss in 2011 primarily reflected the impact of increases in Alberta forward power prices on the portfolio position and the reversal of previously recognized unrealized gains on contracts which settled in 2011.

Upon acquisition of the New England plants in the second quarter of 2011, the Company acquired heat rate options related to the Bridgeport and Tiverton facilities. The Tiverton heat rate options subsequently expired in 2011. In 2012, the Company recognized an unrealized loss of $15 million related to its Bridgeport heat rate options. This loss primarily resulted from increases in the underlying forward power prices and the reversal of the 2011 unrealized gain. In 2011, the Company recognized an unrealized gain of $9 million on the heat rate options related to the Bridgeport facility which primarily resulted from decreases in the underlying forward power prices.

Natural gas portfolio activities in 2012 accounted for an unrealized net loss of $4 million which primarily reflected the impact of fluctuating forward natural gas prices on changes in the portfolio position during the fourth quarter of 2012.

In the first quarter of 2012, the Company sold its investment in Atlantic Power shares resulting in an unrealized loss of $5 million representing the reversal of the unrealized gain which was recorded in the fourth quarter of 2011. The sale resulted in a realized gain of $4 million which was included in the Corporate category.

The Company divested its limited partnership units of CPILP on November 4, 2011. In 2011, CPILP's revenues included unrealized net losses of $10 million for changes in the fair value of foreign exchange contracts which were primarily due to an increase in the forward prices for U.S. dollars relative to Canadian dollars for the period ended November 4, 2011.

Consolidated Other Expenses and Non-controlling Interests

(unaudited, $ millions)	Year ended December 31	
	2012	2011
Interest on borrowings less capitalized interest	(64)	(78)
Realized losses on the settlement of forward bond contracts	(7)	(12)
Other finance expense – sundry interest and guarantee and other fees	(7)	(8)
	(78)	(98)
Reversal of previously recognized unrealized losses (gains) representing changes in the fair value of forward bond contracts	8	(2)
Other finance expense – amortization and accretion charges	(5)	(5)
Total finance expense	(75)	(105)
Depreciation and amortization	(221)	(229)
Impairments	(74)	(43)
Foreign exchange losses	-	(13)
Gains on disposals	15	93
Income tax recovery	4	-
Net income attributable to non-controlling interests	28	111

Finance expense

Finance expense in 2012 included the reversal of previously recognized unrealized decreases in the fair value of forward bond contracts of $8 million partly offset by realized losses of $7 million resulting in a net decrease to finance expense and an increase to pre-tax income of $1 million. 2011 finance expense included unrealized decreases in the fair value of bond forward contracts of $2 million and realized losses of $12 million resulting in a net increase to finance expense and a decrease to pre-tax income of $14 million. These contracts economically hedged the Company's exposure to interest rate risk on anticipated debt issues. While these contracts settled at a loss, future interest payments on the debt were and will be incurred at a rate lower than the rate that was locked in by the hedge.

In addition, finance expense for 2012 decreased compared with the prior year since there was no finance expense related to CPILP subsequent to its disposal in November 2011.

Depreciation and amortization

Decreases in depreciation and amortization from the CPILP assets more than offset increased depreciation and amortization related to the 2011 additions of the North East U.S. commercial plants, Keephills 3 and the North Carolina plants and the 2012 addition of Halkirk. The net result was decreased depreciation of $8 million for 2012 compared with the prior year.

Impairments

Impairments, on a pre-tax basis, were $74 million for 2012 compared with $43 million for 2011. The impairment of $74 million recognized in the second quarter of 2012 related to the North East U.S. commercial plants and resulted from reduced expected operating margins. The reductions to the expected operating margins were largely the result of weaker spark spreads in the New England power market. See Significant Events. In the second quarter of 2011, an asset impairment loss of $43 million was recognized related to the CPILP management and operations contracts.

Foreign exchange losses

Foreign exchange losses were $nil for 2012 since no material foreign exchange contracts settled in the year. Foreign exchange losses of $13 million for 2011 consisted of losses realized on the settlement of foreign exchange contracts entered into in anticipation of U.S. cash payments related to the acquisition of the New England facilities and foreign currency translation losses primarily related to U.S. dollar denominated debt.

Gains on disposals

In 2012, the Company recognized a pre-tax gain of $15 million on disposal of its limited partnership that owned the two hydro facilities, Brown Lake and Miller Creek.

The gains on disposals in 2011 primarily related to a pre-tax gain recognized by the Company on disposal of CPILP, including the termination of the manager contracts, of $89 million after deducting legal and other disposal costs of $10 million.

Income tax recovery

Income tax recovery increased $4 million for 2012 compared with the prior year primarily due to the impact of higher tax rates on certain 2012 losses of U.S. operations and the impairment of North East U.S. plants, and lower pre-tax income compared with 2011.

Non-controlling interests

For 2012, approximately 32% (2011 – 49%) of CPLP's net income was attributable to EPCOR which is reported as net income attributable to non-controlling interests by the Company. Net income attributable to non-controlling interests also included the Genesee coal mine partner's share of the consolidated coal costs. EPCOR's April 5, 2012 exchange of exchangeable common limited partnership units for common shares of Capital Power reduced its interest in CPLP to 29% from 39% which will reduce the proportion of net income attributable to non-controlling interests reported by the Company in future periods. See Significant Events.

For 2011, approximately 29% of CPILP's net income was included in CPLP's income with the remaining 71% attributable to non-controlling interests. Therefore, the net income attributable to non-controlling interests in CPLP included approximately 14% (49% of 29%) of CPILP net income for 2011. There are no comparable figures for 2012 because the Company disposed of its interest in CPILP in November 2011.

Other Comprehensive Income

($ millions)	Year ended December 31			
	2012		2011	
Other comprehensive income	**Before tax**	**After tax**	**Before tax**	**After tax**
Net unrealized gains (losses) on derivatives designated as cash flow hedges	66	54	(118)	(100)
Net realized (gains)losses and ineffective portion of unrealized (gains) losses on cash flow hedges reclassified to revenues and/or energy purchases and fuel	(14)	(12)	55	47
	52	42	(63)	(53)
Unrealized gains (losses) on available-for-sale financial assets	-	-	(2)	(1)
Unrealized actuarial gains (losses) related to Company/s defined benefit pension plans	(8)	(6)	(7)	(5)
Unrealized foreign exchange gains (losses) on the translation of foreign operations	(10)	(10)	39	39
Losses realized in net income on disposal of CPILP	-	-	31	21
	34	26	(2)	1
Income taxes on above items	(8)	n/a	3	n/a
	26	**26**	**1**	**1**

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.

Financial Position

The significant changes in the Consolidated Statements of Financial Position from December 31, 2011 to December 31, 2012 were as follows:

(unaudited, $ millions)	As at December 31		Increase	
	2012	2011	(decrease)	Explanation of increase (decrease)
Trade and other receivables	354	198	156	Primarily due to a $50 million deposit related to Shepard Energy Centre, the addition of Quality Wind, higher generation sales receivable from the Alberta Electric System Operator resulting from higher power prices in December 2012 compared with December 2011, the land lease renewal holdback related to the sale of the hydro facilities, timing of the settlement of sales receivables, and increased sales receivable related to Genesee 3 which experienced a forced outage in December 2011.
Inventories	72	59	13	Primarily due to the increase in Genesee mine coal inventory.
Other financial assets – current	-	53	(53)	Sold Atlantic Power shares.
Net derivative financial instruments assets (liabilities)	13	(36)	49	Primarily due to increases in the fair value of derivative power contracts resulting from decreasing Alberta forward power prices.
Finance lease receivable	461	58	403	Primarily due to the addition of Quality Wind.
Other financial assets – non-current	60	42	18	Primarily due to the Sundance force majeure claim discussed under Contractual Obligations and Contingent Liabilities.
Intangible assets	316	296	20	Primarily due to additions related to information technology systems and a long-term service agreement entered into at the Joffre facility.
Property, plant and equipment	3,628	3,842	(214)	Primarily due to depreciation and the disposal of the hydro facilities partly offset by capital expenditures (most significantly, the Halkirk project).
Goodwill	22	46	(24)	Primarily due to the impairment of the North East U.S. commercial plants.
Trade and other payables	210	220	(10)	Primarily due to a three-year Regional Greenhouse Gas Initiative compliance period related to the Company's North East U.S. commercial plants accrued for in 2011 and settled in 2012, partly offset by higher natural gas accruals due to fuel purchases for the North East U.S. commercial plants.
Loans and borrowings (including current portion)	1,659	1,480	179	$250 million debt issue partly offset by repayment of credit facility.
Share capital	1,903	1,499	404	Common and preferred shares issued.
Non-controlling interests	829	1,072	(243)	Conversion of common limited partnership units of CPLP to common shares of Capital Power by EPCOR in April 2012 and distributions offset by earnings attributable to non-controlling interests.

Liquidity and Capital Resources

(unaudited, $ millions)	Year ended December 31		
Cash inflows (outflows)	**2012**	**2011**	**Increase (decrease)**
Operating activities	242	461	(219)
Investing activities	(466)	(985)	519
Financing activities	205	541	(336)

Operating activities

Cash flows from operating activities for 2012 decreased compared with 2011 primarily due to the disposal of CPILP which reduced cash inflows and increases in trade and other receivables and trade and other payables due to the timing of settlement of certain accounts.

Investing activities

The cash flows used in investing activities for 2012 included $598 million for capital expenditures (most significantly, the Quality Wind and Halkirk projects) partly offset by $116 million of proceeds received on the sale of shares in Atlantic Power and the divestiture of the British Columbia hydro assets. Business acquisitions in 2011, including the New England facilities, significantly contributed to the year-over-year decrease in cash flows used in investing activities.

Capital expenditures

(unaudited, $ millions)		Year ended December 31		Total project		
	Pre-2011	**2011**	**2012**	**Actual or Projected** (1) (3)	**Budget**	**Timing**
Keephills 3	892	57	-	949	949	Completed 3rd quarter 2011
Quality Wind	24	131	264	405 to 415	455	Completed 4th quarter 2012
Halkirk	-	183	131	325 to 335	357	Completed 4th quarter 2012
Port Dover & Nanticoke	25	24	19	340	340	Projected completion 4th quarter 2013
K2	-	-	3	291	291	Projected completion 2015
Shepard Energy Centre	-	-	50	860	860	Projected completion 2015
Subtotal growth projects		395	467			
CPILP		21	-			
Sustaining – plant maintenance and other		77	102			
Sustaining – Genesee mine lands		15	17			
Total capital expenditures (2)		**508**	**586**			
Emission credits		21	35			
Capitalized interest		(36)	(23)			
Net payments to acquire property, plant and equipment and other assets		**493**	**598**			

(1) Capital expenditures to be incurred over the life of the project are based on management's estimates.

(2) Capital expenditures include capitalized interest. Capital expenditures excluding capitalized interest are presented on the Statement of Cash Flows as payments to acquire property, plant and equipment and other assets.

(3) Projected costs for projects completed in 2012 consist of certain costs that are expected to be incurred subsequent to the date of commercial operations such as site remediation, vendor optimization, project clean-up and project close-out costs.

Total capital expenditures for the Quality Wind and Halkirk projects were approximately 10% and 8%, respectively, lower than budget.

Construction of the Port Dover & Nanticoke project was delayed by completion of the land title transfers and regulatory proceedings, which resulted in $57 million of planned expenditures being deferred to 2012. The delay is not expected to impact the total cost of the project, but the project's completion date was delayed until the fourth quarter of 2013.

Sustaining capital expenditures include spending on plant maintenance, the Genesee mine, information technology systems, and leasehold improvements for offices in Calgary and Edmonton.

Financing activities

The cash flows from financing activities in 2012 primarily reflected proceeds from the $250 million CPLP debt offering in February 2012 and the $150 million proceeds on the December 2012 preferred share issue partly offset by debt repayments of $62 million and distributions and dividends paid of $110 million.

The Company's credit facilities consisted of:

($ millions)		As at December 31, 2012			As at December 31, 2011		
	Maturity timing	**Total facilities**	**Credit facility utilization**	**Available**	**Total facilities**	**Credit facility utilization**	**Available**
CPLP committed credit facility	2017	1,200	341	859	1,200	352	848
CPLP demand facility	n/a	20		20	20	-	20
Capital Power Corporation demand facility	n/a	5		5	5	-	5
		1,225	**341**	**884**	**1,225**	**352**	**873**

As at December 31, 2012, the committed credit facility utilization consisted of $207 million in letters of credit outstanding, $104 million in bankers' acceptances outstanding and $30 million in U.S. dollar bank loans. This reflects an increase of $20 million in letters of credit outstanding, a reduction of $61 million in bankers' acceptances and an increase of $30 million in U.S. dollar bank loans since December 31, 2011. In July 2012, the committed credit facilities were amended to include an accordion feature to increase the facility size by $300 million in the future, subject to certain conditions including lender approval.

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

The loan and credit agreements with EPCOR require CPLP to meet certain financial covenants, including maintaining a consolidated senior debt to consolidated capitalization ratio of not more than 0.75 to 1.0 as at the end of any fiscal quarter. In addition, in the event that CPLP is assigned a credit rating by S&P that is less than BBB- or by DBRS that is less than BBB(low) (in each case with a stable outlook), then CPLP must also maintain a ratio of consolidated EBITDA to consolidated interest expense (each as defined in the credit agreement with EPCOR) of not less than 2.5 to 1.0 as at the end of each fiscal quarter.

On November 16, 2012, S&P revised CPLP's corporate credit rating from BBB to BBB- with a stable outlook. The BBB- rating assigned by S&P is an investment grade credit rating. 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 received a long-term debt credit rating of BBB from 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. A BBB rating is an investment grade credit rating, which enhances CPLP's ability to re-finance existing debt as it matures and to access cost competitive capital for future growth.

Future cash requirements

The following estimates of future cash requirements are subject to variable factors including those discussed in Forward-looking Information. Capital Power's estimated cash requirements for 2013 are expected to include approximately $737 million for capital expenditures, approximately $36 million for CPLP distributions to EPCOR (subject to approval by the Board of Directors of CPLP's general partner), approximately $85 million for Capital Power's common share dividends, and approximately $12 million for quarterly preferred share dividends (subject to approval by Capital Power Corporation's Board of Directors). Effective January 1, 2012, the Company launched a Dividend Re-investment Plan where shareholders may elect to reinvest their quarterly cash dividends for additional shares of Capital Power as an alternative to receiving cash dividends. The participation rate in the Dividend Re-investment Plan at December 31, 2012 was approximately 30% and depending on the participation rate for 2013, cash requirements for common share dividends may differ from the above expectations.

The current portion of loans and borrowings on the statement of financial position of $19 million consists primarily of $14 million payable to EPCOR in 2013.

The Company expects to fund the construction of the Port Dover & Nanticoke and K2 wind projects and the Shepard Energy Centre project from cash flows from operating activities, asset divestitures, proceeds from preferred share issuance and using existing bank credit facilities. When construction is complete, the Company expects to put long-term financing in place. 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's two short form base shelf prospectuses provide, market conditions permitting, the Company with the ability to obtain new debt and equity capital from external markets when required for a major investment. Under the short form base shelf prospectuses, Capital Power may raise up to $2 billion by issuing common shares, preferred shares, or subscription receipts exchangeable for common shares or other securities of the Company, and up to $1 billion by issuing medium-term notes with maturities of not less than one year. As of the date of this MD&A, Capital Power has approximately $1.6 billion of equity and $1 billion of debt available under these short form base shelf prospectuses.

Financial market stability remains an issue. If instability reoccurs in the Canadian and U.S. financial markets, the Company'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. CPLP has credit exposure relating to various agreements, particularly with respect to its PPA, trading and supplier counterparties. While CPLP 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 $208 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-balance sheet 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	
	2012	**2011**
Loans and borrowings	1,659	1,480
Less cash and cash equivalents	53	73
Net debt	1,606	1,407
Non-controlling interests	829	1,072
Share capital	1,903	1,499
Retained earnings and other reserves	20	24
Total equity	2,752	2,595
Total capital	**4,358**	**4,002**

Shareholder Rights Plan

On November 21, 2012, Capital Power announced that its Board of Directors approved a Shareholder Rights Plan (Rights Plan) effective November 20, 2012. 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 be presented to shareholders for ratification at Capital Power's annual meeting on April 26, 2013 and, if ratified, will continue in force until the end of the annual meeting of shareholders in 2016. The Rights Plan will expire at the termination of the April 26, 2013 annual meeting of shareholders if not ratified by the shareholders.

Contractual Obligations and Contingent Liabilities

(unaudited, $ millions)	Payments Due by Period						
	2013	**2014**	**2015**	**2016**	**2017**	**Thereafter**	**Total**
Acquired PPA obligations – fixed (1)	57	60	59	60	60	129	425
Acquired PPA obligations – variable (1)	36	35	35	37	38	187	368
Capital – growth projects (2)	635	742	-	-	-	-	1,377
Energy purchase and transportation contracts (3)	105	21	11	11	11	52	211
Operating and maintenance contracts (4)	10	13	13	12	11	69	128
Environmental credits	13	14	11	9	7	2	56
Operating leases	5	5	5	5	5	59	84
Loans and borrowings	19	13	314	145	149	1,032	1,672
Interest on loans and borrowings	87	86	85	65	58	146	527
Net commodity contracts-for-differences	52	6	3	2	2	-	65
Decommissioning provisions (5)	2	2	2	3	2	320	331
Total	**1,021**	**997**	**538**	**349**	**343**	**1,996**	**5,244**

(1) 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 depreciation, decommissioning, return on equity, and return on debt and working capital.

(2) Capital Power's obligations for capital – growth projects include the K2, Port Dover & Nanticoke and Shepard Energy Centre projects. Capital Power Energy Centre is not included.

(3) Natural gas transportation contracts are based on estimates subject to changes in regulated rates for transportation and have expiry terms ranging from 2013 to 2017.

(4) Operating and maintenance contracts are related to a 10-year service agreement for Quality Wind which commenced November 2012 at a cost of approximately $5 million per year.

(5) Capital Power's decommissioning provisions reflect the undiscounted cash flow required to settle obligations for the retirement of its generation plants and Genesee coal mine.

Contingent liabilities

Capital Power is participating in a 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. On April 16, 2012, the AUC issued its decision that the factors utilized from 2006 to the present time were non-compliant with the applicable legislation and regulations. Capital Power and other Alberta generators subsequently submitted applications to review and vary that decision. The AUC has advised that a future proceeding will: (1) consider whether the decision, or part of the decision, should be reviewed and if so, (2) determine whether the decision should be varied and, if so, how. This includes the potential application of alternative factors on a prospective or retrospective basis. Capital Power 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. It is anticipated that the AUC's decision may be issued no sooner than the last half of 2013.

In July 2012, the Sundance plant owner made a force majeure claim for $39 million with respect to the 2011 third quarter outage of Unit 6 due to a transformer failure. The Company has a 52% interest in the Sundance PPA for Units 5 and 6 and thus is contractually responsible for paying its share of the claimed amount in advance of final determination of whether or not a force majeure situation, as specified in the PPA, occurred. Accordingly, Capital Power paid its share of the claimed amount and, based on the Company's view that the claim will not meet the PPA specified force majeure tests, recorded it as an amount receivable until final resolution of the claim. The claim currently is under arbitration and an arbitration decision is not expected until 2014. The total amount receivable of $20 million recorded on Capital Power's December 31, 2012 statement of financial position would be reduced by estimated insurance recoveries of $3 million in the event that the arbitration decision resulted in an adverse result for the Company.

Upon close of the sale of the Company's hydro facilities, $10 million of the gross proceeds were paid to a third party escrow agent. These funds will be held in escrow pending the issuance of a new lease, by the Province of British Columbia to the purchaser (Innergex), in respect of certain lands included in the hydro assets. As long as the new lease does not contain variations from the previous lease that significantly impact the economic value of the hydro assets, the full amount will be released to the Company. Subsequent to December 31, 2012, Innergex has indicated that, in their opinion, the new lease is substantially different from the previous lease. The Company does not agree with this assessment and expects to receive the full amount of the escrow payment.

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.

Transactions with Related Parties

(unaudited, $ millions)		Year ended December 31	
	Note	2012	2011
EPCOR (shareholder)			
CPLP distributions paid	(a)	42	60
Purchase of distribution and transmission services	(b)	22	23
Purchase of other services	(b)	6	7
Power sales	(b)	9	239
Interest incurred on unsecured senior debt payable and expensed	(c)	20	30
Interest incurred on unsecured senior debt payable and capitalized	(c)	5	8
Repayment of unsecured senior debt payable	(c)	25	237
The City of Edmonton (sole shareholder of EPCOR)			
Power sales	(b)	36	34

		As at December 31	
	Note	2012	2011
EPCOR (shareholder)			
Trade and other receivables	(b)	1	1
Trade and other payables	(b)	17	22
Provision for future maintenance costs associated with EPCOR's Rossdale plant	(d)	4	7
Loans and borrowings	(c)	357	382
The City of Edmonton (sole shareholder of EPCOR)			
Trade and other receivables	(b)	7	7

(a) In April 2012, a subsidiary of EPCOR exchanged a total of 9.775 million of its exchangeable common limited partnership units in CPLP for common shares of Capital Power on a one-for-one basis. Subsequently, EPCOR entered into an agreement for a secondary offering of 9.775 million common shares of Capital Power. As a result, at December 31, 2012, EPCOR owned 28.441 million exchangeable common limited partnership units of CPLP, and 28.441 million accompanying special voting shares and one special limited voting share of Capital Power Corporation. At December 31, 2011, EPCOR owned 38.216 million exchangeable common limited partnership units of CPLP and 38.216 million accompanying special voting shares and one special limited voting share of Capital Power Corporation. In connection with EPCOR's shareholdings, CPLP paid distributions to EPCOR for the years ended December 31, 2012 and 2011.

(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 the exchange amounts which were based on normal commercial rates. The Company has a lease agreement with EPCOR for office space that requires payment to EPCOR of $4 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 2013 and 2018. If EPCOR no longer owns, directly or indirectly, at least 20% of the outstanding common limited partnership units of CPLP, then 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 180 days after delivery of notice, and if it is $200 million or more, then it and the accrued interest thereon shall be payable 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 for the Company are established by the Board of Directors annually 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 on a quarterly basis.

Capital Power has implemented 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 Director, 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. 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:

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 spot electricity 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, the acquired Sundance PPA plant, and the Company's North East U.S commercial facilities, electricity spot 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 potential higher prices in the future which may result in lost opportunity costs. 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 include, among other risks, 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.

The sensitivity of changes in Alberta power prices (based on the expected portfolio position) on the Company's adjusted EBITDA (assuming all other potential variables are held constant) is estimated as follows:

($ millions)	**Alberta power price**	
Estimated increase (decrease) in adjusted EBITDA	**Increase of $1.00 per MWh**	**Decrease of $1.00 per MWh**
2013	4	(4)
2014	4	(4)
2015	6	(6)

The sensitivity of changes in North East U.S. spark spreads on the Company's adjusted EBITDA (assuming all other potential variables are held constant) is estimated as follows:

($ millions)	**North East U.S. spark spread**	
Estimated increase (decrease) in adjusted EBITDA	**Increase of $1.00 per MWh**	**Decrease of $1.00 per MWh**
2013	6	(6)
2014	6	(7)
2015	7	(7)

Strategies 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 commercial contracts such as those contracts for the Company's Genesee 1 and 2, Halkirk, Kingsbridge 1, Quality Wind, Island Generation, Roxboro and Southport plants.
- Establish and 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 usage hours and off-peak usage 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.

Political, legislative and regulatory 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. While 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, there has been an increase in regulatory activity and penalties. Capital Power is also required to maintain numerous licenses, permits and governmental approvals for the 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 Dodd-Frank Wall Street Reform and Consumer Protection Act, 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.

Many of 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.

Strategies for managing political, legislative and regulatory 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 by performing 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.
- Proactive identification of 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.

Operations, process and infrastructure 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.

Strategies for managing operations risk

- Execute appropriate operating and maintenance practices 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.
- 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.
- Establish appropriate business interruption and property and boiler insurance to reduce the impact of prolonged outages caused by insured events.

Many of Capital Power's generation plants operate under PPAs, 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. Electricity sales are accounted for as long-term fixed margin contracts, which limit the impact of swings in wholesale spot electricity prices, unless plant availability drops significantly below the PPA target availability for an extended period. 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.

Strategies for managing PPA contract risk

- Measure performance against benchmarks.
- Execute appropriate operating and maintenance practices to minimize the likelihood of prolonged unplanned down time.

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 rates 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.

Strategies for managing Sundance PPA risk

- Work with plant owner to execute appropriate operating and maintenance practices to minimize the likelihood of prolonged unplanned down time.
- Proactively assess and appropriately respond to, including legal actions, any claims of force majeure incidents.

In 2011, Capital Power initiated two information technology implementation projects, one for an Energy Trading Risk Management system and another for an Enterprise Resource Planning system which have been substantially implemented. These systems are expected to support the Company's long-term strategy since they are planned to provide the flexibility and scalability necessary for Capital Power's business. During the final stages of implementation in 2013, existing processes and internal resources will be strained which will increase the potential for errors in the related transactions and for failure to successfully implement the new systems on time and on budget. There are no further major information technology system implementations planned for 2013.

Strategies for managing major information technology system implementation risk

- Minimize the customization of the associated software, monitor the impacts on processes and internal controls and undertake remedial actions, as required.
- Ensure projects are properly resourced with qualified staff and contractors.

Capital Power employs several key computer application systems to support its operations, such as electricity plant control systems in addition to the major energy trading risk management and enterprise resource planning systems. Failure of any of these systems could result in significant lost revenues, increased costs or regulatory fines.

Liquidity, credit and financing 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 as well as 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 terms acceptable to Capital Power, it could have an adverse effect on Capital Power's business plan and financial condition.

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 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.
- 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 for managing counterparty credit risk

- Establish 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 account and credit derivatives.
- Monitor and report credit risk exposures.

People risk

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, environmental hazards and more.

Strategies for managing health and safety risk

- Establish and maintain company-wide health and safety 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'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 facing 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.

Effective December 21, 2012, the Company completed negotiations with Communications, Energy and Paperworkers Union of Canada Local 1123 at the Island Generation facility to renew its labour contract which expired in April 2012. This ended the Company's lockout of the union employees which started on October 30, 2012. The Company had adequate management staffing and contingency plans and continued to operate the plant during this labour disruption.

Strategies for managing human resources risk

- Establish and maintain good human resource practices including monitoring developments and contingency plans.

Competition, acquisition and development 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, prior to 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 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 for managing competition, acquisition and development 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.

Environmental risk

Environmental risk is disclosed in several different types of risks discussed in other areas of this Risk and Risk Management section including political, legislative and regulatory risk, technology risk, physical (such as weather) risk, litigation risk and reputation risk.

External factors risk

Capital Power requires energy from sources such as coal, natural gas, water, wind, wood waste and tire derived fuel to generate electricity. A disruption in the supply or a significant increase in the price of any fuel 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 facility heat rates (1) do 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. Decreases in wind speed or duration could have a material negative impact on revenues for these facilities.

(1) Heat rate is a measure of the efficiency of the conversion of fuel into electricity.

Strategies for managing fuel supply risk

- Establish long-term supply agreements.
- Maintain coal stock-pile inventories.
- Establish contracts with fuel cost-flow provisions, where possible.

Capital Power's operations are exposed to potential damage resulting from extreme storm and other weather conditions and natural disasters.

Strategies 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.

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.

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 taxes, foreign exchange, its corporate structure, weather, legal and arbitration proceedings, and risks that are not fully covered by various insurance policies.

On July 23, 2012, TransAlta Corporation (TransAlta) and TransCanada Corporation reported the independent arbitration panel's decision regarding TransAlta's claims of force majeure and destruction for its Sundance Units 1 and 2 which are now expected to return to service in the fall of 2013. The return to service will add 560 MWs of power to the Alberta market which is expected to decrease Alberta power prices. Capital Power's earnings and cash flow will be negatively affected until such time as equivalent demand increases or existing supply is retired from the market.

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

The sensitivity of changes in income tax rates on the Company's net earnings is estimated as follows:

($ millions)	**Income tax rate**	
	Increase of 1%	**Decrease of 1%**
Estimated increase (decrease) in net income	(1)	1

The statutory income tax rate on income before income taxes for 2012 was 25.0% (2011 – 26.5%). 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 for managing tax risk

- Develop and maintain tax expertise and resources necessary to interpret tax legislation.
- Comply with tax laws of jurisdictions that Capital Power operates in.
- Consult with government with respect to policy development and proposed legislation.

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 for managing reliance on 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, 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, 2012, the Company has loaned $266 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.

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.

Conflicts of interest and disputes may arise between Capital Power and EPCOR relating to a potential misalignment between the companies' corporate objectives and business interests or the companies' past and ongoing relationships. Capital Power may not be able to resolve a potential conflict, and if it does, the resolution may be less favourable to Capital Power than if it were dealing with a party that was not a significant holder of equity of the Company.

Furthermore, 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 four directors of the Company. There are currently twelve 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, 2012, EPCOR's interest in the Company was approximately 29%. EPCOR has advised the Company that it intends to eventually sell all or a substantial number 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 for managing corporate structure 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.

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, 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 has recorded decommissioning provisions of $173 million as at December 31, 2012 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 $56 million in future years and expects to use these credits to comply with certain environmental regulations.

On April 23, 2012, Capital Power and its partners of TransAlta, Enbridge Inc. and the federal and provincial governments decided not to proceed with their carbon capture and storage project following an extensive engineering and design study. While the project proved to be technically feasible, the economics of the project did not support a decision to proceed.

Critical Accounting Estimates and Accounting Judgments

In preparing the consolidated financial statements, management necessarily made estimates in determining transaction amounts and financial statement balances. The following are the Company's critical accounting estimates which make assumptions about matters that are highly uncertain at the time the accounting estimate is made or period-to-period changes in the estimate would have a material impact on financial condition, changes in financial condition or financial performance.

Financial instruments

The Company is required to estimate the fair value of certain assets and obligations for determining the valuation of derivative instruments and certain other financial instruments.

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 as appropriate, in the most advantageous active market for that instrument. 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. 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.

Non-financial assets

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.

In the first quarter of 2011, management performed a review of the useful life of the Company's coal plants and determined that the useful life did not match common industry practices. As a result of an analysis compared with industry peers, historical averages, and the Company's maintenance practices, the estimate of the useful life of the coal plants was revised. Effective January 1, 2011, the Company prospectively revised its estimate of the useful life of its coal plants from 35 years to 45 years. The change in estimate resulted in lower depreciation expense.

For determining purchase price allocations for business combinations, the Company is required to estimate the fair value of acquired assets and obligations. 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. Goodwill acquired in an acquisition is, from the date of acquisition, allocated to each of the cash generating units (CGU) that are expected to benefit from the acquisition.

Estimates of fair value for the recoverable amount of CGUs undergoing impairment testing, and for purchase price allocations for business combinations are primarily based on discounted cash flow projection techniques employing estimated future cash flows based on assumptions regarding the expected market outlook and cash flows from each CGU or asset. The cash flow estimates will vary with the circumstances of the particular assets or CGU and will be based on, among other things, the lives of the assets, contract prices, estimated future prices, revenues and expenses, including growth rates and inflation, and required capital expenditures.

For purposes of impairment testing of non-financial assets, assets that are managed as a portfolio 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 purpose 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.

The Company has determined its CGUs and for non-financial assets subject to depreciation and amortization, it performs impairment testing 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 circumstances indicate that the carrying amount may be impaired.

Identifying events or changes in circumstances that may indicate or cause a non-financial asset's carrying amount to exceed its recoverable amount requires judgment in assessing what events or circumstances would have such an impact. For 2011, the Company recognized an impairment loss of $43 million on management contracts associated with the operations of CPILP prior to the sale of CPILP units to Atlantic Power.

Impairment charges or reversals of impairment charges are expected to occur more frequently than reported in the past due to changes in Canadian GAAP. Assets that are acquired or developed are initially recorded at their fair value which is subject to change as company, industry and general economic conditions fluctuate. The Company performs goodwill impairment testing on an annual basis and current assessments of fair value of its assets on a regular basis which may result in the recognition of impairment losses or reversals of losses such as the 2012 second quarter's impairment loss with respect to its North East U.S. plants. See Significant Events.

Decommissioning and other provisions

Measurement of the Company's provisions and the related change in discount rate require the use of estimates with respect to the amount and timing of asset retirements, the extent of site remediation required, and related future cash flows for the decommissioning provisions and estimates of expected customer renewals for the Company's other provisions.

The Company estimates the undiscounted amount of cash flow required to settle its decommissioning obligations is approximately $331 million, calculated using inflation rates ranging from 2% to 3%. The expected timing for settlement of the obligations is between 2013 and 2066, which reflects the anticipated useful lives of the different power plants. The majority of the payments to settle the obligations are expected to occur between 2032 and 2066 for the power generation plants and between 2013 and 2019 for sections of the Genesee coal mine. Discount rates used to calculate the carrying amount of the obligation ranged from 1.14% to 2.95%. The actual costs to settle decommissioning obligations may vary from estimates as a result of changes to contractor rates required to perform the decommissioning.

The Company holds retail and commercial natural gas customer contracts in Alberta, acquired as part of the July 1, 2009 acquisition of assets from EPCOR. 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 was recorded to reflect the estimated present value of the loss on these contracts. The expected timing of settlement of these contracts range from 2013 to 2046 and the costs were discounted using risk free rates between 1.10% and 2.46%. The timing and settlement of the obligation is dependent on expectations or renewal of the contracts and expectations of the forward price of natural gas.

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 tax assets are assessed to determine the likelihood that they will be realized from future taxable income.

Revenue recognition

Estimates of the value of electricity and natural gas consumed by customers but not billed until subsequent to period-end are based on volume data provided by the parties responsible for delivering the commodity and contracted prices. Actual results may differ from these estimates with adjustments to previous estimates being recorded in the period that they become known.

Leases or arrangements containing a lease

The Company has exercised judgment in determining whether the risks and rewards of its generation assets which are subject to a PPA or other electricity purchase agreement (EPA) are transferred to the contracted purchaser, in determining whether a lease exists and if so, whether the lease should be treated as a finance or operating lease.

The PPA under which the Company's Kingsbridge1 power generation facility operates and the EPA under which the Quality Wind facility operates are accounted for as finance leases.

For other power generation plants operating under PPAs, their assets are accounted for as assets under operating leases.

Future Accounting Changes

The following new and amended accounting and reporting standards will be effective in future periods as indicated. The Company has preliminarily assessed the effect on its consolidated financial statements of adopting these standards and amendments. For those standards where earlier application is permitted, Capital Power expects to apply the changes on the effective date.

International Accounting Standard (IAS) 1 *Presentation of Financial Statements*

In June 2011, the International Accounting Standards Board (IASB) issued amendments to IAS 1 which requires entities to group items within other comprehensive income on the basis of whether or not they will be reclassified to income or loss in a future period. The implications of adopting the amendments to IAS 1 will be limited to the Company's presentation within its statement of other comprehensive income. The amendments are effective for annual periods beginning on or after July 1, 2012 and are to be applied retrospectively. Earlier application is permitted.

IAS 19 *Employee Benefits*

In June 2011, the IASB issued an amendment to IAS 19 which introduced changes related to: (a) eliminating the option to defer the recognition of actuarial gains and losses, known as the corridor method, (b) requiring a new method of calculating finance costs on defined benefit plans where a single discount rate is applied to the net pension assets or obligations, and (c) requiring enhanced disclosures regarding the characteristics and associated risks of the entities' defined benefit plans. Capital Power expects that the adoption of this new standard will have an immaterial effect on its consolidated financial statements. Amendments to IAS 19 are effective for annual periods beginning on or after January 1, 2013 and are to be applied retrospectively. Earlier application is permitted.

International Financial Reporting Standards Interpretations Committee (IFRIC) 20 *Stripping Costs in the Production Phase of a Surface Mine*

In October 2011, the IASB issued an interpretation which clarifies the accounting requirement for waste removal costs incurred in the production phase of a surface mine (stripping costs). IFRIC 20 addresses (a) when stripping costs are recognized as an asset, (b) where the costs should be classified on the statement of financial position, and (c) the initial and subsequent measurement of the asset. The Company does not expect that the adoption of this interpretation will have a material effect on the consolidated financial statements, as it is substantially aligned with the Company's current policies. This interpretation is effective for annual periods beginning on or after January 1, 2013 and is to be applied prospectively. Earlier application is permitted.

International Financial Reporting Standard (IFRS) 7 *Financial Instruments: Disclosures* and IAS 32 *Financial Instruments: Presentation*

In December 2011, the IASB issued amendments to IFRS 7 which identify enhanced disclosure requirements for the actual and potential effects of netting arrangements on the entity's financial position. The adoption of the amendments to IFRS 7 will result in additional disclosure to the Company's consolidated financial statement disclosures. The amendments are effective for annual periods beginning on or after January 1, 2013 and are to be applied retrospectively. Earlier application is permitted.

In December 2011, the IASB issued amendments to IAS 32 which clarifies the criteria for offsetting financial assets and liabilities. Capital Power does not expect that the adoption of the amendments will have a material effect on the consolidated financial statements as they are substantially aligned with the Company's current policies. The amendments are effective for annual periods beginning on or after January 1, 2014 and are to be applied retrospectively. Earlier application is permitted.

IFRS 9 *Financial Instruments*

In November 2009, the IASB issued IFRS 9 which addresses the classification and measurement requirements of financial assets. The standard was amended in October 2010 to include the requirements for the classification and measurement of financial liabilities. The changes are effective for annual periods beginning on or after January 1, 2015 and are to be applied retrospectively. Earlier application is permitted.

IFRS 10 *Consolidated Financial Statements*

In May 2011, the IASB issued IFRS 10 which replaces IAS 27 *Consolidated and Separate Financial Statements* and Standing Interpretations Committee (SIC) 12 *Consolidation – Special Purpose Entities*. IFRS 10 establishes principles for the presentation and preparation of consolidated financial statements. The new standard provides a revised definition of control and a single consolidation model as the basis for consolidation for all types of entities. The new standard also provides additional guidance to assist in the determination of control. Capital Power does not expect that the adoption of this new standard will have a material effect on the consolidated financial statements. Application of the new definition of control is not expected to require a change in the Company's accounting treatment for entities in which it holds an interest. IFRS 10 is effective for annual periods beginning on or after January 1, 2013 and is to be applied retrospectively. Earlier application is permitted but must be applied simultaneously with IFRS 11 and IFRS 12.

IFRS 11 *Joint Arrangements*

IFRS 11 was issued in May 2011 and supersedes IAS 31 *Interests in Joint Ventures* and SIC 13 *Jointly Controlled Entities – Non-Monetary Contributions by Venturers*. The standard classifies joint arrangements as joint operations or joint ventures. Joint operations are arrangements where the jointly controlling parties have rights to the assets and obligations for the liabilities of the joint arrangement. The joint operators will account for their respective shares of the arrangement using the proportionate consolidation method. Joint ventures are arrangements where the parties with joint control have rights to the net assets of the arrangement. IFRS 11 eliminates the choice to account for joint ventures using the proportionate consolidation method and instead requires the equity method of accounting. The Company does not expect that the adoption of this new standard will have a material effect on the consolidated financial statements, as it is substantially aligned with the Company's current practice. IFRS 11 is effective for annual periods beginning on or after January 1, 2013 and is to be applied retrospectively. Earlier application is permitted but must be applied simultaneously with IFRS 10 and IFRS 12.

IFRS 12 *Disclosures of Interests in Other Entities*

In May 2011, the IASB issued IFRS 12, a new standard of comprehensive disclosure requirements for all forms of interests in other entities, including subsidiaries, joint arrangements, associates and unconsolidated structured entities. As a result, the Company anticipates providing additional financial statement disclosures relating to interests in subsidiaries and joint arrangements. IFRS 12 is effective for annual periods beginning on or after January 1, 2013 and is to be applied retrospectively. Earlier application is permitted but must be applied simultaneously with IFRS 11 and IFRS 10.

IFRS 13 *Fair Value Measurement*

In May 2011, the IASB issued IFRS 13 which defines fair value, sets out in a single IFRS a framework for measuring fair value and enhances disclosures about fair value measurements. IFRS 13 applies to fair value measurements required or permitted by other IFRSs, but does not (a) introduce any new requirements to measure an asset or a liability at fair value, (b) change what is measured at fair value in IFRSs, or (c) address how to present changes in fair value. The adoption of this new standard is expected to affect the Company's fair value disclosures for financial instruments and asset impairment calculations. IFRS 13 is effective for annual periods beginning on or after January 1, 2013 and is to be applied prospectively. Earlier application is permitted.

Financial Instruments

The Company has various financial assets that are classified for financial reporting purposes as available for sale, held at fair value through income or loss, or loans and receivable. Financial liabilities are classified as either held at fair value through income or loss or other liabilities. Initially, all financial assets and financial liabilities are recorded on the statement of financial position at fair value with subsequent measurement determined by the classification of each financial asset and liability. Trade and other receivables and trade and other payables 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 amounts and fair values of financial instruments held at December 31, 2012 and 2011 were as follows:

($millions)		As at December 31			
		2012		2011	
	Classification	Carrying amount	Fair value	Carrying amount	Fair value
Financial assets:					
Cash and cash equivalents	Loans and receivables	53	53	73	73
Trade and other receivables	Loans and receivables	354	354	198	198
Derivative financial instruments assets – current and non-current	Financial assets designated at fair value through income or loss	77	77	38	38
Other financial assets - current	Financial assets designated at fair value through income or loss	-	-	53	53
Finance lease receivable	Loans and receivables	461	374	58	50
Other financial assets – non-current	Loans and receivables	55	55	38	37
Other financial assets – non-current	Available for sale	5	5	4	4
Financial liabilities:					
Trade and other payables	Other financial liabilities	210	210	220	220
Derivative financial instruments liabilities – current and non-current	Financial liabilities designated at fair value through income or loss	64	64	74	74
Loans and borrowings (including current portion)	Other financial liabilities	1,659	1,676	1,480	1,571

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 revenues or energy purchases and cost of fuel, as appropriate. 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 instruments assets and liabilities held at December 31, 2012 as compared with 2011 and used for risk management purposes were measured at fair value and consisted of the following:

($ millions)	**Energy cash flow hedges**	**Energy non-hedges**	**Interest rate non-hedges**	**Total**
Derivative instruments net assets (liabilities) at December 31, 2012	29	(16)	-	13
Derivative instruments net assets (liabilities) at December 31, 2011	(23)	(5)	(8)	(36)

Energy derivatives designated as accounting hedges

At December 31, 2012, the fair value of the energy derivative instruments designated and qualifying for hedge accounting was a net asset of $29 million, an increase from the net liability of $23 million at December 31, 2011. The increase in the net asset primarily reflects the impact of decreased forward Alberta power prices on power derivative contracts relative to the contract prices. Unrealized gains and losses for fair value changes on derivatives that qualify for hedge accounting are recorded in other comprehensive income and reclassified to net income as revenues or energy purchases and fuel, as appropriate, when realized.

Derivatives not designated as accounting hedges

At December 31, 2012, the fair value of energy derivative instruments not designated as hedges for accounting purposes was a net liability of $16 million as compared with a net liability of $5 million at December 31, 2011. The difference primarily reflected the impact of changes in the fair value of heat rate options related to the Bridgeport plant. Unrealized and realized gains and losses for fair value changes on energy derivative instruments that do not qualify for hedge accounting are recorded in revenues or energy purchases and fuel as appropriate.

As at December 31, 2012, the Company did not have any forward bond contracts. At December 31, 2011, the fair value of the Company's two $100 million forward bond contracts was a derivative instrument liability of $8 million. The unrealized changes in the fair value of these contracts and reversals of these changes were recognized in finance expense as discussed under Consolidated Other Expenses and Non-controlling Interests.

In November 2011, the Company disposed of its interest in CPILP as discussed under Significant Events. Accordingly, at December 31, 2012 and 2011, the Company did not have any forward foreign currency contracts outstanding since these contracts were primarily used to economically hedge U.S. dollar denominated revenues and expected future net U.S. dollar cash flows from CPILP's U.S. plants.

Disclosure Controls and Procedures and Internal Control over Financial Reporting

As at December 31, 2012, 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, 2012, 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 standards of the Committee of Sponsoring Organizations, a recognized control model, and the requirements of the Canadian Securities Administrators' National Instrument 52-109.

There were no changes in the Company's internal controls over financial reporting that occurred during 2012 that have materially affected, or are reasonably likely to materially affect the Company's internal control over financial reporting.

Summary of Quarterly Results

(GWh)	Three months ended							
Electricity generation	**Dec 31 2012**	**Sep 30 2012**	**Jun 30 2012**	**Mar 31 2012**	**Dec 31 2011**	**Sep 30 2011**	**Jun 30 2011**	**Mar 31 2011**
Total generation excluding acquired Sundance PPA and CPILP plants	4,078	4,575	3,499	4,222	3,780	4,221	3,207	2,451
Alberta commercial plants and acquired Sundance PPA								
Genesee 3	272	507	453	399	222	496	477	482
Keephills 3	403	489	473	430	485	336	50	-
Clover Bar Energy Centre 1, 2 and 3	174	130	140	27	132	57	40	162
Joffre	65	87	97	92	104	90	57	98
Halkirk	44	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Taylor Coulee Chute	n/a	n/a	n/a	n/a	2	12	2	-
Clover Bar Landfill Gas	7	8	9	8	7	9	9	8
Alberta commercial plants – owned	965	1,221	1,172	956	952	1,000	635	750
Acquired Sundance PPA	517	738	660	695	596	545	701	758
	1,482	1,959	1,832	1,651	1,548	1,545	1,336	1,508
Alberta contracted plants								
Genesee 1	830	755	767	814	855	843	661	768
Genesee 2	767	815	589	843	849	845	789	831
	1,597	1,570	1,356	1,657	1,704	1,688	1,450	1,599
Ontario and British Columbia contracted plants								
Island Generation	3	8	-	66	1	-	55	52
Kingsbridge 1	35	15	22	37	35	12	24	31
Quality Wind	70	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Brown Lake	2	14	16	15	14	8	15	14
Miller Creek	1	22	16	4	8	49	26	5
	111	59	54	122	58	69	120	102
North East U.S. commercial plants								
Bridgeport	863	905	300	844	499	872	645	n/a
Rumford	15	229	87	33	83	170	68	n/a
Tiverton	389	416	354	452	389	422	289	n/a
	1,267	1,550	741	1,329	971	1,464	1,002	n/a
North Carolina U.S. contracted plants								
Roxboro	50	64	61	55	36	n/a	n/a	n/a
Southport	88	111	115	103	59	n/a	n/a	n/a
	138	175	176	158	95	n/a	n/a	n/a
CPILP plants	n/a	n/a	n/a	n/a	427	1,294	1,155	1,139

Plant availability	Three months ended							
	Dec 31 2012	Sep 30 2012	Jun 30 2012	Mar 31 2012	Dec 31 2011	Sep 30 2011	Jun 30 2011	Mar 31 2011
Total average plant availability excluding acquired Sundance PPA and CPILP plants	89%	97%	81%	97%	87%	97%	91%	93%
Alberta commercial plants and acquired Sundance PPA								
Genesee 3	56%	100%	95%	84%	44%	100%	100%	100%
Keephills 3	100%	100%	100%	95%	99%	100%	n/a	n/a
Clover Bar Energy Centre 1, 2 and 3	98%	97%	97%	98%	99%	91%	65%	54%
Joffre	65%	98%	99%	94%	93%	99%	78%	99%
Halkirk	95%	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Taylor Coulee Chute	n/a	n/a	n/a	n/a	100%	100%	94%	100%
Clover Bar Landfill Gas	92%	92%	86%	95%	77%	86%	86%	95%
Alberta commercial plants – owned	81%	99%	98%	93%	84%	97%	82%	87%
Acquired Sundance PPA	74%	97%	90%	95%	81%	72%	91%	98%
	79%	98%	96%	93%	83%	89%	84%	91%
Alberta contracted plants								
Genesee 1	98%	93%	97%	97%	100%	100%	81%	92%
Genesee 2	94%	99%	72%	100%	100%	100%	99%	100%
	96%	96%	85%	98%	100%	100%	90%	96%
Ontario and British Columbia contracted plants								
Island Generation	100%	100%	100%	100%	100%	100%	100%	99%
Kingsbridge 1	100%	99%	99%	99%	98%	99%	99%	98%
Quality Wind	99%	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Brown Lake	100%	99%	100%	99%	93%	53%	99%	100%
Miller Creek	85%	71%	38%	85%	78%	92%	99%	78%
	100%	97%	94%	98%	98%	98%	100%	97%
North East U.S. commercial plants								
Bridgeport	85%	95%	35%	96%	59%	96%	100%	n/a
Rumford	84%	97%	84%	98%	94%	95%	99%	n/a
Tiverton	89%	99%	77%	100%	89%	97%	100%	n/a
	86%	97%	58%	98%	76%	96%	99%	n/a
North Carolina U.S. contracted plants								
Roxboro	89%	97%	84%	96%	100%	n/a	n/a	n/a
Southport	90%	100%	87%	96%	100%	n/a	n/a	n/a
	90%	99%	86%	96%	100%	n/a	n/a	n/a
CPILP plants	n/a	n/a	n/a	n/a	96%	96%	88%	92%

Financial results

(unaudited, $ millions)	Three months ended							
	Dec 31 2012	**Sep 30 2012**	**Jun 30 2012**	**Mar 31 2012**	**Dec 31 2011**	**Sep 30 2011**	**Jun 30 2011**	**Mar 31 2011**
Revenues and other income								
Alberta commercial plants, acquired Sundance PPA and portfolio optimization	145	207	141	180	168	144	215	266
Alberta contracted plants	75	69	63	75	86	87	64	77
Ontario and British Columbia contracted plants	18	12	12	14	13	12	13	13
North East U.S. commercial plants and portfolio optimization	65	62	34	59	51	71	51	-
North Carolina U.S. contracted plants	16	19	18	18	14	-	-	-
CPILP plants	-	-	-	-	51	139	129	128
Other portfolio activities	10	10	4	29	21	19	18	34
Corporate	5	5	7	9	5	5	6	6
Interplant category transaction eliminations	(4)	(8)	(7)	(18)	(11)	(16)	(17)	(20)
	330	376	272	366	398	461	479	504
Unrealized changes in fair value of CPLP's energy derivative instruments and Atlantic Power shares	(34)	18	(11)	14	-	(5)	(8)	(49)
Unrealized changes in fair value of CPILP's foreign exchange contracts	-	-	-	-	9	(23)	1	3
	(34)	18	(11)	14	9	(28)	(7)	(46)
	296	394	261	380	407	433	472	458
Adjusted EBITDA								
Alberta commercial plants, acquired Sundance PPA and portfolio optimization	64	113	55	87	70	72	44	38
Alberta contracted plants	51	38	35	45	51	57	35	47
Ontario and British Columbia contracted plants	15	8	9	10	10	8	10	10
North East U.S. commercial plants and portfolio optimization	(1)	12	1	13	6	10	10	-
North Carolina U.S. contracted plant	2	-	-	2	4	-	-	-
CPILP plants	-	-	-	-	19	48	37	44
Other portfolio activities	(1)	4	-	7	6	-	2	-
Corporate	(30)	(30)	(28)	(25)	(26)	(28)	(28)	(23)
Interplant category transaction eliminations	-	-	-	-	-	-	-	-
	100	145	72	139	140	167	110	116
Unrealized changes in fair value of CPLP's energy derivative instruments and Atlantic Power shares	(27)	7	(8)	13	-	(5)	-	(34)
Unrealized changes in fair value of CPILP's foreign exchange and natural gas contracts	-	-	-	-	10	(23)	2	2
	(27)	7	(8)	13	10	(28)	2	(32)
	73	152	64	152	150	139	112	84

Quarterly revenues, net income and cash flows provided by 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 as well as items outside the normal course of operations. Net income is also affected by changes in the fair value of the Company's derivative power and natural gas, foreign exchange and forward bond contracts.

Financial highlights

(unaudited, $ millions except per share amounts)	Three months ended							
	Dec 31 2012	**Sep 30 2012**	**Jun 30 2012**	**Mar 31 2012**	**Dec 31 2011**	**Sep 30 2011**	**Jun 30 2011**	**Mar 31 2011**
Revenues and other income	296	394	261	380	407	433	472	458
Adjusted EBITDA[1]	73	152	64	152	150	139	112	84
Net income (loss)	19	63	(58)	66	152	44	(22)	14
Net income (loss) attributable to shareholders of the Company	15	39	(32)	40	84	15	(25)	3
Basic earnings (loss) per share ($)	0.19	0.55	(0.50)	0.66	1.47	0.29	(0.67)	0.06
Normalized earnings per share ($) [1]	0.23	0.55	0.07	0.46	0.36	0.43	0.07	0.34

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

	Three months ended							
Spot price averages	**Dec 31 2012**	**Sep 30 2012**	**Jun 30 2012**	**Mar 31 2012**	**Dec 31 2011**	**Sep 30 2011**	**Jun 30 2011**	**Mar 31 2011**
Alberta power ($/MWh)	79	78	40	60	76	95	52	82
New England mass hub (US$/MWh)	45	37	29	33	38	47	43	n/a
Alberta natural gas (AECO) ($/Gj)	2.16	2.16	1.80	2.06	3.03	3.47	3.68	3.57
Capital Power's Alberta portfolio's average realized power price ($/MWh)	65	81	60	83	75	74	56	64

Factors impacting the 2012 fourth quarter results

During the quarter ended December 31, 2012, the Company recorded net income attributable to shareholders of $15 million and normalized earnings per share of $0.23 which were lower than the comparable amounts in the fourth quarter of 2011. This decrease was primarily attributable to realized losses on the Bridgeport heat rate option and the pricing of physical natural gas purchases for the Bridgeport plant.

The Quality Wind and Halkirk wind projects commenced commercial operations in this quarter adding a total capacity of 292 MW to the Company's generation portfolio while the finalization of the sale of the British Columbia hydro facilities decreased capacity by 40 MW. The Company recognized a pre-tax gain of $15 million on the sale of the Brown Lake and Miller Creek hydro facilities.

For the three months ended December 31, 2012, Alberta commercial plants and acquired Sundance PPA electricity generation was lower than experienced in preceding quarters of 2012 primarily due to a planned outage at Genesee 3 which was extended by nine days. The production associated with the acquired Sundance PPA was lower than production in the previous quarters of 2012 and 2011 due to a fourth quarter outage. Revenues and adjusted EBITDA reflected these plant operating factors, lower pricing in the Alberta marketplace and increased maintenance expenses associated with the Genesee 3 outage.

Electricity generation, availability and revenues of the Alberta contracted plants in the fourth quarter of 2012 were consistent with previous quarterly results. Adjusted EBITDA increased in the quarter due to a change in the estimate of coal inventory which decreased energy purchases and fuel costs by approximately $7 million.

The portfolio of plants in the Ontario and British Columbia contracted plants category shifted significantly as the Quality Wind facility commenced commercial operations on November 6, 2012 and the sale of the Brown Lake and Miller Creek hydro facilities was finalized on October 12, 2012. Availability of the plants in this category was strong for the periods of time that they were operated by Capital Power. Revenues and adjusted EBITDA for the quarter increased relative to previous quarters primarily based on the addition of Quality Wind.

The 2012 fourth quarter plant operating results for the Bridgeport, Rumford and Tiverton plants in the North East U.S. plant category were below average results of previous quarters primarily due to outage days experienced on a pre-emptive basis in consideration of Hurricane Sandy. Net pre-tax losses of $10 million related to the North East U.S. plants were incurred during the fourth quarter. A heat rate option that was in place on the Bridgeport facility at the time of acquisition in 2011 settled at a loss for November and December 2012 due to a significant shift in the underlying locational basis risk associated with the option. The basis risk existed because the plant delivers power to and procures gas from locations differing from those referenced in the heat rate option. The correlation between the locations has historically been very high for both power and natural gas. However, in November and December 2012, there was a spike in North East U.S. natural gas demand combined with supply constraints resulting in a significant shift in North East U.S. gas fundamentals. These factors led to a significant widening of the price spread between the Bridgeport plant's natural gas consumption point and the heat rate option location resulting in the loss. In addition, December 2012 physical natural gas consumption for Bridgeport was locked-in at prices higher than actual prices resulting in an additional loss. These losses were partly offset by gains realized on a financial hedge executed to reduce the locational basis risk. These trades were implemented to limit the exposure to the natural gas basis risk associated with the heat rate option.

Factors impacting results for the previous quarters

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

In the third quarter of 2012, Alberta commercial plants experienced strong performance which was dampened by an unscheduled outage at Genesee 1 resulting from a trial project intended to increase the marketability of fly ash by-product.

In the second quarter of 2012, a pre-tax impairment loss of $74 million on Capital Power's North East U.S. plants based on reduced expected operating margins for the Bridgeport, Rumford and Tiverton plants largely as a result of weaker spark spreads in the Northeast U.S. power market was recognized. Results for the North East U.S commercial plants were impacted by lower than expected market spark spreads and an unplanned outage at the Bridgeport facility.

The 2012 first quarter reflected strong results for Alberta commercial plants and portfolio optimization largely due to the movement of Alberta power prices and their impact on portfolio position selling forward length at prices higher than the spot market. The production and contributions from Alberta commercial plants was strong with the inclusion of Keephills 3 since its commercial operations commenced in September 2011. The Company recognized significant unrealized net gains on its energy derivatives due to the reversal of unrealized losses accrued at the previous year-end on contracts which settled in the first quarter of 2012 and the impact of decreasing Alberta forward power prices on its portfolio position.

In the fourth quarter of 2011, the Company sold its limited partnership units of CPILP to Atlantic Power effective November 5, 2011 resulting in the recognition of a pre-tax gain on disposal of $89 million after deducting legal and other disposal costs of $10 million. From that point forward, the Company's operations and corporate structure were simplified as there was a decrease in the number of plants and legal entities and CPILP's results were no longer consolidated with the Company's results. Absent other changes, the disposal decreased revenues, net income and net income attributable to non-controlling interests for the fourth quarter of 2011 and future quarters relative to past quarters. Capital Power's Genesee 3 plant experienced an unplanned outage which reduced its generation volumes but this was partly offset by increased generation from the Company's CBEC facility. This and other Alberta portfolio optimization activities given the higher power prices experienced due to plant outages and higher demand helped offset a portion of the loss of earnings from Genesee 3 being offline.

In the third quarter of 2011, the average Alberta power price increased significantly due to warmer temperatures, reduced supply resulting from several plant outages in the area, and Saskatchewan tie-line restrictions. Higher Alberta power prices had a favourable impact on the Company's Alberta portfolio position. Sundance Unit 6 went offline on August 18, 2011 due to a transformer failure and remained offline until October 14, 2011 to also perform planned maintenance. The penalty revenues received for this outage were based on high rolling average power prices partly offset the loss of margin from the facility being unavailable on the Alberta commercial plant and portfolio optimization results. The high rolling average power prices also had a favourable impact on availability incentive income for the Alberta contracted plants which had 100% availability in the quarter. Corporate results included a $6 million foreign exchange losses related to the translation of U.S. denominated debt.

In the second quarter of 2011, North East U.S. commercial plants and portfolio optimization results reflected contributions from the Bridgeport, Rumford and Tiverton facilities and trading in the North East U.S. power market since the acquisition of these plants in April 2011. Alberta contracted plants results included $5 million of availability incentive penalties relating to a scheduled maintenance outage at Genesee 1. An impairment loss of $43 million on Capital Power's management and operations contracts with CPILP was recorded. Finance expense included a $12 million loss related to the settlement of forward bond contracts. Income taxes included the reversal of a provision recorded in the second quarter of 2010 for deferred income taxes associated with the possible sale of the Company's interest in CPILP.

In the first quarter of 2011, the average Alberta power price increased significantly primarily due to colder weather than normal and the shutdown of two large coal plants in the region. The sudden increase in Alberta power prices had an unfavourable impact on the Company's Alberta portfolio position.

Share and Partnership Unit Information

Quarterly common share trading information

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

	Three months ended							
	Dec 31 2012	Sep 30 2012	Jun 30 2012	Mar 31 2012	Dec 31 2011	Sep 30 2011	Jun 30 2011	Mar 31 2011
Share price ($/common share)								
High	23.20	24.53	24.47	25.72	25.78	26.38	28.00	26.44
Low	20.88	20.75	22.48	23.29	22.88	21.50	24.90	22.80
Close	22.73	21.29	23.78	23.49	25.12	25.45	25.00	25.92
Volume of shares traded (millions)	10.8	9.6	10.3	9.0	10.6	7.6	9.5	8.9

Outstanding share and partnership unit data

As at February 26, 2013, the Company had 70.257 million common shares outstanding, 28.441 million special voting shares outstanding, 5 million Cumulative Rate Reset Preference Shares, Series 1 outstanding, 6 million Cumulative Rate Reset Preference Shares, Series 3 and one special limited voting share outstanding. Assuming full conversion of the outstanding and issuable share purchase options and the outstanding special voting shares to common shares and ignoring exercise prices, the outstanding and issuable common shares as at February 26, 2013 were 102.958 million. All of the outstanding special voting shares and the outstanding special limited voting share are held by EPCOR.

As at February 26, 2013, CPLP had 21.750 million general partnership units outstanding, 46.699 million common limited partnership units outstanding and 28.441 million exchangeable common limited partnership units outstanding, which are exchangeable for 28.441 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, 2012 and 2011

Management's responsibility for financial reporting

The preparation and presentation of the accompanying consolidated financial statements of Capital Power Corporation 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 March 1, 2013. 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 and Chief Financial Officer

March 1, 2013

CAPITAL POWER CORPORATION

Consolidated Financial Statements

Years ended December 31, 2012 and 2011

KPMG

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Chartered Accountants
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Canada

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INDEPENDENT AUDITORS' REPORT

To the Shareholders of Capital Power Corporation

We have audited the accompanying consolidated financial statements of Capital Power Corporation, which comprise the consolidated statements of financial position as at December 31, 2012 and 2011, the consolidated statements of income, comprehensive income, changes in equity and cash flows for the years ended December 31, 2012 and 2011, 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.

KPMG

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Capital Power Corporation as at as at December 31, 2012 and 2011, and its consolidated financial performance and its consolidated cash flows for the years ended December 31, 2012 and 2011 in accordance with International Financial Reporting Standards.

KPMG LLP

Chartered Accountants

March 1, 2013
Edmonton, Canada

CAPITAL POWER CORPORATION

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

Years ended December 31, 2012 and 2011

	2012	2011
Revenues	$ 1,291	$ 1,691
Other income	40	79
Energy purchases and fuel	(553)	(904)
Gross income	778	866
Other raw materials and operating charges (note 4)	(132)	(149)
Staff costs and employee benefits expense (note 4)	(143)	(155)
Depreciation and amortization (note 4)	(221)	(229)
Impairments (note 10)	(74)	(43)
Other administrative expenses (note 4)	(62)	(77)
Foreign exchange losses	-	(13)
Operating income	146	200
Gains on disposals (note 8)	15	93
Finance expense (note 5)	(75)	(105)
Income before tax	86	188
Income tax recovery (note 6)	4	-
Net income	$ 90	$ 188
Attributable to:		
Non-controlling interests	$ 28	$ 111
Shareholders of the Company	$ 62	$ 77

Earnings per share (all from continuing operations attributable to common shareholders of the Company):

	2012	2011
Basic (note 7)	$ 0.84	$ 1.60
Diluted (note 7)	$ 0.84	$ 1.59

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, 2012 and 2011

	2012	2011
Net income	$ 90	$ 188
Other comprehensive income (loss):		
Available-for-sale assets:		
Unrealized losses on available-for-sale financial assets [1]	-	(1)
Cash flow hedges:		
Unrealized gains (losses) on derivative instruments [2]	54	(100)
Reclassification of (gains) losses on derivative instruments to income for the year [3]	(12)	45
Reclassification of ineffective portion to income for the year [4]	-	2
Defined benefit plans:		
Actuarial losses [5]	(6)	(5)
Net investment in foreign subsidiaries:		
Unrealized (loss) gain [4]	(10)	39
Losses realized in net income on disposal of CPILP [6]	-	21
Other comprehensive income, net of tax	26	1
Total comprehensive income	$ 116	$ 189
Attributable to:		
Non-controlling interests	$ 42	$ 110
Shareholders of the Company	$ 74	$ 79

[1] For the year ended December 31, 2012, net of income tax expense of nil. For the year ended December 31, 2011, net of income tax recovery of $1.

[2] For the year ended December 31, 2012, net of income tax expense of $12. For the year ended December 31, 2011, net of income tax recovery of $18.

[3] For the year ended December 31, 2012, net of reclassification of income tax expense of $2. For the year ended December 31, 2011, net of reclassification of income tax recovery of $8.

[4] For the years ended December 31, 2012 and December 31, 2011, net of income tax expense of nil.

[5] For the year ended December 31, 2012, net of income tax recovery of $2. For the year ended December 31, 2011, net of income tax recovery of $2.

[6] For the year ended December 31, 2011, net of reclassification of income tax recovery of $10.

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, 2012 and 2011

	2012	2011
Assets		
Current assets:		
Cash and cash equivalents (note 11)	$ 53	$ 73
Trade and other receivables (note 12)	354	198
Inventories (note 13)	72	59
Derivative financial instruments assets (note 14)	47	25
Other financial assets (note 16)	-	53
	526	408
Non-current assets:		
Other assets	21	24
Derivative financial instruments assets (note 14)	30	13
Finance lease receivable (note 15)	461	58
Other financial assets (note 16)	60	42
Deferred tax assets (note 17)	70	14
Intangible assets (note 18)	316	296
Property, plant and equipment (note 19)	3,628	3,842
Goodwill (note 20)	22	46
Total assets	$ 5,134	$ 4,743

Approved on behalf of the Board:

Donald Lowry
Director and Chairman of the Board

William Bennett
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, 2012 and 2011

	2012	2011
Liabilities and equity		
Current liabilities:		
Trade and other payables (note 21)	$ 210	$ 220
Derivative financial instruments liabilities (note 14)	52	67
Loans and borrowings (note 22)	19	28
Deferred revenue and other liabilities	8	13
Provisions (note 23)	24	33
	313	361
Non-current liabilities:		
Derivative financial instruments liabilities (note 14)	12	7
Loans and borrowings (note 22)	1,640	1,452
Deferred revenue and other liabilities	91	76
Deferred tax liabilities (note 17)	112	55
Provisions (note 23)	214	197
	2,069	1,787
Equity:		
Equity attributable to shareholders of the Company		
Share capital (note 24)	1,903	1,499
Retained earnings (deficit)	(1)	16
Other reserves (note 25)	21	8
Retained earnings (deficit) and other reserves	20	24
	1,923	1,523
Non-controlling interests	829	1,072
Total equity	2,752	2,595
Commitments and contingencies (note 33)		
Subsequent event (note 36)		
Total liabilities and equity	$ 5,134	$ 4,743

See accompanying notes to the consolidated financial statements

CAPITAL POWER CORPORATION

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

	Share capital (note 24)	Cash flow hedges [1]	Cumulative translation 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	Total
Equity as at January 1, 2012	$ 1.499	$ (10)	$ 17	$ (7)	$ 8	$ 16	$ 1,523	$ 1,072	$ 2,595
Net income	-	-	-	-	-	62	62	28	90
Other comprehensive income (loss):									
Cash flow derivative hedge gains	-	66	-	-	-	-	66	-	66
Reclassification of gains to income	-	(14)	-	-	-	-	(14)	-	(14)
Unrealized loss on foreign currency translation	-	-	(10)	-	-	-	(10)	-	(10)
Defined benefit plan actuarial losses	-	-	-	(8)	-	-	(8)	-	(8)
Tax on items recognized directly in equity	-	(10)	-	2	-	-	(8)	-	(8)
Attributed to non-controlling interests	-	(17)	3	-	-	-	(14)	14	-
Other comprehensive income (loss)	$ -	$ 25	$ (7)	$ (6)	$ -	$ -	$ 12	$ 14	$ 26
Total comprehensive income (loss)	-	25	(7)	(6)	-	62	74	42	116
Issue of share capital	389	-	-	-	(1)	12	400	(253)	147
Transaction costs	(5)	-	-	-	-	-	(5)	-	(5)
Deferred taxes	1	-	-	-	-	-	1	-	1
Distributions to non-controlling interests	-	-	-	-	-	-	-	(39)	(39)
Additional investment by non-controlling interests	-	-	-	-	-	-	-	7	7
Common share dividends (note 24)	-	-	-	-	-	(85)	(85)	-	(85)
Preferred share dividends (note 24)	-	-	-	-	-	(6)	(6)	-	(6)
Dividends reinvested	19	-	-	-	-	-	19	-	19
Share-based compensation	-	-	-	-	2	-	2	-	2
Equity as at December 31, 2012	$ 1,903	$ 15	$ 10	$ (13)	$ 9	$ (1)	$ 1,923	$ 829	$ 2,752

[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.

CAPITAL POWER CORPORATION

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

	Share capital (note 24)	Cash flow hedges [1]	Cumulative translation account [1]	Available-for-sale financial assets [1]	Defined benefit plan actuarial gains (losses) [1]	Employee benefits reserve	Retained earnings	Equity attributable to shareholders of the Company	Non-controlling interests	Total
Equity as at January 1, 2011	$ 820	$ 7	$ (7)	$ 1	$ (2)	$ 6	$ 8	$ 833	$ 1,779	$ 2,612
Net income	-	-	-	-	-	-	77	77	111	188
Other comprehensive income (loss):										
Net change in fair value of available-for-sale financial assets	-	-	-	(2)	-	-	-	(2)	-	(2)
Cash flow derivative hedge losses	-	(118)	-	-	-	-	-	(118)	-	(118)
Reclassification of losses to income	-	53	-	-	-	-	-	53	-	53
Reclassification of ineffective portion to income	-	2	-	-	-	-	-	2	-	2
Defined benefit plan actuarial losses	-	-	-	-	(7)	-	-	(7)	-	(7)
Unrealized gain on foreign currency translation	-	-	39	-	-	-	-	39	-	39
Losses realized in net income on disposal of CPILP	-	23	11	(3)	-	-	-	31	-	31
Tax on items recognized directly in equity	-	(1)	-	2	2	-	-	3	-	3
Attributed to non-controlling interests	-	25	(26)	2	-	-	-	1	(1)	-
Other comprehensive income (loss)	-	(16)	24	(1)	(5)	-	-	2	(1)	1
Total comprehensive income (loss)	-	(16)	24	(1)	(5)	-	77	79	110	189
Issue of share capital	694	-	-	-	-	(1)	3	696	(242)	454
Transaction costs	(20)	-	-	-	-	-	-	(20)	-	(20)
Deferred taxes	5	(1)	-	-	-	-	-	4	-	4
Distributions to non-controlling interests	-	-	-	-	-	-	-	-	(115)	(115)
Additional investment by non-controlling interests	-	-	-	-	-	-	-	-	11	11
Reduction in non-controlling interests on disposal of CPILP	-	-	-	-	-	-	(6)	(6)	(474)	(480)
Issue of partnership units	-	-	-	-	-	-	-	-	14	14
Common share dividends (note 24)	-	-	-	-	-	-	(60)	(60)	-	(60)
Preferred share dividends (note 24)	-	-	-	-	-	-	(6)	(6)	-	(6)
Preferred share dividends paid by subsidiary	-	-	-	-	-	-	-	-	(11)	(11)
Share-based compensation	-	-	-	-	-	3	-	3	-	3
Equity as at December 31, 2011	$ 1,499	$ (10)	$ 17	$ -	$ (7)	$ 8	$ 16	$ 1,523	$ 1,072	$ 2,595

[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, 2012 and 2011

	2012	2011
Cash flows from operating activities:		
Net income	$ 90	$ 188
Non-cash adjustments to reconcile net income to net cash flows from operating activities:		
Depreciation and amortization (note 4)	221	229
Gains on disposals (note 8)	(15)	(93)
Impairments (note 10)	74	43
Finance expense (note 5)	75	105
Fair value changes on derivative instruments	3	49
Unrealized foreign exchange losses	-	6
Income tax recovery (note 6)	(4)	-
Other items	4	(6)
Interest paid [1]	(59)	(88)
Income taxes paid	(7)	(14)
Change in non-cash operating working capital (note 26)	(140)	42
Net cash flows from operating activities	242	461
Cash flows used in investing activities:		
Payments to acquire property, plant and equipment and other assets	(598)	(493)
Proceeds on disposal of assets	116	131
Business acquisitions, net of acquired cash	-	(647)
Other cash flows from investing activities	16	24
Net cash flows used in investing activities	(466)	(985)
Cash flows from financing activities:		
Proceeds from issue of loans and borrowings	250	604
Repayment of loans and borrowings	(62)	(293)
Debt issue costs	(3)	(5)
Proceeds from issue of common shares (note 24)	8	469
Proceeds from issue of preferred shares (note 24)	150	-
Share issue costs (note 24)	(5)	(20)
Distributions paid to non-controlling interests (note 27)	(42)	(110)
Common share dividends paid (note 24)	(62)	(51)
Preferred share dividends paid (note 24)	(6)	(6)
Preferred share dividends paid by subsidiary	-	(11)
Interest paid [1]	(23)	(36)
Net cash flows from financing activities	205	541
Foreign exchange losses on cash held in a foreign currency	(1)	-
Net (decrease) increase in cash and cash equivalents	(20)	17
Cash and cash equivalents at beginning of year	73	56
Cash and cash equivalents at end of year	$ 53	$ 73

[1] Total interest 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 plants and manages its related electricity and natural gas portfolios by undertaking trading and marketing activities.

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

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, 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 March 1, 2013.

(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 70.7% interest in Capital Power L.P. (CPLP) (December 31, 2011 - 60.6%). Based on an assessment of the relationship between Capital Power and CPLP, Capital Power controls CPLP and therefore CPLP is treated as a subsidiary of Capital Power.

EPCOR Utilities Inc. (EPCOR) holds 28.441 million (December 31, 2011 - 38.216 million) exchangeable limited partnership units of CPLP (exchangeable for common shares of Capital Power on a one-for-one basis) which represents approximately 29.3% of CPLP (December 31, 2011 - 39.4%). 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 four directors of Capital Power of the current twelve 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. Since a subsidiary of Capital Power is the general partner of CPLP, Capital Power has control over CPLP and, on that basis, the operations of CPLP are consolidated by Capital Power for financial statement purposes.

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.

2. Significant accounting policies, continued:

(c) 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 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 over impairment of goodwill, refer to the accounting policy for impairment of non-financial assets (note 2(n)).

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.

(d) Investments in joint ventures:

Investments in jointly controlled assets

Capital Power has interests with other parties (the venturers), whereby in each case the venturers have a contractual arrangement that establishes joint control over the economic activities of the arrangement. These arrangements involve the joint ownership of assets which are used to obtain benefits for each venturer, and are considered to be jointly controlled assets.

In these situations Capital Power recognizes its share of the jointly controlled assets and liabilities in accordance with those associated rights and obligations, along with its share of the income from the output of the jointly controlled asset along with its share of any expenses incurred. The accounting policies of these jointly controlled asset arrangements are aligned with the accounting policies of the Company.

2. Significant accounting policies, continued:

(d) Investments in joint ventures, continued:

Investments in jointly controlled entities

The Company, along with two third parties, has an equal interest in a partnership established to develop, construct and operate a wind power project. Joint control of this partnership has been established by contractual agreement and the requirement of unanimous consent for strategic financial and operating decisions.

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

(e) 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 operations that have a functional currency that is different from the Company's functional currency of Canadian dollars, principally on U.S. operations that have a functional currency of U.S. 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.

(f) 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 period-end.

The Company recognizes revenues from certain of its generation units operating under power purchase agreements (PPAs) as described in note 2(g). 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 other generation units operating under PPAs, which have not been assessed as containing a lease are recognized on delivery of output or upon availability for delivery as prescribed by the respective PPA. In determining the fair value of revenue to be recognized for certain long-term contracts which contain fixed rates which vary dependent on cumulative volume delivered, revenue is recognized as the lower of (1) the megawatt hours (MWhs) made available during the period multiplied by the billable contract price per MWh and (2) an amount determined by the MWhs made available during the period, multiplied by the average price per MWh over the term of the contract from the date of acquisition. Any excess of the contract price over the average price is recorded as deferred revenue.

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

Service revenues

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

2. Significant accounting policies, continued:

(f) Revenue recognition, continued:

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 short 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.

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 life of the agreement but no longer than the life of the asset.

(g) 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 on the basis of their relative fair value.

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 on a straight-line basis over the life of the lease. The Company has not entered into any finance lease arrangements as a lessee.

2. Significant accounting policies, continued:

(h) 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 29.

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

Loans and receivables

Loans and receivables are financial assets with fixed or determinable payments that are not quoted in an active market. The Company's current loans and receivables comprise its cash and cash equivalents 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 2013 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(o). 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.

(i) 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.

2. Significant accounting policies, continued:

(i) Derivative instruments and hedging activities, continued:

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

All changes in the fair value of derivatives are recorded in net income unless cash flow hedge accounting is used, in which case changes in the fair value of the effective portion of the derivatives are recorded in other comprehensive income.

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.

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.

The Company may use non-financial or financial commodity derivative trades 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. Such trades are recognized on a net basis in the Company's revenues.

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. 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.

2. Significant accounting policies, continued:

(i) Derivative instruments and hedging activities, continued:

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 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.

(j) Property, plant and equipment:

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

Capitalization

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

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

2. Significant accounting policies, continued:

(j) Property, plant and equipment, continued:

Depreciation

Depreciation is charged to net income on a straight-line basis over the estimated useful lives of each part 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 generation plants and equipment range from 1 to 60 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.

(k) 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 18 for additional discussion over intangible assets.

The only indefinite life intangible assets recorded by the Company are purchased emission credits.

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 plant 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 plant. The Company’s purchased emission credits are not amortized, but are expensed as the associated benefits are realized.

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

Alberta PPAs	11 years
Contract rights	5 years
Water rights	over the lives of the associated property, plant and equipment
Software	1 to 10 years
Customer rights	30 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:

(l) Research and development costs:

Expenditures on research activities, undertaken with the prospect of gaining new scientific or technical knowledge and understanding, are recognized in income or loss as incurred.

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.

(m) Capitalized borrowing costs:

The Company capitalizes interest during construction on its property, plant and equipment and intangible assets to provide for 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. Qualifying assets are those which necessarily take a significant amount of time to get ready for their intended use.

(n) 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 is subject to an operating segment ceiling test and 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 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 would be 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 would be 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.

2. Significant accounting policies, continued:

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

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.

(o) Impairment of financial assets:

Financial assets, other than those classified as held at fair value through income or loss with changes in fair value recognized in the statement of income, are assessed for indicators of impairment at the end of each reporting period. An impairment loss would be 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 an 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.

(p) 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 tax 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.

2. Significant accounting policies, continued:

(p) Income taxes, continued:

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.

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

(q) 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. Natural gas inventory held in storage for trading purposes is recorded at fair value less costs to sell, as measured by the one-month forward price of natural gas. Previous write-downs of inventories from cost to net realizable value can be fully or partially reversed if supported by economic circumstance.

(r) 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.

(s) 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 as a reduction to the related expense or asset.

(t) Provisions:

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

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. Accretion of the liability is recorded in finance expense.

2. Significant accounting policies, continued:

(t) Provisions, continued:

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 expected cost of terminating the contract and the expected net cost of continuing with the contract. Before a provision is established, the Company recognizes any impairment loss on the assets associated with that contract.

(u) Share-based payments:

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

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

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

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

(v) Earnings per share:

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

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

(w) Future accounting changes:

A number of new standards, and amendments to standards and interpretations, as described below, are not yet effective for the year ended December 31, 2012 and have not been applied in preparing these consolidated financial statements. The Company has completed its preliminary assessment of the effect on its consolidated financial statements of adopting these standards and amendments. For those standards where earlier application is permitted, the Company expects to apply the changes at the effective date.

2. Significant accounting policies, continued:

(w) Future accounting changes, continued:

IAS 1 – Presentation of Financial Statements – In June 2011, the International Accounting Standards Board (IASB) issued amendments to IAS 1 which will require entities to group items within other comprehensive income on the basis of whether or not they will be reclassified to income or loss in a future period. The implications of adopting the amendments to IAS 1 will be limited to the Company's presentation within its statement of other comprehensive income. The amendments are effective for annual periods beginning on or after July 1, 2012 and are to be applied retrospectively. Earlier application is permitted.

IFRS 7 – Financial Instruments: Disclosures – In December 2011, the IASB issued amendments to IFRS 7 which establishes enhanced disclosure requirements for the actual and potential effects of netting arrangements on the Company's statements of financial position. The adoption of the amendments to IFRS 7 will result in additional disclosure to the Company's consolidated financial statements. The amendments are effective for annual periods beginning on or after January 1, 2013 and are to be applied retrospectively. Earlier application is permitted.

IFRS 10 – Consolidated Financial Statements – In May 2011, the IASB issued IFRS 10 which replaces IAS 27 – Consolidated and Separate Financial Statements and SIC 12 - Consolidation – Special Purpose Entities. IFRS 10 establishes principles for the presentation and preparation of consolidated financial statements. The new standard provides a revised definition of control and a single consolidation model as the basis for consolidation for all types of entities. The standard also provides additional guidance to assist in the determination of control. Capital Power does not expect that the adoption of this new standard will have a material effect on the consolidated financial statements, as application of the new definition of control is not expected to require a change in the Company's current accounting treatment for entities in which it holds an interest. IFRS 10 is effective for annual periods beginning on or after January 1, 2013 and is to be applied retrospectively. Earlier application is permitted but must be applied simultaneously with IFRS 11 and IFRS 12.

IFRS 11 – Joint Arrangements – IFRS 11 was issued in May 2011 and supersedes IAS 31 – Interests in Joint Ventures and SIC 13 – Jointly Controlled Entities – Non-Monetary Contributions by Venturers. The standard classifies joint arrangements as joint operations or joint ventures. Joint operations are arrangements where the jointly controlling parties have rights to the assets and obligations for the liabilities of the joint arrangement. The joint operators will account for their respective shares of the arrangement using the proportionate consolidation method. Joint ventures are arrangements where the parties with joint control have rights to the net assets of the arrangement. IFRS 11 eliminates the choice to account for joint ventures using the proportionate consolidation method and instead requires the equity method of accounting. The Company does not expect that the adoption of this new standard will have a material effect on the consolidated financial statements, as it is substantially aligned with the Company's current practice. IFRS 11 is effective for annual periods beginning on or after January 1, 2013 and is to be applied retrospectively. Earlier application is permitted but must be applied simultaneously with IFRS 10 and IFRS 12.

IFRS 12 – Disclosures of Interests in Other Entities – In May 2011, the IASB issued IFRS 12, a new and comprehensive standard on disclosure requirements for all forms of interests in other entities, including subsidiaries, joint arrangements, associates and unconsolidated structured entities. As a result, the Company anticipates providing additional financial statement disclosures relating to interests in subsidiaries and joint arrangements. IFRS 12 is effective for annual periods beginning on or after January 1, 2013 and is to be applied retrospectively. Earlier application is permitted but must be applied simultaneously with IFRS 11 and IFRS 10.

2. Significant accounting policies, continued:

(w) Future accounting changes, continued:

IFRS 13 – Fair Value Measurement – In May 2011, the IASB issued IFRS 13 which defines fair value, sets out in a single IFRS a framework for measuring fair value and enhances disclosures about fair value measurements. IFRS 13 applies to fair value measurements required or permitted by other IFRSs, but does not (a) introduce any new requirements to measure an asset or a liability at fair value, (b) change what is measured at fair value in IFRSs, or (c) address how to present changes in fair value. The adoption of this new standard is expected to affect the Company's fair value disclosures for financial instruments and asset impairment calculations. IFRS 13 is effective for annual periods beginning on or after January 1, 2013 and is to be applied prospectively. Earlier application is permitted.

IAS 19 – Employee Benefits – In June 2011, the IASB issued an amendment to IAS 19 which introduced changes related to: (a) eliminating the option to defer the recognition of actuarial gains and losses, known as the corridor method, (b) requiring a new method of calculating finance costs on defined benefit plans where a single discount rate is applied to the net pension assets or obligations, and (c) requiring enhanced disclosures regarding the characteristics and associated risks of the Company's defined benefit plans. Capital Power expects that the adoption of this new standard will have an immaterial effect on its consolidated financial statements. Amendments to IAS 19 are effective for annual periods beginning on or after January 1, 2013 and are to be applied retrospectively. Earlier application is permitted.

International Financial Reporting Standards Interpretations Committee (IFRIC) 20 – Stripping Costs in the Production Phase of a Surface Mine – In October 2011, the IASB issued an interpretation which clarifies the accounting requirement for waste removal costs incurred in the production phase of a surface mine (stripping costs). IFRIC 20 addresses (a) when stripping costs are recognized as an asset, (b) where the costs should be classified on the statement of financial position, and (c) the initial and subsequent measurement of the asset. The Company does not expect that the adoption of this interpretation will have a material effect on the consolidated financial statements, as it is substantially aligned with the Company's current policies. This interpretation is effective for annual periods beginning on or after January 1, 2013 and is to be applied prospectively. Earlier application is permitted.

IAS 32 – Financial Instruments: Presentation – In December 2011, the IASB issued amendments to IAS 32 which clarifies the criteria for offsetting financial assets and liabilities. Capital Power does not expect that the adoption of the amendments will have a material effect on the consolidated financial statements, as they are substantially aligned with the Company's current policies. The amendments are effective for annual periods beginning on or after January 1, 2014 and are to be applied retrospectively. Earlier application is permitted.

IFRS 9 – Financial Instruments – In November 2009, the IASB issued IFRS 9 – Financial Instruments which addresses the classification and measurement requirements of financial assets. The standard was amended in October 2010 to include the requirements for the classification and measurement of financial liabilities. The changes are effective for annual periods beginning on or after January 1, 2015 and are to be applied retrospectively. Earlier application is permitted.

3. Use of judgments and estimates:

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

Critical judgments in applying accounting policies

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

Non-financial assets

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

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(g), 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 15.

Key sources of estimation uncertainty

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

Financial instruments

The valuation of the Company's derivative instruments and certain other financial instruments requires estimation of the fair value of each instrument at the reporting date. Details of the basis on which fair values are estimated are provided in notes 14 and 29.

Non-financial assets

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.

For determining purchase price allocations for business combinations, the Company is required to estimate the fair value of acquired assets and obligations. 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. Goodwill acquired in an acquisition is, from the date of acquisition, allocated to each of the CGUs that are expected to benefit from the acquisition.

Estimates of fair value for the recoverable amount of CGUs undergoing impairment testing, and for purchase price allocations for business combinations, are primarily based on discounted cash flow projection techniques employing estimated future cash flows based on assumptions regarding the expected market outlook and cash flows from each CGU or asset. The cash flow estimates will vary with the circumstances of the particular assets or CGU and will be based on, among other things, the lives of the assets, contract prices, estimated future prices, revenues and expenses, including growth rates and inflation, and required capital expenditures. Details of the key estimates used in assessing the recoverable amount of each CGU at the last impairment review date are provided in note 28. Market capitalization and comparative market multiples, where available, are used to corroborate management's discounted cash flow projections.

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

3. Use of judgments and estimates, continued:

Key sources of estimation uncertainty, continued

Decommissioning and other provisions

Measurement of the Company's provisions and the related change in discount rate require the use of estimates with respect to the amount and timing of asset retirements, the extent of site remediation required and related future cash flows for the decommissioning provisions and estimates of expected customer renewals for the Company's other provisions. The key assumptions used in determining these provisions are provided in note 23.

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 17.

Revenue recognition

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

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. Expenses:

	2012	2011
Included in other raw materials and operating charges		
Research and development costs	$ 1	$ 1
Included in staff costs and employee benefits expense		
Share-based payments (note 28)	3	6
Post-employment defined contribution plan expense	8	9
Post-employment defined benefit plan expense (gain)	3	(1)
Included in depreciation and amortization		
Depreciation of property, plant and equipment (note 19)	198	192
Amortization of intangible assets (note 18)	17	35
Losses on retirement of property, plant and equipment	5	2
Other	1	-
	221	229
Included in other administrative expenses		
Operating lease payments	5	2

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

5. Finance expense:

	2012	2011
Interest expense:		
Interest on borrowings	$ 87	$ 114
Capitalized interest	(23)	(36)
Total interest expense	64	78
Other finance expense:		
(Gain) loss on financial instruments (note 14)	(1)	14
Unwinding of the discount on decommissioning provisions (note 23)	4	5
Other	8	8
Finance expense	$ 75	$ 105

6. Income tax:

	2012	2011
Current income tax		
Current income tax expense	$ 4	$ 5
Deferred income tax		
Relating to previously unrecognized temporary differences	-	(5)
Relating to origination and reversal of temporary differences	17	1
Relating to prior periods	2	1
Relating to tax rate differences	(20)	-
Relating to write-downs of deferred tax assets	(7)	(2)
Total deferred income tax recovery	(8)	(5)
Income tax recovery	$ (4)	$ -

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

	2012	2011
Income before tax	$ 86	$ 188
Income tax at the statutory rates of 25.0% and 26.5% respectively	22	50
Increase (decrease) resulting from		
Amounts attributable to non-controlling interests	(12)	(28)
Amounts relating to gains on acquisitions and disposals	5	(16)
Amounts previously not recognized on investments in subsidiaries	-	(5)
Change in unrecognized tax benefits	(7)	(2)
Non-deductible amounts	5	-
Prior period tax adjustments	2	1
Statutory and other rate differences	(20)	-
Other	1	-
Income tax recovery	$ (4)	$ -

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

7. 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:

	2012	2011
Income for the period attributable to shareholders of the Company	$ 62	$ 77
Preferred share dividends of the Company [1]	(6)	(6)
Earnings used in the calculation of basic earnings per share	$ 56	$ 71

[1] Includes preferred share dividends declared in respect of the years ended December 31, 2012 and 2011 respectively.

	2012	2011
Weighted average number of common shares used in the calculation of basic earnings per share	66,818,697	44,253,610

Diluted earnings per share

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

	2012	2011
Earnings used in the calculation of basic earnings per share	$ 56	$ 71
Effect of exchangeable limited partnership units issued to EPCOR for common shares [2]	-	73
Earnings used in the calculation of diluted earnings per share	$ 56	$ 144

[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, 2012, the potential exchange of such units for common shares of the Company were not included in the calculation of diluted earnings per share as they were anti-dilutive. For the year ended December 31, 2011 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 $89 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 taxes of $16 million.

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:

	2012	2011
Weighted average number of common shares used in the calculation of basic earnings per share	66,818,697	44,253,610
Effect of dilutive share purchase options [3]	-	133,446
Effect of exchangeable limited partnership units issued to EPCOR for common shares	-	46,130,521
Weighted average number of common shares used in the calculation of diluted earnings per share	66,818,697	90,517,577

[3] For the year ended December 31, 2012, the average market price of the Company's common shares was below the exercise price of all granted share purchase options described in note 28 and as a result none of the share purchase options had a dilutive effect on earnings per share. For the year ended December 31, 2011, the average market price of the Company's common shares exceeded the exercise price of certain of the granted share purchase options described in note 28 and as a result had a dilutive effect on earnings per share.

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

8. Disposal of assets:

The gains recognized on disposals of assets were as follows:

	2012	2011
Hydro assets	$ 15	$ -
CPILP	-	89
Other	-	4
Gains on disposals	$ 15	$ 93

On October 12, 2012, the Company completed a transaction with a third party, pursuant to which the third party acquired all of the partnership units of the indirect subsidiary of the Company which held its remaining hydro plant assets, consisting of the Brown Lake and Miller Creek power generation plants (the hydro assets), for gross proceeds of $69 million less transaction costs of $1 million.

Upon close of the transaction, $59 million of the gross proceeds was received by the Company in cash and $10 million of the gross proceeds was paid to a third party escrow agent. These funds will be held in escrow pending the issuance of a new lease, by the Province of British Columbia to the purchaser, in respect of certain lands included in the hydro assets. As long as the new lease does not contain variations from the previous lease that significantly impact the economic value of the hydro assets, the full amount will be released to the Company. Subsequent to the end of 2012, the third party to the transaction has indicated that, in their opinion, the new lease is substantially different from the previous lease. The Company does not agree with this assessment and expects to receive the full amount of the escrow payment.

The carrying amounts of the assets and liabilities of the hydro assets at the time of disposal were as follows:

	2012
Trade and other receivables	$ 1
Intangible assets	4
Property, plant and equipment	56
Deferred tax liabilities	(4)
Provisions – non-current	(4)
Carrying amount of net assets disposed	$ 53

9. Business combinations:

Prior year acquisitions of Bridgeport, Tiverton and Rumford

The purchase price allocations pertaining to the 2011 acquisitions of Bridgeport Energy, LLC (Bridgeport Energy) and Tiverton Power Inc. and Rumford Power Inc. (Tiverton and Rumford) were finalized during 2012 resulting in a decrease of $2 million in trade and other receivables and an increase in goodwill of $2 million related to Bridgeport Energy, and an increase of $2 million in deferred tax assets and a decrease of $2 million in goodwill related to Tiverton and Rumford, from the amounts reported at December 31, 2011.

10. Impairment testing:

The Company reviews its CGUs that contain goodwill on an annual basis, generally in the third quarter, to determine whether an impairment should be recognized. The last impairment review was completed in the second quarter of 2012 for the North East U.S. commercial plants and portfolio optimization CGU (North East U.S. CGU), and in the third quarter of 2012 for the Southport CGU.

Impairments recognized in the years ended December 31, 2012 and 2011, respectively, were as follows:

	2012	2011
Property, plant and equipment (note 19)	$ 50	$ -
Goodwill (note 20)	24	-
Intangibles (note 18)	-	43
Total impairments	$ 74	$ 43

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

10. Impairment testing, continued:

North East U.S. CGU

In conjunction with the Company's long-term forecasting activities, the Company reduced its expected future operating margins for its North East U.S. CGU which includes the Bridgeport, Tiverton and Rumford power generation plants. The reductions to the expected operating margins were largely a result of weakening spark spreads in the New England power market. Spark spreads represent the difference between spot market fuel and power prices and impact the profitability of the Company's North East U.S. plants which sell power into the spot market.

Based upon the above indicator of impairment, the Company tested its North East U.S. CGU for impairment and as a result, recorded $74 million of pre-tax impairments during 2012 within the U.S. geographic area.

Southport CGU

The estimated recoverable amount of the Southport CGU exceeded its carrying amount and as such no impairment was required.

Key assumptions used in calculating recoverable amounts

The recoverable amounts of the North East U.S. and Southport CGUs were based on the respective CGU's fair value less costs to sell, calculated using a discounted cash flow method. The calculation of the recoverable amounts for each CGU is sensitive to several key assumptions as described below.

Discount rates and growth rates

The after-tax discount rates used ranged within the respective CGUs and reflect the market weighted average cost of capital (WACC) using a capital asset pricing model approach, giving consideration to the risks specific to each 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 lives of each 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 amounts for each CGU were as follows:

	North East U.S. CGU		Southport CGU	
	2012	2011	2012	2011
Discount rate	10.4% to 13.8%	11.4% to 15.1%	7.5% to 10.5%	7.6% to 10.8%
Growth rate	2.0%	2.0%	2.0%	2.0%

Future electricity and natural gas prices and other fuel costs

The Company's cash flow projections include estimates of future electricity and natural gas prices and other fuel costs. These estimates incorporate past experience and the Company's current view of future pricing. Consideration is given to externally available information related to future pricing of electricity, natural gas and fuel inputs when developing certain pricing assumptions and such external information is used to validate the Company's current view of future pricing. These external sources of information include market information from the independent system operators in the respective regions and information from third party advisory and research firms serving the industry.

Connecticut Electric Generation Tax

As at the impairment testing date and as at December 31, 2012, the Connecticut Electric Generation Tax (CEG Tax) was effective through the second quarter of 2013 and the Company's calculations of the recoverable amount for the North East U.S. CGU assumed that this tax would no longer apply after that time. Subsequent to December 31, 2012, it was proposed that the CEG tax be extended through 2015. Based on the sensitivity analysis prepared by the Company at the time of testing, such an extension of the CEG Tax would not have changed the impairment recorded on the North East U.S. CGU.

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

11. Cash and cash equivalents:

	December 31, 2012	December 31, 2011
Cash and cash equivalents	$ 53	$ 73

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 jointly controlled asset arrangements of $10 million (December 31, 2011 - $20 million).

12. Trade and other receivables:

	December 31, 2012	December 31, 2011
Accrued revenues	$ 135	$ 103
Trade receivables	127	64
Receivables from related parties (note 27)	8	8
Finance lease receivable (note 15)	13	3
Allowance for doubtful accounts (note 30)	(2)	(1)
Net trade receivables	281	177
Income taxes recoverable	13	14
Deposits on acquisition (note 33(b))	50	-
Prepayments	10	7
	$ 354	$ 198

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

13. Inventories:

	December 31, 2012	December 31, 2011
Parts and other consumables	$ 54	$ 50
Coal	18	9
	$ 72	$ 59

Inventories expensed upon usage for the year ended December 31, 2012 of $48 million (year ended December 31, 2011 - $39 million) were charged to energy purchases and fuel, and other raw materials and operating charges. No write-downs of inventories were recognized in the year ended December 31, 2012 (year ended December 31, 2011 - nil). There were no reversals of previous write downs recognized in the year ended December 31, 2012 (year ended December 31, 2011 - nil). As at December 31, 2012, no inventories were pledged as security for liabilities (December 31, 2011 - nil).

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

14. Derivative financial instruments and hedge accounting:

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

The derivative instruments assets and liabilities used for risk management purposes as described in note 30 consist of the following:

	December 31, 2012			
	Energy		Interest rate	
	Cash flow hedges	Non-hedges	Non-hedges	Total
Derivative instruments assets:				
Current	$ 12	$ 35	$ -	$ 47
Non-current	23	7	-	30
Derivative instruments liabilities:				
Current	(2)	(50)	-	(52)
Non-current	(4)	(8)	-	(12)
Net fair value	$ 29	$ (16)	$ -	$ 13
Net notional buys (sells):				
Megawatt hours of electricity (millions)	(6)	-		
Gigajoules of natural gas (millions)	-	2		
Range of contract terms in years	0.1 to 5.0	0.1 to 5.0		

	December 31, 2011			
	Energy		Interest rate	
	Cash flow hedges	Non-hedges	Non-hedges	Total
Derivative instruments assets:				
Current	$ 6	$ 19	$ -	$ 25
Non-current	5	8	-	13
Derivative instruments liabilities:				
Current	(30)	(29)	(8)	(67)
Non-current	(4)	(3)	-	(7)
Net fair value	$ (23)	$ (5)	$ (8)	$ (36)
Net notional buys (sells):				
Megawatt hours of electricity (millions)	(3)	(9)		
Gigajoules of natural gas (millions)	-	(2)		
Bond forwards			$ 200	
Range of contract terms in years	0.1 to 5.0	0.1 to 6.0	0.2	

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

14. 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 as appropriate, in the most advantageous active 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 market quotes or data becomes 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 financial instruments recognized in other comprehensive income and net income were:

	Year ended December 31, 2012		Year ended December 31, 2011	
	Unrealized gains (losses)	Realized gains (losses)	Unrealized gains (losses)	Realized gains (losses)
Energy cash flow hedges	$ 52	$ 14	$ (62)	$ (53)
Energy non-hedges	(11)	24	(41)	(8)
Foreign exchange non-hedges	-	-	(10)	3
Interest rate non-hedges	8	(7)	(2)	(12)

Realized gains and losses relate only to derivative financial instruments. The following items are included in the Company's statements of income for the years ended December 31, 2012 and 2011.

	2012	2011
Revenues	$ 48	$ (142)
Energy purchases and fuel	(21)	39
Foreign exchange losses	-	(6)
Finance expense	1	(14)

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. If hedge accounting requirements are met, realized gains and losses on financial energy derivatives are recorded in revenues or energy purchases and fuel, as appropriate, while unrealized gains and losses are recorded in other comprehensive income. Unrealized and realized gains and losses on financial foreign exchange derivatives are recorded in revenues or foreign exchange gains and losses while such gains and losses on financial interest rate derivatives are recorded in finance expense.

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. For the year ended December 31, 2012, 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, 2011 - losses of $2 million).

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

14. 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, 2012
Within one year	$ 8
Between one and five years	14
After five years	-
	$ 22

The Company's cash flow hedges extend to 2017.

15. Leases:

Finance lease receivables

	Minimum lease payments		Present value of minimum lease payments	
	December 31, 2012	December 31, 2011	December 31, 2012	December 31, 2011
Amounts receivable under finance leases:				
Less than one year	$ 31	$ 5	$ 13	$ 3
Between one and five years	123	18	57	12
More than five years	571	56	404	46
Unearned finance income	(251)	(18)	-	-
Lease payment receivable	474	61	474	61
Less current portion: (included within trade and other receivables (note 12))	13	3	13	3
	$ 461	$ 58	$ 461	$ 58

The PPAs under which the Company's wind generation facilities located in Kingsbridge, Ontario (Kingsbridge) and Tumbler Ridge, British Columbia (Quality Wind) operate expire in 2026 and 2037 respectively and have effective rates inherent in the leases of 3.21% and 3.99% respectively. The lease receivables contain unguaranteed residual values of $13 million and nil for the Kingsbridge and Quality Wind facilities respectively.

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

Finance income of $5 million was recognized in other income during the year ended December 31, 2012 (year ended December 31, 2011 - $4 million).

Plants under operating leases

Certain power generation plants operate under PPAs that convey the right to the holder of the agreement to use the related property plant and equipment. Consequently, these power generation assets held by subsidiaries of the Company, comprised of the Roxboro, Genesee units 1 and 2, Miller Creek, Brown Lake and Island Generation power generation assets are accounted for as assets under operating leases. Miller Creek and Brown Lake were disposed of in October 2012 as described in note 8. During the comparative period, through to the disposal of CPILP in November 2011, the Manchief, Mamquam, Moresby Lake, Kenilworth, Greeley and Williams Lake power generation assets were also accounted for as assets under operating leases.

As at December 31, 2012 the cost of such property, plant and equipment was $1,220 million (December 31, 2011 - $1,250 million), less accumulated depreciation of $186 million (December 31, 2011 - $143 million).

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

15. Leases, continued:

Plants under operating leases, continued

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

	December 31, 2012
Within one year	$ 61
Between one and five years	246
After five years	207
	$ 514

16. Other financial assets:

	December 31, 2012	December 31, 2011
Other financial assets – non-current:		
Loans and other long-term receivables	$ 55	$ 38
Equity investment in jointly controlled entity (note 32)	3	1
Available for sale - portfolio investments	2	3
	$ 60	$ 42
Other financial assets – current:		
Financial assets designated at fair value through income or loss - Atlantic stock	$ -	$ 53

17. Deferred tax:

Deferred tax assets and liabilities are attributable to the following:

	Assets		Liabilities		Net	
	December 31, 2012	December 31, 2011	December 31, 2012	December 31, 2011	December 31, 2012	December 31, 2011
Losses carried forward	$ 59	$ 35	$ -	$ -	$ 59	$ 35
Difference in accounting and tax basis of property, plant and equipment	-	5	(110)	(148)	(110)	(143)
Difference in accounting and tax basis of intangible assets	12	30	(5)	(14)	7	16
Deferred partnership income	18	-	-	(6)	18	(6)
Derivative instruments	12	4	(10)	-	2	4
Share issue costs and deferred financing charges	7	10	-	-	7	10
Long-term receivable	-	-	(4)	-	(4)	-
Deferred revenue and other liabilities	20	14	-	-	20	14
Finance lease receivable	-	-	(84)	(9)	(84)	(9)
Decommissioning provisions	43	38	-	-	43	38
Prepaid reclamation amounts	-	-	(12)	(10)	(12)	(10)
Other provisions	10	9	-	-	10	9
Other assets	2	1	-	-	2	1
Deferred tax assets (liabilities)	$ 183	$ 146	$ (225)	$ (187)	$ (42)	$ (41)
Set off of tax	(113)	(132)	113	132	-	-
Net deferred tax assets (liabilities)	$ 70	$ 14	$ (112)	$ (55)	$ (42)	$ (41)

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

17. Deferred tax, continued:

Movement in temporary differences during the year ended December 31, 2012:

	As at January 1, 2012	Recognized in net income	Recognized directly in other comprehensive income	Amounts relating to gains on acquisitions and disposals	Recognized directly in equity	Reclassified from equity to net income	As at December 31, 2012
Losses carried forward	$ 35	$ 24	$ -	$ -	$ -	$ -	$ 59
Difference in accounting and tax basis of property, plant and equipment	(143)	42	-	(9)	-	-	(110)
Difference in accounting and tax basis of intangible assets	16	(12)	-	3	-	-	7
Deferred partnership income	(6)	24	-	-	-	-	18
Derivative instruments	4	7	(10)	1	-	-	2
Share issue costs and deferred financing charges	10	(6)	-	-	1	2	7
Long-term receivable	-	(4)	-	-	-	-	(4)
Deferred revenue and other liabilities	14	4	-	2	-	-	20
Finance lease receivable	(9)	(74)	-	(1)	-	-	(84)
Decommissioning provisions	38	3	-	2	-	-	43
Prepaid reclamation amounts	(10)	(2)	-	-	-	-	(12)
Other provisions	9	1	2	(2)	-	-	10
Other assets	1	1	-	-	-	-	2
	$ (41)	$ 8	$ (8)	(4)	$ 1	$ 2	$ (42)

Movement in temporary differences during the year ended December 31, 2011:

	As at January 1, 2011	Recognized in net income	Recognized directly in other comprehensive income	Amounts relating to gains on acquisitions and disposals	Recognized directly in equity	Reclassified from equity to net income	As at December 31, 2011
Losses carried forward	$ 96	$ (4)	$ -	$ (60)	$ 3	$ -	$ 35
Difference in accounting and tax basis of property, plant and equipment	(124)	(52)	-	61	(29)	1	(143)
Difference in accounting and tax basis of intangible assets	(23)	6	-	28	5	-	16
Deferred partnership income	(9)	3	-	-	-	-	(6)
Derivative instruments	13	9	5	(24)	1	-	4
Share issue costs and deferred financing charges	9	(1)	-	(1)	5	(2)	10
Long-term receivable	(7)	-	-	7	-	-	-
Deferred revenue and other liabilities	13	4	-	(5)	2	-	14
Finance lease receivable	(6)	(1)	-	-	(2)	-	(9)
Decommissioning provisions	24	27	-	(17)	4	-	38
Prepaid reclamation amounts	(7)	(1)	-	-	(2)	-	(10)
Other provisions	3	6	-	-	-	-	9
Long-term investments	(14)	7	(1)	8	-	-	-
Other assets	(1)	2	-	-	-	-	1
	$ (33)	$ 5	$ 4	(3)	$ (13)	$ (1)	$ (41)

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

17. Deferred tax, continued:

As at December 31, 2012 the Company has non-capital losses carried forward of approximately $178 million (December 31, 2011 - $114 million), of which $160 million (December 31, 2011 - $111 million) relates to certain U.S. subsidiaries. Of the non-capital losses relating to certain U.S. subsidiaries, $101 million (December 31, 2011 - $106 million) are subject to an annual limitation under Internal Revenue Code Section 382. These losses expire between 2024 and 2032. As at December 31, 2012, the Company has no capital losses for income tax purposes (December 31, 2011 - nil). There are non-capital losses available to be carried forward of $17 million (December 31, 2011 - $22 million) and other deductible temporary differences of $119 million (December 31, 2011 - $118 million) for which no tax benefit has been recognized.

18. Intangible assets:

	Alberta PPAs	CPILP PPAs	Contract rights	Customer rights	Other rights	Emission credits	Software	Total
Cost								
As at January 1, 2011	$ 140	$ 388	$ 101	$ 4	$ 74	$ 19	$ 15	$ 741
Additions from separate acquisition	-	-	28	-	33	33	9	103
Disposal of CPILP	-	(394)	(100)	-	-	-	-	(494)
Other disposals	-	-	-	-	-	(20)	-	(20)
Foreign currency translation adjustments	-	6	-	-	-	-	-	6
As at December 31, 2011	$ 140	$ -	$ 29	$ 4	$ 107	$ 32	$ 24	$ 336
Additions from separate acquisition	-	-	7	-	7	36	18	68
Disposal of hydro assets (note 8)	-	-	-	(4)	-	-	-	(4)
Other disposals	-	-	(1)	-	-	(25)	(4)	(30)
As at December 31, 2012	$ 140	$ -	$ 35	$ -	$ 114	$ 43	$ 38	$ 370
Accumulated amortization								
At January 1, 2011	$ (18)	$ (53)	$ (15)	$ -	$ (1)	$ -	$ (3)	$ (90)
Disposal of CPILP	-	70	58	-	-	-	-	128
Other disposals	-	-	-	-	-	-	1	1
Amortization	(13)	(16)	(1)	-	(2)	-	(3)	(35)
Impairments (note 10)	-	-	(43)	-	-	-	-	(43)
Foreign currency translation adjustments	-	(1)	-	-	-	-	-	(1)
As at December 31, 2011	$ (31)	$ -	$ (1)	$ -	$ (3)	$ -	$ (5)	$ (40)
Other disposals	-	-	-	-	-	-	3	3
Amortization	(12)	-	-	-	(2)	-	(3)	(17)
As at December 31, 2012	$ (43)	$ -	$ (1)	$ -	$ (5)	$ -	$ (5)	$ (54)
Net book value								
As at January 1, 2011	$ 122	$ 335	$ 86	$ 4	$ 73	$ 19	$ 12	$ 651
As at December 31, 2011	$ 109	$ -	$ 28	$ 4	$ 104	$ 32	$ 19	$ 296
As at December 31, 2012	$ 97	$ -	$ 34	$ -	$ 109	$ 43	$ 33	$ 316

Acquired PPAs are recorded at the cost of acquisition. Under the terms of the Company's Sundance and Joffre PPAs (Alberta 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 Alberta PPAs are owned under equity syndication agreements with an equity syndicate. Under the terms of the agreements, the syndicate members receive their proportionate share of the committed generating capacity in exchange for their proportionate share of the price paid for the Alberta PPAs and all payments to the generation unit owners.

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

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

18. Intangible assets, continued:

Other rights include the cost of land lease agreements for use in wind 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, 2012 (year ended December 31, 2011 - $43 million). No previous impairments of intangible assets were reversed during the year ended December 31, 2012 (year ended December 31, 2011 - nil).

Capitalized borrowing costs

Borrowing costs were not capitalized on intangible assets during the years ended December 31, 2012 or 2011.

Restrictions on assets

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

19. Property, plant and equipment:

	Construction work in progress	Land	Plant and equipment	Total
Cost				
As at January 1, 2011	$ 890	$ 68	$ 3,023	$ 3,981
Acquisitions through business combinations	-	4	622	626
Additions	445	1	38	484
Additions into service	(974)	16	958	-
Disposal of CPILP	(3)	(5)	(1,002)	(1,010)
Retirements and other disposals	-	-	(32)	(32)
Revisions to decommissioning costs	-	-	45	45
Foreign currency translation adjustments	-	-	61	61
As at December 31, 2011	$ 358	$ 84	$ 3,713	$ 4,155
Additions	504	-	15	519
Additions into service	(359)	17	342	-
Disposal of hydro assets (note 8)	-	-	(71)	(71)
Retirements and other disposals	-	-	(53)	(53)
Transfers to finance lease receivables	(412)	-	-	(412)
Revisions to decommissioning costs	-	-	9	9
Foreign currency translation adjustments	-	-	(20)	(20)
As at December 31, 2012	$ 91	$ 101	$ 3,935	$ 4,127
Accumulated depreciation				
At January 1, 2011	$ -	$ -	$ (303)	$ (303)
Depreciation	-	-	(192)	(192)
Disposal of CPILP	-	-	163	163
Retirements and other disposals	-	-	23	23
Foreign currency translation adjustments	-	-	(4)	(4)
As at December 31, 2011	$ -	$ -	$ (313)	$ (313)
Depreciation	-	-	(198)	(198)
Disposal of hydro assets (note 8)	-	-	15	15
Retirements and other disposals	-	-	43	43
Foreign currency translation adjustments	-	-	4	4
Impairments (note 10)	-	-	(50)	(50)
As at December 31, 2012	$ -	$ -	$ (499)	$ (499)
Net book value				
As at January 1, 2011	$ 890	$ 68	$ 2,720	$ 3,678
As at December 31, 2011	$ 358	$ 84	$ 3,400	$ 3,842
As at December 31, 2012	$ 91	$ 101	$ 3,436	$ 3,628

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

19. Property, plant and equipment, continued:

Impairments

Impairments of $50 million on property, plant and equipment were recognized during the year ended December 31, 2012 (year ended December 31, 2011 - nil) as described in note 10. No reversals of impairments on property, plant and equipment were recognized during the year ended December 31, 2012 (year ended December 31, 2011 - nil).

Capitalized borrowing costs

Details of borrowing costs capitalized as part of property, plant and equipment are given in note 5. The average borrowing rate used to capitalize interest during the year was 5.12% (year ended December 31, 2011 – 5.24%) for projects financed using general borrowings. For the years ended December 31, 2012 and December 31, 2011, there were no projects financed using specific borrowings.

Restrictions on assets

Details of charges over land, plant and equipment are provided in note 22.

20. Goodwill:

	2012	2011
Cost		
As at January 1	$ 46	$ 139
Acquisitions through business combinations	-	23
Disposal of CPILP	-	(118)
Foreign currency translation adjustments	-	2
As at December 31	$ 46	$ 46
Accumulated impairments		
As at January 1	$ -	$ (35)
Disposal of CPILP	-	35
Impairments (note 10)	(24)	-
As at December 31	$ (24)	$ -
Net book value		
As at January 1	$ 46	$ 104
As at December 31	$ 22	$ 46

The aggregate carrying amounts of goodwill allocated to the Company's CGUs are as follows:

	December 31, 2012	December 31, 2011
Southport	$ 20	$ 20
North East U.S.	-	24
Other	2	2
	$ 22	$ 46

Impairments

Impairments of goodwill of $24 million related to the North East U.S. CGU were recorded in the consolidated statement of income for the year ended December 31, 2012 (year ended December 31, 2011 - nil) as described in note 10.

21. Trade and other payables:

	December 31, 2012	December 31, 2011
Operating accruals	$ 115	$ 124
Trade payables	49	55
Dividends and distributions payable	31	31
Accrued interest	15	10
	$ 210	$ 220

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

22. Loans and borrowings:

	Effective interest rate	December 31, 2012	December 31, 2011
CPLP unsecured senior debt payable to EPCOR			
Due in 2016 at 6.75%	6.16%	$ 132	$ 133
Due in 2018 at 5.80%	5.63%	164	164
Due between 2013 and 2018 at 9.00%	7.41%	61	85
Total CPLP debt payable to EPCOR		357	382
Less: current portion		14	25
		343	357
CPLP debt payable to non-related parties			
Unsecured senior medium-term notes, at 4.60%, due in 2015	4.71%	300	300
Unsecured senior medium-term notes, at 4.85%, due in 2019	4.96%	250	-
Unsecured senior medium-term notes, at 5.28%, due in 2020	5.34%	300	300
Unsecured senior notes (US$230), at 5.21%, due in 2021	5.29%	229	234
Unsecured senior notes (US$65), at 5.61%, due in 2026	5.67%	64	66
Non-recourse financing:			
Joffre Cogeneration Project, at 8.59%, due in 2020	8.31%	39	41
Brown Lake Project		-	5
Revolving extendible credit facilities, at floating rates, due in 2017	2.70%	103	165
Revolving extendible credit facilities (US$30), at floating rates, due in 2017	3.55%	30	-
Total CPLP debt payable to non-related parties		1,315	1,111
Less: current portion		5	3
		1,310	1,108
		1,653	1,465
Less: deferred debt issue costs		13	13
		$ 1,640	$ 1,452

Unsecured senior debt payable to EPCOR

The unsecured senior debt payable to EPCOR matures between 2013 and 2018. On or after December 2, 2012, if EPCOR no longer owns, directly or indirectly, at least 20% of the outstanding limited partnership units of CPLP, a subsidiary of Capital Power, then EPCOR may, by written notice, require repayment of all or any portion of the outstanding principal amount of this debt and accrued interest thereon.

CPLP unsecured senior notes

The CPLP unsecured senior medium-term notes of $300 million, $250 million and $300 million are due in 2015, 2019 and 2020 respectively, with interest payable semi-annually.

The CPLP unsecured senior notes aggregating to $293 million (US$295 million) were issued in two tranches. The $229 million (US$230 million) and $64 million (US$65 million) tranches are due in 2021 and 2026 respectively with interest payable semi-annually.

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

22. Loans and borrowings, continued:

Non-recourse financing

Joffre Cogeneration Project financing represents the Company's share of syndicated loans for the project and bears a fixed interest rate of 8.59% payable quarterly until 2020. The debt is secured by a charge against project assets which have a carrying amount of $69 million.

CPLP revolving extendible credit facilities

Unsecured credit facilities of $700 million, committed to 2017 and uncommitted amounts of $20 million, are available to the Company's subsidiary, CPLP. As at December 31, 2012, the Company has $93 million in bankers' acceptances outstanding under these facilities (December 31, 2011 - $165 million). The Company also has $20 million (US$20 million) in U.S. LIBOR loans (December 31, 2011 – nil) and $10 million (US$10 million) in U.S. base rate loans (December 31, 2011 – nil) outstanding under these facilities. Additional uncommitted amounts of $5 million are available to the Company and are undrawn at December 31, 2012 (December 31, 2011 - nil).

The Company also has unsecured credit facilities of $500 million available through its CPLP subsidiary. These facilities have a maturity date of July 9, 2017. As at December 31, 2012, $10 million in bankers' acceptances have been drawn on these facilities (December 31, 2011 - nil), and letters of credit of $208 million (December 31, 2011 - $187 million) have been issued as described in note 34.

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. Depending on CPLP's credit rating, 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 0.10% to 1.25%. 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 1.10% to 2.25% based on CPLP's credit rating.

23. Provisions:

	December 31, 2012	December 31, 2011
Decommissioning	$ 173	$ 157
Employee benefits	52	43
Other	13	30
	238	230
Less: current portion	24	33
	$ 214	$ 197

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

23. Provisions, continued:

	Decommissioning	Employee benefits	Other	Total
As at January 1, 2011	$ 124	$ 30	$ 21	$ 175
Additional liabilities incurred	38	31	9	78
Liabilities settled	(1)	(16)	-	(17)
Amounts reversed unused	(3)	(2)	(2)	(7)
Foreign currency translation adjustments	3	-	-	3
Revisions to decommissioning costs	45	-	-	45
Unwinding of the discount	5	-	-	5
Settlement on CPILP disposal	(54)	-	-	(54)
Additional liabilities incurred on CPILP disposal	-	-	2	2
As at December 31, 2011	$ 157	$ 43	$ 30	$ 230
Additional liabilities incurred	9	32	1	42
Liabilities settled	(1)	(21)	(9)	(31)
Amounts reversed unused	-	(2)	(9)	(11)
Foreign currency translation adjustments	(1)	-	-	(1)
Revisions to decommissioning costs	9	-	-	9
Unwinding of the discount	4	-	-	4
Settlement on disposal of hydro assets (note 8)	(4)	-	-	(4)
As at December 31, 2012	$ 173	$ 52	$ 13	$ 238

Decommissioning provisions

The Company has recorded decommissioning provisions for its power 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 estimates the undiscounted amount of cash flow required to settle its decommissioning obligations is approximately $331 million, calculated using inflation rates ranging from 2% to 3%. The expected timing for settlement of the obligations is between 2013 and 2066, which reflects the anticipated useful lives of the different power plants. The majority of the payments to settle the obligations are expected to occur between 2032 and 2066 for the power generation plants and between 2013 and 2019 for sections of the Genesee coal mine. Discount rates used to calculate the carrying amount of the obligation ranged from 1.14% to 2.95%. The actual 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, acquired as part of the July 1, 2009 acquisition of assets from EPCOR Utilities Inc. 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 2013 to 2046 and the costs were discounted using risk free rates between 1.10% and 2.46%. 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 gas.

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

24. Share capital:

Authorized shares

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

Issued, called up 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, 2011	30,980,500	$ 698	5,000,000	$ 122	47,416,000	$ -
Shares issued [1]	18,515,000	463	-	-	-	-
Share issue costs	-	(20)	-	-	-	-
Deferred taxes on share issue costs	-	5	-	-	-	-
Shares exchanged [2]	9,200,000	224	-	-	(9,200,000)	-
Share purchase options exercised (note 28)	273,507	7	-	-	-	-
As at December 31, 2011	58,969,007	$ 1,377	5,000,000	$ 122	38,216,000	$ -
Shares issued	-	-	6,000,000	150	-	-
Share issue costs	-	-	-	(5)	-	-
Deferred taxes on share issue costs	-	-	-	1	-	-
Shares exchanged [2]	9,775,000	230	-	-	(9,775,000)	-
Share purchase options exercised (note 28)	348,349	9	-	-	-	-
Dividend reinvestment plan	863,337	19	-	-	-	-
As at December 31, 2012	69,955,693	$ 1,635	11,000,000	$ 268	28,441,000	$ -

[1] Shares issued include issuances of 9,200,000 and 9,315,000 shares at $25.10 and $24.90 per common share respectively. Subsequent to these issuances, matching numbers of common limited partnership units of CPLP were issued to another subsidiary of the Company.

[2] A subsidiary of EPCOR exchanged 9,775,000 (year ended December 31, 2011 - 9,200,000) of their 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 9,775,000 common shares (year ended December 31, 2011 - 9,200,000) of Capital Power at an offering price of $23.55 per common share (year ended December 31, 2011 - $24.40).

There were no transactions in respect of the special voting limited share during the years ended 2012 and 2011 (December 31, 2012 and 2011 - 1 issued, nil).

On December 18, 2012, the Company issued 6 million Cumulative Rate Reset Preferred Shares, series 3 (Series 3 Shares) priced at $25.00 per share for gross proceeds of $150 million, less issue costs of $5 million. Deferred tax assets of $1 million related to the share issue costs were recorded in the preferred share balance. The preferred shares pay fixed cumulative dividends of $1.15 per share per annum, yielding 4.60% per annum, payable on the last business day of March, June, September and December of each year, as and when declared by the board of directors of Capital Power, for the initial period ending December 31, 2018. The 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.

24. Share capital, continued:

Holders of Series 3 Shares will have the right to convert all or any part of their shares into Cumulative Floating Rate Preference Shares, Series 4 (Series 4 Shares), subject to certain conditions, on December 31, 2018 and on December 31 of every fifth year thereafter. Holders of Series 4 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 3.23%, as and when declared by the board of directors of Capital Power.

The Company's 5 million Cumulative Rate Reset Preferred Shares, series 1 (Series 1 Shares) pay fixed cumulative dividends of $1.15 per share per annum, yielding 4.60% per annum, payable on the last business day of March, June, September and December of each year, as and when declared by the board of directors of Capital Power, for the initial five-year period ending December 31, 2015. The 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%. The Series 1 Shares are redeemable by Capital Power, at its option, on December 31, 2015 and on December 31 of every fifth year thereafter.

Holders of Series 1 Shares will have the right to convert all or any part of their shares into Cumulative Floating Rate Preference Shares, Series 2 (Series 2 Shares), subject to certain conditions, on December 31, 2015 and on December 31 of every fifth year thereafter. Holders of Series 2 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%, as and when declared by the board of directors of Capital Power.

The special voting shares and special limited voting shares were issued to a related party, EPCOR (including subsidiaries of 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 share holders 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 CPC common shares and CPLP exchangeable LP units (exchangeable for CPC common shares). The special voting share holders 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 CPC common shares and CPLP exchangeable LP units.

For the year ended December 31, 2012, dividends of $85 million or $1.26 per share have been declared and dividends of $81 million or $1.26 per share have been paid by the Company to the common shareholders (year ended December 31, 2011 - $60 million or $1.26 per share declared and $51 million or $1.26 per share paid). Dividends paid to common shareholders included cash payments of $62 million (year ended December 31, 2011 - $51 million) and dividends reinvested of $19 million (year ended December 31, 2011 – nil). For the year ended December 31, 2012, dividends of $6 million or $1.15 per share have been declared and paid by the Company to preferred shareholders (year ended December 31, 2011 - $6 million or $1.19 per share declared and paid).

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

25. Other reserves:

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

Cash flow hedging

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 gain or loss on the hedging instrument is reclassified to income or loss only when the hedged transaction affects the income or loss, or is included as a basis adjustment to the non-financial hedged item, consistent with the relevant accounting policy.

Cumulative translation reserve

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

Equity settled employee benefits

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 in note 28.

26. Change in non-cash working capital:

	2012	2011
Trade and other receivables	$ (105)	$ 74
Inventories	(14)	3
Trade and other payables	(12)	(50)
Deferred revenue and other liabilities	-	4
Provisions	(9)	11
	$ (140)	$ 42

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

27. Related party balances and transactions:

Nature of transactions

Sales to 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 32, the Company has a number of joint ventures, primarily for the construction and operation of power generation facilities. The joint ventures provide energy to the Company and the Company provides management and operation services to the joint ventures. Transactions with joint ventures are eliminated to the extent of the Company's interest in the joint venture.

Prior to the acquisition of assets and liabilities by the Company from EPCOR, the assets and operations of the Company were a part of the EPCOR consolidated entity and certain subsidiaries of the Company were subsidiaries of EPCOR. EPCOR holds 28.441 million (December 31, 2011 - 38.216 million) exchangeable limited partnership units of CPLP (exchangeable for common shares of Capital Power on a one-for-one basis) representing approximately 29.3% of CPLP (December 31, 2011 - 39.4%). 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, 2012 and December 31, 2011 between the Company and its related parties:

	2012	2011
Revenues – energy sales:		
EPCOR and City of Edmonton [1]	$ 45	$ 273
Energy purchases and fuel:		
EPCOR [2]	22	23
Other raw materials and operating charges:		
EPCOR	6	2
Other administrative expenses:		
EPCOR	-	5
Finance expense:		
EPCOR [3]	20	30

[1] Energy sales of $9 million (year ended December 31, 2011 - $239 million) to EPCOR and its subsidiaries, and $36 million (year ended December 31, 2011 - $34 million) to the City of Edmonton.

[2] Energy purchases and fuel include energy distribution and transmission charges from subsidiaries of EPCOR.

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

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

27. Related party balances and transactions, continued:

	December 31, 2012	December 31, 2011
Trade and other receivables from related parties:		
EPCOR and City of Edmonton [1]	$ 8	$ 8
Intangible assets:		
EPCOR [2]	7	7
Property, plant and equipment:		
EPCOR [3]	5	8
Trade and other payables to related parties:		
EPCOR [4]	17	22
Current provisions:		
EPCOR [5]	-	3
Non-current provisions:		
EPCOR [5]	4	4
Loans and borrowings from related parties (including current portion):		
EPCOR (note 22)	357	382
Share capital:		
EPCOR (note 24)	-	-

[1] Trade and other receivables includes $1 million (December 31, 2011 - $1 million) relating to energy sales to subsidiaries of EPCOR, and $7 million (December 31, 2011 - $7 million) related to energy sales to the City of Edmonton.

[2] Contributions made to subsidiaries of 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, 2011 - $6 million) and distributions payable to EPCOR of $9 million as at December 31, 2012 (December 31, 2011 - $12 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 $39 million to EPCOR for the year ended December 31, 2012 (year ended December 31, 2011 - $57 million). CPLP paid distributions of $42 million to EPCOR in the year ended December 31, 2012 (year ended December 31, 2011 - $60 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 (2011 - nil).

Details of any commitments between CPC and its related parties are disclosed in note 33.

Compensation of key management personnel

	2012	2011
Short-term employee benefits	$ 5	$ 5
Post-employment benefits	-	1
Termination benefits	1	-
Share-based payments	2	3
	$ 8	$ 9

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)

28. Share-based payments:

Share purchase options

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

In March 2012, the Company granted 1,449,568 share purchase options with one third vesting on March 26 of each of 2013, 2014 and 2015. The fair values of these options at grant date were $1.47, $1.52 and $1.56 per option for the 2013, 2014 and 2015 tranches respectively. Granted options may be exercised within 7 years of the grant date at a price of $24.27 per share.

In March 2011, the Company granted 1,445,457 share purchase options with one third vesting on March 21 of each of 2012, 2013 and 2014. The fair values of these options at grant date were $2.05, $2.14 and $2.23 per option for the 2012, 2013 and 2014 tranches respectively. Granted options may be exercised within 7 years of the grant date at a price of $24.90 per share.

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

	Share purchase options issued in: 2012	2011
Share price at grant date	$ 24.27	$ 24.90
Expected volatility [1]	14%	16%
Expected option life [2]	4.5 years	4.5 years
Expected dividend yield	5.19%	5.06%
Risk-free interest rate [3]	1.26%	2.33%
Exercise price	$ 24.27	$ 24.90
Expiry date	March 26, 2019	March 21, 2018

[1] Volatility has been 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 2012 and 2011:

	2012		2011	
	Number of options	Weighted average exercise price	Number of options	Weighted average exercise price
Options outstanding, as at January 1	3,930,334	$ 23.50	3,093,893	$ 22.81
Granted	1,449,568	24.27	1,445,457	24.90
Exercised [4]	(348,349)	23.04	(273,507)	22.90
Forfeited	(645,841)	23.80	(335,509)	23.61
Options outstanding, as at December 31	4,385,712	$ 23.75	3,930,334	$ 23.50
Vested options outstanding, as at December 31	2,118,107	$ 23.20	1,515,331	$ 22.91

[4] The weighted average share price at the date of exercise was $24.88 (2011 - $25.15).

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

28. Share-based payments, continued:

During the year ended December 31, 2012, the Company recorded compensation expenses of $2 million related to share purchase options in staff costs and employee benefits expense (year ended December 31, 2011 - $3 million).

The weighted average remaining contractual life of the Company's outstanding share purchase options as at December 31, 2012 is 4.9 years (December 31, 2011 - 5.3 years). The exercise prices of share purchase options outstanding as at December 31, 2012 and December 31, 2011 range from $22.50 to $24.90.

Performance share units

Capital Power Corporation 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 have a three-year vesting period from the grant date. Upon vesting, participants receive payments based on the number of units that vest including dividend equivalents with an ending value based on the prevailing market price at vesting. PSUs will be paid in cash based on the Company's share performance relative to a group of peer organizations ranging from 50 percent to 150 percent times the market price of the PSU at the release date.

	2012	2011
PSUs outstanding, as at January 1	251,490	153,240
Granted [1]	152,048	146,896
Exercised [2]	(15,631)	(19,416)
Dividends reinvested	19,380	12,650
Forfeited	(50,354)	(41,880)
PSUs outstanding, as at December 31	356,933	251,490

[1] The fair value of the PSUs at the grant date was $24.28 (2011 - $24.84)

[2] The weighted average share price at the date of exercise was $22.43 (2011 - $24.89).

During the year ended December 31, 2012, the Company recorded compensation expenses of $1 million (year ended December 31, 2011 - $2 million) related to the outstanding PSUs 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 may receive their annual equity retainer in the form of DSUs. Directors are entitled to elect to receive their annual retainer, committee retainer, and/or committee chair retainer in full or partial DSUs. Directors will receive additional DSUs in respect of dividends payable on common shares of the Company based on the value of a DSU at that time. During the year ended December 31, 2012, the Company recorded compensation expenses of less than $1 million (year ended December 31, 2011 - $1 million) related to the outstanding DSUs in staff costs and employee benefits expense.

29. Financial instruments:

Fair values

Details of the fair values of the Company's derivative instruments are described in note 14.

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 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.

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

29. Financial instruments, continued:

Fair values, continued

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

	December 31, 2012		December 31, 2011	
	Carrying amount	Fair value	Carrying amount	Fair value
Other financial assets (note 16)				
Loans and receivables	$ 55	$ 55	$ 38	$ 37
Financial assets designated at fair value through income or loss (note 16)	-	-	53	53
Finance lease receivable (note 15)				
Loans and receivables	461	374	58	50
Loans and borrowings (note 22)				
Other financial liabilities (includes current portion)	1,659	1,676	1,480	1,571

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, 2012 and December 31, 2011.

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, 2012 and December 31, 2011. 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.

Fair value hierarchy

Fair value represents the Company's estimate of the price at which a financial instrument could be exchanged between knowledgeable and willing parties in an orderly arm's length transaction under no compulsion to act. Fair value measurements recognized in the consolidated statement of financial position are categorized into levels within a fair value hierarchy based on the nature of the valuation inputs and precedence is given to those fair value measurements calculated using observable inputs over those using unobservable inputs. The determination of fair value requires judgment and is based on market information where available and appropriate. The following levels were established for each input:

- Level 1: Fair value is based on quoted prices (unadjusted) in active markets for identical instruments. Financial instruments 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.

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

29. Financial instruments, continued:

Fair value hierarchy, continued

- 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 financial instruments that are valued using commonly used valuation techniques, such as a discounted cash flow model or the Black-Scholes option pricing models. 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. Financial instruments classified in Level 2 include commodity and foreign exchange derivatives whose values are determined based on broker quotes, observable trading activity for similar, but not identical instruments, and prices published on information platforms and exchanges.
- 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 financial instruments 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. Financial instruments classified in Level 3 include long-dated commodity derivatives, commodity contracts involving non-standard features, transmission and commodity based options, and credit derivatives whose values are in part determined based on historical data such as plant operation costs, credit default probabilities, transmission congestion, demand profiles, volatilities and correlations between products derived from historical prices.

The fair value measurement of a financial instrument 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 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 described above:

	December 31, 2012			
	Level 1	Level 2	Level 3	Total
Derivative financial instruments assets				
Commodity derivatives	$ 25	$ 52	$ -	$ 77
Derivative financial instruments liabilities				
Commodity derivatives	(30)	(18)	(16)	(64)

	December 31, 2011			
	Level 1	Level 2	Level 3	Total
Other financial assets	$ 53	$ -	$ -	$ 53
Derivative financial instruments assets				
Commodity derivatives	-	37	1	38
Derivative financial instruments liabilities				
Commodity derivatives	(1)	(63)	(2)	(66)
Interest rate derivatives	-	(8)	-	(8)
	$ (1)	$ (71)	$ (2)	$ (74)

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

29. Financial instruments, continued:

Fair value hierarchy, continued

There were no significant transfers between Level 1 and 2 for the years ended December 31, 2012 and 2011.

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

	2012	2011
As at January 1 [1]	$ (1)	$ 12
Unrealized and realized losses included in net income [2]	(23)	(13)
Settlements [3]	8	-
As at December 31	$ (16)	$ (1)
Total unrealized losses for the year included in net income	$ (15)	$ (13)

[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.

[3] Relates to settlement of financial derivative instruments.

All instruments classified as level 3 are derivative type instruments, which include financial and non-financial commodity contracts, financial commodity and transmission options, and credit derivatives. Gains and losses associated with Level 3 balances may not necessarily reflect the underlying exposures of the Company. As a result, unrealized gains and losses from Level 3 financial instruments are often offset by unrealized gains and losses on financial instruments that are classified in Levels 1 or 2.

For the significant financial instruments, the Company performs a sensitivity analysis for fair value measurements classified as Level 3, substituting the unobservable inputs with one or more reasonably possible alternative assumptions, if available, to the valuation models. The sensitivity analyses reflected a negligible difference compared with the fair value used to record financial instruments classified in Level 3.

30. Risk management:

Risk management overview

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

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. Capital Power's Audit Committee of the Board of Directors, in its oversight role, monitors the assessment of risk management controls and procedures to ensure compliance with applicable policies.

30. Risk management, continued:

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, Ontario and the U.S. The Company's energy procurement activities consist of power generation, non-market traded and market traded electricity and 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 variously:

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

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

The fair value of the Company's energy related derivatives as at December 31, 2012, that are required to be measured at fair value with the respective changes in fair value recognized in net income are disclosed in note 14.

30. Risk management, continued:

Market risk, continued

Commodity price risk, continued

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, 2012, there is a 99% probability that unfavourable daily market variations would not reduce the trading portfolio by more than $6 million.

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.

30. 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.

As at December 31, 2012, holding all other variables constant, a $0.10 strengthening or weakening of the Canadian dollar against the U.S. dollar would not have a significant impact on net income attributable to common shareholders. 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, financial instruments that are non-monetary items, 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, 2012, the proportion of fixed rate loans and borrowings was approximately 92% of total loans and borrowings outstanding (December 31, 2011 - 89%). The Company may also use derivative instruments to manage interest rate risk. As at December 31, 2012, the Company did not hold any interest rate derivatives.

Assuming that the amount and mix of fixed and floating rate loans and borrowings and net loans and borrowings remains unchanged from that held as at December 31, 2012, a 100 basis point decrease or increase to interest rates would not have a significant impact on full year net income attributable to common shareholders 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. There would be no impact on net income for loans and borrowings issued and held by the Company at fixed 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 and 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)

30. 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, 2012	December 31, 2011
Cash and cash equivalents	$ 53	$ 73
Trade and other receivables [1]	354	198
Derivative financial instruments assets [1]	77	38
Loans and other long-term receivables	55	38
Finance lease receivables	461	58
Loan commitments to third parties	-	6
	$ 1,000	$ 411

[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 $240 million (December 31, 2011 - $104 million) for generation and $191 million (December 31, 2011 - $132 million) for wholesale at December 31, 2012.

This table does not take into account collateral held. As at December 31, 2012, the Company held cash deposits of $6 million (December 31, 2011 - $5 million) as security for certain counterparty trade and other receivables and derivative contracts. The Company is not permitted to sell or re-pledge this collateral in the absence of default of the counterparties providing the collateral. As at December 31, 2012, the Company also held other forms of credit enhancement in the forms of letters of credit of $53 million (December 31, 2011 - $26 million), property registrations valued at $34 million (December 31, 2011 - $24 million) and parental guarantees of $957 million (December 31, 2011 - $960 million) related to the financial assets noted above. As at December 31, 2012 and December 31, 2011, the Company also held parental guarantees which do not have a defined 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 derivative instruments, and provide 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.

30. Risk management, continued:

Credit risk, continued

Loans and long-term financing

As at December 31, 2012 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.

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.

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

30. Risk management, continued:

Credit risk, continued

Trade and other receivables and allowance for doubtful accounts, continued

The aging of trade and other receivables was:

	Gross trade and other receivables	Allowance for doubtful accounts	Net trade and other receivables
Current [1]	$ 322	$ -	$ 322
Outstanding 30 - 60 days	24	-	24
Outstanding greater than 90 days	10	2	8
	$ 356	$ 2	$ 354

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

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

	2012	2011
As at January 1	$ 1	$ 1
Amounts reversed unused	(1)	-
New allowance	2	-
As at December 31	$ 2	$ 1

Bad debt expenses (net of recoveries) of $1 million and nil were recognized in the years ended December 31, 2012 and 2011 respectively.

As at December 31, 2012, the Company held $6 million of customer deposits for the purpose of mitigating the credit risk associated with accounts receivable from customers.

As at December 31, 2012, there was no provision for credit losses associated with trade and other receivables from treasury, trading and energy procurement counterparties as all balances are 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.

CPC 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, 2012, the Company had undrawn bank credit facilities and operating lines of credit and demand facilities, totaling $884 million (December 31, 2011 - $873 million), of which $859 million is committed for at least four years (December 31, 2011 - $848 million committed for at least three years).

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

30. Risk management, continued:

Liquidity risk, continued

In addition to the facilities noted above, the Company, 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, 2012, CPC had a Canadian shelf prospectus, which expires in March 2014, under which it may raise up to $2 billion collectively in common shares of the Company and subscription receipts exchangeable for common shares and/or other securities of the Company. As at December 31, 2012, the amounts available on the shelf prospectus are $1,620 million. In the second quarter of 2012, the Company's subsidiary, CPLP, issued a Canadian shelf prospectus, which expires in July 2014, under which it may raise up to $1 billion in medium-term notes, to replace a previously issued shelf prospectus which expired during the year. As at December 31, 2012 CPLP has not drawn on the newly issued shelf prospectus. In addition the Company has $125 million of preferred shares, outstanding under a short-form prospectus (December 31, 2011 - $125 million).

The following are the undiscounted cash flow requirements and contractual maturities of the Company's financial liabilities, including interest payments, and where applicable, net of financial assets that generate cash inflows to meet cash outflows on financial liabilities as at December 31, 2012:

	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	$ 19	$ 13	$ 314	$ 145	$ 149	$ 1,032	$ 1,672
Interest payments on loans and borrowings	87	86	85	65	58	146	527
Trade and other payables [1]	195	-	-	-	-	-	195
Other current liabilities and deferred revenue	8	-	-	-	-	-	8
Derivative financial liabilities:							
Net commodity contracts for differences	52	6	3	2	2	-	65
Total	$ 361	$ 105	$ 402	$ 212	$ 209	$ 1,178	$ 2,467

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

31. Capital management:

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

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

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

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

31. Capital management, continued:

The following table represents the total capital of the Company:

	December 31, 2012	December 31, 2011
Loans and borrowings (note 22)	$ 1,659	$ 1,480
Cash and cash equivalents (note 11)	(53)	(73)
Net debt	1,606	1,407
Non-controlling interests	829	1,072
Share capital (note 24)	1,903	1,499
Retained earnings and other reserves	20	24
Total equity	2,752	2,595
	$ 4,358	$ 4,002

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:

- 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.

These capital restrictions are defined in accordance with the respective agreements.

For the year ended December 31, 2012, 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, redeem preferred shares, issue new CPLP units, repay existing loans and borrowings or adjust dividends paid to its shareholders.

32. Investments in joint ventures:

Investments in jointly controlled assets

The Company holds 50% interests in the Genesee 3 Project and the Keephills 3 Project, and holds a 40% interest in the Joffre Cogeneration Project.

Under the terms of the Company's interest in the Genesee 3 project and the Keephills 3 Project, the Company and its respective partners have guaranteed financial and performance obligations under the joint arrangements limited to $50 million and $50 million respectively.

Investments in jointly controlled entities

The Company holds a 33% interest in the partnership established to develop, construct and operate the Kingsbridge 2 wind power project (K2 Wind). As at December 31, 2012, the Company has recorded its equity investment in the jointly controlled entity of $3 million (December 31, 2011 - $1 million) within non-current other financial assets. The Company recorded equity losses on its interest in K2 Wind of $1 million during the year ended December 31, 2012 within other administrative expenses (year ended December 31, 2011 - nil).

There are no contingent liabilities relating to Capital Power's interest in the joint ventures described above.

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

33. Commitments and contingencies:

(a) Under the terms of the acquired Alberta PPAs, the Company is obligated to make monthly payments for fixed and variable costs. The estimated annual total of these payments for 2013 is $93 million. It is expected that the annual payments over the remaining terms of the Alberta PPAs, as described in note 18, will range from $93 million to $108 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 and scheduled outages.

(b) The Company has entered into a series of agreements with a third party to purchase a 50% interest in the 800 MW Shepard Energy Centre (Shepard) in southern Alberta. The Company expects to invest approximately $860 million, including capitalized borrowing costs, into Shepard, which is expected to commence commercial operations in 2015. The two parties will build, own and operate Shepard under a joint venture agreement. In conjunction with the joint venture agreement, 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 venture for the years 2015 through 2017 decreasing to 50% of the output for the years 2018 to 2035. As at December 31, 2012, the Company has paid a $50 million deposit into an escrow account, which reduces the Company's total remaining expected investment to $810 million.

(c) The Company's Port Dover & Nanticoke Wind Project (PDNW) will be located in southern Ontario, and developed by a subsidiary of the Company at an expected total cost of $340 million. As at December 31, 2012 the estimated total remaining capital cost to be incurred is $272 million. Energy generated by PDNW will be sold under a 20-year contract with the third party. PDNW is expected to commence commercial operations in 2013.

(d) The K2 wind joint venture, in which the Company holds a 33% interest as described in note 32, will develop, construct and operate the 270 MW K2 Wind Ontario (K2) power project in southern Ontario. K2 has an expected capital cost of $874 million, which will be shared by each of the three venturers equally through their equity interests in the jointly controlled entity. As at December 31, 2012 the estimated total remaining capital cost for the Company's share of the project is $285 million. Energy generated by K2 will be sold under a PPA to a third party. K2 is expected to commence commercial operations in 2015 pending regulatory and other approvals. Included in the estimated remaining capital cost to be incurred by the Company is the Company's $5 million share of a termination payment to a third party outside of this joint venture, for a previous contract related to the construction of wind turbines, that will be required upon receipt of regulatory approval for K2.

(e) The Company has entered into 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	$ 105	$ 10	$ 13	$ 5
Between one and five years	54	49	41	20
After five years	52	69	2	59
	$ 211	$ 128	$ 56	$ 84

[1] Operating lease amounts include $4 million per year through 2031 which will be payable to the Company's related party, EPCOR, for the leasing of office space.

33. Commitments and contingencies, continued:

(f) Capital Power is participating in a 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. On April 16, 2012, the AUC issued its decision that the factors utilized from 2006 to the present time were non-compliant with the applicable legislation and regulations. Capital Power and other Alberta generators subsequently submitted applications to review and vary that decision. The AUC has advised that a future proceeding will (1) consider whether the decision, or part of the decision, should be reviewed and if so, (2) determine whether the decision should be varied and, if so, how. This includes the potential application of alternative factors on a prospective or retrospective basis. Capital Power 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. It is anticipated that the AUC's decision may be issued no sooner than the last half of 2013.

(g) In July 2012, the Sundance plant owner made a force majeure claim for $39 million with respect to the 2011 third quarter outage of Unit 6 due to a transformer failure. The Company has a 52% interest in the Sundance PPA for Units 5 and 6 and thus is contractually responsible for paying its share of the claimed amount in advance of final determination of whether or not a force majeure situation, as specified in the PPA, occurred. Accordingly, Capital Power paid its share of the claimed amount and, based on the Company's view that the claim will not meet the PPA specified force majeure tests, recorded it as an amount receivable until final resolution of the claim. The claim currently is under arbitration which is not expected to issue a decision until 2014. The total amount receivable of $20 million is recorded on Capital Power's December 31, 2012 statement of financial position as a non-current other financial asset and would be reduced by estimated insurance recoveries of $3 million in the event that the arbitration decision resulted in an adverse result for the Company.

(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.

34. Guarantees:

The Company, through its subsidiary CPLP, has issued letters of credit of $208 million (December 31, 2011 - $187 million) to meet the credit requirements of energy market participants, to meet conditions of certain service agreements, and to satisfy legislated reclamation requirements.

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

35. Segment information:

The Company operates in one reportable business segment involved in the operation of electrical generation plants within Canada (Alberta, British Columbia and Ontario) and in the U.S. (Connecticut, Maine, North Carolina and Rhode Island), as this is how management assesses performance and determines resource allocations. The assets disposed of during the year ended December 31, 2012, as described in note 8, operated within Canada (British Columbia). Since the disposal of those assets did not represent the disposal of a separate major line of business or geographic area, the disposal of those assets is not considered a discontinued operation.

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

	Year ended December 31, 2012				Year ended December 31, 2011			
	Canada	U.S.	Inter-area eliminations	Total	Canada	U.S.	Inter-area eliminations	Total
Revenues and other income - external	$ 982	$ 349	$ -	$1,331	$1,311	$ 459	$ -	$1,770
Revenues and other income - inter-area	18	8	(26)	-	3	1	(4)	-
Total revenues and other income	$ 1,000	$ 357	$ (26)	$1,331	$1,314	$ 460	$ (4)	$1,770

	As at December 31, 2012			As at December 31, 2011		
	Canada	U.S.	Total	Canada	U.S.	Total
Property, plant and equipment	$ 2,947	$ 681	$ 3,628	$ 3,043	$ 799	$ 3,842
Intangible assets	298	18	316	276	20	296
Goodwill	-	22	22	-	46	46
Other assets	21	-	21	24	-	24
	$ 3,266	$ 721	$ 3,987	$ 3,343	$ 865	$ 4,208

36. Subsequent event:

On February 28, 2013, the purchase of the first tranche of the Company's interest in Shepard, as described in note 33(b), closed. Upon close of this transaction, the Company paid $237 million and acquired a 25% interest in Shepard. The total amount incurred by the Company to the date of close was $287 million compared to the total anticipated capital cost of $860 million. The second tranche, expected to close in the first quarter of 2014, will result in the Company's acquisition of an additional 25% interest in Shepard, bringing its total ownership interest to 50%. Subsequent to the close of the first tranche, and prior to the close of the second tranche, all decisions related to Shepard will require unanimous approval by the Company and the third party. As a result, the Company jointly controls Shepard with the third party upon close of the first tranche. Based on the terms of the Shepard agreements, the Company will account for the Shepard joint arrangement under the new accounting standard for joint arrangements, as described in note 2(w), as a joint operation.

3-YEAR OPERATIONAL AND FINANCIAL HIGHLIGHTS

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

	2012	2011	2010
Operational			
Number of facilities at year-end(1)	16	16	32
Electricity generation(1) (GWh)	16,374	13,659	9,205
Plant availability average(1) (%)	91%	92%	90%
Financial Position			
Total assets	$5,134	$4,743	$5,296
Loans and borrowings including current portion	$1,659	$1,480	$1,869
Income			
Revenues and other income	$1,331	$1,770	$1,762
Adjusted EBITDA(2)	$441	$485	$418
Net Income	$90	$188	$77
Net income attributable to shareholders	$62	$77	$17
Normalized earnings attributable to common shareholders(2)	$86	$55	$32
Basic earnings per share	$0.84	$1.60	$0.77
Diluted earnings per share(3)	$0.84	$1.59	$0.69
Normalized earnings per share(2)	$1.29	$1.24	$1.40
Cash Flows			
Funds from operations(2,4)	$381	$352	$277
Discretionary cash flow(2)	$132	$131	$110
Cash flow per share(2)	$3.89	$3.89	$3.53
Capital expenditures	$598	$493	$329
Dividend			
Dividends per common share	$1.26	$1.26	$1.26
Payout ratio(5)	47%	45%	47%

Common Share Information (C$ except volume and shares)			
High	$25.72	$28.00	$24.84
Low	$20.75	$21.50	$20.97
Close	$22.73	$25.12	$23.65
Volume traded (millions)	39.7	36.6	17.8
Average daily trading volume (thousands)	158.0	146.4	71.1
Weighted average number of common shares outstanding (millions)	66.8	44.3	22.2

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 three years.

2 The consolidated financial highlights, except for adjusted EBITDA, normalized earnings attributable to common shareholders, normalized earnings per share, funds from operations, cash flow per share, and discretionary cash flow, were prepared in accordance with GAAP. See Non-GAAP Financial Measures in the Management's Discussion and Analysis.

3 Diluted earnings per share was calculated after giving effect to share purchase options and the 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.

4 Excluding non-controlling interests in CPILP.

5 Calculated as dividends per common share divided by adjusted funds from operations (AFFO) per share. AFFO is defined as funds from operations excluding non-controlling interests in CPILP less sustaining capital expenditures.

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2013 Expected Common Share Dividend Dates

	Ex-dividend date	Record date	Payment date
Quarter 1	March 26	March 28	April 30
Quarter 2	June 26	June 28	July 31
Quarter 3	September 26	September 30	October 31
Quarter 4	December 27	December 31	January 31, 2014

2013 Expected Preferred Shares Series 1 & 3 Dividend Dates

	Ex-dividend date	Record date	Payment date
Quarter 1	March 13	March 15	March 28
Quarter 2	June 13	June 17	June 28
Quarter 3	September 13	September 17	September 30
Quarter 4	December 12	December 16	December 31

Auditors
KPMG LLP, Edmonton, Alberta

Stock Exchange and Index Membership
Toronto Stock Exchange (TSX)

Member of S&P/TSX Composite Index (June 2011)

Trading Symbols
Common shares: CPX
Preferred shares:
Series 1 - CPX.PR.A
Series 3 - CPX.PR.C

Total Outstanding Common Shares as of December 31, 2012

Public Float: 69,955,693

Total (fully diluted): 98,396,693

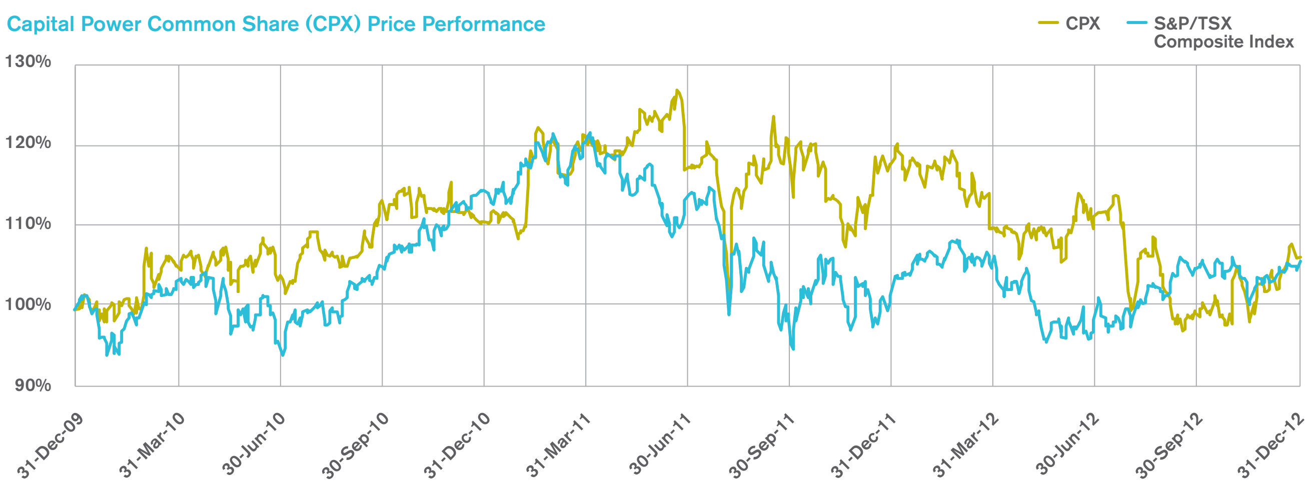
Market capitalization (fully diluted): $2.24 billion

Public float has increased from 28% of fully diluted shares at the Initial Public Offering (IPO) in June 2009 to 71% as of December 31, 2012.

Dividend Reinvestment Plan (DRIP)
Effective January 1, 2012, eligible Capital Power common shareholders can take advantage of our automatic dividend reinvestment plan to acquire additional shares at 95 percent of the average market price without brokerage commissions or service charges.

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

Capital Power Common Share (CPX) Price Performance



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