Capital Power Corporation
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For immediate release March 9, 2010

Capital Power reports fourth quarter 2009 results

EDMONTON, Alberta – Capital Power Corporation (Capital Power, or the Company) (TSX: CPX) released today its financial results for the three and six month periods ended December 31, 2009. Reported net income for the fourth quarter 2009 was $7 million or $0.33 per share. For the six months since completion of the Company's Initial Public Offering, net income was $21 million or $0.97 per share. After adjusting for one-time items and fair value adjustments, normalized earnings per share in the fourth quarter 2009 was $0.18 per share and $0.60 per share for the six months ended December 31, 2009.

"Fourth quarter operating performance was in line with our expectations," said Brian Vaasjo, President and Chief Executive Officer of Capital Power. "With the planned outage at our Genesee 1 plant in the quarter, average plant availability was 92 per cent in the quarter and 94 per cent for the six months. Alberta power prices were significantly lower in the second half of 2009 compared to the same period in 2008. However, a significant portion of the company's merchant production in the latter half of 2009 was hedged at an average price approximately 16 per cent higher than the average spot price for electricity."

"We continue to experience weak power prices in Alberta that are expected to remain low in 2010, mainly due to low natural gas prices," continued Vaasjo. "However, substantially all of the company's merchant production in 2010 has been hedged at an average price above the current forward curve, thereby minimizing the company's exposure to depressed power prices. The long-term fundamentals of the Alberta power market remain positive and Alberta power prices are expected to be amongst the first to recover in North America based on the favourable supply/demand balance."

"In December 2009, we completed the commissioning of the third and final natural gas turbine at the Clover Bar Energy Centre, well ahead of schedule and at a cost approximately $21 million lower than previous estimates, with the facility now at full capacity to provide 243 megawatts of peaking power to the Alberta market," added Vaasjo. "In addition, the construction of the Keephills 3 plant is on track for completion in the second quarter of 2011, providing us with further significant leverage to recovering Alberta power prices. Over and above these initiatives and, in line with our long-term strategy, we continue to evaluate additional opportunities for growth."

Highlights of Capital Power's operational and financial performance included:

Operational and Financial Highlights[1] (unaudited) *(millions of dollars except per share and operational amounts)*	**Three months ended Dec 31, 2009**	**Six months ended Dec 31, 2009**
Electricity generation (GWh)	3,481	7,015
Generation plant availability (%)	92%	94%
Revenues	$497	$1,008
Gross margin[2]	$216	$434
Operating margin[2]	$154	$323
Net income	$7	$21
Earnings per share	$0.33	$0.97
Earnings per share[2] (normalized)	$0.18	$0.60
Dividends declared per share	$0.315	$0.63
Funds from operations[2]	$71	$164
Funds from operations excluding non-controlling interests in CPILP[2]	$49	$119
Capital expenditures	$127	$235

(1) The operational and financial highlights in this press release are derived from and should be read in conjunction with Management's Discussion and Analysis and the Consolidated Financial Statements for the six months ended December 31, 2009, which are available on the Company's website at www.capitalpower.com and on SEDAR at www.sedar.com.

(2) Gross margin, Operating margin, Earnings per share (normalized), Funds from operations and Funds from operations excluding non-controlling interests in CPILP are Non-GAAP financial measures and do not have standardized meanings under GAAP, and therefore, may not be comparable to similar measures used by other enterprises. See "Non-GAAP Financial Measures" in the Company's annual Management's Discussion and Analysis for its year ended December 31, 2009, which are available on the Company's website at www.capitalpower.com and on SEDAR at www.sedar.com.

Recent corporate developments

Sale of Battle River Power Syndicate Agreement

On January 15, 2010, the Company sold its remaining 15% interest in the Battle River Power Syndicate Agreement (PSA) for cash proceeds of $64 million resulting in a pre-tax gain of $28 million and $2 million of associated income taxes. At December 31, 2009, the 15% interest was classified for financial reporting purposes as current assets held for sale.

Two new turbines at Clover Bar Energy Centre

Two new 100 megawatts (MWs) natural gas-fired turbines commenced operations at the Company's Clover Bar Energy Centre; one in September, 2009 and the other in December, 2009. These two units combined with the first unit, which commenced operations in the first quarter of 2008, provide a net capacity of 243 MW for the total facility.

Construction of the final 100-MW unit was completed approximately six months ahead of schedule as the Company was able to capitalize on lessons learned during the construction of Unit 2. The cost of all three units will be approximately $263 million compared to previous estimates of approximately $284 million. The units will contribute to meeting the expected demand for additional peaking generation in Alberta. These new high-efficiency units are also designed to use 85% less water and produce 70% less nitrogen oxides (NOx) than the four turbines in the old Clover Bar plant which was decommissioned in 2007.

Keephills 3 receives funding for carbon capture and storage

Keephills 3 is a joint development and equal ownership project of Capital Power and TransAlta Corporation (TransAlta) for the construction of a 495-MW supercritical coal-fired generation plant at TransAlta's Keephills site. As part of Keephills 3, Capital Power is partnering with TransAlta and Alstom Canada (Alstom) to develop one of the world's largest carbon capture and storage (CCS) projects, Project Pioneer (Pioneer). In October 2009, a letter of intent was signed with the Province of Alberta under which Pioneer will be eligible to receive funding from the province's $2 billion CCS fund. The Government of Canada is also contributing toward the project through its Clean Energy Fund. The first stage of the project is to conduct front-end engineering and design (FEED) studies that will confirm the detailed engineering and economics of the project.

Using Alstom's chilled ammonia process, Pioneer will be designed to capture one million tonnes of greenhouse gas emissions annually. Keephills 3 was designed to reduce greenhouse gas emissions by 18% compared with vintage facilities and Pioneer will deliver a further 31% reduction in Keephills 3's carbon dioxide (CO_2) emissions. The second phase of FEED work for Pioneer is scheduled to be completed by early 2011 (previously June 2010), and will include detailed engineering and procurement planning. The development of Pioneer is not expected to affect the construction schedule for Keephills 3.

In addition to the Pioneer project, Capital Power will complete the FEED work on its pre-combustion CCS project (the Genesee Integrated Gasification Combined Cycle (IGCC) power plant). The FEED project is being conducted in conjunction with the Canadian Clean Power Coalition, in partnership with the Alberta Energy Research Institute and Natural Resources Canada. However, Capital Power does not intend to develop an IGCC facility at this time, primarily because the technology is not economic in today's power price environment.

Update on Keephills 3 project

In October 2009, the Board of Directors of Capital Power and TransAlta approved additional funding and a revised schedule for the Keephills 3 project. The total project cost was revised from approximately $1.8 billion to approximately $1.9 billion and Capital Power's share was correspondingly revised from approximately $903 million to approximately $955 million. The increase primarily relates to additional labour required for the construction of the power island which is the portion of the plant that includes the turbine, boiler, air quality control system, water-treatment plant and control room. The station service transformer began receiving power in November 2009 which signified achievement of the project's first commissioning milestone. Commencement of the plant's commercial operations was rescheduled from the first quarter of 2011 to the second quarter of 2011.

Analyst Conference Call and Webcast

Capital Power will be hosting a conference call and live webcast with analysts on March 10, 2010 at 1:00 pm (ET) to discuss fourth quarter results. The conference call dial-in numbers are: (416) 340-8018 or (866) 223-7781 (toll-free). Interested parties may access the webcast on the Company's website at www.capitalpower.com. An archive of the webcast will be available on the website.

A replay of the conference call will be available following the call at: (416) 695-5800 or (800) 408-3053 (toll-free) and entering pass code 7386730. The replay will be available until 11:59 p.m. (ET) on March 17, 2010.

Forward-looking Information

Certain information in this news release is forward-looking within the meaning of Canadian securities laws as it relates 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.

Forward-looking information in this news release includes, among other things, information relating to: (i) expected timing of commercial operation and project cost of Keephills 3; (ii) the expected improvement in and reduction of current and future plants' environment emission levels and ability to capture future emissions; (iii) expectations for Alberta spot power prices in 2010; (iv) expectation that the Alberta commercial portfolio position in 2010 will reduce exposure to changes in power prices; and (v) the expected total costs for all three units of the Clover Bar Energy Centre.

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 include, but are not limited to: (i) the operation of the Company's facilities; (ii) power plant availability, including those subject to acquired PPAs; (iii) the Company's financial position and credit facilities; (iv) the Company's assessment of commodity and power markets; (v) the Company's assessment of the markets and regulatory environments in which it operates; (vi) weather; (vii) availability and cost of labour and management resources; (viii) performance of contractors and suppliers; (ix) availability and cost of financing; (x) foreign exchange rates; (xi) management's analysis of applicable tax legislation; (xii) the currently applicable and proposed tax laws will not change and will be implemented; (xiii) currently applicable and proposed environmental regulations will be implemented; (xiv) counterparties will perform their obligations; (xv) renewal and terms of PPAs; (xvi) ability to successfully integrate and realize benefits of its acquisitions; (xvii) ability to implement strategic initiatives which will yield the expected benefits; and (xviii) the Company's assessment of capital markets and ability to complete future share offerings.

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 risks and uncertainties include, but are not limited to risks relating to: (i) operation of the Company's facilities; (ii) power plant availability and performance; (iii) unanticipated maintenance and other expenditures; (iv) availability and price of energy commodities; (v) electricity load settlement; (vi) regulatory and government decisions including changes to environmental, financial reporting and tax legislation; (vii) weather and economic conditions; (viii) competitive pressures; (ix) construction; (x) availability and cost of financing; (xi) foreign exchange; (xii) availability and cost of labour, equipment and management resources; (xiii) performance of counterparties, partners, contractors and suppliers in fulfilling their obligations to the Company; (xiv) developments in the North American capital markets; (xv) compliance with financial covenants; (xvi) ability to successfully realize the benefits of acquisitions and investments; and (xvii) the tax attributes of and implications of any acquisitions. If any such risks actually occur, they could materially adversely affect the Company's business, financial condition or results of operations. In that case the trading price of the Company's common shares could decline, perhaps materially.

Readers are cautioned not to place undue reliance on any such forward-looking statements, which speak only as of the date made. Forward-looking statements are provided for the purpose of providing information about management's current expectations, and plans relating to the future. Readers are cautioned that such information may not be appropriate for other purposes. 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.

About Capital Power

Capital Power is a growth-oriented North American independent power producer, building on more than a century of innovation and reliable performance. The Company's vision is to be recognized as one of North America's most respected, reliable and competitive power generators. Headquartered in Edmonton, Alberta, Capital Power has interests in 31 facilities in Canada and the U.S. totaling approximately 3,500 megawatts of generation capacity. Capital Power and its subsidiaries develop, acquire and optimize power generation from a wide range of energy sources.

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CAPITAL POWER CORPORATION

Management's Discussion and Analysis

This management's discussion and analysis (MD&A), dated March 9, 2010, should be read in conjunction with the audited consolidated financial statements of Capital Power Corporation (the Company) and its subsidiaries for the six months ended December 31, 2009, the annual information form (AIF) of Capital Power Corporation dated March 9, 2010 and the cautionary statement regarding forward-looking information which begins on page 57. 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. Financial information for the six months ended December 31, 2009 in this MD&A is based on the audited consolidated financial statements of the Company, which are prepared in accordance with Canadian generally accepted accounting principles (GAAP), and is 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.

Capital Power was incorporated on May 1, 2009 under the *Canada Business Corporations Act* as 7166575 Canada Inc. and changed its name to Capital Power Corporation pursuant to articles of amendment dated May 6, 2009. The Company became a reporting issuer under Canadian securities regulation on June 26, 2009. On July 9, 2009, the Company completed its initial public offering (IPO) and acquisition of power generation assets and operations (the Reorganization) from EPCOR Utilities Inc. (EPCOR), as described under Significant Events. The Company's outstanding share capital on December 31, 2009 consisted of 21.75 million common shares, 56.625 million special voting shares and one special limited voting share.

The Company commenced operations in July 2009 and its first fiscal year ended on December 31, 2009. Accordingly, the Company's audited financial statements for the period ended December 31, 2009 do not include prior year comparative information. To facilitate the analysis of the Company's audited financial statements this MD&A includes unaudited pro forma consolidated financial information for the six months ended December 31, 2008. As the comparative period predates the closing of the IPO, this comparative financial information is provided for reference purposes only and is not intended to be a comprehensive comparison of financial results.

Overview

The Company is among Canada's largest independent power generation companies (as measured by revenue, total assets and capacity), and owns or operates approximately 3,500 megawatts (MW) of power generating capacity in North America. The Company's facilities consist of 31 power plants with geographic, fuel source and counterparty diversification. Many of these facilities were built and commissioned by EPCOR over the last decade, providing the Company with development and construction experience and capability. The Company is constructing 495 MW of additional generation capacity at Keephills, and has other development and acquisition projects in progress which represent approximately 1,000 MW of future capacity.

The Company's performance in the second half of 2009 was in line with management's expectations. Plant availability averaged 94% in the second half of 2009 which was 2% higher than in the corresponding period in 2008. The second unit at Clover Bar Energy Centre commenced operations in September 2009 and the third and final unit commenced operations in December 2009. Construction continued on the Company's major construction projects including Keephills 3 and Capital Power Income L.P.'s (CPILP) North Carolina plants. The separation of Capital Power's business operations from EPCOR and subsequent transition activities also went according to plan.

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 the maintenance requirements of assets in order to ensure high levels of fleet availability. In addition, Capital Power is working with federal and provincial governments to develop technologies that will enhance the feasibility of near-zero emission coal-fired power generation. The Company also remains committed to a culture of zero injury and occupational illness.

Strong and sustainable growth

The Company has a pipeline of projects under construction or development. Building on the success of Genesee 3 and Clover Bar Energy Centre, the Company is building the Keephills 3 facility, representing 495 MW of new generation capacity, of which Capital Power has a 248 MW ownership interest. Keephills 3 is expected to be fully operational in 2011. The Company also 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. As market conditions create new opportunities, the Company expects to capitalize on its experience to seek to acquire high quality assets. For 2010, the Company's target is to commit to at least $500 million of new development or acquisitions. However, 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.

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 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 better meet customer requirements and optimize its portfolio of assets in the Networked Hub in response to factors such as heat rate and commodity prices. Heat rate is the amount of combustible fuel (e.g. natural gas or coal) required to produce a unit of electricity. The Company believes that its approach of managing assets at the hub level improves efficiency and reduces risk through portfolio diversification.

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 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 and Capital Power remains committed to being a leader in the development of technologies that establish or maintain economic or environmental advantages over other power generators.

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 selecting target regions with a preference for markets with favourable reserve margins and spark spreads, regulatory frameworks conducive to competitive power generation, sufficient scale to support the establishment of a Networked Hub of power facilities and liquid trading markets. Reserve margin means the difference between power demand during peak usage periods and the total supply of power available to meet this demand for a particular power market and is generally expressed as a percentage that is calculated as total supply less the peak demand divided by total supply. Spark spread means the theoretical difference between the price of electricity as the output and its energy cost of production.

Based on these criteria for selecting target region markets, Capital Power intends to maintain its existing strong position in Alberta and initially 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 Northeast U.S., including the New York Independent System Operator and the New England Power Pool; and the Southwest U.S., including the California Independent System Operator and Desert Southwest (Arizona and Nevada). In addition, other North American markets, especially where Capital Power has existing operations, will be considered on a case-by-case basis if opportunities arise for the development of contracted facilities. For example, Capital Power expects that long-term contracts from renewable projects will be achievable in both the Ontario and British Columbia markets.

Financial discipline

Capital Power is committed to a policy of financial discipline founded upon operational success, long-term contracting and targeted growth while maintaining an investment-grade credit rating. Capital Power believes that by maintaining a strong financial position with an appropriate dividend yield on its common shares, 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 and maintain a target for contracted plants to provide at least 50% of the Company's total operating margin.

The Company measures its performance in relation to the 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, safety and people. The core measures are specific to certain groups of the Company and include plant operating income, committed capital, construction budget and schedule, and plant site safety.

Significant Events

Capital Power IPO closing and Reorganization

On July 9, 2009, Capital Power issued 21.75 million common shares at $23.00 per share pursuant to the IPO. The proceeds from the IPO net of issue costs were approximately $475 million, of which approximately $468 million was used to purchase an approximate 27.8% equity interest in Capital Power LP (CPLP). CPLP purchased substantially all of the power generation assets of EPCOR in early July 2009 through the following series of transactions (the Reorganization):

- Formation of CPLP: Capital Power and Capital Power LP Holdings Inc., a wholly-owned subsidiary of Capital Power, formed CPLP. Capital Power acquired one general partner unit (GP Unit) and became the initial general partner of CPLP. Capital Power LP Holdings Inc. acquired one common limited partnership unit and as a result, became the initial limited partner of CPLP.
- Sale of EMCC Limited to Capital Power Corporation: EPCOR transferred all of the outstanding common shares of EMCC Limited to Capital Power in return for payment of approximately $468 million in cash.

- Contribution of Assets by EMCC Limited to CPLP: EMCC Limited contributed substantially all of its assets (consisting primarily of certain securities of subsidiary entities, class B shares in the capital of CPI Investments Inc., formerly EPLP Investments Inc. and a promissory note of CPI Investments Inc.) to CPLP in return for 21.75 million GP Units. Capital Power Corporation transferred its GP Unit in CPLP to EMCC Limited and as a result EMCC Limited became the general partner of CPLP. Following the completion of these transactions, EMCC Limited was renamed Capital Power GP Holdings Inc.

- Sale of Assets Net of Liabilities by EPCOR Power Development Corporation (EPDC) to CPLP: EPDC transferred substantially all of its assets (consisting primarily of assets related to Genesee Units 1 and 2, the Genesee Coal Mine joint venture and certain interests in partnerships) to CPLP in return for 56.625 million exchangeable limited partnership units of CPLP and approximately $896 million in cash. CPLP financed the cash payment with the proceeds of a long-term debt obligation to EPCOR.

  Concurrently, EPDC subscribed for 56.625 million special voting shares of Capital Power for a nominal amount.

Immediately following completion of the Reorganization, Capital Power held general partnership units representing an ownership interest of approximately 27.8% of CPLP while EPCOR held 56.625 million exchangeable limited partnership units (exchangeable for common shares of Capital Power on a one-for-one basis) representing an ownership interest in CPLP of approximately 72.2%. 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. Capital Power and EPCOR have agreed that for so long as EPCOR holds not less than a 20% interest in the common shares of Capital Power, the number of directors will not be less than nine. The special voting shares entitle EPCOR, voting separately as a class, to nominate and elect a maximum of four directors of the Company. There are currently twelve directors on Capital Power's board of directors.

Immediately following completion of the Reorganization, CPLP held 49% and EPCOR held 51% of the voting rights in CPI Investments Inc. which owned the approximate 30.6% interest (30.5% interest at December 31, 2009) in CPILP previously owned by EPCOR. However, CPLP is entitled to all of the economic interest in CPI Investments Inc. Under Canadian GAAP, CPLP is the primary beneficiary of CPI Investments Inc. and accordingly, effective July 2009 Capital Power has consolidated the financial results of CPILP.

In July 2009, Capital Power entered into various agreements with EPCOR to provide for certain aspects of the separation of the business of Capital Power from EPCOR, to provide for the continuity of operations and services, and to govern the ongoing relationships between the two entities and their subsidiaries.

Two new turbines at Clover Bar Energy Centre

Two new 100-MW natural gas-fired turbines commenced operations at the Company's Clover Bar Energy Centre; one on September 1, 2009 and the other on December 16, 2009. These two units combined with the first unit, which commenced operations in the first quarter of 2008, provide a net capacity of 243 MW for the total facility.

Construction of the final 100-MW unit was completed approximately six months ahead of schedule as the Company was able to capitalize on lessons learned during the construction of Unit 2. The cost of all three units will be approximately $263 million compared to previous estimates of approximately $284 million. The units will contribute to meeting the expected demand for additional peaking generation in Alberta. These new high-efficiency units are also designed to use 85% less water and produce 70% less nitrogen oxides (NOx) than the four turbines in the old Clover Bar plant which was decommissioned in 2007.

Keephills 3 receives funding for carbon capture and storage

Keephills 3 is a joint development and equal ownership project of Capital Power and TransAlta Corporation (TransAlta) for the construction of a 495-MW supercritical coal-fired generation plant at TransAlta's Keephills site. As part of Keephills 3, Capital Power is partnering with TransAlta and Alstom Canada (Alstom) to develop one of the world's largest carbon capture and storage (CCS) projects, Project Pioneer (Pioneer). In October 2009, a letter of intent was signed with the Province of Alberta under which Pioneer will be eligible to receive funding from the province's $2 billion CCS fund. The Government of Canada is also contributing toward the project through its Clean Energy Fund. The first stage of the project is to conduct front-end engineering and design (FEED) studies that will confirm the detailed engineering and economics of the project.

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In addition to the Pioneer project, Capital Power will complete the FEED work on its pre-combustion CCS project (the Genesee Integrated Gasification Combined Cycle (IGCC) power plant). The FEED project is being conducted in conjunction with the Canadian Clean Power Coalition, in partnership with the Alberta Energy Research Institute and Natural Resources Canada. However, Capital Power does not intend to develop an IGCC facility at this time, primarily because the technology is not economic in today's power price environment.

Update on Keephills 3 project

In October 2009, the Boards of Directors of Capital Power and TransAlta approved additional funding and a revised schedule for the Keephills 3 project. The total project cost was revised from approximately $1.8 billion to approximately $1.9 billion and Capital Power's share was correspondingly revised from approximately $903 million to approximately $955 million. The increase primarily relates to additional labour required for the construction of the power island which is the portion of the plant that includes the turbine, boiler, air quality control system, water-treatment plant and control room. The station service transformer began receiving power in November 2009 which signified achievement of the project's first commissioning milestone. Commencement of the plant's commercial operations was rescheduled from the first quarter of 2011 to the second quarter of 2011.

Capital Power Income L.P. name change

On November 5, 2009, EPCOR Power L.P. changed its name to Capital Power Income L.P.

CPI Preferred Equity Ltd. $100 million preferred share issue

On November 2, 2009, CPI Preferred Equity Ltd., a subsidiary of CPILP, issued 4 million Cumulative Rate Reset Preferred Shares, Series 2 (the Series 2 Shares) at a price of $25.00 per share. Net proceeds of $97 million were used to pay outstanding bank indebtedness. The Series 2 Shares pay fixed cumulative dividends of $1.75 per share per annum, as and when declared, for an initial five-year period ending December 31, 2014. The dividend rate will be reset on December 31, 2014 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 4.18%. The Series 2 Shares are redeemable at $25.00 per share by CPI Preferred Equity Ltd. on December 31, 2014 and every five years thereafter. The holders of the Series 2 Shares will have the right to convert their shares into Cumulative Floating Rate Preferred Shares, Series 3 (Series 3 Shares) of CPI Preferred Equity Ltd., subject to certain conditions, on December 31, 2014 and every five years thereafter. The holders of Series 3 Shares will be entitled to receive quarterly floating rate cumulative dividends, as and when declared by the board of directors of CPI Preferred Equity Ltd., at a rate equal to the sum of the then 90-day Government of Canada treasury-bill rate for the relevant quarter year period and 4.18%.

Change to CPILP distributions and launch of distribution reinvestment plan

On October 13, 2009, CPILP announced a change in the frequency of its distributions to monthly from quarterly. Cash distributions of CPILP for periods commencing after September 30, 2009 will be made in respect of each calendar month instead of the quarters ending March, June, September and December of each year. CPILP has indicated that its annual distributions are expected to remain at $1.76 per unit, in keeping with CPILP's target long-term payout ratio.

CPILP also announced the launch of a distribution plan (the Plan) that provides eligible unitholders with two alternatives to receiving the monthly cash distributions. Eligible unitholders may opt to accumulate additional units in CPILP by reinvesting cash distributions in additional units at a 5% discount to the Average Market Price of such units (as defined in the Plan) on the applicable distribution payment date. Under the Plan, eligible unitholders may elect to exchange these additional units for a cash payment equal to 102% of the regular cash distribution on the applicable distribution payment date.

Subsequent Event

On January 15, 2010, the Company sold its remaining 15% interest in the Battle River Power Syndicate Agreement (PSA) for cash proceeds of $64 million resulting in a pre-tax gain of $28 million and $2 million of associated income taxes. At December 31, 2009, the 15% interest was classified for financial reporting purposes as current assets held for sale.

This sale was pursuant to the agreement entered into in June 2006 whereby the Company agreed to sell its Battle River Power Purchase Arrangement (PPA) and related interest in the Battle River PSA to ENMAX Corporation over a four-year period ending in January 2010. An initial interest of 55% was sold for cash proceeds of $343 million in June 2006, followed by the sale of 10% interests on each of January 1, 2007, January 15, 2008 and January 15, 2009 for cash proceeds of $59 million, $53 million and $47 million, respectively. The sale of the initial 55% interest and associated sale of a 17.8% interest in the Sundance PSA resulted in an after-tax gain of $327 million in 2006. The after-tax gains on sale were $30 million in each of 2007 and 2008 and $26 million in 2009.

The Business

The Company's power generation operations and assets are owned by CPLP. At December 31, 2009, the Company held approximately 21.75 million general partner units and one common limited partnership unit of CPLP which represented approximately 27.8% and zero %, respectively, of CPLP, and EPCOR held 56.625 million exchangeable limited partnership units of CPLP (exchangeable for common shares of Capital Power on a one-for-one basis) representing approximately 72.2% of CPLP. The general partner of CPLP is wholly-owned by Capital Power and EPCOR's representation on the Board of Directors does not represent a controlling vote. Accordingly, Capital Power controls CPLP and the operations of CPLP have been consolidated for financial statement purposes effective July 2009.

The assets used in the operating business of the Company are primarily held through CPLP and its subsidiary entities. The interests held by the Company or its directly owned subsidiaries are not material to the Company's operating business or the Company's consolidated financial statements and are primarily a consequence of the Company's organizational structure. The primary assets and liabilities of the Company that are held outside of CPLP are:

- The Company's indirect interest in the general partners of the Canadian limited partnerships through which CPLP's Canadian power generation facilities are held, representing an equity interest of 1% or less in each of these partnerships;
- The Company's indirect interest in a subsidiary entity (CP Regional Power Services Limited Partnership) that, pursuant to various management and operation agreements, provides management and administrative services to CPILP and the Company's Canadian limited partnerships;
- Future income tax assets and liabilities resulting primarily from the Company's interest in CPLP which, as a limited partnership is not a taxable entity; and
- Certain natural gas customer contracts for which a non-current liability has been recorded on the consolidated balance sheet to reflect the estimated loss in fair value of the contracts which arose at the time of acquisition of these contracts from EPCOR.

These items did not have a material impact on the Company's revenues or expenses for the six months ended December 31, 2009.

Summary of Financial and Other Information

The Company reports results of operations in the following categories: (i) Alberta commercial plants and portfolio optimization, (ii) Alberta contracted plants, (iii) Ontario and British Columbia contracted plants, (iv) CPILP plants, and (v) other portfolio activities.

Alberta commercial plants and portfolio optimization

Alberta commercial plants and portfolio optimization consist of generation facilities for which the Company has not contracted substantially all of their power and capacity to third parties. This category is a Networked Hub and includes the Company's directly-owned facilities located in Alberta consisting of Genesee 3, Joffre, Clover Bar Energy Centre, Taylor Coulee Chute, Clover Bar Landfill Gas Plant and Weather Dancer, and the Company's interests in the Battle River and Sundance Power Purchase Arrangements (acquired PPAs). The output of the plants, with the exception of Joffre, is sold by the Company into the open Alberta power market. Portfolio optimization includes (i) trading activities in the Alberta market undertaken primarily to manage the Company's exposure to electricity price movements, (ii) power sales contracts with competitive wholesale commercial and industrial customers, and (iii) power supply management for rate-regulated tariff (RRT) customers of regulated retailers.

The Company seeks to maximize earnings from Alberta commercial plants and portfolio optimization by achieving high production from the facilities when it is economic to do so. It also actively manages the commodity price risk of its portfolio of assets and contracts by trading in a variety of financial and non-financial derivative instruments in the Alberta market with power generators, large energy-consuming entities and other trading counterparties. Credit limits are established and monitored by the Company for these counterparties.

Alberta contracted plants

Alberta contracted plants are comprised of the Genesee 1 and 2 generation facilities whose capacity and output are sold under a long-term Power Purchase Arrangement (PPA) with the Alberta Balancing Pool which expires in 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 incentive/penalty payments based on targeted availability. The Company seeks to maximize earnings for contracted plants by achieving high availability of the plants and managing costs within the PPA terms.

Ontario and British Columbia contracted plants

Ontario and British Columbia contracted plants include the Kingsbridge and Port Albert wind farms in Ontario and the Brown Lake and Miller Creek hydro facilities in British Columbia. Revenues from these plants are earned under contracts with the Ontario Power Authority and BC Hydro and consist of sales of committed amounts of energy (firm energy sales) and sales of energy generated in excess of the firm commitment amount (excess energy sales).

CPILP plants

CPILP plants consist of a fleet of 20 facilities located in Canada and the U.S. with PPAs and fuel supply contracts that provide for stable cash flows. The Company indirectly owns 30.4% of the limited partnership units of CPILP and consolidates CPILP's results in its financial statements. In this MD&A the CPILP facilities are discussed on a combined basis rather than individually unless otherwise stated. Eighteen of CPILP's plants are contracted and although the PPAs for the other two plants expired in December 2009, the plants are operating under the terms of the expired PPAs.

Other portfolio facilities

Other portfolio activities include natural gas trading in Alberta and electricity trading in eastern Canada, the U.S. Northeast and the U.S. Pacific Northwest markets. The Company also holds retail and commercial natural gas customer contracts in Alberta but the Company 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.

Unrealized changes in fair value of derivative instruments and natural gas inventory held for trading

The Company's financial results for the Alberta commercial and CPILP plants and other portfolio activities include unrealized changes in the fair value of derivative instruments and natural gas inventory held for trading. The Company believes that these unrealized fair value changes are not representative of the instruments' or inventory's underlying economic value when they are not considered in conjunction with the economically hedged items to which they relate, such as natural gas required for future plant operations, future power sales, and future cash flows denominated in foreign currencies. While the changes in the fair value of the derivatives used to hedge the exposures, but not designated as hedges for accounting purposes, are recognized in net income in each reporting period, the changes in the fair value of the associated economically hedged exposures are not. Accordingly, derivative instruments that are recorded at fair value for accounting purposes can produce volatility in net income as a result of changes in forward commodity prices and foreign exchange rates, which does not necessarily represent the underlying economics of the hedging transactions.

While the Company's net income can vary significantly from period to period due to fair value changes that the Company believes are not necessarily representative of the underlying economic performance of the business, the Company's cash flows are relatively stable. Accordingly, management views funds from operations as a key performance indicator since it highlights the key sources of cash generation and liquidity of the Company. See Non-GAAP Financial Measures.

Generation volume information

(unaudited, GWh)	Six months ended	
Electricity generation[1]	Dec 31, 2009	Dec 31, 2008
Alberta commercial plants		
Genesee 3	954	752
Joffre	162	146
Clover Bar Energy Centre 1, 2 and 3[2]	25	18
Taylor Coulee Chute	14	13
Clover Bar Landfill Gas	19	19
Weather Dancer	0	1
	1,174	949
Alberta contracted plants		
Genesee 1	1,455	1,642
Genesee 2	1,618	1,583
	3,073	3,225
Ontario and British Columbia contracted plants		
Kingsbridge 1	46	54
Miller Creek	61	63
Brown Lake	26	29
	133	146
CPILP plants	2,635	2,634
Total	**7,015**	**6,954**

(1) Electricity generation reflects the Company's share of plant output.
(2) Clover Bar Energy Centre includes Units 1, 2 and 3 as of their commercial operation dates, March 10, 2008, September 1, 2009 and December 16, 2009, respectively.

(unaudited)	Six months ended	
Generation plant availability[1]	Dec 31, 2009	Dec 31, 2008
Alberta commercial plants		
Genesee 3	98%	77%
Joffre	95%	86%
Clover Bar Energy Centre 1, 2 and 3[2]	97%	100%
Taylor Coulee Chute	83%	100%
Clover Bar Landfill Gas	92%	93%
Weather Dancer	28%	61%
	97%	82%
Alberta contracted plants		
Genesee 1	87%	98%
Genesee 2	96%	94%
	92%	96%
Ontario and British Columbia contracted plants		
Kingsbridge 1	99%	99%
Miller Creek	92%	82%
Brown Lake	98%	96%
	97%	92%
CPILP plants[3]	93%	95%
Average[3]	**94%**	**92%**

(1) 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.

(2) Clover Bar Energy Centre includes Units 1, 2 and 3 as of their commercial operation dates, March 10, 2008, September 1, 2009 and December 16, 2009, respectively.

(3) Average generation plant availability is an average of individual plant availability weighted by the capacity owned or operated by the Company.

The increase in electricity generation for the six months ended December 31, 2009 compared with the six months ended December 31, 2008 primarily relates to the Genesee 3 and Joffre plants, partly offset by lower output from Genesee 1. Genesee 3 experienced a 39-day outage for a turbine blade failure in the second half of 2008 compared with no major outages in the second half of 2009. Joffre experienced a 38-day outage for a generator rewind in September 2008 compared with no major plant outages in the second half of 2009. Genesee 1 experienced a planned outage in the fourth quarter of 2009 whereas there were no plant outages at Genesee 1 during the second half of 2008.

Financial highlights

(unaudited, $millions, except earnings per share)	Six months ended	
	Dec 31, 2009	Dec 31, 2008[(2)]
Revenues	1,008	1,302
Gross margin[(1)]	434	252
Operating margin[(1)]	323	128
Net income	21	33
Earnings per share[(4)]	$0.97	
Fully diluted earnings per share[(3)(4)]	$0.89	
Normalized earnings per share[(1)(4)]	$0.60	
Funds from operations[(1)(4)]	164	
Capital expenditures[(4)]	235	
Long-term debt including current portion[(4)]	1,719	
Total assets[(4)]	5,036	

(1) The consolidated financial information, except for gross margin, operating margin, normalized earnings per share and funds from operations has been prepared in accordance with Canadian GAAP. See Non-GAAP Financial Measures.

(2) Financial highlights for the six months ended December 31, 2008 are unaudited pro forma consolidated financial information included in the Consolidated Net Income section.

(3) Fully diluted earnings per share is calculated after giving effect to the exchanged limited partnership units of CPLP (exchangeable for common shares of Capital Power on a one-for-one basis) held by EPCOR.

(4) The unaudited pro forma financial information does not include a balance sheet, a statement of cash flows or earnings per share.

Funds from Operations

(unaudited, $millions)	Three months ended		Six months ended
	Dec 31, 2009	Sept 30, 2009	Dec 31, 2009
Funds from operations[(1)]	$ 71	$ 93	$ 164
Funds from operations excluding non-controlling interests in CPILP[(1)]	$ 49	$ 70	$ 119

(1) Funds from operations and funds from operations excluding non-controlling interests in CPILP are non-GAAP measures. See Non-GAAP Measures.

Funds from operations excluding non-controlling interests in CPILP were approximately $21 million lower for the fourth quarter of 2009 compared with the third quarter of 2009. The decrease was in accordance with management's expectations considering the scheduled outage at Genesee 1 which resulted in availability penalty payments and reduced compensation from the Alberta Balancing Pool for cost recoveries under the terms of the PPA, as well as maintenance costs incurred during the outage. These factors account for most of the quarter-over-quarter decrease in funds from operations.

The Company uses funds from operations as its primary cash flow measure. Since the non-controlling interests in CPILP's funds from operations are approximately 69.6%, (69.5% at December 31, 2009) the Company uses funds from operations excluding non-controlling interests in CPILP to provide a more meaningful measure of the Company's cash flows. The quarter-over-quarter changes in both measures were not significantly different ($21 million compared with $22 million) as CPILP's funds from operations were relatively stable over the two periods.

Normalized net income and normalized earnings per share

(unaudited, $millions except earnings per share)	Three months ended		Six months ended
	Dec 31, 2009	Sept 30, 2009	Dec 31, 2009
Earnings per share	**$ 0.33**	**$ 0.64**	**$ 0.97**
Net income	**7**	**14**	**21**
Less adjustments	(3)	(5)	(8)
Normalized net income[1]	**4**	**9**	**13**
Normalized earnings per share[1]	**$ 0.18**	**$ 0.42**	**$ 0.60**

(1) Normalized net income and normalized earnings per share are non-GAAP measures. See Non-GAAP Measures.

Normalized net income was lower in the fourth quarter than the third quarter of 2009, primarily due to the impact of the outage at Genesee 1 as described above under Funds from Operations, and higher indirect administration expenses, net of the associated income taxes and non-controlling interests. The increase in indirect administration expenses included in normalized net income reflects higher costs related to information technology, the employee stock option plan and transition costs for the Reorganization.

The Company uses normalized net income and normalized earnings per share to measure performance by period on a comparable basis. Normalized net income is based on net income as reported in the consolidated financial statements and adjusted for items that are not reflective of performance in the period such as fair value changes, impairments, unusual tax adjustments and gains or losses on disposal of assets. Normalized earnings per share reflect normalized net income divided by 21.75 million weighted average common shares outstanding. See Non-GAAP Measures.

Consolidated Net Income

Pro forma consolidated financial information

The pro forma consolidated financial information for the six months ended December 31, 2008 has been prepared by management and presents the effects of the completion of the IPO, the Reorganization and the related use of the net proceeds as if they occurred on January 1, 2008. The unaudited pro forma consolidated financial information for 2008 is based on currently available information and assumptions that management believes provide a reasonable basis for presenting the significant effects of the completion of the IPO and the Reorganization. In management's opinion, all material adjustments necessary to present fairly the pro forma consolidated financial information have been made. The unaudited pro forma consolidated financial information is presented for information purposes only and is not necessarily indicative of what the financial position and results of operations would have been had the completion of the IPO and the Reorganization occurred at the dates indicated, nor does it purport to be indicative of the financial position as of any future date or results of operations for any future period. Actual adjustments will differ from the pro forma adjustments.

The unaudited pro forma consolidated financial information has been prepared in accordance with Canadian GAAP consistent with the significant accounting policies described in note 2 to the consolidated financial statements for the six months ended December 31, 2009. The presentation of the unaudited pro forma consolidated information also conforms to the presentation of the audited financial statements for the period ended December 31, 2009.

(unaudited, $millions)	Six months ended	
	Dec 31, 2009	Dec 31, 2008[(1)]
Revenues	$ 1,008	$ 1,302
Energy purchases and fuel	574	1,050
	434	252
Operations, maintenance and direct administration	102	115
Indirect administration	64	68
Property taxes	9	9
Depreciation, amortization and asset retirement accretion	92	91
Foreign exchange losses	4	8
Impairments	-	42
Net financing expenses	34	60
	305	393
Income (loss) before income tax expense and non-controlling interests	129	(141)
Income tax expense (reductions)	10	(54)
Income before non-controlling interests	119	(87)
Non-controlling interests	98	(120)
Net income	**$ 21**	**$ 33**

(1) Unaudited pro forma consolidated information for the six months ended December 31, 2008 conforms to the presentation adopted for the six months ended December 31, 2009.

Consolidated Net Income

(unaudited, $millions)	
Pro forma consolidated net income for the six months ended December 31, 2008	**$ 33**
Unrealized changes in the fair value of CPILP's derivative instruments	280
Write-downs of CPILP goodwill and PERH in 2008	42
Lower net financing expenses	26
Impairment loss on venture capital investment in 2009	(4)
Lower operating margin for electricity trading in eastern Canada and northeastern U.S.	(10)
Gain on sale of venture capital investment in 2008	(10)
Unrealized changes in the fair value of CPLP's derivative instruments and natural gas inventory held for trading	(15)
Lower Alberta contracted plants operating margin	(18)
Lower Alberta commercial plants operating margin	(29)
Higher income taxes	(64)
Other	8
	206
Higher non-controlling interests:	
- CPLP	(31)
- CPILP	(186)
- Preferred share dividends paid by subsidiary company	(1)
	(218)
Decrease in net income	(12)
Net income for the six months ended December 31, 2009	**$ 21**

Net income decreased $12 million for the six months ended December 31, 2009 compared with the six months ended December 31, 2008 due to the net impact of the following:

- The year-over-year change in unrealized fair value adjustments for CPILP's derivative contracts were favourable primarily due to the designation of certain natural gas supply contracts as hedges for accounting purposes effective July 1, 2009. The fair value of these natural gas supply contracts decreased in the six months ended December 31, 2008 due to decreased forward prices for natural gas. In addition, the fair value of CPILP's foreign exchange contracts increased in the six months ended December 31, 2009 due to strengthening future prices for the Canadian dollar relative to the U.S. dollar and decreased in the corresponding period in 2008 due to weakening future prices for the Canadian dollar.

- In the fourth quarter of 2008, impairment losses of $20 million on goodwill related to the investment in CPILP and $22 million on CPILP's investment in Primary Energy Recycling Holdings LLC (PERH) were recognized. The December 2009 annual testing for impairment did not result in further write-downs.
- The decrease in financing expenses for the six months ended December 31, 2009 compared with the corresponding period in 2008 primarily relates to lower short-term interest expense and higher interest capitalized for construction work in progress. The Company capitalizes borrowing costs as part of its cost of construction projects and in the second half of 2009 the Company had higher construction work in progress compared with the corresponding period in 2008.
- In the fourth quarter of 2009, the Company wrote down its venture capital investment to $3 million, resulting in a loss of $4 million. There were no impairment losses on venture capital investments in the six months ended December 31, 2008.
- The decrease in the operating margin for electricity trading in the eastern Canada and northeastern U.S. markets was primarily due to reduced trading opportunities in the import and export markets.
- In the six months ended December 31, 2008, a gain of $10 million was recognized on the sale of a venture capital investment. The Company did not sell any investment shares in the corresponding period in 2009.
- The unrealized changes in the fair value of CPLP's derivative instruments and natural gas inventory held for trading that were not designated as hedges for accounting purposes for the six months ended December 31, 2009 were unfavourable compared with the corresponding period in 2008 primarily due to a smaller net increase in the fair value of derivative electricity sales and purchase contracts. These net increases for derivative electricity contracts reflected the impact of decreases in Alberta forward power prices on net short positions in both periods and less price volatility in the six months ended December 31, 2009. In addition, the fair value of the Joffre contract-for-differences (CfD) decreased in the six months ended December 31, 2009 and increased in the corresponding period in 2008. These changes in fair value were primarily due to lower forward Alberta power prices in the 2009 period and higher forward prices in the 2008 period relative to the contract prices. See Unrealized Changes in Fair Value of Derivative Instruments and Natural Gas Inventory held for Trading under Results by Plant Category.
- The operating margin for Alberta contracted plants was lower primarily as a result of lower net availability incentive revenues due to penalty payments incurred under the terms of the Genesee PPA during a planned outage at Genesee in the fourth quarter of 2009, and maintenance costs for the outage. In addition, the pricing for incentive income during periods of availability was lower in the 2009 period due to lower Alberta power prices.
- The operating margin for the Alberta commercial plants was lower primarily due to a lower average realized price for the portfolio, lower sales volumes to commercial and industrial customers and higher operating costs for the acquired PPAs.
- Income taxes were higher primarily due to higher income before taxes and non-controlling interests.
- Non-controlling interests reflect higher income before taxes from CPLP and CPILP in the six months ended December 31, 2009 compared with the six months ended December 31, 2008.

Results by Plant Category

(unaudited, $millions)	Six months ended Dec 31, 2009	Dec 31, 2008[2]
Revenues[2]		
Alberta commercial plants and portfolio optimization	$ 486	$ 682
Alberta contracted plants	131	145
Ontario and British Columbia contracted plants	8	10
CPILP plants	253	301
Other portfolio activities	63	91
Inter-plant category eliminations	(19)	(24)
	922	1,205
Unrealized changes in fair value of CPLP's power and natural gas derivative instruments and natural gas held for trading	45	156
Unrealized changes in fair value of CPILP's foreign exchange contracts	41	(59)
	86	97
	$ 1,008	**$ 1,302**
Gross margin[1][2]		
Alberta commercial plants and portfolio optimization	$ 103	$ 131
Alberta contracted plants	106	121
Ontario and British Columbia contracted plants	8	11
CPILP plants	151	162
Other portfolio activities	20	48
Inter-plant category eliminations	(17)	(19)
	371	454
Unrealized changes in fair value of CPLP's power and natural gas derivative instruments and natural gas held for trading	42	57
Unrealized changes in fair value of CPILP's foreign exchange and natural gas contracts	21	(259)
	63	(202)
	$ 434	**$ 252**
Operating margin[1][2]		
Alberta commercial plants and portfolio optimization	$ 80	$ 109
Alberta contracted plants	74	92
Ontario and British Columbia contracted plants	6	8
CPILP plants	95	91
Other portfolio activities	6	30
Inter-plant category eliminations	(1)	-
	260	330
Unrealized changes in fair value of CPLP's power and natural gas derivative instruments and natural gas held for trading	42	57
Unrealized changes in fair value of CPLP's foreign exchange and natural gas contracts	21	(259)
	63	(202)
	$ 323	**$ 128**

(1) The results by plant category, except for gross margin and operating margin, have been prepared in accordance with Canadian GAAP. See Non-GAAP Financial Measures.

(2) The presentation of results by plant category for the six months ended December 31, 2008 conforms to the presentation for the six months ended December 31, 2009. See Consolidated Net Income.

Spot price averages for the six months ended	Dec 31, 2009	Dec 31, 2008
Alberta power ($/MWh)[1]	47.88	87.69
Eastern region power ($/MWh)[1]	26.13	49.26
Western region power (Mid-C) ($/MWh)[1]	39.78	61.76
Alberta natural gas (AECO) ($/Gj)[2]	3.53	6.84
Capital Power's Alberta portfolio captured power price ($/MWh)[1][3]	56	64

(1) Megawatt hours (MWh)

(2) Gigajoule (Gj). AECO means a historical virtual trading hub, located in Alberta, which is now known as the Nova Inventory Transfer System operated by TransCanada Pipelines Limited.

(3) Captured power price represents the price realized on the Company's commercial contracted sales and portfolio optimization activities.

Alberta commercial plants and portfolio optimization

Alberta commercial plants and portfolio optimization revenues, gross margin and operating margin for the six months ended December 31, 2009 were lower compared with the corresponding period in 2008 due to a lower realized average price for the portfolio and decreased commercial and industrial sales volumes. The operating margin was also impacted by higher operating costs for the acquired PPAs.

Alberta power prices were significantly lower in the second half of 2009 compared with the second half of 2008 due to the impacts of the downturn in the Alberta economy. Decreased natural gas prices and reduced customer demand for power caused power prices to decline. The average spot price was $48/MWh for the six months ended December 31, 2009 compared with $88/MWh for the six months ended December 31, 2008. Since a significant portion of the Company's Alberta portfolio was sold forward at fixed prices under contracts with commercial and industrial customers or under wholesale financial contracts, the Company's average realized price for the portfolio for the six months ended December 31, 2009 was approximately $56/MWh, or $8/MWh higher than the average spot price. However, the average realized price was $8/MWh lower in the six months ended December 31, 2009 compared with the corresponding period in 2008, primarily due to a combination of more length in the portfolio that was exposed to the spot price and lower spot prices in the 2009 period.

The volume of commercial and industrial sales decreased primarily due to reduced demand resulting from the economic slowdown. The increase in operating costs for the acquired PPAs was primarily related to higher capacity payments and environmental costs. Under the terms of the PPAs, capacity payments are impacted by the plant operators' cost schedules and escalation factors, which resulted in higher payments in the current period and included retroactive adjustments of $6 million that were recognized in the second half of 2009. The increase in environmental charges under the PPAs reflects higher CO_2 emissions at Sundance and a higher cost per tonne for emission offsets.

Revenues from the Alberta commercial plants and portfolio optimization decreased $196 million primarily due to the lower realized average power price, and the impact of lower Alberta power prices on the exposed length in the portfolio and on the price for the supply of electricity to EPCOR's RRT customers. Electricity sales volumes were also lower due to decreased demand by the commercial and industrial customers and fewer RRT customers.

The decrease in revenue from the Company's RRT business did not have a significant impact on operating margin as the Company's purchases and revenues for this business are equally impacted by changes in the Alberta power price and provide a low margin per MWh. Therefore the reduction in RRT supply volumes also had an immaterial impact on operating margin. The decrease in generation resulting from the Company's reduced interest in the Battle River PPA following the sale of a 10% interest in January, 2009 was substantially offset by higher generation from Genesee 3 due to the 39-day outage in the fourth quarter of 2008 for a turbine rotor blade failure.

Alberta contracted plants

The availability of the Alberta contracted plants decreased to 92% for the six months ended December 31, 2009 from 96% for the six months ended December 31, 2008. The reduced availability was primarily due to a planned outage at Genesee 1 during the period from October 30, 2009 to November 17, 2009 compared with no major outages at Genesee 1 and 2 in the third and fourth quarters of 2008. The planned outages in 2008 at Genesee 1 and 2 occurred in the first and second quarters. Maintenance costs for the outage of $10 million also contributed to a lower operating margin for the six months ended December 31, 2009.

Net availability incentive revenue was $2 million for the six months ended December 31, 2009 compared with $18 million for the six months ended December 31, 2008. Under the terms of the PPA, penalty payments were incurred during the period of the outage at Genesee 1 in 2009. Availability incentive income during periods of availability was also lower in the second half of 2009 due to lower Alberta power prices. The price for availability incentive income and penalties is a function of a 30-day rolling average of Alberta power prices which were generally lower in 2009 than in 2008.

Ontario and British Columbia contracted plants

Revenues, gross margin and operating margin for the Ontario and British Columbia contracted plants decreased in the six months ended December 31, 2009 in comparison with the corresponding period in the previous year primarily due to lower generation volume as a result of lower wind resources and water flow levels.

CPILP plants

CPILP has twenty generation facilities, all of which operated under PPAs in the six months ended December 31, 2008 and 2009. These PPAs combined with long-term energy supply and operating contracts provided stability to cash flows. The year-over-year change in generation output from CPILP's plants for the six months ended December 31, 2009 was immaterial as lower dispatch of the North Carolina plants resulting from lower natural gas prices was offset by higher generation from the Morris plant which was acquired on October 31, 2008. The North Carolina plants are fuelled by wood waste, tire-derived fuel and coal and therefore in periods of low natural gas prices they are not as economical to run as competitive natural gas-fired power generation plants. This was the case in the six months ended December 31, 2009 and resulted in lower dispatch of these plants.

CPILP plant revenues decreased $48 million in the six months ended December 31, 2009 compared with the corresponding period in 2008 primarily due to decreased electricity prices at the California plants driven by lower natural gas prices, lower dispatch of the North Carolina plants, and lower enhancement activity at the Ontario plants, partly offset by revenue from the Morris plant. Under the terms of the PPAs for four Ontario plants, CPILP has the option of curtailing dispatch of the plants when the market price for natural gas makes it economic to sell the plant's natural gas supply (enhancement activity). Since natural gas prices were lower in the 2009 period, the plants' enhancement activities were lower.

The gross margin excluding fair value changes for the six months ended December 31, 2009 decreased $11 million in comparison with the corresponding period in 2008 primarily due to lower enhancement profits at the Ontario plants and lower dispatch of the North Carolina facilities, partly offset by a higher gross margin from the Morris facility. The reduction in revenue from the California facilities was partly offset by lower fuel expense due to lower natural gas prices.

The operating margin for the CPILP plants increased $4 million for the six months ended December 31, 2009 compared with the corresponding period in 2008 due to a decrease in operations and maintenance expenses, which more than offset the decrease in gross margin described above. Operations and maintenance expenses were lower primarily due to fewer maintenance overhauls in the 2009 period and power turbine repair costs incurred at the North Island facility in the 2008 period. In addition, a non-recurring milestone payment of $5 million was incurred in the fourth quarter of 2008 under the terms of a long-term service agreement with the manufacturer of the turbine at the Frederickson plant.

Other portfolio activities

The decrease in revenues of $28 million primarily reflects lower trading activity in the eastern Canada and northeastern U.S. electricity markets and a $10 million gain on sale of a venture capital share investment in the second half of 2008 compared with no similar sales in the six months ended December 31, 2009. The decrease in trading activity in the eastern Canada and northeastern U.S. markets reduced the gross margin and operating margin by $10 million. Reduced demand for electricity caused by the economic slowdown resulted in lower price spreads between markets and thereby reduced the Company's trading opportunities in the import and export markets.

Unrealized changes in fair value of derivative instruments and natural gas inventory held for trading

Revenues for unrealized changes in the fair value of derivative instruments and natural gas inventory held for trading decreased $11 million in the six months ended December 31, 2009 compared with the corresponding period in 2008. Gross margin for the unrealized changes in the fair value of these assets increased $265 million.

CPILP's revenues included a net gain of $41 million on changes in the fair value of foreign exchange contracts in the six months ended December 31, 2009 due to strengthening future prices for the Canadian dollar relative to the U.S. dollar compared with a net loss of $59 million in the corresponding period in 2008 due to weakening future prices for the Canadian dollar in the 2008 period.

Decreases in the fair value of CPILP's natural gas contracts increased fuel expense by $20 million in the six months ended December 31, 2009 and $200 million in the corresponding period in 2008. On July 31, 2009 CPILP designated certain of its natural gas contracts as hedges for accounting purposes. Accordingly, the fair value loss recorded in fuel expense in the income statement for the six months ended December 31, 2009 primarily relates to decreases in forward natural gas prices in the month of July 2009. The fair value of the designated contracts decreased $9 million in the period from August 1, 2009 to December 31, 2009 and these losses were recorded in other comprehensive income. In the corresponding period in 2008, the $200 million decrease in the fair value of natural gas contracts resulting from decreases in forward natural gas prices was included in fuel expense in the income statement.

Changes in the fair value of CPLP's Joffre contract-for-differences (CfD) increased revenues and energy purchases by $2 million and $5 million, respectively (a loss of $3 million) in the six months ended December 31, 2009. In the corresponding period in 2008, the fair value changes of this instrument decreased revenues and expenses by $5 million and $12 million, respectively (a gain of $7 million). These changes were primarily due to the forward prices for Alberta power which were lower in the six months ended December 31, 2009 and higher in the corresponding period in 2008 relative to the contract prices. The CfD is a tolling agreement between the Company and the Joffre joint venture for the sale of 50 MW of the plant's capacity to the Company at a contracted floating price calculated monthly. The joint venture owns the Joffre facility and consists of Nova Chemicals Corporation, ATCO Power Canada Ltd. and the Company. The purpose of the CfD is to minimize the joint venture's exposure to spot electricity prices.

Changes in the fair value of CPLP's derivative electricity and natural gas contracts and natural gas storage held for trading, that were not designated as hedges for accounting purposes increased revenues by $43 million and decreased energy purchases by $2 million (a gain of $45 million) in the six months ended December 31, 2009. In the corresponding period in 2008, the fair value changes of these instruments increased revenues and expenses by $161 million and $111 million, respectively (a gain of $50 million). These changes primarily reflect the impact of decreases in the Alberta forward power prices on net short positions for these instruments in both periods, and less volume of contracts and less price volatility in the six months ended December 31, 2009.

The increases in revenues in both periods primarily reflect the impact of decreases in forward Alberta power prices on derivative electricity sell contracts. However, the increase in revenues was lower in the six months ended December 31, 2009 primarily due to less volatility in the forward Alberta power prices and reduced volumes in the 2009 period.

Consolidated Other Expenses

(unaudited, $millions)	Six months ended	
	Dec 31, 2009	Dec 31, 2008[1]
Indirect administration	64	68
Depreciation, amortization and asset retirement accretion	92	91
Foreign exchange losses	4	8
Net financing expenses	34	60
Income taxes (reductions)	10	(54)
Non-controlling interests		
- CPLP	68	37
- CPILP	26	(160)
- Preferred share dividends paid by CPI Preferred Equity Ltd.[2]	4	3

(1) The presentation of consolidated other expenses for the six months ended December 31, 2008, conforms to the presentation for the six months ended December 31, 2009. See Consolidated Net Income.

(2) CPI Preferred Equity Ltd. is a subsidiary of CPILP. See Significant Events.

Indirect administration

Indirect administration expenses include the cost of support departments and services such as treasury, finance, internal audit, legal, human resources, corporate risk management, asset management and health and safety, as well as business development expenses including CCS and IGCC projects. The decrease in indirect administration expense was primarily due to a bad debt expense recognized by CPILP in the six months ended December 31, 2008 for a potential default by Equistar on pre-Chapter 11 petition amounts owed to CPILP, and a small decrease in business development costs as a result of progress delays on certain projects such as the Quality Wind Project. These decreases were partly offset by an impairment loss of $4 million recognized in the fourth quarter of 2009 on a venture capital investment compared with no similar write-down in the six months ended December 31, 2008.

Foreign exchange losses

Most of the Company's U.S. operations are owned by CPILP. During the fourth quarter of 2008, changes in economic circumstances caused CPILP to re-evaluate the functional currency of the partnership's U.S. subsidiaries. As a result, the functional currency of CPILP's U.S. subsidiaries was determined to be the U.S. dollar. Accordingly, commencing in the fourth quarter of 2008 translation gains and losses arising from foreign currency translation of CPILP's U.S. subsidiaries are deferred and included in accumulated other comprehensive income resulting in lower foreign exchange expense recognized into income in the six months ended December 31, 2009. The foreign exchange expense for the six months ended December 31, 2009 primarily reflects the translation of U.S. monetary assets and liabilities not owned by CPILP.

Net financing expenses

Financing expenses were $26 million lower for the six months ended December 31, 2009 than for the corresponding period in 2008. The decrease was primarily due to lower short-term interest expense and higher capitalized interest combined with no net increase in debt borrowings to fund ongoing capital requirements. See Liquidity and Capital Resources. The Company capitalizes borrowing costs as part of its capital construction projects and the amount capitalized is a function of the cost of the construction in progress. In the second half of 2009, construction work in progress, particularly for Keephills 3, was higher compared with the corresponding period in 2008.

Income taxes (reductions)

Income taxes for the six months ended December 31, 2009 were higher than for the corresponding period in 2008 primarily due to higher income before taxes and non-controlling interests.

Non-controlling interests

The non-controlling interests in CPILP reflect approximately 69.5% of the income from CPILP which was higher for the six months ended December 31, 2009 than for the corresponding period in the previous year. The non-controlling interests in CPLP reflect approximately 72.2% of the income from CPLP which was higher in the six months ended December 31, 2009 than the six months ended December 31, 2008.

Income from CPLP included approximately 30.5% of the income from CPILP. Therefore the non-controlling interests in CPLP included 22.0% (72.2% of 30.5%) of the income from CPILP.

Non-GAAP Financial Measures

The Company uses (i) gross margin, (ii) operating margin, (iii) funds from operations, (iv) funds from operations excluding non-controlling interests in CPILP and (v) normalized earnings per share as financial performance measures. These terms are not defined financial measures according to Canadian GAAP and do not have standardized meanings prescribed by GAAP, and therefore may not be comparable to similar measures used by other enterprises. These measures should not be considered alternatives to net income, cash flow from operating activities or other measures of financial performance calculated in accordance with Canadian GAAP. Rather, these measures are provided to complement Canadian GAAP measures in the analysis of the Company's results of operations from management's perspective.

Gross margin and operating margin

Capital Power uses gross margin and operating margin to measure the operating performance of plants and groups of plants from period to period. A reconciliation of gross margin and operating margin to net income is as follows:

(unaudited, $millions)	Six months ended	
	Dec 31, 2009	Dec 31, 2008
Revenues	$ 1,008	$ 1,302
Energy purchases and fuel	574	1,050
Gross margin	**434**	**252**
Operations, maintenance, and direct administration	111	124
Operating margin	**323**	**128**
Deduct (add):		
Indirect administration	64	68
Depreciation, amortization and asset retirement accretion	92	91
Foreign exchange losses	4	8
Impairments	-	42
Net financing expenses	34	60
Income taxes (reduction)	10	(54)
Non-controlling interests	98	(120)
Net income	$ 21	$ 33

Prior to the third quarter of 2009, the Company used adjusted earnings before foreign exchange gains and losses, interest, income tax, depreciation and amortization and impairments (adjusted EBITDA) to measure plant operating performance. Commencing with the third quarter of 2009, the Company adopted operating margin rather than adjusted EBITDA to measure plant performance. Operating margin is more representative of plant performance as it excludes corporate administration and business development expenses (indirect administration). The presentation of the pro forma consolidated information for the six months ended December 31, 2008 conforms to the presentation adopted for the six months ended December 31, 2009.

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

Capital Power uses funds from operations to measure the Company's ability to generate funds from current operations. Funds from operations are cash provided by operating activities excluding changes in working capital. Changes in working capital are impacted by the timing of cash receipts and payments and are not comparable from period to period. Therefore, the Company uses funds from operations as its primary operating cash flow measure. The Company measures its interest in cash flows by excluding the non-controlling interest in CPILP's cash flows. A reconciliation of (i) funds from operations and (ii) funds from operations excluding non-controlling interests in CPILP, to cash provided by operating activities is as follows:

(unaudited, $millions)	Three months ended		Six months ended
	Dec 31, 2009	Sept 30, 2009	Dec 31, 2009
Funds from operations excluding non-controlling interests in CPILP	**$ 49**	**$ 70**	**$ 119**
Funds from operations due to non-controlling interests in CPILP	22	23	45
Funds from operations	71	93	164
Change in non-cash operating working capital	50	(40)	10
Cash provided by operating activities	**$ 121**	**$ 53**	**$ 174**

Normalized net income 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 net income according to Canadian GAAP adjusted for items that are not reflective of performance in the period such as fair value changes, impairments, unusual tax adjustments and gains or losses on disposal of assets. A reconciliation of normalized net income to net income, and normalized earnings per share to earnings per share is as follows:

(unaudited, $millions except earnings per share)	Three months ended		Six months ended
	Dec 31, 2009	Sept 30, 2009	Dec 31, 2009
Earnings per share	**$ 0.33**	**$ 0.64**	**$ 0.97**
Net income	**7**	**14**	**21**
Less adjustments			
Unrealized changes in fair value of CPLP's derivative instruments and natural gas held for trading	(5)	(3)	(7)
Unrealized changes in fair value of CPILP's derivative instruments	(1)	(1)	(2)
Venture capital investment write-down	1	-	1
Income tax adjustments	2	(1)	1
	(3)	(5)	(8)
Normalized net income	**4**	**9**	**13**
Normalized earnings per share	**$ 0.18**	**$ 0.42**	**$ 0.60**

Balance Sheet

Changes in consolidated assets:
June 30, 2009 and December 31, 2009

(unaudited, $millions)	June 30, 2009	Acquisition [1]	Increase (decrease)	Dec 31, 2009	Explanation of increase (decrease)
Cash and cash equivalents	$ -	$ 71	(19)	52	Refer to Liquidity and Capital Resources below.
Accounts receivable (including income taxes recoverable)	-	247	57	304	Higher receivables in December 2009 compared to June 2009 for wholesale and EPCOR RRT sales, and for generation sales to the Alberta Balancing Pool, due to higher power prices and higher volumes driven by seasonality.
Derivative instruments assets (current)	-	140	6	146	Increase in fair value of derivative instrument power, natural gas and forward foreign exchange contracts.
Other current assets	-	112	(8)	104	Reduction in inventory as a result of completion of scheduled maintenance at Genesee 1 in the fourth quarter of 2009.
Property, plant and equipment	-	3,136	106	3,242	Capital expenditures partly offset by depreciation and amortization expense and the impact of strengthening Canadian dollar on the translation of property, plant and equipment of U.S. subsidiaries.
Power purchase arrangements	-	582	(54)	528	Amortization and the impact of the strengthening Canadian dollar on the translation of PPAs of U.S. subsidiaries.
Contract and customer rights and other intangible assets	-	169	15	184	Purchase of emission assets, rights to Keephills 3 dragline assets, and new software assets.
Derivative instruments assets (non-current)	-	74	81	155	Increase in fair value of derivative instrument power contracts due to the impact of decreases in forward power prices on net short positions, and forward foreign exchange contracts due to strengthening future prices for the Canadian dollar relative to the U.S. dollar.
Future income tax assets (non-current)	-	64	(3)	61	Reclassifications between future income tax assets and liabilities resulting in an insignificant change in the net future income taxes on the balance sheet.
Goodwill	-	145	(5)	140	
Other assets	-	122	(2)	120	

[1] Acquisition reflects the allocation of the $468 million purchase price for the power generation assets acquired from EPCOR. See Significant Events.

Changes in consolidated liabilities and shareholders' equity: June 30, 2009 and December 31, 2009					
(unaudited, $millions)	June 30, 2009	Acquisition (1)	Increase (decrease)	Dec 31, 2009	Explanation of increase (decrease)
Accounts payable and accrued liabilities	$ -	$ 259	62	321	Higher energy purchases due to higher Alberta power prices, higher operating costs for the acquired PPAs, higher purchases for Genesee 1 maintenance and higher emission asset purchases.
Derivative instruments liabilities (current)	-	143	(35)	108	Increase in fair value of derivative instrument power, natural gas and forward foreign exchange contracts, primarily due to the impact of increases in forward prices on derivative buy power and natural gas contracts and strengthening future prices for the Canadian dollar relative to the U.S. dollar.
Other current liabilities	-	(15)	44	29	Primarily higher future income tax liabilities due to reclassifications between future income tax assets and liabilities resulting in an insignificant change in the net future income taxes on the balance sheet.
Long-term debt (including current portion)	-	1,761	(42)	1,719	Scheduled repayments of long-term debt payable to EPCOR and CPILP's repayment of debt outstanding under a credit facility, partly offset by CPILP and CPLP draws on credit facilities.
Derivative instruments liabilities (non-current)	-	65	37	102	Decrease in fair value of derivative instrument power and natural gas contracts primarily due to the impact of decreases in forward prices on derivative buy contracts.
Other non-current liabilities	-	107	2	109	
Future income tax liabilities (non-current)	-	137	(42)	95	Reclassifications between future income tax assets and liabilities resulting in an insignificant change in net future income taxes on the balance sheet.
Non-controlling interests	-	1,937	127	2,064	Non-controlling interests' share of CPLP and CPILP net income and other comprehensive income, and subsidiary preferred shares issue, partly offset by non-controlling interests' share in CPILP and CPLP distributions.
Shareholders' equity	-	468	21	489	Net Income and other comprehensive income, partly offset by common share dividends.

Liquidity and Capital Resources

Cash inflows (outflows)

	Six months ended Dec 31, 2009			
(unaudited, $millions)	Acquisition[1]	Other	Total	
Cash from Operating Activities	$ -	$ 174	$ 174	See Funds from Operations
Investing	(1,293)	(232)	(1,525)	• Acquisition and reorganization includes cash paid for purchase of net assets from EPCOR, net of cash acquired. • Other includes capital expenditures, primarily for property plant and equipment.
Financing	1,456	(49)	1,407	• Acquisition and reorganization includes issue of long-term debt and common shares, net of issue costs. • Other includes scheduled repayments of long-term debt, distributions to non-controlling interests, dividends paid to common shareholders and repayments of a portion of CPILP debt drawn under credit facilities, partly offset by proceeds from the issue of subsidiary preferred shares.

(1) Acquisition reflects cash inflows and outflows relating to the Reorganization. See Significant Events.

Upon closing of the IPO, CPLP had $1,220 million of credit facilities, of which $500 million may be utilized for issuing letters of credit. On December 31, 2009, $1,001 million remained available under these facilities. Also on December 31, 2009, CPILP had revolving credit facilities of approximately $366 million, of which $287 million remained available and Capital Power Corporation had an undrawn bank line of credit of $5 million.

Upon closing of the IPO, CPLP had obligations to pay $943 million pursuant to long-term debt agreements and on June 30, 2009 CPILP had obligations to pay $811 million pursuant to long-term debt agreements. In September 2009, CPLP made a $39 million repayment on the long-term debt owing to EPCOR and in the fourth quarter of 2009 it had a net increase in drawings of $23 million on its extendible revolving syndicated bank credit facility (Syndicated Facility). These funds were used for capital projects. In October, CPILP repaid a portion of its drawings on its revolving credit facilities with the proceeds from its subsidiary's preferred share offering. Draws on its credit facilities were used to fund its capital projects.

Long-term debt outstanding at December 31, 2009 consisted of the following:

(unaudited)	Carrying amount ($ millions)	Maturity date	Nominal interest rate
Long-term debt payable to EPCOR	$ 872	Ranging from 2010 to 2018	Ranging from 5.80% to 9.00%
Joffre Cogeneration and Brown Lake project non-recourse financing	47	2020 and 2016	Fixed 8.59% and 8.70% and floating[1]
CPLP revolving extendible credit facilities	100	2012	floating[1]
CPILP long-term debt	715	Ranging from 2010 to 2036	Fixed ranging from 5.87% to 11.25% and floating[1]
	$ 1,734		

[1] Floating interest rates are a function of the prevailing bankers' acceptance rates.

CPLP will be required to make principal repayments of $247 million in 2010 under terms of its long-term debt agreements and it has adequate credit facilities to cover these repayments. The long-term debt payable to EPCOR was issued in connection with the Reorganization pursuant to a credit agreement entered into by CPLP and EPCOR on July 9, 2009. Some of the indebtedness of CPLP to EPCOR mirrors certain debt obligations of EPCOR to the public and has repayment and interest rate terms that correspond with EPCOR's mirrored debt. The remainder of the indebtedness of CPLP to EPCOR includes an amount sufficient to meet certain debt obligations of EPCOR related to indebtedness of The City of Edmonton assumed by EPCOR, and will be repaid in accordance with an amortization schedule. 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, then EPCOR may, by written notice to CPLP, require repayment of all or any portion of the outstanding principal amount under the credit agreement and accrued interest thereon. If the principal amount specified in such repayment notice is less than $200 million, then such principal amount and accrued interest thereon shall be payable 180 days after delivery of notice. If the principal amount specified in such repayment notice is $200 million or more, then such principal amount and accrued interest thereon shall be payable 365 days after delivery of notice.

CPLP's credit facilities include the Syndicated Facility of up to $700 million with an initial term of three years and an extendible revolving club credit facility (Club Facility) of up to $500 million with an initial 364 day period following which any drawn portion of the facility will convert into a non-revolving facility for a one year term-out period. Borrowings and repayments under the Club Facility will be made by CPLP with each lender on an individual lender basis up to that lender's commitment, and not on a pro-rata basis. The Syndicated Facility, the Club Facility and the credit agreement with EPCOR require CPLP to meet certain financial covenants, including maintaining a consolidated senior debt to consolidated capitalization ratio of not more than 0.65 to 1.0 as at the end of any fiscal quarter. In addition, in the event that CPLP is assigned a credit rating by Standard and Poor's (S&P) that is less than BBB- or by DBRS Limited (DBRS) that is less than BBB(low) (in each case with a stable outlook), then CPLP must also maintain a ratio of consolidated EBITDA (earnings before interest, income tax, depreciation and amortization) 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. The Syndicated Facility, the Club Facility and the credit agreement with EPCOR also 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. These agreements also contain provisions for default, including on a Change of Control. In the event that a Change of Control occurs, then if (i) in the case of the Syndicated Facility and the Club Facility, immediately thereafter the long term senior unsecured and unsubordinated debt rating of CPLP (Debt Rating) is BBB- or higher from S&P and BBB(low) or higher from DBRS (in each case with a stable outlook) (Investment Grade), the lenders will have the option to elect to shorten the term of the facility to the lesser of 364 days and the then current maturity date, and (ii) immediately thereafter the Debt Rating of CPLP is not Investment Grade, it shall constitute an event of default unless the Change of Control is consented to by the lenders within a specified number of days after the occurrence thereof. Change of Control means (i) a change in the general partner of CPLP (unless such new general partner is an affiliate of Capital Power Corporation or EPCOR) or (ii) if any person, or group of persons acting jointly or in concert, acquires beneficial ownership of securities of Capital Power Corporation or the general partner of CPLP to which are attached 50% or more of the votes that may be cast to elect directors thereof (but excluding for greater certainty any such acquisition of securities by Capital Power Corporation, EPCOR or their affiliates). Capital Power also has revolving demand credit facilities totaling $25 million.

At December 31, 2009, CPILP's credit facilities included two revolving facilities of $100 million each with terms expiring in September and October 2011, and a revolving facility of $125 million expiring in June 2011. The two $100 million facilities were amended in October 2009 to add a U.S. co-borrower to facilitate funding of capital expenditures at the partnership's U.S. plants. CPILP also has two demand facilities, one for $20 million and the other for US$20 million.

Under the terms of its debt agreements, CPILP must maintain a debt to capitalization ratio of not more than 65% at the end of each fiscal quarter. In addition, under the revolving credit facilities, in the event CPILP is assigned a rating of less than BBB+ by S&P and BBB(high) by DBRS CPILP would be required to maintain a ratio of EBITDA to interest expense of not less than 2.5 to 1, measured quarterly. Although CPILP is not required to meet the EBITDA to interest ratio, the ratio was 4.3 at as at December 31, 2009. CPILP was compliant with all of its debt covenants under its debt agreements for the years ended December 31, 2009. If an event of default occurs and continues under CPILP's credit facilities, CPILP may not declare, make or pay distributions (subject to certain limited exceptions).

The committed bank credit facilities are expected to be used primarily for the purposes of providing funds for capital expenditures, letters of credit and general corporate purposes. Letters of credit are issued to meet conditions of certain debt and service agreements, to meet the credit requirements of energy market participants and to satisfy legislated reclamation requirements. On December 31, 2009, CPILP had $78 million of long-term debt borrowings and less than $1 million of letters of credit outstanding under its credit facilities, and CPLP had $100 million of debt and $119 million of letters of credit outstanding under its credit facilities.

CPLP has received a corporate credit rating of BBB from S&P and a long term debt credit rating of BBB from DBRS.

The BBB rating assigned by S&P is within the BBB rating category which is the fourth highest rating of S&P's ten corporate credit ratings, which range from AAA to D. 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. S&P's ratings outlook is stable which reflects their expectation that CPLP will maintain its business risk profile in the long-term.

The BBB rating assigned by DBRS is the fourth highest rating of DBRS' ten rating categories for long-term debt obligations, which range from AAA to D. According to DBRS, long-term debt rated BBB is of adequate credit quality. Protection of interest and principal is considered acceptable, but the entity is fairly susceptible to adverse changes in financial and economic conditions, or there may be other adverse conditions present which reduce the strength of the entity and its rated securities. The outlook trend for this rating is stable as DBRS believes credit metrics will remain within a range consistent with the current ratings.

Credit ratings are intended to provide investors with an independent assessment of the credit quality of an issue or an issuer of securities and such ratings do not address the suitability of a particular security for a particular investor. The ratings assigned to a security may not reflect the potential impact of all risks on the value of the security. A rating is not a recommendation to buy, sell or hold securities and may be subject to revision or withdrawal at any time by the rating organization.

Having an investment grade credit rating impacts CPLP's ability to re-finance existing debt as it matures and to access cost competitive capital for future growth.

(unaudited, $ millions)	Six months ended Dec 31, 2009
Capital expenditures	
Keephills 3	$ 113
CPILP's North Carolina plants enhancement project	47
Clover Bar Energy Centre	18
Other	57
Total capital expenditures	$ 235

Capital spending in the six months ended December 31, 2009 included expenditures for the Keephills 3 and Clover Bar Energy Centre projects which are described under Significant Events. CPILP's enhancement project for its Southport and Roxboro plants in North Carolina will reduce the plants' environment emission levels and improve their economic performance. The Company's other capital expenditures for the six months ended December 31, 2009 were primarily for the sustainment of existing facilities.

Future cash requirements – excluding CPILP

Capital Power's estimated cash requirements for 2010, excluding CPILP's cash requirements and subject to variable factors including those discussed in Forward-looking Information, are expected to include approximately $310 million for capital expenditures, approximately $72 million for CPLP distributions to EPCOR, and approximately $28 million for Capital Power's quarterly dividends subject to approval by the Board of Directors. This estimate for CPLP distributions includes $18 million distributed on January 27, 2010 and the estimate for Capital Power's quarterly dividends includes $7 million paid on January 29, 2010 at $0.315 per share. The major capital expenditures are expected to include approximately $250 million for the Keephills 3 construction project, approximately $30 million for maintenance capital and approximately $20 million for emission offsets. If total cash requirements for 2010 remain as planned, the sources of capital will be cash on hand, cash provided by operating activities, distributions from CPILP and the use of existing credit facilities. The Company is also considering additional financing options available to it.

Future cash requirements – CPILP

CPILP's estimated cash requirements for 2010, subject to variable factors including those discussed in Forward-looking Information, are expected to include approximately $17 million for the completion of the Roxboro and Southport enhancement project, approximately $16 million for the repowering project at Oxnard and approximately $95 million for distributions subject to approval by the CPILP Board of Directors. The amount of distributions will vary depending on the number of unitholders who opt under the Plan to accumulate additional units in lieu of cash distributions. If CPILP's total cash requirements for 2010 remain as planned, the sources of capital will be cash on hand, cash provided by operating activities and use of existing credit facilities. If major investments of capital are required CPILP may obtain new capital from external markets at the time of the required investment utilizing its $1 billion shelf prospectus which expires in August 2010.

Although liquidity in the financial markets improved in 2009, financial market stability remains an issue. If the instability in the Canadian and U.S. financial markets continues, it may adversely affect Capital Power's ability to raise new capital, to meet its financial requirements and to refinance indebtedness under existing credit facilities and debt agreements at their maturity dates. In addition, Capital Power has credit exposure with a number of counterparties to various agreements, most notably its PPA, trading and supplier counterparties. While the Company continues to monitor its exposure to its significant counterparties, there can be no assurance, particularly in light of the current economic environment, that all counterparties will be able to meet their commitments.

Contractual Obligations

Capital Power's contractual obligations at December 31, 2009 were as follows:

	Payments Due by Period						
(unaudited, $ millions)	2010	2011	2012	2013	2014	Thereafter	Total
Acquired PPA obligations[1]	$ 91	$ 91	$ 101	$ 109	$ 116	$ 880	$ 1,388
Capital projects[2]	290	36	-	-	-	-	326
Energy purchase and transportation contracts[3][4]	132	91	77	64	66	138	568
Operating and maintenance contracts[5]	27	27	28	28	29	74	213
Operating leases	2	1	4	4	4	68	83
Forward foreign exchange contracts and commodity contracts-for-differences	80	50	5	-	2	-	137
Long-term debt	247	313	127	20	214	809	1,730
Interest on long-term debt[6]	97	86	69	65	64	384	765
Asset retirement obligations[7]	1	1	1	10	10	363	386
Loan commitments	6	-	-	-	-	-	6
Other purchase obligations[8]	5	5	4	4	4	5	27
Total	$ 978	$ 701	$ 416	$ 304	$ 509	$ 2,721	$ 5,629

(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.

(2) Capital Power's obligations for capital projects include Keephills 3 and Clover Bar Energy Centre and CPILP's Roxboro, Southport, and Oxnard facility enhancements.

(3) The natural gas purchase contracts have fixed and variable components. The variable components are based on estimates subject to variability in plant production. These contracts have expiry terms ranging from 2010 to 2016 with built-in escalators in the contracts' terms for pricing.

(4) The natural gas transportation contracts are based on estimates subject to changes in regulated rates for transportation and have expiry terms ranging from 2011 to 2017.

(5) Operating and maintenance contracts are based on fixed fees subject to annual escalators and have expiry terms ranging from 2017 to 2018.

(6) Repayments of bankers' acceptances outstanding under CPLP's and CPILP's extendible credit facilities at December 31, 2009, are reflected in the year of the maturity of the respective credit facility.

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

(8) Other primarily consists of a contract to purchase environmental products to reduce emission levels at the Genesee plants.

Off-balance Sheet Arrangements

As at December 31, 2009, the Company had no off-balance sheet arrangements.

Related Party Transactions

EPCOR, including its subsidiaries is the only related party with which the Company had material transactions in the six months ended December 31, 2009. The Company's acquisition of power generation assets from EPCOR in July 2009 was recorded at cost for the non-controlling interests' approximate 72.2% share of the transaction and at fair value for Capital Power's approximate 27.8% interest in the transaction. The acquisition is described under Significant Events. As part of the Reorganization, the Company issued 56.625 million special voting shares and one special limited voting share to EPCOR for $57 million. In the second quarter, the Company issued one special limited voting share to EPCOR for one dollar. The special limited voting share entitles EPCOR to 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. Also, as part of the Reorganization, the Company borrowed $918 million of long-term debt, including $22 million of fair value increments, of which $39 million was repaid in the third quarter of 2009 as discussed under Liquidity and Capital Resources, and $7 million of the fair value increment was amortized. The terms and interest rates of this debt mirror the debt payable by EPCOR or provide for sufficient payments to EPCOR related to indebtedness of The City of Edmonton assumed by EPCOR. The interest incurred on the Company's long-term debt payable to EPCOR was $30 million for the six months ended December 31, 2009, of which $20 million was capitalized as property, plant and equipment for construction work in progress and the remainder was included in net financing expense.

The Company entered into various agreements with EPCOR to provide for certain aspects of the separation of the business of Capital Power from EPCOR, to provide for the continuity of operations and services and to govern the ongoing relationships between the two entities and their subsidiaries. These transactions are in the normal course of operations and are recorded at the exchange values which are based on normal commercial rates.

The Company's revenues for power sold to EPCOR for resale to its customers were $219 million for the six months ended December 31, 2009. Power sales prices were market determined. The Company's purchases of distribution and transmission services from EPCOR were $13 million. The Company also contributed $8 million to EPCOR for the construction of aerial and underground transmission lines. These transactions were in the normal course of operations.

At December 31, 2009, the balances resulting from transactions with EPCOR were as follows:

(unaudited, $ millions)	Dec 31, 2009
Balance sheet	
Accounts receivable	$ 63
Other assets	8
Property, plant and equipment	20
Accounts payable and accrued interest on debt	13
Long-term debt (including current portion)	872
Share capital	-

Outlook

The following discussion should be read in conjunction with the Forward-looking Information section of this MD&A as this information contains forward-looking statements based on risks and assumptions as of the date of this MD&A and as disclosed in that section. These forward-looking statements are for the purpose of providing information about management's current expectations and plans relating to the future and may not be appropriate for other purposes.

Consistent with the Company's plant operating history, the Company's operational target for 2010 is an average availability of 94% for all plants, where availability is as defined under Summary of Financial and

Other Information. This target takes into consideration two scheduled outages at Genesee; one at Genesee 2 and the other at Genesee 3.

Management's strategy has been to sell its Battle River PPA and a portion of its interest in the Sundance PPA and replace this power output with power produced from its own new physical facilities. As described under Subsequent Event interests in the PPAs were sold over the period from 2006 to 2009 and the final 15% interest in the Battle River PPA was sold in January 2010. These disposals preceded the addition of the new facilities, as Clover Bar Unit 1 commenced operations in 2008, followed by Units 2 and 3 in the third and fourth quarters of 2009 respectively. Keephills 3 is expected to be commissioned in 2011. Accordingly, the Company's operating margin and cash flow from operations are expected to be negatively impacted by the Company's reduced interest in acquired PPAs in 2010 and are expected to increase as the new facility comes on line in 2011.

Alberta forward power prices are expected to remain low in 2010 mainly due to low natural gas prices. However, the Company's overall Alberta commercial portfolio position for 2010 has been substantially sold forward at an average price in the low-$60/MWh range. Nevertheless, the Company expects some volatility in earnings to result from monthly buy and sell transactions for changes in anticipated patterns of energy demand as well as position changes as opportunities in the market arise. The addition of the units at Clover Bar Energy Centre also enhances the Company's ability to physically manage its exposure to changing electricity prices and participate in rising power market opportunities. In 2010, the Alberta commercial plants are expected to represent approximately 40% of operating margin excluding unrealized changes in the fair value of derivative instruments. In 2011, demand growth in the Alberta electricity market is expected to increase due to oil sands investment activity. In addition, demand for new generation capacity is expected with the retirement of some capacity on the Alberta electricity grid in 2011. The Company's Alberta commercial portfolio's open position is expected to increase in 2011 to be approximately 30% of the total portfolio which could introduce more variability in operating margin, excluding unrealized fair value adjustments, and in cash flow resulting from changes in power prices. The average contracted price is in the low-$60/MWh range for the generation sold forward in 2011. The Company will continue to monitor commodity price forecast movements and undertake transactions to optimize the portfolio and limit exposure to price movements.

The sensitivity to an increase/decrease of $1/MWh in the Alberta power price, assuming all other factors are held constant, is estimated to be an operating margin (excluding unrealized fair value adjustments) increase/decrease of $0.5 million for 2010. In 2011, this sensitivity is expected to increase to approximately $2.5 million due to the open position on the Keephills 3 facility and the expiration of certain of the Company's Alberta wholesale and commercial and industrial customer contracts. The Alberta power price sensitivity provides a range of outcomes assuming all other factors are held constant and current risk management strategies, including hedges, are in place. Under normal circumstances, such other factors will not be held constant. In addition, the sensitivity is presented at December 31, 2009 and the degree of sensitivity will change as the Company's mix of assets and operations subject to this factor changes or the degree of commodity hedge coverage changes.

As discussed under Significant Events, the Company's share of the total construction cost of the Keephills 3 facility is expected to be approximately $955 million and commercial operation of the plant is anticipated to commence in the second quarter of 2011. Progress on the Quality Wind project, in British Columbia, including environmental assessment work, has been delayed as BC Hydro has not completed its selection of projects under its 2008 Clean Power Call. In 2008, the power generation business of EPCOR submitted a bid in response to the 2008 Clean Power Call proposing a 142-MW wind farm located near Tumbler Ridge, British Columbia. In December 2009, the Quality Wind project advanced to the next stage when BC Hydro announced that 47 proposals are continuing in the process and may qualify for an electricity purchase agreement.

Capital expenditures, excluding CPILP's capital expenditures, are expected to be approximately $310 million in 2010. The major items that are expected to impact operating margin (excluding unrealized fair value adjustments and gain on sale of interests in the Battle River PSA), and cash flow from operations in 2010 relative to 2009 on an annualized basis are:

- higher operating margin for the facility at Clover Bar Energy Centre due to a full year of operation of the second and third units which were commissioned in 2009;
- higher captured power price for the Alberta commercial portfolio as a significant portion of the portfolio has been sold forward at fixed prices in the low-$60/MWh range.
- the impact of the Company's reduced interest in the Battle River PPA after the sale of the remaining portion in January 2010;
- maintenance outages scheduled in 2010 at the Genesee site for Units 2 and 3 compared with only one scheduled outage in 2009. In general, major maintenance expenses for the Genesee maintenance programs can vary significantly depending on the frequency of scheduled turnarounds. The total operating expenses for the two outages in 2010 for both units is expected to be between $18 million and $22 million;
- lower operating margin at Genesee 3 as a result of the scheduled outage.

Apart from these items, income in 2010 excluding fair value adjustments and the gain on the sale of interests in the Battle River PSA is expected to be consistent with 2009 on an annualized basis.

Business Risks

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

Risk management is carried out at three levels. Firstly, 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 regularly to review enterprise risk management performance and to evaluate significant or emerging risks. Secondly, 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 polices and processes. He is also responsible for the leadership of the commodity risk management (middle office) function. Thirdly, individual executive risk owners are accountable for carrying out the risk management and mitigation activities associated with the risks in their respective operations. Management views risk management as an ongoing process and continually looks for ways to enhance the Company's risk management processes.

The Company maintains an Ethics Policy which includes an Accounting and Auditing Complaint Procedure to provide for confidential disclosure of any wrong-doing relating to accounting, reporting and auditing matters. The policy prohibits any retaliation against a person making a complaint.

Operations Risk

The operation of power plants involves many risks, including: (i) the breakdown or failure of, and the necessity to repair, upgrade or replace, power and steam generation equipment, transmission lines, pipelines or other equipment, structures or processes; (ii) the inability to secure critical or back-up parts for generator equipment on a timely basis; (iii) fire, explosion or other property damage; (iv) an inability to obtain adequate fuel supplies, site control, and operation and maintenance and other site services for at least the term of any PPA; (v) performance of generation equipment below expected levels, including those pertaining to efficiency and availability; (vi) non-compliance with any operating permits and licences (including environmental permits and emissions restrictions) under applicable laws and regulations; and (viii) an inability to retain, at all times, adequate skilled personnel, the occurrence of any of which could have a material adverse effect on Capital Power, including a shut-down of a power plant or reduction in its operating capacity, emissions in excess of permitted levels, or diversion of water levels below levels required by regulation. The inability of Capital Power's power plants to generate the expected amount of electricity that will be sold under contract or to the applicable market would have a significant adverse impact on the revenues of Capital Power. 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 be increased and/or Capital Power's 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 Company's operational risks are partly mitigated by its, and the acquired PPA (Sundance) plant owner's operating and maintenance practices that are intended to minimize the likelihood of prolonged unplanned down time. The terms of the PPAs provide appropriate incentives to owners to keep the plants well maintained and operational. They also provide force majeure protection for high-impact low probability events including major equipment failures. The Company's maintenance practices are augmented by an inventory of strategic spare parts, which can reduce down time considerably in the event of failure. Finally, the Company has secured appropriate business interruption insurance to reduce the impact of prolonged outages caused by insured events.

In the fourth quarter of 2008, there was an unplanned outage at Capital Power's Genesee Unit 3 facility due to a turbine rotor blade failure that kept the unit offline for 39 days. Revenues were not earned during this period and gross margin was negatively impacted by an estimated $23 million. Although Capital Power continues to investigate the turbine blade failure at Genesee Unit 3, it has not yet ascertained the absolute cause of such failure, and, accordingly, there can be no assurance that such a failure will not recur in the future at either the Genesee Unit 3 facility or the Keephills 3 facility at which the same turbine equipment is to be installed.

Electricity Price and Volume Risk

Capital Power's revenues are tied, directly and indirectly, to the market price for electricity in the jurisdictions in which Capital Power operates. 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 at any point in time; the price of raw materials that are used to generate electricity; the cost of complying with applicable regulatory requirements, including environmental; the structure of the particular market; and weather conditions. It is not possible to predict future electricity prices with complete certainty, and electricity price volatility could therefore have a material adverse 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. Most of the Company's other plants, including Brown Lake, Miller Creek, and Kingsbridge I, operate under long-term commercial contracts. 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% interest in Genesee 3 is not covered by a long-term commercial contract, it is a base-load coal-fired generating plant with a relatively low variable cost and it will generally run when it is available. It is subject to electricity spot price exposure when those prices are below the plant's variable costs or when the plant suffers an unplanned outage. The CPILP facilities generally operate under long-term power sales contracts, thereby reducing their electricity price and volume risks. The Company seeks to re-contract existing generation plants under new or extended contracts and its growth strategy includes maintaining at least 50% of the Company's operating margin from contracted plants.

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. Capital Power attempts to minimize exposure to extreme price fluctuations, especially during higher priced peak hour periods. In order to do this, Capital Power relies on historical aggregate consumption data (load shape) provided by load settlement agents and local distribution companies to anticipate what aggregate customer 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 the electricity if it is short or sell the electricity if it is long. Such exposures can be exacerbated by other events such as unexpected generation plant outages and unusual weather patterns.

In order to manage its exposure to spot price variability within specified risk limits, the Company enters into purchase and sale arrangements, including contracts-for-differences (CfD) and firm price physical contracts, for periods of varying duration. A contract-for-differences is an arrangement whereby a payment is made by one party to the contract to the other, based on the difference between a reference price and the market price of an underlying commodity such as electricity or natural gas. However, 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 exposure and stop-loss limits, and generally trades in electricity to reduce the Company's exposure to changes in electricity prices or to match physical and financial obligations.

PPA Contract Risk

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 associated with certain of Capital Power's facilities are governed by the terms of a PPA. These 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.

Power generated from Capital Power's facilities is, in many cases, sold under PPAs that expire at various times.

When a PPA expires, there can be no assurance that a subsequent PPA will be available or, if available, that any such subsequent PPA will be on terms, or at prices, acceptable to Capital Power. Failure by Capital Power to enter into a subsequent PPA on terms and at prices that permit the operation of a facility on a profitable basis could have a material adverse effect on Capital Power's operations and financial condition, and may even require Capital Power to temporarily or permanently cease operations at the affected facility.

The PPAs for CPILP's North Carolina facilities expired on December 31, 2009. The electric output from the facilities is sold to Carolina Power & Light Company (CP&L), which is a regulated utility servicing North Carolina and South Carolina, and is a subsidiary of Progress Energy Inc. (Progress). To date, CPILP and Progress have been unable to finalize new PPAs that are acceptable to both parties. CPILP filed for arbitration with the North Carolina Utilities Commission (NCUC). The NCUC has required that CP&L continue to purchase electrical output from the North Carolina facilities pursuant to the terms of the expired PPAs until the arbitration is resolved. There is no assurance that new PPAs will be entered into between the CPILP and Progress or will result in positive cash provided by operating activities for the facilities.

Energy Supply Risk

Capital Power requires energy from sources such as natural gas, coal, wood waste, waste heat, tire derived fuel, water and wind, to generate electricity. A disruption in the supply of, 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: the projected supply and demand for such fuel supplies; the quality of the fuel (particularly in regards to wood waste); and 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.

Capital Power's fuel expense for the Genesee plants is predominantly comprised of coal supply. Coal is supplied under long-term agreements with the Genesee Coal Mine joint venture, of which the Company holds a 50% interest. 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. To the extent that coal mine equipment suffers significant disruption and existing coal inventories are exhausted, the generation of electricity from the Genesee generation units and the associated revenues could be negatively impacted. To mitigate this risk the Company and the joint venture maintain coal stock-pile inventories sufficient for approximately six months of operations.

Performance of hydroelectric facilities is dependent upon the availability of water. Variances in water flows, which may be caused by shifts in weather or climate patterns, the timing and rate of melting and other uncontrollable weather-related factors affecting precipitation, could result in volatility of hydroelectric plant revenues. In addition, the hydroelectric facilities are exposed to potential dam failure, which could affect water flows and have a material adverse impact on revenues from the associated plants. There is an increasing level of regulation respecting the use, treatment and discharge of water, and respecting the licensing of water rights. A continued tightening of such regulations could have a material adverse effect on Capital Power’s business, financial condition and results of operation.

Capital Power's wind power facilities have no fuel costs but are dependent on the availability and constancy of sufficient wind resources to meet generation capacity. Wind resources can vary due to abnormal weather conditions, and decreases in wind speed or duration can negatively impact the performance of the wind turbines and, in turn, could potentially have a material negative impact on related revenues.

Some of Capital Power's natural gas-fired plant operations are susceptible to the risks associated with the volatility of natural gas prices beyond any fixed price term. Natural gas purchases for several of Capital Power's power plants are made under variable price structures with fuel cost flow-through provisions; however, each of these power plants has PPAs extending for terms in excess of existing contractual supply arrangements. The failure to contract for additional fuel supply for these plants at the end of existing contract terms at acceptable prices may lead to a disruption in operations and an inability to perform under their power and steam purchase agreements.

Capital Power also maintains a quantity of natural gas in storage for trading and management of natural gas needs. This inventory is subject to resale in current or forward markets and volatility of the market price for natural gas may result in gains or losses on such natural gas.

Wood waste is required to fuel CPILP’s two Canadian biomass wood waste plants, Williams Lake and Calstock. In addition, the enhancements that are nearing completion at the North Carolina plants will increase the level of wood waste consumption at those plants. At Williams Lake, the cost of delivered wood waste for the firm energy component (approximately 80% of fuel supply cost) is flowed through to BC Hydro, while CPILP is at risk for the wood waste price escalation for the remaining 20% of the fuel supply. At Calstock, there are no flow-through provisions in the PPA with OEFC and CPILP is at risk for wood waste price escalation. Weakness in the North American economy has placed economic hardships on forestry mills, which has caused mills to shut down or scale back production in British Columbia and Ontario. In the event that CPILP’s wood waste suppliers curtail or shut down operations, CPILP's biomass wood waste operations could be adversely affected.

CPILP's five Ontario plants (namely, Nipigon, Kapuskasing, North Bay, Calstock and Tunis) also generate electricity in part from the use of waste heat gases from adjoining natural gas compressor stations. Supply of the waste heat gases is secured under long-term contracts; however the availability of the waste heat gases varies depending on the output of the compressor stations along the Northern mainline pipeline system, and the hosts' altering those operations under the terms of a Waste Heat Optimization Agreement. In addition, the availability of waste heat gases is also dependent on the compressor stations remaining in use and their ability to supply the waste heat gases.

Project Construction and Development Risk

Capital Power participates in the design, construction and operation of new power generation facilities and is actively assessing and pursuing power development and acquisition opportunities. In the course of assessing and pursuing such opportunities, such as bidding on RFPs, 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, being awarded a contract or bringing a project into development. There can be no assurance that Capital Power will pursue any opportunities currently being assessed or being considered for the future or be successful in winning RFPs.

Development of power generation facilities is subject to substantial risks, including various engineering, construction, stakeholder, government and environmental risks. Generally, in developing a power generation facility, there are numerous tasks Capital Power must complete, including: government permits and approvals, site agreements and construction contracts, access to power grids and 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, 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 direct 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, materially and adversely affecting Capital Power's financial position, operating results and business.

The Company attempts to mitigate these risks by performing detailed project analyses and due diligence prior to and during construction or acquisition. Corrective actions are taken when necessary to increase the likelihood of investment recovery. The Company also seeks to enter into favourable long-term contracts for the projects' output whenever possible.

Environmental Risk

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, GHG and other air emissions, water usage, wastewater discharges, hazardous material handling, storage, treatment and disposal of waste and other materials and remediation of sites and land-use responsibility. These regulations can impose liability for costs to investigate and remediate contamination without regard to fault and under certain circumstances, liability may be joint and several resulting in one contributing party being held responsible for the entire obligation. Further, there can be no assurances that compliance with and/or changes to environmental regulations will not materially adversely impact Capital Power's business, prospects, financial conditions, operations or cash flow.

The Company's business is a significant emitter of carbon dioxide (CO_2), nitrogen oxide (NOx), sulphur dioxide (SO_2) and mercury and is required to comply with all licenses and permits and existing and emerging federal, provincial and state requirements, including programs to reduce or offset GHG emissions. Compliance with new regulatory requirements may require Capital Power and/or CPILP to incur significant capital expenditures and/or additional operating expenses, and failure to comply with such regulations could result in fines, penalties or the forced curtailment of operations. The Company complies with regulatory requirements while reducing environmental impact.

Canadian Federal Government - Greenhouse Gas Regulation

In December 2009, the United Nations held its fifteenth climate change conference referred to as the Conference of the Parties in Copenhagen, Denmark, where more than 190 countries, including Canada, participated. It was widely anticipated that the meeting would establish a binding agreement for GHG reduction targets. Instead of a binding agreement the conference produced a non-binding framework, referred to as the Copenhagen Accord, which required each nation to, among other things; submit economy wide emission targets by January 31, 2010. Canada submitted its target on January 31, 2010 which included a 17% reduction of GHG emissions from 2005 by 2020, to be aligned with the final economy-wide emissions target of the U.S. enacted legislation. This target is lower and with a different base line year, than the targets published in 2008 in the Turning the Corner framework, which stated a 20% reduction by 2020, from 2006 levels. It is widely anticipated negotiations to develop a formal binding agreement will occur through 2010. Due to the expected impact climate change regulations may have on international trade the Canadian Environment Minister indicated that Canada will wait to establish the Canadian climate change regulations in concert, and generally consistent, with the U.S. which has already been demonstrated as Canada has adopted the same GHG emission reduction target as the U.S. Notwithstanding the announcement of the new target, there is insufficient information to determine the impact of the Canadian climate change regulations on Capital Power, although to the extent that additional regulation is passed it is likely Capital Power will incur increased costs.

Canadian Federal Government - Air Emission Regulations

The Canadian government is also considering regulations which may place stricter limits on NOx and SO_2 from fossil-fired generating stations in Canada. Working groups, including industry participants, have been established by the Canadian government to develop the elements of a regulatory framework to minimize NOx and SO_2. The proposed federal framework appears to be consistent with requirements currently in place in certain provinces, and Capital Power is actively monitoring the progress but there is insufficient information to assess the financial implication to operations, although as additional regulation is passed it is likely Capital Power will incur increased costs.

Alberta - Greenhouse Gas Regulation

The Specified Gas Emitters Regulation (the SGER) under the *Climate Change and Emissions Management Act* (Alberta) came into force on August 1, 2007. The SGER is applicable to all facilities in Alberta that produce over 100,000 tonnes of GHG, measured as carbon dioxide equivalents (CO_2Es), per year. The Alberta Government recognizes three mechanisms for compliance with this regulation: (1) operational or plant changes to reduce emission intensity; (2) payment into the Alberta Government Climate Change Emission Management Fund (currently set at $15 per tonne) for all emissions in excess of the emission intensity target; or (3) purchase GHG emissions offsets created from Alberta based projects. The reporting deadline for the 2009 compliance period is March 31, 2010. The SGER imposes a CO_2E intensity reduction of 12% from the average CO_2E emissions intensity based on the 2003 to 2005 period.

Accordingly, Capital Power's Genesee Unit 1, Unit 2 and Unit 3 generating stations and the Sundance 5 and 6 units PPAs are subject to the SGER. The costs associated with compliance with the SGER for Genesee Unit 1 and Unit 2 were approximately $5 million for 2009 and are estimated to be approximately $6 million per year in the future and are recoverable from the PPA holder under the terms of the PPA. The compliance cost associated with the Sundance PPA will be passed on to Capital Power, as the PPA buyer, in proportion to its ownership interest until the PPA reaches its expiry date or is sold. The first GHG targets on Genesee 3 began in 2009 following a three year grace period. The reductions in the targets are graduated starting at 2% per annum and increase at a rate of 2% per annum. The 2009 target was therefore 2% and equated to approximately 35,000 tonnes for Capital Power's 50% share.

Capital Power's business has been purchasing offsets for over five years and has entered into more than 15 offset purchase agreements. Approximately $10 million worth of offsets were purchased in 2009 (compared with $4 million of purchases in 2008 and $1 million of purchases in 2007) and approximately 550,000 tonnes of offsets were applied against the 2008 compliance obligations associated with its ownership of the Sundance and Battle River PPAs. The use of these offsets, instead of purchasing fund credits through the Province of Alberta's Climate Change Emission Management Fund, resulted in a savings to Capital Power of approximately $5 million in 2009.

Alberta - Air Emission Regulations

In 2009, Capital Power participated with industry, government and non-government organization stakeholders in the five-year Clean Air Strategic Alliance Review of the Alberta Electricity Framework. This review was ongoing through 2009 and will continue in 2010. It is expected that recommendations to the Alberta Minister of Environment will be made later in 2010 on new air emission standards for coal and natural gas fired electricity generating plants approved after 2010. The electricity framework also requires a review of the particulate matter emissions from existing coal-fired units that may result in additional control costs in future years. There is, however, insufficient information at this time to determine the financial implications of the review.

The Government of Alberta regulations require coal-fired plant operators, including Capital Power, to monitor mercury emissions and capture at least 70% of the mercury in the coal starting January 1, 2011. In 2009, the Corporation installed an activated carbon injection system and mercury Continuous Emission Monitoring System on Genesee Unit 1, Unit 2, and Genesee Unit 3 to meet the regulatory requirements. The systems will be commissioned in 2010 and will be ready for the January 1, 2011 deadline. Capital and operating costs will be passed through to the PPA buyer for Genesee Unit 1 and Unit 2. For Genesee Unit 3, the capital costs are approximately $2.5 million and operating costs are expected to be approximately $1.0 million per year. Capital Power anticipates it will be charged the costs associated with these requirements under its Sundance PPA.

Ontario

In May 2009, the Ontario Government introduced to the Ontario Legislature proposed amendments to the *Environmental Protection Act* that will enable the government to establish a provincial GHG cap and trade system. The government has stated that it aims to harmonize its cap and trade program with Canadian federal, North American and international approaches. However, the timing and specifics of such a GHG cap and trade system are not known at this time, although public consultation occurred through the fall of 2009 and final regulations may not be implemented until 2012. There is insufficient information at this time to determine the impact of this proposed system on Capital Power, although as additional regulation is passed it likely Capital Power will incur increased costs.

U.S.

Capital Power continually assesses the potential impact on its assets of future legislation and regulatory requirements in the U.S. for certain air emissions regulations including those related to climate change.

U.S. - Greenhouse Gas Regulation

The United States Environmental Protection Agency introduced a federal Greenhouse Gas Mandatory Reporting Rule (MRR) which came into effect December 29, 2009 with a reporting deadline currently scheduled for March 2011. In addition, the State of California has also implemented mandatory GHG reporting with a reporting deadline scheduled for April 1, 2010. Capital Power is able to meet the reporting requirements of both jurisdictions.

In December 2009 the U.S. Environmental Protection Agency (USEPA) reached a finding that the current and projected concentrations of GHG in the atmosphere threaten the public health and welfare of current and future generations. This finding does not impose any regulatory requirements but is a prerequisite to any future GHG regulations imposed by USEPA. It is expected that instead of regulations established by USEPA that U.S. Congress will work to establish some form of GHG legislation.

Several U.S. Senators have proposed Climate Change bills, with the American Clean Energy and Security Act and the Clean Energy Job and American Power Act as the two prominent bills. These two bills are receiving the majority of the focus, but there are other bills that have been recently proposed. With multiple bills proposed and no clear direction from the climate change meeting in Copenhagen the direction of U.S. federal climate change legislation remains unclear. Consistent with the Copenhagen Accord the U.S.

submitted its GHG emission reduction targets to be in the range of 17% reduction of GHG emissions from 2005, the base line year, by 2020. It also indicated that pending legislation would entail a 30% reduction in 2025 and a 42% reduction in 2030, in line with the goal to reduce emissions 83% by 2050. Notwithstanding the announcement of the new target there is insufficient information to determine the impact of the U.S. climate change regulations on Capital Power, although to the extent additional regulation is passed, it is likely Capital Power will incur increased costs.

Several states have proposed or implemented various climate change legislation. Seven New England states have implemented the Regional Greenhouse Gas Initiative (RGGI). The regulations are implemented on a state-by-state basis. CPILP's Kenilworth site is exempt based on size.

The Western Climate Initiative (WCI), a collaborative effort of Western states and certain Canadian provinces, including BC and Ontario, to reduce GHGs, may impact the operation of CPILP's four facilities in California, the Frederickson facility in Washington, the Williams Lake Facility in BC and the Ontario facilities. With respect to federal GHG regulation, RGGI and the WCI, Capital Power is monitoring the regulatory process to understand the potential impact of these initiatives, but at this time there is insufficient information to assess the full financial and operational implications on these facilities. To the extent that additional regulation is passed, Capital Power could incur increased costs.

U.S. - Air Emission Regulations

Capital Power performs on-going assessments of the potential impact of future legislation and regulatory requirements for certain air emissions under the U.S. Clean Air Act (CAA). In July, 2008, the U.S. Court of Appeals for the District of Columbia Circuit vacated the CAA Clean Air Interstate Rule (CAIR) which was designed to control NOx and SO_2 emissions through a regional cap and trade program. In December 2008, a full panel of the same court decided to remand CAIR to the USEPA rather than vacating the rules. The December 2008 ruling leaves CAIR and the CAIR trading programs in place until USEPA issues a new rule to replace CAIR in accordance with the July 2008 decision. USEPA informed the Court that development and finalization of a replacement rule could take up to two years. Despite the delay, it is anticipated that CAIR may require reductions in NOx and SO_2 at CPILP's Southport and Roxboro facilities. CPILP has elected to move forward with planned capital upgrades to emissions control equipment to reduce NOx and SO_2 emissions and improve economic performance. Assuming that CAIR remains in effect, CPILP may have to purchase additional NOx and SO_2 credits in the short term (2010-2011), but should subsequently have allocations of allowances in excess of those needed for compliance. Such excess allowances would be available for sale. The cost of the NOx and SO_2 credits is estimated at $1.5 million per annum. Given the continuing uncertainty about the future of CAIR, Capital Power will continue to monitor and assess the situation.

The Clean Air Mercury Rule (CAMR) was vacated prior to the CAIR vacation but unlike CAIR, the CAMR vacation is final. The state of North Carolina could still promulgate maximum available control technology standards under Section 112(j) of the CAA, which would establish facility-specific mercury limits. While the USEPA intends to propose new air toxics standards for coal and oil-fired electric generating units by the end of the first quarter of 2010, the fuel mix and other controls at the Southport and Roxboro plants should preclude additional requirements for further mercury controls.

U.S. - Comprehensive Environmental Response, Compensation and Liability Act

The *Comprehensive Environmental Response, Compensation and Liability Act* (CERCLA), also referred to as "Superfund", requires investigation and remediation (cleanup) of sites from which there has been a release or threatened release of hazardous substances. It also authorizes the Environmental Protection Agency to take response actions at Superfund sites, including ordering potentially responsible parties liable for the release to pay for such actions. Many states have similar laws. CERCLA defines "potentially responsible" broadly to include past and present owners and operators of, as well as generators of wastes, sent to a site. As of the present time, Capital Power is not subject to any material liability for any Superfund matters. However, Capital Power generates certain wastes, including hazardous wastes, and sends certain of its wastes to third party waste disposal sites. As a result, there can be no assurance that Capital Power will not incur liability under CERCLA in the future.

Initiatives

As part of its strategy to reduce its GHG emission and to be better positioned for compliance with future regulation, the Company has a focus on technology to reduce CO_2 from coal generation. The Genesee 3 plant and the Keephills 3 facility currently under construction, use supercritical coal-burning technology which reduces CO_2 by 18% as a result of the facilities' design. In addition, the Company is participating in a $33 million research project to complete a front-end engineering design study of a clean coal project. The Company, Alberta Energy Research Institute and NRC have each contributed $11 million to the study. The study is to be completed in early 2010. Additionally, the Company announced it will be partnering with TransAlta and Alstom Canada to develop one of the world's largest carbon capture and storage (CCS) projects as part of Keephills 3 which will be designed to capture approximately 1 million tonnes of GHG emissions annually. The project has signed a letter of intent with the Province of Alberta to receive funding from the province's $2 billion CCS fund. The Government of Canada is also contributing toward the project through its Clean Energy Fund.

Counterparty Risk

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 steam purchase agreements may not be replaceable on similar terms, particularly those agreements that have favourable pricing for Capital Power relative to their current markets. Capital Power is also dependant upon counterparties with respect to its cogeneration hosts and suppliers of fuel to its plants. In the wholesale electricity market, should a counterparty default, Capital Power may not be able to effectively replace such counterparty in order to manage short or long electricity positions, resulting in reduced revenues or increased power costs. Failure of any such counterparties could impact the operations of some of Capital Power's plants and could adversely impact Capital Power's financial results. Furthermore, a prolonged deterioration in economic conditions could increase the foregoing risks.

The Company's risk management program includes a credit policy which has been approved by the Board of Directors. The credit policy establishes limits for credit risk exposure levels and provides the framework for counterparty credit risk management activities within the Company. The credit review procedures require assessment of individual counterparty creditworthiness and establishment of a credit limit prior to entering into a transaction with the counterparty. Periodic credit reviews are also conducted on existing counterparties with which the Company has credit exposure. The Company uses credit enhancements such as cash deposits, parent company guarantees and bank letters of credit as well as master netting agreements, margin accounts and credit derivatives to mitigate its credit risk. The credit management procedures also provide for monitoring the Company's credit risk exposures and regular reporting to the executive team.

Health and Safety Risk

The ownership and operation of Capital Power's generation assets carry an inherent risk of liability related to public health and worker health and safety, including the risk of government imposed orders to remedy unsafe conditions and potential penalties for contravention of health and safety laws and potential civil liability. Capital Power may become subject to government orders, investigations, inquiries or other proceedings (including civil claims) relating to health and safety matters as a result of which its operations may be limited or suspended. The occurrence of any of these events or any changes, additions to or more rigorous enforcement of, health, safety and environmental laws could have a material and adverse impact on operations and result in significant expenditures. Capital Power's operations are subject to the risks of a widespread influenza outbreak or other pandemic illness that could disrupt its operations and have a material adverse effect on Capital Power.

The Company manages its health and safety risks through a company-wide health and safety management system and measures its health and safety performance against recognized industry and internal performance measures. Compliance audits are conducted by internal and external auditors to verify that the health and safety management system meets the regulatory requirements for the businesses in which it operates. The Company has plans to respond to potential pandemic influenza to help maintain a sufficient healthy workforce and enable the Company to deliver reliable power to customers in such an event.

Political, Legislative and Regulatory Risk

Capital Power is subject to significant regulatory oversight and control in the jurisdictions in which it operates. Existing federal, provincial, state, local or common law and regulations applicable to Capital Power may be revised or reinterpreted and new laws and regulations may be adopted or become applicable to it. The political conditions in the jurisdictions in which Capital Power operates are also subject to change. It is not possible to predict whether there will be any further changes in the regulatory environment or what the ultimate effect of a changing regulatory environment would have on its business, income tax status or operations. Any new law or regulation could require Capital Power to make significant expenditures to achieve or maintain compliance, and failure to comply with any such law or regulation in a timely manner could have a material adverse effect on Capital Power.

Capital Power is also required to maintain numerous licenses, permits and governmental approvals for operation of its projects. If Capital Power fails to satisfy the conditions or comply with any of the restrictions imposed under its licenses, permits and governmental approvals, or the restrictions imposed under any statutory or regulatory requirement, it may become subject to regulatory enforcement action and the operation of the affected project(s) could be adversely affected or subject to fines, penalties or additional costs. In addition, Capital Power may not be able to renew, maintain or obtain all necessary licenses, permits and governmental approvals required for the continued operation of its projects, as a result of which the operation of Capital Power's projects may be limited or suspended. Capital Power's failure to renew, maintain or obtain all necessary licenses, permits or governmental approvals could have a material adverse effect on its assets, liabilities, business, financial condition and results of operations.

The development, construction and operation of power generation facilities requires regulatory approval from multiple levels of government and government agencies. Many of the regulatory approval processes include a stakeholder input component and/or specific requirements for stakeholder consultation and issue resolution. Capital Power’s permits and approvals for facility expansions, new facilities, decommissioning, license renewals and ongoing operations could be denied or revoked, subjected to conditions that affect the economic viability of the project or delayed causing negative economic impacts due to the stakeholder intervention.

Liquidity Risk

Capital Power's internally generated funds from operations may not provide sufficient capital for Capital Power, whether to undertake or complete ongoing or future development, enhancement opportunities or acquisition plans or otherwise, and, accordingly, Capital Power may require additional financing from time to time. The ability of Capital Power to refinance existing indebtedness and arrange additional financing in the future will depend in part upon prevailing market conditions at the time as well as the business performance of Capital Power. Uncertainty and volatility in global markets, and in particular, the Canadian and U.S. financial markets, may adversely affect Capital Power's ability to arrange permanent long-term financing for significant capital expenditures and potentially to refinance acquisitions and to refinance indebtedness under the credit facilities outstanding at their maturity dates. This may also affect credit ratings. There can be no assurance that debt or equity financing, the ability to borrow funds or cash generated by operations will be available or sufficient to replace financing as it matures or becomes due, or to meet or satisfy Capital Power's initiatives, objectives or requirements or, if financing is available to Capital Power, that it will be on terms acceptable to Capital Power. See Liquidity and Capital Resources. The inability of Capital Power to access sufficient amounts of capital on terms acceptable to Capital Power for its operations could have a material adverse effect on Capital Power's business, prospects and financial condition.

Sundance PPA Risk

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, including events which preclude the subsequent purchasers of the rights and obligations under such PPAs from fulfilling their obligations, could have a material negative impact on the ability of Capital Power to generate revenue. In such circumstances, Capital Power may be required to replace the electricity that was not delivered to it 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.

Reliance on Transmission Systems Risk

Capital Power depends on transmission facilities owned and operated by third parties to deliver the wholesale power it sells from its power generation plants to its customers. If transmission is disrupted, or if the transmission capacity infrastructure is inadequate or becomes damaged, Capital Power’s ability to sell and deliver wholesale power may be adversely impacted. If a region’s power transmission infrastructure is inadequate, Capital Power's recovery of wholesale costs and profits may be limited. If restrictive transmission price regulation is imposed, the transmission companies may not have sufficient incentive to invest in expansion of transmission infrastructure.

Capital Power also cannot predict whether transmission facilities will be expanded in specific markets to accommodate competitive access to those markets. Capital Power’s ability to develop new projects is also impacted by the availability of various transmission and distribution systems. In the Company’s relationships with regulators and government it supports the timely development of appropriate transmission capability.

Labour Risk

Capital Power’s ability to continuously operate its facilities and grow the business is dependent upon 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 few years**.** In addition, the competition for labour and management, particularly in Alberta and British Columbia, can be extremely competitive, posing a risk of shortages of workers with required skills and risks to the timing and cost of projects in those provinces. Failure to secure sufficient qualified labour may negatively impact Capital Power’s operations or materially increase expenses. The Company employs good human resource practices including monitoring developments and reviewing its strategies in human resources.

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. Future industrial action, or the threat of future industrial action by Capital Power's employees in response to any future efforts by management to reduce labour costs, restrain wage increases or modify work practices, could adversely affect Capital Power's business by disrupting operations or constraining Capital Power's ability to carry out such efforts. In the event of a labour disruption such as a strike or lock-out, the ability of Capital Power's generation assets to generate electricity may be impaired.

Technology Risk

Improvements to current electricity generation technologies could render certain existing technologies obsolete. To the extent that research and development activities improve upon existing alternative power technologies, including fuel cells, micro turbines, wind turbines and photovoltaic (solar) cells, it is possible that such technological advances will further reduce the cost of alternative methods of power generation. In addition, newer plants owned by Capital Power’s competitors may be more efficient than Capital Power's plants, which may put some of these plants at a competitive disadvantage to the extent Capital Power’s competitors are able to consume the same, less, or lower cost fuel as Capital Power’s plants consume. Over time, Capital Power’s plants may be displaced from their markets, or may be unable to compete with these more efficient plants. If this were to happen, Capital Power's assets, liabilities, business, financial condition and results of operations could be materially and adversely affected as a result.

Dependence on CPLP, Operating Subsidiaries and CPILP Risk

The Corporation’s principal assets are the equity interests it owns in CPLP, its operating subsidiaries and CPILP. As a result, the Corporation is dependent upon cash dividends, distributions or other transfers from CPLP, its subsidiaries and CPILP in order to repay any debt the Corporation may incur, make dividend payments to its shareholders and meet its other obligations. The right of the Corporation, as a unitholder of CPLP, as a shareholder of any of its subsidiaries and as a unitholder of CPILP, to realize on the assets of

CPLP, any subsidiary or CPILP in the event of the bankruptcy or insolvency of the subsidiary would be subordinate to the rights of creditors of CPLP, its subsidiaries and CPILP 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. Under CPILP's revolving credit facilities, CPILP may not declare, make or pay distributions if (subject to certain limited exceptions) a default or event of default has occurred and is continuing under such facilities. In addition, CPILP may not make any distributions if the declaration of dividends on preferred shares issued by a CPILP subsidiary is in arrears. The market price for limited partnership units of CPILP, and accordingly the value of Capital Power's investment in CPILP, may be volatile and subject to wide fluctuations in response to numerous factors, many of which are beyond Capital Power's and CPILP's control.

Derivatives and Energy Trading Risk

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 higher prices in the future, which not only may result in lost opportunity costs but also may require Capital Power to post significant amounts of cash collateral or other credit support to its counterparties. 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 or if a counterparty fails to perform under a contract.

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 timing differences that may be associated with buying and transporting fuel, converting fuel into energy and delivering the energy to a buyer.

In order to mitigate these risks, the Company has a Commodity Risk Management Program in place. The Program provides an infrastructure that enables the Company to manage commodity and trading risks associated with the commodity business. In addition, the Company takes market risk positions within authorized limits approved by Capital Power's executive team and Board of Directors. Key risk measures in relation to applicable limits are reported daily to the executive team and reviewed by the Board of Directors quarterly. The Company employs specific volumetric limits and a Value-at-Risk (VaR) methodology to manage risk exposures to commodity prices. VaR measures the estimated potential loss over a given period of time at a given level of confidence. Capital Power's VaR uses a statistical confidence interval of 95% over a twenty business day holding period. This measure reflects a 5% probability that, over the twenty day period, the fair value of the overall commodity portfolio could decrease by an amount in excess of the VaR amount. As VaR is not a perfect measure the Company applies a safety factor to the calculated VaR amount to estimate total exposure (TE) which attempts to capture unaccounted for exposures. Capital Power's Board of Directors has approved an aggregate TE limit which is monitored and reported to the executive team on a daily basis. To supplement the total exposure estimates, the portfolio is stress-tested regularly to observe the effects of plausible scenarios taking into account historical maximum volatilities and maximum observed price movements.

Weather Risk and Catastrophic Event Risks

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. Capital Power's operations are exposed to potential damage, including partial or full loss, resulting from disasters such as an earthquake, hurricane, fire, explosion, flood, severe storm, terrorist attack or other comparable events. In certain cases, there is the potential that some events may not excuse Capital Power from performing its obligations pursuant to agreements with third parties. Capital Power may be liable for damages or suffer further losses as a result.

Financial exposures associated with extreme weather are partially mitigated through the Company's insurance programs.

Foreign Exchange Risk

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.

The foreign exchange risk of anticipated U.S. dollar denominated cash flows, net of debt service obligations, is managed through the use of forward foreign exchange contracts for periods of up to seven years. In addition, large value equipment purchase prices are generally fixed in Canadian dollars by contracting in Canadian dollars or using forward foreign exchange contracts.

Risk That Future Acquisition Activities May Have Adverse Effect

Capital Power may seek to acquire additional companies or assets in Capital Power's industry. The acquisition of power generation companies and assets is subject to substantial risks, including the failure to identify material problems during due diligence, the risk of over-paying for assets and the inability to arrange financing for an acquisition as may be required or desired. Further, the integration and consolidation of acquisitions requires substantial human, financial and other resources and, ultimately, Capital Power's acquisitions may not be successfully integrated. Despite extensive due diligence procedures prior to any acquisition, 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.

General Economic Conditions, Business Environment and Other Risks

The business of Capital Power is subject to the general economic conditions of the jurisdictions in which Capital Power operates. Adverse changes in general economic and market conditions could negatively impact demand for electricity, revenue, operating costs, results of financing efforts, and the timing and extent of capital expenditures. Volatility in natural gas prices, coal prices, other fuel prices, future electricity prices, and fluctuations in interest rates, product supply and demand, market competition, risks associated with technology, risks associated with existing and potential future lawsuits and other regulations, assessments and audits (including income tax) against Capital Power and its subsidiaries and difficulty in obtaining necessary regulatory approvals could materially adversely impact Capital Power's business, prospects, financial condition, results of operation or cash flows.

Capital Power's operations are complex, and the computation of the provision for income taxes involves 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 believes 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 the Canada Revenue Agency or other taxation authorities with respect to Capital Power's tax filings.

Capital Power employs several key computer application systems to support its operations, such as electricity plant control systems and electricity settlement and billing systems. Failure of any of these systems to prevent malicious corruption of systems or electronic theft of data or to accurately capture data and, through their operation, produce timely and accurate information could result in lost revenue, regulatory fines or the occurrence of public health issues. The Company has security measures which protect its IT assets and application systems to mitigate the risk related to loss of data due to theft or corruption. In addition, system recovery programs are in place to minimize any losses experienced as a result of a computer application system shutdown.

Capital Power's property, business interruption and liability insurance is 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, all events that could give rise to a loss or liability are insurable, or the amounts of insurance (net of applicable deductibles) will at all times be sufficient to cover each and every loss or claim that may occur involving the assets or operations of the facilities or Capital Power.

In the normal course of Capital Power's operations, it may become involved in, named as a party to or the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, relating to personal injuries, property damage, property taxes, land rights, the environment and contract disputes. The outcome with respect to outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to Capital Power and as a result, could have a material adverse effect on Capital Power's assets, liabilities, business, financial condition and results of operations.

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.

Risks Related to Significant Ownership by EPCOR

For so long as EPCOR maintains a significant indirect equity and voting interest in the Corporation, including its Special Voting Shares and the Special Limited Voting Shares of the Corporation and the general partner of CPLP, 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 Corporation. However, EPCOR has advised the Company that it intends to act only as an investor in and not as a manager of the Company.

In addition, EPCOR may not act in a way that promotes the interest of the Corporation's other shareholders. Furthermore, EPCOR's significant equity ownership may discourage transactions involving a change of control of the Corporation, 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 share holders 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.

Risks Related to Ability of the Corporation and EPCOR to Sell Common Shares

EPCOR has no contractual obligation to retain any Exchangeable LP Units or Common Shares. EPCOR has advised the Corporation that it may eventually sell all or a substantial number of the Common Shares underlying its Exchangeable LP Units, subject to market conditions, its requirement for capital and other circumstances that may arise in the future. Any sale of substantial amounts of Common Shares in the public market by EPCOR or the Corporation, or the perception that such sales could occur, could adversely affect prevailing market prices for the Common Shares and impede the Corporation's ability to raise capital through the issuance of additional equity securities.

Risk of Possible Business Conflicts of Interest between Capital Power and EPCOR

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 any potential conflicts, and, even 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 Corporation.

Conflict of Interest Risk with CPILP

As a result of Capital Power's relationship with CPILP, certain conflicts of interest could arise and Capital Power may find that its interests are not aligned with those of CPILP. CPILP's terms of reference for the board of directors of CPILP's general partner denote that the board of directors shall be composed of not more than eight members, at least four of whom shall be independent directors who are not officers, directors or employees of the Corporation, its subsidiaries and affiliates and are free from any direct or indirect interest, any business or other relationship that could interfere with a director's independence or ability to act in the best interests of CPILP's general partner and CPILP. Any non-arms' length agreements or transactions between CPILP and Capital Power are evaluated solely by a committee of independent directors of CPILP. There are four senior officers of the Corporation who are members of CPILP's General Partner's board of directors and are not considered independent in relation to CPILP. The Chairman, who is an executive officer of the Corporation, has a casting vote in case of a tie vote at any meeting of the board of directors of CPILP's general partner.

Future Accounting Changes

International Financial Reporting Standards

In February 2008, the CICA confirmed that Canadian reporting issuers will be required to report under International Financial Reporting Standards (IFRS) effective January 1, 2011, including comparative figures for the prior year.

In January 2008, EPCOR established a core team to develop a plan which would result in the first interim report for 2011 being in compliance with IFRS. In July 2009, Capital Power organized its own IFRS team to work in conjunction with the EPCOR core team to continue with the plan and implement IFRS in Capital Power in time to meet the 2011 reporting requirements. The terms of the services to be provided by EPCOR to Capital Power for IFRS support are outlined in the Services Agreement by and between Capital Power and EPCOR.

The diagnostic phase of the project was completed in April 2008. For each international standard, EPCOR identified the primary differences from Canadian GAAP and made an initial assessment of the impact of the required changes for the purpose of prioritizing and assigning resources. The assessments were subsequently reviewed from a Capital Power perspective. The following standards are likely to have a significant impact on Capital Power:

International Financial Reporting Standard
IFRS 7, IAS 32, IAS 39 Financial Instruments
IAS 23 Borrowing Costs
IAS 18 Revenue
IAS 16 Property, Plant and Equipment
IAS 31 Interests in Joint Ventures
IAS 21 The Effects of Changes in Foreign Exchange Rates
IFRS 3 Business Combinations
IAS 12 Income Taxes
IAS 17 Leases
IAS 37 Provisions, Contingent Liabilities and Contingent Assets
IAS 36 Impairment of Assets

The information obtained from the diagnostic phase was used to develop a detailed plan for convergence and implementation. The convergence and implementation work has five key sections: Financial Statement Adjustments, Financial Statements, Systems Updates, Policies and Internal Controls, and Training.

Financial Statement Adjustments

For each international standard, the Company will determine the quantitative impacts to the financial statements, system requirements, accounting policy decisions, and changes to internal controls and business policies. The initial accounting policy decisions will be brought forward to the Audit Committee for their information as each standard is addressed. However, final accounting policy decisions for all standards in effect at the end of 2009 will be made in the fourth quarter of 2010, as they should not be determined in isolation of other policy decisions. Policy decisions for any new or amended standards issued in 2010 will be made in conjunction with the Company's analysis of those standards in 2010.

The more significant impacts of IFRS on the Company are expected to be:

- Property, plant and equipment (PP&E) will be primarily impacted by IAS 16 – Property, Plant and Equipment and IAS 23 – Borrowing Costs. Unlike Canadian GAAP, IFRS does not allow certain costs related to the construction PP&E, such as training costs, overheads and borrowing costs in excess of the actual entity's cost of debt, to be capitalized.

  Accounting for the components of PP&E is required at a more detailed level under Canadian GAAP than under IFRS. IFRS require a separate component for assets with a distinct depreciation method or rate of deprecation. The implementation of this standard is expected to result in increased depreciation expense for Capital Power. The Company expects to quantify this impact by the end of the second quarter of 2010.

- IFRS 3 – Business Combinations requires non-controlling interests to be recognized at fair value on acquisition, or at the non-controlling interests' share of the amounts recognized for the acquisition excluding goodwill. Under Canadian GAAP, non-controlling interests are initially recognized at amounts based on the carrying amounts in the acquired entity's financial statements. In the second quarter of 2010, the Company will review the potential impact of this section's requirements on accounting for the July 2009 Reorganization.

- IAS 37 – Provisions, Contingent Liabilities and Contingent Assets requires asset retirement obligations to be measured at management's best estimate of the costs of decommissioning assets whereas Canadian GAAP requires such obligations to be measured at the cost of using third party services for decommissioning. Since the Company's decommissioning work is generally performed by the employees of the Company, the estimated decommissioning costs would be significantly less under IFRS than the Company's current estimates under Canadian GAAP. Accordingly, if the provisions of IAS 37 remain unchanged, there should be a decrease in the asset retirement obligation upon conversion to IFRS. However, the International Accounting Standards Board issued an exposure draft which proposes to replace IAS 37 with a new standard that would require decommissioning liabilities to be measured using third party cost estimates. A revised standard is expected in the third quarter of 2010.

- IAS 36 – Impairment of Assets requires a one-step approach using discounted cash flow techniques for asset impairment testing and measurement. Canadian GAAP's two-step approach requires the application of discounted cash flow techniques to measure the impairment amount, but only after the use of undiscounted cash flow analysis has indicated the existence of an impairment. The adoption of IAS 36 may result in more frequent asset write downs since the carrying values of assets which are supported by undiscounted future cash flows may be determined to be impaired when the future cash flows are discounted in accordance with the IFRS requirements. Unlike Canadian GAAP, previous impairment losses may be reversed or reduced under IFRS if the circumstances which led to the impairment change.

  IAS 36 also requires impairment testing to be applied at a cash-generating unit level, which will likely be determined to be by individual plant for Capital Power. In addition, goodwill must be allocated to cash-generating units for impairment testing purposes. Under Canadian GAAP goodwill is not allocated to plants. Accordingly, the transition to IAS 36 increases the likelihood of a goodwill write down. The Company expects to have quantified the impact of IAS 36 in the second half of 2010.

- IFRS 1 – First Time Adoption of IFRS provides first time adopters with a number of elections, exempting them from retrospectively adopting certain IFRS. The following elections are relevant to Capital Power:

  An entity may deem the cost of an asset at the date of transition to be its fair value at that date. This election is available on an asset by asset basis.

  An entity may select any date prior to the transition date and elect to not apply IFRS 3 Business Combinations retrospectively to business combinations occurring prior to that date.

  On transition, an entity may elect to deem any balance for cumulative translation amounts to be zero and to reclassify the previous balance to retained earnings with no impact on the income statement.

On transition, an entity is not required to reassess its determination of a contract as a lease. An entity may also choose to determine whether an arrangement existing at the date of transition contains a lease on the basis of facts and circumstances existing at that date, rather than at the date of inception of the lease.

An entity may apply a simplified calculation for the restatement of decommissioning liabilities and associated property, plant and equipment and accumulated depreciation.

An entity may elect to recognize all cumulative actuarial gains and losses relating to employee benefits at the date of transition.

Capital Power has not made any decisions or recommendations with respect to any of the elections.

Capital Power anticipates completing the quantification of the opening financial statement adjustments resulting from the application of all currently effective IFRS, by the end of the third quarter of 2010.

As the project progresses, the timing of the completion of certain items may be impacted by changes to the standards and changes in priorities resulting from external factors such as discussions with stakeholders. However, the Company believes the project has sufficient resources to meet the overall project timeline.

Financial Statements

There are a number of international standards which relate to financial statement presentation. Draft financial statements highlighting the disclosure and presentation requirements will be reviewed by and discussed with the Audit Committee in March 2010. The development of the financial statement presentation will evolve throughout the project as the impacts of implementing the various standards are quantified.

Systems Updates

Systems must be able to capture 2010 financial information under both the prevailing Canadian GAAP and IFRS to allow comparative reporting in 2011, the first year of reporting under IFRS. The Company completed its system updates in the third quarter of 2009 to meet both requirements and is implementing the operational procedures to capture the applicable accounting data throughout 2010.

Policies and Internal Controls

In the determination of the financial statement adjustments, requirements for changes to the Company's policies and internal controls are being identified and documented. As there may be factors other than IFRS impacting the policies and internal controls, the formal documentation and approval of revised policies and internal controls will not occur until the third quarter of 2010.

The impact of IFRS on certain agreements, such as debt, shareholder and compensation agreements, has also been included in the plan. Assessments of most agreements have been completed and will continue to be monitored as IFRS differences are quantified.

Training

The Company recognizes that training at all levels of the Company is essential to a successful conversion and integration. Accounting staff have attended three training sessions with more planned to occur throughout the conversion process. A training session for the Board of Directors and Audit Committee is scheduled for March 2010 and the Audit Committee will receive regular updates throughout 2010.

In January 2009, the CICA issued Handbook Sections 1601 - Consolidated Financial Statements, Section 1602 – Non-controlling Interests and Section 1582 - Business Combinations, which are effective on January 1, 2011. These amendments are included in the scope of the Company's IFRS project.

Disclosures about financial instruments

In June 2009, the CICA amended Handbook Section 3862 Financial Instruments – Disclosures, to adopt the amendments recently made by the International Accounting Standards Board to IFRS 7 Financial Instruments: Disclosures. The amendments require enhanced disclosures about fair value measurements, including the relative reliability of the inputs used in those measurements, and about the liquidity risk of financial instruments. The classification of the Company's fair value measures and accompanying disclosures are included in Note 21 of the consolidated financial statements.

Critical Accounting Estimates and Policies

In preparing the consolidated financial statements, management necessarily made estimates in determining transaction amounts and financial statement balances. The following are the Company's most significant accounting policies and the items for which critical estimates were made in the financial statements.

Revenue recognition under PPAs

Revenues from the Company's power generation plants are recognized upon delivery of output or upon availability for delivery as prescribed by contractual arrangements. These contractual arrangements are also commonly referred to as PPAs. Revenues under the Curtis Palmer and Morris PPAs are recognized at the lower of (1) the 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. Any excess of the contract price for the period over the average price is recorded as deferred revenue.

Financial instruments

The Company is required to estimate the fair value of certain assets and obligations for determining the valuation of certain financial instruments. The financial instrument fair value measurements that are recognized in the consolidated balance sheet are categorized into three levels of a hierarchy based on the reliability of the inputs used to estimate the fair value, as described below. The fair value measurement for a financial instrument is included in the lowest level of those levels attributable to its significant inputs.

Level 1 – Fair value is based on unadjusted quoted prices in active markets for identical instruments.

Level 2 – Fair value is based on other than unadjusted quoted prices included in level 1, which are either directly or indirectly observable. This includes models using inputs that are quoted prices in active markets for similar instruments, quoted prices for identical or similar instruments in markets that are not active and other observable inputs that are principally derived from or corroborated by observable market data for substantially the full term of the instrument. The majority of the Company's fair value estimates for financial instruments are based on valuation models, primarily the discounted cash flow model, that directly or indirectly use observable market inputs. The observable market inputs include commodity prices, interest rates, foreign exchange rates, and credit spreads.

Level 3 – Fair value is based on models using significant inputs that are not based on observable market data. The Company uses models with unobservable inputs to estimate the fair value of its financial instruments that are not actively traded. For example, the fair values of certain credit derivative and option products are estimated using models with unobservable inputs such as default probabilities and volatilities.

The Company's equity investments that do not have quoted market prices in active markets are classified as available for sale and are recorded at their cost amount on the balance sheet. Management assesses these financial assets for impairment by estimating their fair values based on discounted expected cash flow analyses. Such analyses consider factors such as the financial condition and future prospects of the issuer of the instrument. On December 31, 2009, the Company recorded an impairment loss of $4 million on venture capital investments classified as available for sale.

Long-lived assets

Depreciation and amortization allocate the cost of assets over their estimated useful lives on a systematic and rational basis. Depreciation and amortization also include amounts for future decommissioning costs and asset retirement obligation accretion expenses. Estimating the appropriate useful lives of assets requires significant judgement and is generally based on estimates of the life characteristics of common assets.

The Company reviews the valuation of long-lived assets subject to amortization when events or changes in circumstances may indicate or cause a long-lived asset's carrying amount to exceed the total undiscounted future cash flows expected from the asset's use and eventual disposition. An impairment loss, if any, would be recorded as the excess of the carrying amount of the asset over its fair value.

For determining purchase price allocations for business combinations, the Company is required to estimate the fair value of acquired assets and obligations. Goodwill arising on business combinations is tested for impairment annually or more frequently if events and circumstances indicate that a possible impairment may exist. To test for impairment, the fair value of the reporting unit to which the goodwill relates is compared with the carrying value, including goodwill, of the reporting unit. If the carrying value of the reporting unit exceeds its fair value, the fair value of the reporting unit's goodwill is compared with its carrying amount to measure the impairment loss, if any.

Estimates of fair value for goodwill and other asset impairments, and purchase price allocations are primarily based on depreciable replacement cost or discounted cash flow techniques employing estimated future cash flows based on a number of assumptions and using an appropriate discount rate. The cash flow estimates will vary with the circumstances of the particular assets or reporting unit and will be based on, among other things, the lives of the assets, contract prices, estimated future prices, revenues and expenses, including inflation, and required capital expenditures.

Asset retirement obligations

The fair values of asset retirement obligations are estimated using the total undiscounted amount of the estimated future cash flows required to settle the obligations and applying the appropriate credit-adjusted risk-free discount rate. In this process assumptions are made regarding the useful lives of the assets and the legal restoration obligations. The range for the estimates of fair value for the purposes of determining an asset retirement obligation varies by asset.

Income taxes

The Company follows the asset and liability method of accounting for income taxes. Income tax expense is based on the earnings of the period, the jurisdiction in which the income is earned, and any differences between the calculations of pre-tax income under Canadian GAAP and income tax law. These factors impact the income tax rates and amounts of income tax expense.

Current income taxes are recognized for the estimated income taxes payable or recoverable for the period. Estimates of future income taxes resulting from temporary differences between the carrying values of assets and liabilities in the financial statements and their tax values are recognized as future income tax assets and liabilities. The Company applies estimated future income tax rates to the temporary differences to determine the amount of income tax expense and change in future income tax assets and liabilities for the period. The future income tax rates are estimated based on the rates that are anticipated for the future periods in which the temporary difference are expected to reverse. When a government announces a change in future income tax rates, the carrying amounts of the Company's future income tax assets or liabilities are adjusted and reflected in income tax expense or other comprehensive income as appropriate. In the six months ended December 31, 2009, the impact of changes in income tax laws and rates resulted in a $2 million reduction in income tax expense.

Future income tax assets are assessed to determine the likelihood that they will be recovered from future taxable income. To the extent recovery is not considered likely, a valuation allowance is recorded and charged against income in the period that the allowance is created or revised.

Estimates of the provision for current income taxes, future income tax assets and liabilities and any related valuation allowance might vary from actual amounts incurred. Income taxes will vary with taxable income and, under certain conditions, with fair values of assets and liabilities. The effective income tax rate can change depending on the mix of earnings from different jurisdictions, the magnitude of tax amounts and income attributable to non-controlling interests, and the amount of deductions that do not fluctuate with earnings. The effective tax rate on earnings before income taxes for the six months ended December 31, 2009 was 8% and was lower than the statutory income tax rate primarily due to $23 million of income taxes related to taxable income attributable to non-controlling interests.

Leases or arrangements containing a lease

Leases or other arrangements entered into for use of property, plant and equipment are classified as either capital or operating leases. Leases or other arrangements that transfer substantially all of the benefits and risks of ownership of property to the Company are classified as capital leases. Equipment acquired under capital leases is depreciated over the term of the lease. Rental payments under operating leases are expensed as incurred.

Certain power generation plants operate under PPAs that convey the rights to use the related property, plant and equipment to the holder of the agreements. Consequently, these power generation plants are accounted for as assets under operating leases.

Foreign currency translation

CPILP has operations in the U.S. with a functional currency of U.S. dollars. Accordingly, these operations are translated using the current rate method whereby assets and liabilities are translated into Canadian dollars at the exchange rate in effect at the balance sheet date. Revenues and expenses are translated at rates in effect at the time of the transactions. The resulting foreign exchange gains and losses are accumulated as a component of accumulated other comprehensive income.

Consolidation of CPILP and CPLP

While the Company indirectly owns only 30.4% (30.5% at December 31, 2009) of the outstanding units of CPILP and an approximate 27.8% interest in CPLP, it controls both partnerships under Canadian GAAP. Accordingly, CPILP and CPLP are consolidated in the financial statements of the Company.

Financial Instruments

The Company has various financial instruments that are classified for financial reporting purposes as available for sale, held for trading, held to maturity, or loans and receivables. Financial liabilities are classified as either held for trading or other liabilities. Initially, all financial assets and financial liabilities are recorded on the balance sheet at fair value with subsequent measurement determined by the classification of each financial asset and liability.

The Company classifies its cash, cash equivalents and current and non-current derivative instruments assets and liabilities as held for trading, and measures them at fair value. Accounts receivable and long-term loans are classified as loans and receivables and accounts payable and accrued liabilities are classified as other liabilities. Accounts receivable and accounts payable and accrued liabilities are measured at amortized cost and their fair values are not materially different from their carrying values due to their short-term nature.

The classification, carrying amounts and fair values of other financial instruments held at December 31, 2009 are as follows:

	Carrying amount		Fair value
(unaudited, $ millions)	Loans and receivables	Other financial liabilities	
Other assets	$ 75	$ -	$ 73
Long-term debt (including current portion)	$ -	$ 1,719	$ 1,724

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 balance sheet unless the Company elects the fair value exemption 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. The derivative instruments assets and liabilities used for risk management purposes are measured at fair value and consist of the following:

(unaudited, $ millions)	Energy cash flow hedges	Energy non-hedges	Foreign exchange non-hedges	Total
Total derivative instruments net assets (liabilities) as at December 31, 2009	$ (13)	$ 79	$ 25	$ 91

Energy derivatives designated as accounting hedges

At December 31, 2009, the net fair value of energy derivative instruments designated and qualifying for hedge accounting was a net liability of $13 million and is included in derivative instruments assets and derivative instruments liabilities on the consolidated balance sheet. The net derivative liability is primarily due to a decrease in the forward Alberta natural gas prices relative to the derivative 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 energy revenues, energy purchases, or fuel as appropriate when realized.

On July 31, 2009, CPILP applied hedge accounting to certain of its natural gas purchase contracts. An unrealized loss of $9 million for the decrease in the fair value of these contracts for the period from the inception of the hedge to December 31, 2009 was recognized in other comprehensive income. Prior to the application of the hedge, the unrealized changes in the fair value of these contracts were recognized in net income.

Energy derivatives not designated as accounting hedges

At December 31, 2009, the net fair value of energy derivative instruments not designated as hedges for accounting was a net asset of $79 million and is included in derivative instruments assets and derivative instruments liabilities on the consolidated balance sheet. This net derivative asset was primarily due to unrealized gains arising from a net short position for the portfolio combined with lower forward Alberta electricity prices, relative to the derivative contract prices.

At December 31, 2009, the fair value of the Company's forward foreign currency contracts was a net derivative instrument asset of $25 million. The net asset was due to the impact of a strengthening Canadian dollar relative to the U.S. dollar on forward foreign exchange sales contracts used to hedge U.S. dollar denominated revenues. The weighted average fixed exchange rate for contracts outstanding at December, 2009 was $1.11 for every U.S. dollar. Unrealized and realized gains and losses on foreign exchange derivatives that are not designated as hedges for accounting purposes are recorded in energy revenues or foreign exchange gains and losses.

All non-financial derivative instruments are measured at fair value unless they are designated as contracts used for the purpose of receipt or delivery of a non-financial item in accordance with the Company's expected purchase, sale or usage requirements as defined by accounting standards, or are designated and qualify for hedge accounting. Some of the Company's physical power and natural gas purchase and sales contracts that are used to meet power generation and retail customer requirements were not designated as contracts used in accordance with the Company's expected purchase requirements and therefore are recorded at fair value in the balance sheet.

Risk management and hedge accounting

The Company uses various financial and non-financial derivatives primarily for risk management purposes. Unrealized changes in the fair value of financial and non-financial derivatives that either do not qualify for hedge accounting or the Company elects not to apply hedge accounting, and non-financial derivatives that do not qualify for the expected purchase, sale or usage requirements of the contract, are recorded in energy revenues, energy purchases or 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, 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 balance sheet 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.

Other comprehensive income

Changes in the fair value of the effective hedge portion of the financial derivative contracts used to manage the energy portfolio and designated as accounting hedges, are recorded in other comprehensive income. The ineffective portion of the contracts is recorded in net income.

For the period ended December 31, 2009, losses on derivative instruments designated as cash flow hedges, net of income taxes, of $2 million were recorded in other comprehensive income for the effective portion of cash flow hedges, and a realized loss, net of income taxes, of $31 million was reclassified to energy purchases and revenues as appropriate. There was no ineffective portion of cash flow hedges for which unrealized gains or losses were required to be recognized in income. Of the $29 million in net unrealized fair value gains related to derivative instruments designated as cash flow hedges included in accumulated other comprehensive income at December 31, 2009, net losses of $5 million, net of taxes of $2 million are expected to settle and be reclassified to net income over the next twelve months.

Internal Control over Financial Reporting

As part of the Reorganization and acquisition of the power generation assets and operations from EPCOR in July 2009, the Company assumed the underlying processes and internal controls. The agreements between the Company and EPCOR for transitional and ongoing services between the two entities and their subsidiaries also provide for continuity of internal controls after the Reorganization and acquisition.

As of December 31, 2009, management conducted an evaluation of the design and effectiveness of the Company's disclosure controls and procedures to provide reasonable assurance that 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 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.

Also as of December 31, 2009, management conducted an evaluation of the design and effectiveness 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 Canadian 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 the six months ended December 31, 2009 that have materially affected, or are reasonably likely to materially affect the Company's internal control over financial reporting.

Forward-looking Information

Certain information in this MD&A is forward-looking within the meaning of Canadian securities laws as it relates 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.

Forward-looking information in this MD&A includes, among other things, information relating to: (i) expected timing of commercial operation and project cost of Keephills 3; (ii) expected improvement in and reduction of future plants' environment emission levels and ability to capture future emissions; (iii) expectations for the sources of capital and use of the Company's committed bank credit facilities; (iv) Capital Power's and CPILP's cash requirements for 2010, including expectations relating to capital expenditures; (v) expectations regarding future financial strength and access to and terms of future financings; (vi) the expected impact of the further reduction in the Company's interest in the Battle River PPA and of Keephills 3 coming on line, on cash flow from operations and operating margin; (vii) expectations for Alberta spot power prices in 2010 and their impact on operating margin and cash flow from operations; (viii) expectation that the Alberta commercial portfolio position in 2010 will reduce the exposure to changes in power prices; (ix) the Company's estimated sensitivity to Alberta power prices in 2010 and 2011; (x) the expected annual spending for maintenance capital and other capital for the Company as well as expected project completion dates; (xi) expectation that the two maintenance outages scheduled in 2010 at the Genesee site will reduce operating margin (excluding unrealized fair value adjustments) and cash flow from operations, and the expected amount of operating expense for the two outages; (xii) expectation that in 2010 Alberta commercial plants will represent 40% of operating margin excluding unrealized changes in the fair value of derivative instruments and that the operating margin will benefit from a full year of operation of the second and third units of Clover Bar Energy Centre; (xiii) expected future power demand and ability to meet demand; (xiv) expected plant performance and availability targets; (xv) expectations about future income and future CPLP and CPILP distributions; (xvi) expectations regarding future environmental regulation compliance costs; (xvii) expected business development costs and project completion dates as well as ability to receive government funding; (xviii) expected impact of transition to IFRS and expected project review completion dates; (xix) expectations regarding the Company's strategy, including (a) the Company's expectation to maintain a stable dividend and an investment-grade credit rating supported by contracted cash flows, (b) the Company's expectation to commit at least $500 million of new development or acquisitions in 2010, (c) the goal of owning or operating 10,000 MW of power generation by 2010 and (d) the Company's expectation of continuing to sell forward a significant portion of its generation output and capacity, and maintain a target for contracted plants to provide at least 50% of the Company's operating margin; (xx) expectations that CPILP's enhancement project for its Southport and Roxboro plants in North Carolina will reduce the plants' environment emission levels and improve their economic performance; and (xxi) expectations regarding the Company's operational target for 2010.

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 include, but are not limited to: (i) the operation of the Company's facilities; (ii) power plant availability, including those subject to acquired PPAs; (iii) the Company's financial position and credit facilities; (iv) the Company's assessment of commodity and power markets; (v) the Company's assessment of the markets and regulatory environments in which it operates; (vi) weather; (vii) availability and cost of labour and management resources; (viii) performance of contractors and suppliers; (ix) availability and cost of financing; (x) foreign exchange rates; (xi) management's analysis of applicable tax legislation; (xii) the currently applicable and proposed tax laws will not change and will be implemented; (xiii) currently applicable and proposed environmental regulations will be implemented; (xiv) counterparties will perform their obligations; (xv) renewal and terms of PPAs; (xvi) ability to successfully integrate and realize benefits of its acquisitions; (xvii) ability to implement strategic initiatives which will yield the expected benefits; and (xviii) the Company's assessment of capital markets and ability to complete future share offerings.

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 risks and uncertainties include, but are not limited to risks relating to: (i) operation of the Company's facilities; (ii) power plant availability and performance; (iii) unanticipated maintenance and other expenditures; (iv) availability and price of energy commodities; (v) electricity load settlement; (vi) regulatory and government decisions including changes to environmental, financial reporting and tax legislation; (vii) weather and economic conditions; (viii) competitive pressures; (ix) construction; (x) availability and cost of financing; (xi) foreign exchange; (xii) availability and cost of labour, equipment and management resources; (xiii) performance of counterparties, partners, contractors and suppliers in fulfilling their obligations to the Company; (xiv) developments in the North American capital markets; (xv) compliance with financial covenants; (xvi) ability to successfully realize the benefits of acquisitions and investments; and (xvii) the tax attributes of and implications of any acquisitions. If any such risks actually occur, they could materially adversely affect the Company's business, financial condition or results of operations. In that case the trading price of the Company's common shares could decline, perhaps materially.

This MD&A includes the following updates to previously disclosed forward-looking statements: (i) the estimated total costs for all three units at Clover Bar Energy Centre was revised from previous estimates of $284 million and $278 million to $263 million while the actual date for Clover Bar Energy Centre Unit 3 to commence commercial operations was December 16, 2009 revised from the previously disclosed timing of the first quarter of 2010; (ii) the expected timing of BC Hydro's selection of projects under its 2008 Clean Power Call was revised from the end of 2009 to the second quarter of 2010; (iii) the estimated completion date for the second phase of the FEED study for the Pioneer project was revised from June 2010 to the fourth quarter of 2010 or first quarter of 2011; and (iv) the expected completion date of upgrades at the Southport and Roxboro facilities was revised from the fourth quarter of 2009 to the second quarter of 2010.

Readers are cautioned not to place undue reliance on any such forward-looking statements, which speak only as of the date made. Forward-looking statements are provided for the purpose of providing information about management's current expectations, and plans relating to the future. Readers are cautioned that such information may not be appropriate for other purposes. 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.

Quarterly Information

Financial highlights

(unaudited, $ millions except earnings per share)	Three months ended	
	Dec 31, 2009	Sept 30, 2009
Revenues[3]	497	511
Gross margin[1]	216	218
Operating margin[1]	154	169
Net income	7	14
Earnings per share	$ 0.33	$ 0.64
Fully diluted earnings per share[2]	$ 0.30	$ 0.59
Funds from operations[1]	71	93
Normalized earnings per share[1]	$ 0.18	$ 0.42
Capital expenditures	127	108
Long-term debt including current portion	1,719	1,771
Total assets	5,036	4,918

(1) The consolidated financial information, except for gross margin, operating margin, funds from operations and normalized earnings per share, has been prepared in accordance with Canadian GAAP. See Non-GAAP Financial Measures.

(2) Fully diluted earnings per share is calculated after giving effect to the exchanged limited partnership units of CPLP (exchangeable for common shares of Capital Power on a one-for-one basis) held by EPCOR.

(3) Revenues for the three months ended September 30, 2009 have been restated for a reclassification which resulted in a reduction of revenue and energy purchases by $14 million each. The restatement had no impact on gross margin, operating margin or net income and the presentations for both periods in the table above are consistent.

Generation volume information

(unaudited, GWh)	Three months ended	
Electricity generation[1]	Dec 31, 2009	Sept 30, 2009
Alberta commercial plants		
Genesee 3	484	470
Joffre	73	89
Clover Bar Energy Centre 1, 2 and 3[2]	9	16
Taylor Coulee Chute	2	12
Clover Bar Landfill Gas	10	9
Weather Dancer	-	-
	578	596
Alberta contracted plants		
Genesee 1	618	837
Genesee 2	817	801
	1,435	1,638
Ontario and British Columbia contracted plants		
Kingsbridge 1	32	14
Miller Creek	14	47
Brown Lake	15	11
	61	72
CPILP plants	1,407	1,228
Total	**3,481**	**3,534**

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

(2) Clover Bar Energy Centre includes Units 2 and 3 as of their commercial operation dates, September 1, 2009 and December 16, 2009, respectively.

(unaudited)	Three months ended	
Generation plant availability[1]	Dec 31, 2009	Sept 30, 2009
Alberta commercial plants		
Genesee 3	99%	97%
Joffre	94%	96%
Clover Bar Energy Centre 1, 2 and 3[2]	98%	96%
Taylor Coulee Chute	66%	100%
Clover Bar Landfill Gas	94%	90%
Weather Dancer	0%	55%
	97%	96%
Alberta contracted plants		
Genesee 1	74%	100%
Genesee 2	97%	95%
	85%	97%
Ontario and British Columbia contracted plants		
Kingsbridge 1	100%	99%
Miller Creek	97%	88%
Brown Lake	99%	97%
	99%	94%
CPILP plants[3]	92%	93%
Average[3]	**92%**	**95%**

(1) 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.

(2) Clover Bar Energy Centre includes Unit 2 and Unit 3 as of their commercial operation dates, September 1, 2009 and December 16, 2009, respectively.

(3) Average generation plant availability is an average of individual plant availability weighted by owned or operated capacity.

Factors impacting quarterly financial results

Quarterly revenues, net income and funds 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, planned and unplanned plant outages, as well as items outside the normal course of operations. In addition, net income is affected by changes in the fair value of the Company's derivative power and natural gas contracts, natural gas held for trading and foreign exchange contracts.

Results by Plant Category

(unaudited, $ millions)	Three months ended Dec 31, 2009	Sept 30, 2009[2]
Revenues		
Alberta commercial plants and portfolio optimization	$ 248	$ 238
Alberta contracted plants	61	70
Ontario/British Columbia contracted plants	4	4
CPILP plants	130	123
Other portfolio activities	40	23
Inter-plant category transaction eliminations	(9)	(10)
	474	448
Unrealized fair value changes in derivative instruments and natural gas inventory held for trading		
- CPLP	15	30
- CPILP	8	33
	23	63
	$ 497	**$ 511**
Gross margin[1]		
Alberta commercial plants and portfolio optimization	$ 53	$ 50
Alberta contracted plants	48	58
Ontario/British Columbia contracted plants	4	4
CPILP plants	74	77
Other portfolio activities	12	8
Inter-plant category transaction eliminations	(9)	(8)
	182	189
Unrealized fair value changes in derivative instruments and natural gas inventory held for trading		
- CPLP	26	16
- CPILP	8	13
	34	29
	$ 216	**$ 218**
Operating margin[1]		
Alberta commercial plants and portfolio optimization	$ 39	$ 41
Alberta contracted plants	27	47
Ontario/British Columbia contracted plants	3	3
CPILP plants	47	48
Other portfolio activities	4	2
Inter-plant category transaction eliminations	-	(1)
	120	140
Unrealized fair value changes in derivative instruments and natural gas inventory held for trading		
- CPLP	26	16
- CPILP	8	13
	34	29
	$ 154	**$ 169**

(1) The results by plant category, except for gross margin and operating margin, have been prepared in accordance with Canadian GAAP. See Non-GAAP Financial Measures.

(2) Revenues and energy purchases for the third quarter of 2009 have been restated. See Quarterly Information - Financial Highlights.

Factors impacting the 2009 fourth quarter operating margin

The Company's plant availability decreased to 92% in the fourth quarter of 2009 from 95% in the third quarter of 2009, primarily due to an eighteen-day scheduled maintenance outage at Genesee 1 in the fourth quarter.

Revenues for the Alberta commercial plants and portfolio optimization reflect an increase in sales volumes for wholesale customers and for the supply to EPCOR's RRT customers due to increased demand in the winter season. In addition, the decrease in Alberta power prices in the quarter resulted in gains on the settlement of merchant derivative sell contracts in the period.

The increase in wholesale sales volumes had a favourable impact on gross margin and operating margin for the Alberta commercial plant category. The realized price for the portfolio for the fourth quarter of 2009 was \$57/MWh which was \$11/MWh higher than the average Alberta power price for the period as a substantial portion of the portfolio was sold forward at fixed contract prices. Operating costs for the fourth quarter of 2009 included increases in acquired PPA capacity payments in accordance with the plant operators' cost schedules and escalation factors and included a retroactive adjustment of \$3 million. Environmental charges under the terms of the acquired PPAs also increased in the fourth quarter due to increases in CO_2 emissions at the Sundance plant and an increased cost per tonne for these charges.

The impact of the planned outage at Genesee 1 on the fourth quarter results for the Alberta contracted plants was in line with management's expectations. Under the terms of the PPA, penalty payments were incurred during the outage, and compensation from the Alberta Balancing Pool for variable costs was reduced due to the decrease in generation resulting from the outage. These factors reduced revenue by approximately \$6 million. Operating margin was also reduced by approximately \$10 million of maintenance costs for the outage. Increased operational costs for environmental studies further reduced the operating margin for the Alberta contracted plants in the fourth quarter of 2009.

Revenues for the CPILP plants for the fourth quarter of 2009 reflected higher pricing under the terms of the power sales contracts for the Ontario plants during the winter months and higher generation at the Curtis Palmer plant due to water flows which are higher in winter than summer. These favourable factors were partly offset by lower revenue from the California facilities due to lower pricing in the winter months under the terms of the PPAs and lower generation from the North Carolina facilities which in periods of low natural gas prices are not as economical to run as competitive natural gas-fired power generation plants. The impact of lower pricing at the California plants was partly offset by higher generation volumes from these plants. The gross margin and operating margin were unfavourably impacted by increased fuel expense for the higher generation from the California plants.

Revenues, gross margin and operating margin for other portfolio activities in the fourth quarter of 2009 reflected an increase in natural gas sales volumes due to increased demand from end-use customers in the winter months.

The changes in the fair value of CPLP's derivative contracts increased revenues in the fourth quarter of 2009 primarily due to the impact of decreased forward prices on derivative sell contracts. The increase in gross margin and operating margin for fair value adjustments also include increases in the fair value of natural gas derivative buy contracts expiring in the near term due to decreased forward natural gas prices for the corresponding term.

The increase in CPILP's revenue, gross margin and operating margin for fair value changes in the fourth quarter of 2009 reflects an increase in the fair value of its foreign exchange contracts resulting from strengthening future prices for the Canadian dollar relative to the U.S. dollar.

Factors impacting the 2009 third quarter operating margin

There were no major plant outages in the third quarter of 2009 and the average availability for all plants was 95%. Alberta power prices averaged \$49/MWh and the Company's average realized price for the Alberta commercial plants and portfolio optimization was \$54/MWh as the portfolio was substantially sold forward at fixed contract prices. Results for the Alberta, Ontario and British Columbia contracted plants were in line with expectations. Revenues for the CPILP plants reflected normal seasonal variances including lower pricing for the Ontario plants and lower water volumes at the hydro facilities, partly offset by summer performance bonuses for the California plants.

The fair value of CPLP's derivative instruments and natural gas inventory held for trading increased $16 million in the third quarter primarily due to the impact of decreased forward electricity prices on a net short position for the portfolio of electricity derivative instruments.

The fair value of CPILP's foreign exchange contracts increased $33 million in the third quarter due to strengthening future prices for the Canadian dollar relative to the U.S. dollar. The fair value of CPILP's natural gas supply contracts decreased $20 million due decreased forward prices for natural gas. On July 31, 2009, CPILP designated certain of its natural gas supply contracts as hedges for accounting purposes. Therefore, the $20 million fair value loss primarily relates to the period from July 1, 2009 to July 31, 2009.

Factors impacting consolidated expenses

(unaudited, $millions)	Three months ended	
	Dec 31, 2009	Sept 30, 2009
Indirect administration	37	27
Depreciation, amortization and asset retirement accretion	48	44
Foreign exchange losses	1	3
Net financing expenses	17	17
Income taxes (reductions)	12	(2)
Non-controlling interests		
- CPLP	24	44
- CPILP	6	20
- Preferred share dividends paid by CPI Preferred Equity Ltd.	2	2

The quarter-over-quarter changes in consolidated expenses were primarily due to the following:

- Indirect administration expenses were higher in the fourth quarter compared with the third quarter primarily due to an impairment loss of $4 million on a venture capital investment, an increase in information technology costs of $2 million, higher employee stock option costs, and higher transition costs. The carrying amount of the remaining balance of the venture capital investment is $3 million.
- The increase in depreciation expense reflects losses incurred on the disposal of assets in December 2009 and depreciation for Clover Bar Energy Centre Units 2 and 3 commencing September 1, 2009 and December 16, 2009, respectively.
- Foreign exchange expense for both quarters reflects the impact of a weakening U.S. dollar relative to the Canadian dollar on the translation of the Company's U.S. monetary assets and liabilities that are not included in CPILP's self sustaining operations. The change in the exchange rate was larger in the third quarter than the fourth quarter resulting in a quarter over quarter decrease in foreign exchange expense. The translation gains and losses relating to CPILP's U.S. operations are included in other comprehensive income rather than the income statement as the functional currency for those operations is U.S. dollars.
- Income taxes were higher primarily due to an income tax recovery in the third quarter of 2009 for the recognition of a net future income tax asset for a $10 million out-of-period adjustment associated with CPILP's interest in PERH. In the fourth quarter of 2009, this income tax recovery was reclassified and included in the acquisition of assets from EPCOR since it related to periods prior to July 1, 2009. This increase in income tax expense was partly offset by the tax effect of lower income before taxes.
- The decrease in non-controlling interests reflects the quarter-over-quarter decrease in income.

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.

(unaudited)	Three months ended		
	Dec 31, 2009	Sept 30, 2009	June 30, 2009
Share price			
High	$21.78	$22.39	$23.00
Low	$18.95	$19.50	$22.00
Close	$21.37	$19.75	$22.35
Volume traded (millions)	6.5	12.1	5.8

As at March 9, 2010, the Company had 21.75 million common shares outstanding, 56.625 million special voting shares outstanding and one special limited voting share outstanding. The weighted average number of shares outstanding for the six months ended December 31, 2009 was 78.375 million. All of the outstanding special voting shares and the outstanding special limited voting share are held indirectly by EPCOR.

As at March 9, 2010, CPLP had 21.75 million general partner units outstanding, one common limited partnership unit outstanding and 56.625 million exchangeable limited partnership units outstanding, which are exchangeable for 56.625 million common shares of the Company. All of the outstanding general partner units and the outstanding common limited partnership unit are held, indirectly, by the Company. All of the outstanding exchangeable limited partnership units are held indirectly by EPCOR.

As at March 9, 2010, CPILP had 54.3 million limited partnership units outstanding and 16.5 million of such units, representing 30.4% of the outstanding limited partnership units, were held by CPI Investments Inc. EPCOR held 51 Class A Shares of CPI Investments Inc. representing 51% of the votes and CPLP held 49 Class B Shares of CPI Investments Inc. representing 49% of the votes. CPLP had an effective 100% economic interest in CPI Investments Inc.

Additional Information

Additional information relating to Capital Power Corporation, including continuous disclosure documents, is available on SEDAR at www.sedar.com.

Consolidated Financial Statements of

CAPITAL POWER CORPORATION

(In millions of dollars)
Six months ended December 31, 2009

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 Canadian generally accepted accounting principles. 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 9, 2010. 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 Canadian generally accepted accounting principles. 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 fulfils 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 9, 2010

CAPITAL POWER CORPORATION
Consolidated Financial Statements

Six months ended December 31, 2009

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

Telephone (780) 429-7300
Fax (780) 429-7379
Internet www.kpmg.ca

AUDITORS' REPORT TO THE SHAREHOLDERS OF CAPITAL POWER CORPORATION

We have audited the consolidated balance sheet of Capital Power Corporation as at December 31, 2009 and the consolidated statements of income, changes in shareholders' equity, comprehensive income, and cash flows for the six month period then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2009 and the results of its operations and its cash flows for the six month period then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants

Edmonton, Canada

March 9, 2010

CAPITAL POWER CORPORATION

Consolidated Statement of Income
(In millions of dollars)

	Six months ended December 31, 2009
Revenues	$ 1,008
Energy purchases and fuel	574
	434
Operations, maintenance and direct administration	102
Indirect administration	64
Property taxes	9
Depreciation, amortization and asset retirement accretion (note 5)	92
Foreign exchange losses	4
Net financing expenses (note 17)	34
	305
Income before income tax expense and non-controlling interests	129
Income tax expense (note 18)	10
Income before non-controlling interests	119
Non-controlling interests (note 13)	98
Net income	$ 21
Earnings per share (note 14)	
Basic	$ 0.97
Diluted	0.89
Weighted average number of common shares outstanding	
Basic	21,750,000
Diluted	78,375,000

See accompanying notes to consolidated financial statements.

CAPITAL POWER CORPORATION

Consolidated Balance Sheet
(In millions of dollars)

December 31, 2009

		2009
Assets		
Current assets:		
Cash and cash equivalents (note 25)	$	52
Accounts receivable		275
Income taxes recoverable		29
Inventories (note 4)		58
Prepaid expenses		8
Derivative instruments assets (note 20)		146
Future income tax assets (note 18)		2
Assets held for sale (note 32)		36
		606
Property, plant and equipment (note 5)		3,242
Power purchase arrangements (note 6)		528
Contract and customer rights and other intangible assets (note 7)		184
Derivative instruments assets (note 20)		155
Future income tax assets (note 18)		61
Goodwill (note 8)		140
Other assets (note 9)		120
	$	5,036

See accompanying notes to consolidated financial statements.

Approved on behalf of the Board:

Donald Lowry
Director and Chairman of the Board

William Bennett
Director and Chairman of the Audit Committee

	2009
Liabilities and Shareholders' Equity	
Current liabilities:	
Accounts payable and accrued liabilities	$ 321
Derivative instruments liabilities (note 20)	108
Other current liabilities	8
Future income tax liabilities (note 18)	21
Current portion of long-term debt (note 10)	247
	705
Long-term debt (note 10)	1,472
Derivative instruments liabilities (note 20)	102
Other non-current liabilities (note 11)	109
Future income tax liabilities (note 18)	95
	2,483
Non-controlling interests (note 13)	2,064
Shareholders' equity:	
Share capital (note 14)	477
Contributed surplus (note 14)	2
Retained earnings	7
Accumulated other comprehensive income (note 15)	3
Retained earnings and accumulated other comprehensive income	10
	489
Commitments and contingencies (note 28)	
Subsequent events (note 32)	
	$ 5,036

See accompanying notes to consolidated financial statements.

CAPITAL POWER CORPORATION

Consolidated Statement of Changes in Shareholders' Equity
(In millions of dollars)

	Six months ended December 31, 2009
Share capital:	
Common shares issued (notes 3 and 14)	$ 477
Balance, end of period (note 14)	477
Contributed surplus:	
Stock options granted (note 14)	2
Balance, end of period	2
Retained earnings:	
Net income	21
Common share dividends	(14)
Balance, end of period	7
Accumulated other comprehensive income:	
Other comprehensive income	3
Balance, end of period (note 15)	3
Total shareholders' equity, end of period	$ 489

See accompanying notes to consolidated financial statements.

CAPITAL POWER CORPORATION

Consolidated Statement of Comprehensive Income
(In millions of dollars)

	Six months ended December 31, 2009
Net income	$ 21
Other comprehensive income (loss), net of income taxes:	
Changes in gains and losses on derivative instruments designated as cash flow hedges[1]	(2)
Reclassification of losses on derivative instruments designated as cash flow hedges to net income[2]	31
Unrealized loss in self-sustaining foreign operations[3]	(43)
Non-controlling interests[3] (note 13)	17
	3
Comprehensive income	$ 24

1 For the six months ended December 31, 2009, net of income tax recoveries of $2.

2 For the six months ended December 31, 2009, net of reclassification of income tax recovery of $3.

3 For the six months ended December 31, 2009, net of income tax expense of nil.

See accompanying notes to consolidated financial statements.

CAPITAL POWER CORPORATION

Consolidated Statement of Cash Flows
(In millions of dollars)

	Six months ended December 31, 2009
Operating activities:	
Net income	$ 21
Adjustments to reconcile net income to cash flows from operating activities:	
Depreciation, amortization and asset retirement accretion (note 5)	92
Non-controlling interests in CPILP and CPLP (note 13)	94
Fair value changes on derivative instruments	(56)
Unrealized foreign exchange losses	3
Future income taxes	6
Other	4
	164
Change in non-cash operating working capital (note 16)	10
	174
Investing activities:	
Property, plant and equipment and other assets	(235)
Change in non-cash working capital	3
Business acquisition, net of acquired cash (note 3)	(1,293)
	(1,525)
Financing activities:	
Proceeds from issue of long-term debt	1,040
Repayment of long-term debt	(120)
Issue of common shares (notes 3 and 14)	500
Issue of subsidiary preferred shares (note 13)	100
Distributions to non-controlling interests	(58)
Common share dividends paid	(7)
Share issue costs (notes 3, 13 and 14)	(35)
Debt issue costs	(13)
	1,407
Foreign exchange losses on cash held in a foreign currency	(4)
Increase in cash and cash equivalents	52
Cash and cash equivalents, beginning of period	-
Cash and cash equivalents, end of period	$ 52
Supplementary cash flow information:	
Interest paid net of interest received	$ 45
Income taxes paid net of income taxes recovered	1

See accompanying notes to consolidated financial statements.

1. Description of business:

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 Company operates in one reportable business segment within the geographic areas of Canada and the United States (U.S.), with its head office located in Edmonton, Alberta.

The common shares of the Company are traded on the Toronto Stock Exchange under the symbol “CPX”.

2. Summary of significant accounting policies:

(a) Basis of presentation:

These consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles (GAAP). In the opinion of management, these consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the significant accounting policies summarized below.

These audited consolidated financial statements include the accounts of Capital Power, its subsidiaries, and its proportionate share of assets, liabilities, revenues and expenses of joint ventures. They also include the accounts of the Company’s approximate 30.5% interest in Capital Power Income L.P. (CPILP), formerly EPCOR Power L.P. (name changed effective November 5, 2009), and the Company’s approximate 27.8% interest in Capital Power LP (CPLP). Under GAAP, Capital Power controls CPILP and CPLP which therefore are subsidiaries of Capital Power.

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

The Company was incorporated on May 1, 2009, but did not have any results from operations or significant cash flows in the period from May 1 to June 30, 2009. Accordingly, the Company’s statements of income, comprehensive income and cash flows reflect only information for the six months ended December 31, 2009 and there is no comparative balance sheet as at December 31, 2008 or comparative statement of income, statement of changes in shareholders’ equity, statement of comprehensive income and statement of cash flows for the period ended December 31, 2008.

(b) Changes in significant accounting policies:

Future accounting changes

The CICA has announced that Canadian reporting issuers will need to begin reporting under International Financial Reporting Standards (IFRS), including comparative figures, by the first quarter of 2011. The Company is currently working on its IFRS conversion project which includes assessing the impact of the differences in accounting standards on the Company’s future financial reporting requirements.

In January 2009, the CICA issued Handbook Section 1601 – Consolidated Financial Statements and Section 1602 - Non-controlling Interests, which replace Section 1600 – Consolidated Financial Statements. Section 1601 establishes the standards for the preparation of consolidated financial statements while Section 1602 establishes the standards for accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. Section 1602 is equivalent to the corresponding provisions of IFRS IAS 27 – Consolidated and Separate Financial Statements.

Sections 1601 and 1602 will apply to interim and annual consolidated financial statements relating to periods commencing on or after January 1, 2011. Earlier adoption is permitted as of the beginning of a fiscal year, provided Section 1582 – Business Combinations is also adopted at the same time. The impact of the new standards and the option to adopt them early is being assessed as part of the Company’s IFRS conversion project.

2. Summary of significant accounting policies, continued:

(b) Changes in significant accounting policies, continued:

Future accounting changes, continued

In January 2009, the CICA issued Handbook Section 1582 – Business Combinations, which replaces Section 1581 – Business Combinations and provides the Canadian equivalent to IFRS 3 – Business Combinations. The section will apply, on a prospective basis, to future business combinations for which the acquisition date is on or after January 1, 2011. Earlier adoption is permitted as of the beginning of a fiscal year provided Sections 1601 – Consolidated Financial Statements and 1602 – Non-controlling Interests are also adopted at the same time. The impact of the new standard and the option to adopt it early is being assessed as part of the Company's IFRS conversion project.

(c) Measurement uncertainty:

The preparation of the Company's financial statements, in accordance with Canadian GAAP, requires management to make estimates that affect the reported amounts of revenues, expenses, assets and liabilities as well as the disclosure of contingent assets and liabilities at the financial statement date. The Company uses the most current information available and exercises careful judgment in making these estimates and assumptions.

For certain accounting measures such as determining asset impairments, purchase price allocations for business combinations, recording financial assets and liabilities, recording certain non-financial derivatives and for certain disclosures, the Company is required to estimate the fair value of certain assets or obligations. Estimates of fair value may be based on readily determinable market values or on depreciable replacement cost or discounted cash flow techniques employing estimated future cash flows based on a number of assumptions and using an appropriate discount rate.

Estimates of the value of electricity and natural gas consumed by customers but not billed until subsequent to year-end are based on volume data provided by the parties responsible for delivering the commodity and contracted prices.

Depreciation and amortization is an estimate to allocate the cost of an asset over its estimated useful life on a systematic and rational basis. Estimating the appropriate useful lives of assets requires significant judgment and is generally based on estimates of common life characteristics of common assets.

Measurement of the Company's asset retirement obligations and the related accretion expense requires 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.

Income taxes are determined based on estimates of the Company's current income taxes and estimates of future income taxes resulting from temporary tax differences. Future income tax assets are assessed to determine the likelihood that they will be realized from future taxable income. To the extent that realization is not considered likely, a valuation allowance is recorded and charged against income in the period that the allowance is created or revised.

Measurement of certain of the Company's pension costs and plan assets and obligations requires the use of estimates with respect to expected plan investment performance, salary escalation, retirement ages of employees, timing of related future cash flows and appropriate discount rates for use in discounted cash flow and actuarial techniques.

Adjustments to previous estimates, which may be material, will be recorded in the period they become known.

2. Summary of significant accounting policies, continued:

(d) Revenue recognition:

Revenues from the sales of electricity and natural gas are recognized on 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.

PPAs are a form of long-term sales arrangement between the owner of a generation unit and the buyer of the PPA to purchase power and steam on a predetermined basis. As described in note 2(q), PPA's may be classified as a lease (either operating or capital) and the income is recognized in revenue according to that classification. For those PPAs that are not considered to contain a lease, income earned on the PPA is recognized in revenue as described in the paragraphs below.

Revenues from certain of the Company's power generation plants are recognized on delivery of output or on availability for delivery as prescribed by the respective PPA. Revenue from certain long-term contracts with fixed payments is recognized at 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.

The Company recognizes revenue from its Alberta generation units operating under acquired PPAs as described in note 2(k).

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 occurs and unrealized gains and losses are recorded as revenue based on the related changes in fair value at the end of the reporting period.

(e) Financial instruments:

Financial assets are identified and classified as either available for sale, held for trading, held to maturity, or loans and receivables. Financial liabilities are classified as either held for trading or other liabilities. Initially, all financial assets and financial liabilities are recorded on the balance sheet at fair value with subsequent measurement determined by the classification of each financial asset and liability.

Financial assets and financial liabilities held for trading are measured at fair value with the changes in fair value reported in net income. Financial assets held to maturity, loans and receivables and financial liabilities other than those held for trading are measured at amortized cost. Available-for-sale financial assets are measured at fair value with changes in fair value reported in other comprehensive income until the financial asset is disposed of, or becomes impaired. Investments in equity instruments classified as available for sale that do not have quoted market prices in an active market are measured at cost.

Upon initial recognition, the Company may designate financial instruments as held for trading 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. The Company has designated its cash and cash equivalents as held for trading. All other non-derivative financial assets not meeting the Company's criteria for designating as held for trading are classified as available for sale, loans and receivables or held to maturity.

2. Summary of significant accounting policies, continued:

(e) Financial instruments, continued:

Financial assets purchased or sold, where the contract requires the asset to be delivered within an established timeframe, are recognized on a settlement date basis.

Transaction costs on financial assets and liabilities classified as other than held for trading are capitalized and amortized over the expected life of the instrument, based on contractual cash flows, utilizing the effective interest method. 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.

(f) Derivative instruments and hedging activities:

To reduce its exposure to movements in energy commodity prices, interest rate changes, and foreign currency exchange rates, the Company uses various risk management techniques including the use of derivative instruments. Derivative instruments may include forward contracts, fixed-for-floating swaps, and option contracts. Such instruments may be used to establish a fixed price for an energy commodity, an interest-bearing obligation or an obligation denominated in a foreign currency. All derivative instruments, including embedded derivatives, are recorded at fair value on the balance sheet as derivative instruments assets or derivative instruments liabilities except for embedded derivatives instruments that are clearly and closely linked 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. 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 fair value of the effective portion of the derivatives are recorded in other comprehensive income. 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.

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 hedging derivatives recognized in other comprehensive income are included in the initial carrying amount of the asset acquired in the same period or periods during which the asset acquired affects net income.

2. Summary of significant accounting policies, continued:

(f) Derivative instruments and hedging activities, continued:

The Company may use physical 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 and fuel, as appropriate. The amounts recognized in accumulated other comprehensive income are reclassified into net income in the same period or periods in which the hedged item occurs and is recorded in net income or when the hedged item becomes probable of not occurring. The Company has not designated any fair value hedges at the balance sheet date.

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 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 as described above. The fair value of derivative 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 price 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.

2. Summary of significant accounting policies, continued:

(g) Income taxes:

The Company's Canadian subsidiaries are subject to income taxes pursuant to the Income Tax Act (Canada) (ITA) and provincial income tax acts. The Company's U.S. subsidiaries are subject to income tax pursuant to U.S. federal and state tax laws.

The Company follows the asset and liability method of accounting for income taxes. Under this method, current income taxes are recognized for the estimated income taxes payable or recoverable for the current year. Future income tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Future income tax assets and liabilities are measured using enacted or substantively enacted rates of tax expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on future tax assets and liabilities is recognized in income in the period that includes the date of enactment or substantive enactment.

(h) Cash and cash equivalents:

Cash and cash equivalents include cash or highly liquid, investment-grade short-term investments and are recorded at fair market value.

(i) Inventories:

Small parts and other consumables and coal, the majority 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 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 circumstances.

(j) Property, plant and equipment:

Property, plant and equipment are recorded at cost and include contracted services, materials, interest, direct and indirect labour, directly attributable overhead costs, asset retirement costs, development costs associated with specific property, plant and equipment, and net revenues during the pre-operating period. Contributions received for financing the costs of assets are recorded as a reduction of the related asset cost.

Depreciation on property, plant and equipment is provided on the straight-line basis over their estimated useful lives. No depreciation is provided on construction work in progress.

The Company capitalizes interest during construction to provide for the costs of borrowing on 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.

2. Summary of significant accounting policies, continued:

(k) Power purchase arrangements:

Acquired PPAs are reflected on the consolidated balance sheet as power purchase arrangements and are recorded at cost and are amortized over their terms on a straight-line basis.

Under the terms of the 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. At December 31, 2009, the remaining term of the 20-year Sundance PPA is approximately 11 years. The Company was also obligated to make fixed and variable payments to the buyer of the Battle River PPA, in proportion to its effective ownership interest, until the sale of the Company's remaining interest in the Battle River Power Syndicate Agreement (Battle River PSA) was completed in 2010 as described in note 32.

The Company's 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.

The Company's investment in the Alberta PPAs and its related revenues and expenses are recorded on a proportionate basis, after deducting the equity syndicate's share.

The CPILP PPAs reflect the cost to acquire long-term sales contracts under which revenue is earned by CPILP's generation units. The CPILP PPAs are amortized over the remaining terms of the contracts.

(l) Contract and customer rights and other intangible assets:

Contract rights include acquired management and operations agreements and water rights. Costs assigned to contract rights related to management and operations agreements are amortized on a straight-line basis, from the dates of acquisition, over the remaining contract terms which range from 5 to 57 years. Water rights associated with acquired hydroelectric power generation plants are recorded at cost and are amortized over the remaining useful lives of the associated property, plant and equipment.

Other rights include the cost of land lease agreements for use in wind power projects in Ontario and coal supply access rights relating to the Keephills 3 Project (note 28(a)). The lease rights are amortized on a straight-line basis over the estimated useful lives of the related wind power assets, commencing when those assets are constructed and commissioned for service. The access rights will be amortized over the life of the coal supply agreement and amortization will commence when the Keephills 3 plant is commissioned for service.

Other intangible assets, which include the costs of acquired software, are amortized over the estimated useful lives of the assets which range from 1 to 10 years.

Customer rights represent the costs to acquire the rights to a long-term sales contract for the output of the Brown Lake plant. The costs are amortized on a straight-line basis over the 30-year term of the contract.

(m) Goodwill:

Goodwill is the cost of an acquisition less the fair value of the net assets of an acquired business. Goodwill is tested for impairment by comparing the fair value of each reporting unit to which the goodwill relates to the carrying amount, including goodwill, of each reporting unit. If the carrying amount of the reporting unit exceeds its fair value, indicating an impairment, a second test is performed to measure the amount of the impairment. In the second test, the fair value of the reporting unit's goodwill is compared with its carrying amount to measure the impairment loss, if any.

2. Summary of significant accounting policies, continued:

(n) Other assets:

Loans and other long-term receivables are comprised of promissory notes receivable and amounts due from customers more than one year from the balance sheet date and will be repaid between 2010 and 2025.

Investments in which the Company exercises significant influence are accounted for using the equity method. Other investments are classified as available for sale and are recorded at fair value unless the investments do not have a quoted market price in an active market in which case the investments are recorded at cost. Investments recorded at cost for which there is a decline in fair value below cost that is other than temporary are written down and the loss is recognized in net income.

(o) Impairment of long-lived assets:

The Company reviews the valuation of long-lived assets subject to depreciation and amortization when events or changes in circumstances may indicate or cause a long-lived asset's carrying amount to exceed the total undiscounted future cash flows expected from its use and eventual disposition. An impairment loss, if any, would be recorded as the excess of the carrying amount of the asset over its fair value, measured by either market value, if available, or estimated by calculating the present value of expected future cash flows related to the asset.

(p) Asset retirement obligations:

The Company recognizes asset retirement obligations in the period in which they are incurred, unless the fair value cannot be reasonably determined. A corresponding asset retirement cost is added to the carrying amount of the associated long-lived asset, and is depreciated over the estimated useful life of the asset. Accretion of the liability due to the passage of time is an operating expense, and is recorded over the estimated time period until settlement of the obligation.

The Company has recorded asset retirement obligations for its power generation plants and Genesee coal mine as it is legally required to remove the facilities at the end of their useful lives and restore the plant and mine sites to their original condition. Asset retirement obligations 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.

(q) Leases or arrangements containing a lease:

The Company has entered into PPAs to sell power at predetermined rates. 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 and such types of arrangements are classified as either capital or operating leases. PPAs that transfer substantially all of the benefits and risks of ownership of property to the PPA counterparty are classified as capital leases.

Finance income related to leases or arrangements accounted for as direct financing leases are recognized in a manner that produces a constant rate of return on the net investment in the lease. The net investment is composed of net 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 in net income over the lease term.

2. Summary of significant accounting policies, continued:

(r) Foreign currency translation:

The Company's self-sustaining foreign operations are translated to Canadian dollars using the current rate method. Assets and liabilities are translated at the exchange rate in effect at the balance sheet date. 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 until there is a reduction in the Company's net investment in the foreign operations.

(s) Employee future benefits:

The employees of the Company are either members of the Local Authorities Pension Plan (LAPP) or other defined contribution or benefit plans.

The LAPP is a multiemployer defined benefit pension plan. The Trustee of the plan is the Treasurer of Alberta and the plan is administered by a Board of Trustees. The Company and its employees make contributions to the plan at rates prescribed by the Board of Trustees to cover costs under the plan. Since the plan is a multiemployer plan, it is accounted for as a defined contribution plan. Accordingly, the Company does not recognize its share of any plan surplus or deficit.

The Company maintains additional defined contribution and defined benefit pension plans to provide pension benefits to those employees (comprising less than 35% of total employees of Capital Power) who are not otherwise served by LAPP.

The Company accrues its obligations for its defined benefit pension plans net of plan assets in the employee future benefits liabilities included in other non-current liabilities. The cost of pension benefits earned by employees is actuarially determined using the projected benefit method pro-rated on services and management's best estimate of expected plan investment performance, salary escalation and retirement ages of employees. For the purpose of calculating the expected return on plan assets, those assets are valued at quoted market value. The discount rate used to calculate the interest cost on the accrued benefit obligation is determined by reference to market interest rates at the balance sheet date on high-quality debt instruments with cash flows that match the timing and amount of expected benefit payments. Past service costs from plan amendments are amortized on a straight-line basis over the estimated average remaining service of employees active at the date of amendment. The excess of the net cumulative unamortized actuarial gain or loss over 10% of the greater of the accrued benefit obligation and the market value of plan assets is amortized over the estimated average remaining service period of the active employees.

The Company has an unfunded long-term disability benefit plan which provides provincial health care premiums, health and dental benefits, and required pension contributions for current disabled employees. The plan is a defined benefit plan and the obligation related to long-term disability benefits is actuarially determined using the projected benefit method pro-rated on services and management's best estimate of future health care costs, salary escalation for estimating future benefit contributions, recovery and termination experience, and inflation rates. The Company's accrual for the long-term disability benefit plan is reflected in the employee future benefits liabilities included in other non-current liabilities. The discount rate used to calculate the interest cost on the accrued benefit obligation is determined by reference to market interest rates at the balance sheet date on high-quality debt instruments with cash flows that match the timing and amount of expected benefit payments. Actuarial gains or losses on the accrued benefit obligation arise from differences between actual and expected experience and from changes in the actuarial assumptions used to determine the accrued benefit obligation. Actuarial gains and losses are recognized in income immediately.

2. Summary of significant accounting policies, continued:

(t) Stock-based compensation:

The Company determines the fair value of stock options using a binomial option pricing model at the date of grant. The fair value of the granted options is recognized over the vesting period as a compensation expense and contributed surplus. Contributed surplus is reduced as the options are exercised and the amount initially recorded in contributed surplus is credited to share capital. The Company has not incorporated an estimated forfeiture rate for stock options that will not vest, as the Company accounts for actual forfeitures as they occur.

(u) 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. This method computes the number of additional shares by assuming all outstanding options, for which the average market price of the common shares for the period exceeds the exercise price, are exercised. The total number of shares is then reduced by the number of common shares assumed to be repurchased from the total issuance proceeds, using the average market price of the Company's common shares for the period. The average market price of the Company's common shares for the period ended December 31, 2009 was below the exercise price of all granted options and as a result none of the share purchase options described in note 14 have a dilutive effect on earnings per share. Exchangeable common limited partnership units of CPLP, as described in note 3, are exchangeable for common shares of the Company and have a dilutive effect on earnings per share as described in note 14.

(v) Government assistance:

Government assistance is recognized when it is more likely than not that it will be realized and such assistance is recorded as a reduction to the related expense or asset.

(w) Offsetting of financial assets and financial liabilities:

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.

(x) Long-term debt discounts, premiums and issue expenses:

Debenture discounts, premiums and issue expenses with respect to long-term debt are amortized over the term of the related debt using the effective interest rate method.

3. Acquisition of assets and initial public offering:

Pursuant to its initial public offering on July 9, 2009, the Company issued 21,750,000 common shares at a price of $23.00 per share for net proceeds of $468 million after deducting underwriting commissions of $25 million and offering expenses of $7 million. The net proceeds of the offering were used to purchase a 27.8% equity interest in CPLP. CPLP purchased substantially all of the power generation assets from EPCOR Utilities Inc. (EPCOR), effective July 1, 2009 through the following series of transactions (the Reorganization):

- Formation of CPLP: Capital Power and a wholly-owned subsidiary of Capital Power (Capital Power LP Holdings Inc.) formed CPLP. Capital Power acquired one general partner unit (GP Unit) and became the initial general partner of CPLP. Capital Power LP Holdings Inc. acquired one common limited partnership unit and as a result, became the initial limited partner in CPLP.
- Sale of EMCC Limited to Capital Power: EPCOR transferred all of the outstanding common shares of EMCC Limited to Capital Power in return for payment of approximately $468 million in cash.
- Contribution of Assets by EMCC Limited to CPLP: EMCC Limited contributed substantially all of its assets (consisting primarily of certain securities of subsidiary entities, its class B shares in the capital of CPI Investments Inc., formerly EPLP Investments Inc. and promissory note of CPI Investments Inc.) to CPLP in return for GP Units. Capital Power transferred its GP Unit in CPLP to EMCC Limited and as a result EMCC Limited became the general partner of CPLP. Following the completion of these transactions, EMCC Limited has been renamed Capital Power GP Holdings Inc.
- Sale of assets net of liabilities by EPCOR Power Development Corporation (EPDC) to CPLP: EPDC transferred substantially all of its assets (consisting primarily of assets related to Genesee Units 1 and 2, the Genesee Coal Mine joint venture and certain interests in partnerships) to CPLP in return for 56.625 million exchangeable limited partnership units of CPLP and approximately $896 million in cash. CPLP financed the cash payment with the proceeds from a long-term debt obligation to EPCOR.

Immediately following completion of the Reorganization, Capital Power held general partnership units of CPLP representing an ownership interest of approximately 27.8% of CPLP while EPCOR held 56.625 million exchangeable limited partnership units of CPLP (exchangeable for common shares of Capital Power on a one-for-one basis) representing approximately 72.2% of CPLP. 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. Capital Power and EPCOR have agreed that for so long as EPCOR holds not less than a 20% interest in the common shares of Capital Power, the number of directors will not be less than nine. 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. Since EPCOR's representation on the board of directors does not represent a controlling vote and since Capital Power GP Holdings Inc., a subsidiary of Capital Power, is the general partner of CPLP, Capital Power will have control over CPLP. On that basis, the operations of CPLP will be consolidated by Capital Power for financial statement purposes.

Immediately following completion of the Reorganization, CPLP held 49% and EPCOR held 51% of the voting rights in CPI Investments Inc. CPI Investments Inc. owns the approximate 30.5% interest (30.6% interest at July 1, 2009) in CPILP previously owned by EPCOR. However, CPLP is entitled to all of the economic interest in CPI Investments Inc. Under GAAP, CPLP is the primary beneficiary of CPI Investments Inc. and accordingly, effective July 1, 2009, Capital Power will consolidate the financial results of CPILP.

(Tabular amounts in millions of dollars)

3. Acquisition of assets and initial public offering, continued:

The $468 million purchase price was allocated to the assets acquired and liabilities assumed based on estimated fair values as follows:

Cash and cash equivalents	$ 71
Other current assets	463
Property, plant and equipment	3,136
Power purchase arrangements	582
Contract and customer rights and other intangible assets	169
Derivative instruments assets – non-current	74
Future income tax assets – non-current	64
Acquired goodwill	145
Other non-current assets	122
Assets held for sale	36
Current liabilities	(387)
Long-term debt (including current portion)	(1,761)
Derivative instruments liabilities – non-current	(65)
Future income tax liabilities – non-current	(137)
Other non-current liabilities	(107)
	2,405
Non-controlling interests in net assets (note 13)	(1,937)
Fair value of net assets acquired	$ 468

The values of the assets and liabilities above reflect management's best estimates.

The $169 million of contract and customer rights and other intangibles includes $106 million of contract rights, $42 million of coal supply access rights and $21 million of other rights which include customer rights, lease rights, software intangibles and emission credits. Substantially all of the acquired contract and customer rights and other intangible assets are subject to amortization as described in note 2(l).

The amount allocated to acquired goodwill is not deductible for income tax purposes.

Non-controlling interests in net assets acquired include preferred share and other non-controlling interests in CPILP at the acquisition date of $122 million and $383 million respectively, as well as limited partnership units of CPLP issued to non-controlling interests as a part of the Reorganization of $1,302 million. The remaining non-controlling interests of $130 million relate to the non-controlling interest in net assets acquired.

The results of operations of the subsidiaries and assets acquired from EPCOR are included in the Company's consolidated statements of income, comprehensive income, retained earnings and accumulated other comprehensive income from July 1, 2009, the effective date of the acquisition.

Capital Power has entered into various agreements with EPCOR to provide for certain aspects of the separation of the business of Capital Power from EPCOR, to provide for the continuity of operations and services and to govern the ongoing relationships between the two groups of entities.

(Tabular amounts in millions of dollars)

4. Inventories:

	December 31, 2009
Small parts and other consumables	$ 42
Coal	8
Natural gas held in storage for trading purposes	8
	$ 58

Inventories expensed upon usage during the six months ended December 31, 2009 of $14 million were charged to energy purchases and fuel, and operations, maintenance and direct administration. No write-downs of inventories or reversals of previous write-downs were recognized in the six months ended December 31, 2009. At December 31, 2009, no inventories were pledged as security for liabilities.

5. Property, plant and equipment:

	December 31, 2009			
	Composite Depreciation Rate	Cost	Accumulated Depreciation	Net Book Value
Land	None	$ 68	$ -	$ 68
Plant and equipment	5.3%	2,589	58	2,531
Contributions	12.1%	(28)	(2)	(26)
Construction work in progress	None	669	-	669
		$ 3,298	$ 56	$ 3,242

Depreciation, amortization and asset retirement accretion expense is comprised of:

	Six months ended December 31, 2009
Depreciation on assets in service	$ 65
Amortization of PPAs	24
Gain on settlement of asset retirement obligations (note 12)	(4)
Amortization of contract and customer rights and other intangible assets	4
Accretion on asset retirement obligations (note 12)	3
Amortization of contributions	(2)
Other	2
	$ 92

Interest capitalized to property, plant and equipment for the six months ended December 31, 2009 is $20 million.

6. Power purchase arrangements:

	December 31, 2009		
	Cost	Accumulated amortization	Net book value
Alberta PPAs	$ 140	$ 6	$ 134
CPILP PPAs	412	18	394
	$ 552	$ 24	$ 528

(Tabular amounts in millions of dollars)

7. Contract and customer rights and other intangible assets:

December 31, 2009	Cost	Accumulated amortization	Net book value
Contract rights	$ 105	$ 2	$ 103
Other rights	56	-	56
Emission credits	11	1	10
Software intangibles	11	1	10
Customer rights	5	-	5
	$ 188	$ 4	$ 184

8. Goodwill:

The changes in the carrying amount of goodwill are as follows:

	Six months ended December 31, 2009
Acquired goodwill (note 3)	$ 145
Foreign exchange translation adjustment	(5)
Balance, end of period	$ 140

9. Other assets:

	December 31, 2009
Carrying amount	
Loans and other long-term receivables	$ 48
Net investment in lease	27
Investment in PERH	22
Portfolio investments (note 19)	3
Other	20
	$ 120

Net investment in lease

The PPA under which the Company's power generation facility located in Oxnard, California operates is considered to be a direct financing lease for accounting. The PPA expires in 2020. The current portion of the net investment in lease of $2 million is included in accounts receivable. Financing income for the six months ended December 31, 2009 of $1 million is included in revenues.

Investment in PERH

Through the acquisition described in note 3, the Company, as part of its CPILP subsidiary, acquired 17.0% of the common share interests and 14.2% of the preferred interests in Primary Energy Recycling Holdings LLC (PERH). Effective August 24, 2009, PERH converted its outstanding preferred interests into common shares. As a result of the conversion, the Company now holds 14.3% of the outstanding common shares of PERH. Until the conversion date, the Company's common share interest in PERH was accounted for using the equity method and the preferred interest was recorded on the cost basis. Subsequent to the conversion of the preferred interests into common shares, the Company commenced recording its entire 14.3% common share interest on the cost basis. For the period from July 1 to August 24, 2009, equity losses of $1 million, included in operations, maintenance and direct administration expense, have been recorded against the common share investment in PERH. No gain or loss was recorded on the conversion.

(Tabular amounts in millions of dollars)

10. Long-term debt:

	Effective Interest Rate	December 31, 2009
Unsecured senior debt payable to EPCOR		
Due in 2010 at 6.95%	4.90%	$ 202
Due in 2011 at 6.60%	5.53%	204
Due in 2016 at 6.75%	6.16%	134
Due in 2018 at 5.80%	5.63%	165
Due in 2018 at 9.00%	7.41%	167
		872
CPILP unsecured senior notes (US$190), at 5.90%, due in 2014	6.23%	200
CPILP unsecured senior medium-term notes, at 5.95%, due in 2036	7.11%	203
CPILP unsecured senior medium-term notes (US$150), at 5.87%, due in 2017	6.13%	156
CPILP unsecured senior medium-term notes (US$75), at 5.97%, due in 2019	6.26%	77
CPILP secured term loan, at 11.25%, due in 2010	10.69%	1
Non-recourse financing:		
Brown Lake Project, at 8.7%, due in 2016	7.13%	6
Joffre Cogeneration Project, at fixed and floating rates, due in 2020	8.35%	41
CPLP revolving extendible credit facilities, at floating rates, due in 2010	3.16%	100
CPILP revolving extendible credit facilities, at floating rates, due in 2010	0.96%	78
		1,734
Less: Current portion		247
Deferred debt issue costs		15
		$ 1,472

10. Long-term debt, continued:

Unsecured senior debt payable to EPCOR

The unsecured senior debt payable to EPCOR matures between 2010 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.

CPILP unsecured senior notes

The unsecured senior notes of $200 million (US$190 million) mature in 2014 and are fully and unconditionally guaranteed by CPILP as to payment of principal, premium, if any, and interest on a senior unsecured basis. Interest is payable semi-annually.

The unsecured senior medium-term notes of $203 million are due in 2036 with interest payable semi-annually.

The unsecured senior medium-term notes aggregating to $233 million (US$225 million) were issued in two tranches. The $156 million (US$150 million) and $77 million (US$75 million) are due in 2017 and 2019 respectively with interest payable semi-annually.

CPILP secured term loan

The term loan matures in 2010 and is secured by a first fixed and specific mortgage over the Moresby Lake plant which has a carrying amount of $14 million.

Non-recourse financing

Joffre Cogeneration Project financing represents the Company's share of syndicated loans for the project. A $40 million portion of the debt bears a fixed interest rate of 8.59% payable quarterly until 2020. The remaining debt bears interest at the prevailing bankers' acceptance rate plus a spread of 1.5% which escalates to 1.875% over the term of the loan. The debt is secured by a charge against project assets which have a carrying amount of $99 million. Brown Lake Project financing is secured by a charge against project assets which have a carrying amount of $9 million.

CPILP and CPLP revolving extendible credit facilities

Unsecured two-year credit facilities of $100 million and $100 million and unsecured three-year credit facilities of $125 million, for a total of $325 million, committed to 2011, and uncommitted amounts of $20 million and $21 million (US$20 million), are available to the Company's subsidiary, CPILP. At December 31, 2009, the Company had $74 million in bankers' acceptances and $4 million (US$4 million) in U.S. LIBOR loans outstanding under this facility. Unsecured three-year credit facilities of $700 million, committed to 2012 and uncommitted amounts of $20 million, are available to the Company's subsidiary, CPLP. At December 31, 2009, the Company had $100 million in bankers' acceptances outstanding under this facility. Additional uncommitted amounts of $5 million are available to the Company and are undrawn at December 31, 2009.

The Company also has unsecured credit facilities of $500 million available through its CPLP subsidiary. These facilities have a maturity date of July 8, 2010 with an option to extend for an additional 364 day period. As at December 31, 2009, no amounts have been drawn on this facility, but letters of credit of $119 million have been issued as described in note 29.

(Tabular amounts in millions of dollars)

10. Long-term debt, continued:

CPILP and CPLP revolving extendible credit facilities, continued

Under the terms of the extendible facilities, the Company may obtain advances by way of prime loans, U.S. base rate loans, U.S LIBOR loans and bankers' acceptances. Depending on the facility, amounts drawn by way of prime loans bear interest at the prevailing Canadian prime rate or the average one-month bankers' acceptance rate plus a spread ranging from 0.75% to 1.00%. Amounts drawn by way of U.S. base rate loans bear interest at a bank determined variable commercial lending rate or the prevailing Federal Funds Rate as published by the U.S. Federal Reserve Board plus a spread ranging from 0.75% to 1.00%. Amounts drawn by way of U.S. LIBOR loans bear interest at the prevailing LIBOR rate plus a spread based on the Company's credit rating. Amounts drawn by way of bankers' acceptances bear interest at the prevailing bankers' acceptance rate plus a spread based on the Company's credit rating.

11. Other non-current liabilities:

	December 31, 2009
Asset retirement obligations (note 12)	$ 81
Employee future benefit liabilities	9
Other	19
	$ 109

12. Asset retirement obligations:

	December 31, 2009
Liabilities assumed on acquisition of assets (note 3)	$ 88
Liabilities incurred	3
Liabilities settled	(4)
Asset retirement accretion expense	3
Other	(1)
	89
Less: current portion in accounts payable and accrued liabilities	8
	$ 81

The Company estimates the undiscounted amount of cash flow required to settle its asset retirement obligations is approximately $386 million, calculated using inflation rates ranging from 2% to 3%. The expected timing for settlement of the obligations is between 2013 and 2090. The majority of the payments to settle the obligations are expected to occur between 2023 and 2064 for the power generation plants, and between 2013 and 2017 for sections of the Genesee coal mine. Discount rates ranging from 4.1% to 8.7% were used to calculate the carrying amount of the asset retirement obligations. No assets have been legally restricted for settlement of these liabilities.

(Tabular amounts in millions of dollars)

13. Non-controlling interests:

Results of operations which relate to non-controlling interests are as follows:

	Six months ended December 31, 2009
Non-controlling interests in CPILP	$ 26
Non-controlling interests in CPLP	68
Preferred share dividends paid by subsidiary company	4
	$ 98

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

	December 31, 2009
Non-controlling interests in CPILP in net assets acquired (note 3)	$ 383
Net income attributable to non-controlling interests	26
Other comprehensive loss attributable to non-controlling interests	(34)
Distributions to non-controlling interests	(33)
Issue of CPILP units to non-controlling interests	3
Non-controlling interests in CPILP, end of period	345
Non-controlling interests in CPLP in net assets acquired (note 3)	130
Partnership units issued to non-controlling interests (note 3)	1,302
Net income attributable to non-controlling interests	68
Other comprehensive income attributable to non-controlling interests	17
Distributions to non-controlling interests	(18)
Non-controlling interests in CPLP, end of period	1,499
Preferred shares outstanding in acquired subsidiaries (note 3)	122
Issue of preferred shares	98
Preferred shares issued by subsidiary companies, end of period	220
	$ 2,064

The non-controlling interests in CPILP represent the approximate 69.5% interest in CPILP not owned by CPLP. The non-controlling interests in CPLP represent the approximate 72.2% interest in CPLP not owned by the Company which includes approximately 72.2% of CPLP’s approximate 30.5% interest in CPILP.

(Tabular amounts in millions of dollars)

13. Non-controlling interests, continued:

Preferred shares issued by subsidiary

In November 2009, a subsidiary of CPILP issued 4 million 7.0% Cumulative Rate Reset Preferred Shares, Series 2 (the Series 2 Shares) priced at $25.00 per share for proceeds of $100 million, less issue costs of $3 million, which was used to repay amounts outstanding under revolving credit facilities. Future income tax assets of $1 million related to the share issue costs are recorded in the preferred share balance. The Series 2 Shares pay fixed cumulative dividends of $1.75 per share per annum, as and when declared, for the initial five-year period ending December 31, 2014. The dividend rate will reset on December 31, 2014 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 4.18%. The Series 2 Shares are redeemable at $25.00 per share by CPILP on December 31, 2014 and on December 31 every five years thereafter. The holders of the Series 2 Shares will have the right to convert their shares into Cumulative Floating Rate Preferred Shares, Series 3 (the Series 3 Shares) of CPILP, subject to certain conditions, on December 31, 2014 and every five years thereafter. The holders of Series 3 Shares will be entitled to receive quarterly floating rate cumulative dividends, as and when declared by the board of directors of CPILP, at a rate equal to the sum of the then 90-day Government of Canada treasury bill rate and 4.18%.

A subsidiary of CPILP has issued 5 million 4.85% Cumulative Redeemable Preferred Shares, Series 1 priced at $25.00 per share with dividends payable on a quarterly basis at the annual rate of $1.2125 per share. On or after June 30, 2012, the shares are redeemable by the subsidiary company at $26.00 per share, declining by $0.25 each year to $25.00 per share after June 30, 2016. The shares are not retractable by the holders. Under the terms of the preferred share issue, CPILP will not make any distributions on partnership units if the declaration or payment of dividends on the preferred shares is in arrears. Dividends will not be paid on the preferred shares if the senior unsecured notes of CPILP are in default.

14. Share capital:

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

Issued and outstanding	December 31, 2009
21,750,000 common shares	$ 477
56,625,000 special voting shares	-
1 special limited voting share	-
	$ 477

The $500 million of common shares issued to the public are recorded net of share issue costs of $32 million as described in note 3. Future income taxes of $9 million related to the share issue costs have been recorded as an increase to common shares.

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 the holder 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.

(Tabular amounts in millions of dollars)

14. Share capital, continued:

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.

Share Purchase Options

Under the Company's long term incentive plan, the Company provides stock 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 Corporation under this Plan will not exceed 5,000,000 common shares.

During the six months ended December 31, 2009 the Company granted 2,183,100 stock options with one third vesting on January 1 of each of 2010, 2011, and 2012. Fair value of these options at grant date was $2.57 per option resulting in total compensation expense recognized of $2 million in indirect administration for the six months ended December 31, 2009. Granted options may be exercised within 7 years of the grant date at a price of $23.00 per share.

At December 31, 2009, none of the Company's outstanding stock options were vested.

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

Variable	Value
Expected life	Seven-year term
Risk free interest rate	Based on Government of Canada treasury bills and bonds at December 31, 2008
Volatility	20% (estimated based on similar publicly-traded companies)
Dividend yield	4.75% to 5.5%

Earnings per share

The 56.625 million exchangeable limited partnership units issued to EPCOR as described in note 3 may be exchanged for common shares of Capital Power on a one-for-one basis. For purposes of the diluted earnings per share calculation, the exchange of such units for common shares of the Company would remove the non-controlling interest in net income related to CPLP of $68 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 approximately $19 million.

15. Accumulated other comprehensive income:

The components of accumulated other comprehensive income, at December 31, 2009, are as follows:

	December 31, 2009
Unrealized gains on derivative instruments designated as cash flow hedges[1]	$ 29
Unrealized loss in self-sustaining foreign operations[2]	(43)
Non-controlling interests[2]	17
	$ 3

[1] Net of income tax expense of $1 million.

[2] Net of income tax expense of nil.

(Tabular amounts in millions of dollars)

16. Change in non-cash working capital:

	Six months ended December 31, 2009
Accounts receivable	$ (61)
Income taxes recoverable	3
Inventories	(4)
Prepaid expenses	2
Accounts payable and accrued liabilities	65
Other current liabilities	5
	$ 10

17. Net financing expenses:

	Six months ended December 31, 2009
Interest on long-term debt	$ 53
Capitalized interest	(20)
Other	1
	$ 34

18. Income taxes:

	Six months ended December 31, 2009
Future income taxes	$ 9
Current income taxes	1
	$ 10

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

	Six months ended December 31, 2009
Income before income taxes and non-controlling interests	$ 129
Statutory income tax rates	29.0%
Income taxes at statutory rate	37
Increase (decrease) resulting from:	
Taxable income attributable to non-controlling interests	(23)
Change in valuation allowance	(2)
Non-taxable amounts	(2)
Adjustment for enacted changes in income tax laws and rates and other tax rate differences	(2)
Other	2
	$ 10

(Tabular amounts in millions of dollars)

18. Income taxes, continued:

The tax effects of temporary differences that give rise to significant components of the future income tax assets and future income tax liabilities are presented below:

	December 31, 2009
Property, plant and equipment – differences in net book value and tax bases	$ (102)
Losses carried forward	79
Power purchase arrangements	(27)
Deferred income from partnerships	(19)
Asset retirement obligations	13
Cumulative eligible capital	12
Derivative Instruments	(5)
Other	(4)
Net future income tax liabilities	$ (53)
Presented on the balance sheet as follows:	
Current assets	$ 2
Non-current assets	61
Current liabilities	(21)
Non-current liabilities	(95)
	$ (53)

At December 31, 2009, the Company has non-capital losses carried forward of approximately $263 million, of which $155 million relate to certain U.S. subsidiaries. These losses expire between 2022 and 2029. The Company also has capital losses for income tax purposes of approximately $5 million. There are non-capital losses available to be carried forward of $22 million, capital losses available to be carried forward of $5 million and other deductible temporary differences of $220 million for which no tax benefit has been recognized.

Income Tax Recognition

As a result of the Reorganization (as described in note 3), Capital Power holds an economic interest in CPLP of 27.8%. Accordingly, the Company recognizes current and future income tax assets and liabilities related to its economic interest in CPLP.

(Tabular amounts in millions of dollars)

19. Fair value and classification of non-derivative financial assets and liabilities:

The Company classifies its cash and cash equivalents as held for trading and measures them at fair value. Accounts receivable are classified as loans and receivables; accounts payable and accrued liabilities are classified as other financial liabilities; all of which are measured at amortized cost and their fair values are not materially different from their carrying amounts due to their short-term nature.

The classification, carrying amount and fair value of the Company's other financial instruments at December 31, 2009 are summarized as follows:

		December 31, 2009	
Financial asset or liability	Classification	Carrying amount	Fair value
Other assets			
Loans and other long-term receivables	Loans and receivables	$ 48	$ 46
Net investment in lease	Loans and receivables	27	27
Long-term debt (including current portion)	Other financial liabilities	1,719	1,724

Net investment in lease

The fair value of the Company's net investment in lease is based on the estimated interest rates implicit in comparable lease arrangements or loans plus an estimated credit spread based on the counterparty risk as at December 31, 2009.

Long-term debt

The fair value of the Company's long-term debt is based on determining a current yield for the Company's debt as at December 31, 2009. 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 debt. The estimated credit spread is based on the Company's indicative spread as published by independent financial institutions.

Other financial instruments

Fair values on the remaining financial instruments are determined by reference to quoted bid or ask prices, as appropriate, in active markets at period-end dates.

The fair value of certain capital venture investments and the Company's investment in PERH cannot be measured reliably as the shares are not quoted in an active market and are therefore classified as available for sale. The carrying values, less impairments, recognized on these investments are disclosed in note 9. During the six months ended December 31, 2009, the recoverable amount of one of the Company's capital venture investments declined below its carrying amount, and the Company has determined that the decline was other than temporary. The Company's assessment of the decline as other than temporary is consistent with the factors considered by the venture investment's Fund Manager. The carrying amount of the investment was reduced to its estimated fair value, and the Company recognized an impairment loss of $4 million in indirect administration expense. Such impairment losses are not reversed in subsequent periods. Investments in common shares held at their carrying amount have not been offered for sale and in the event the Company elected to dispose of the shares, they would most likely be sold in a private transaction.

(Tabular amounts in millions of dollars)

20. Derivative 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 22 consist of the following:

	December 31, 2009			
	Energy		Foreign exchange	
	Cash flow hedges	Non-hedges	Non-hedges	Total
Derivative instruments assets:				
Current	$ 15	$ 126	$ 5	$ 146
Non-current	32	97	26	155
Derivative instruments liabilities:				
Current	(23)	(83)	(2)	(108)
Non-current	(37)	(61)	(4)	(102)
Net fair value	$ (13)	$ 79	$ 25	$ 91
Net notional buys (sells):				
Megawatt hours of electricity (millions)	(3)	(4)		
Gigajoules of natural gas (millions)	45	9		
Foreign currency (U.S. dollars)			$ (379)	
Range of contract terms in years	0.1 to 7.0	0.1 to 4.8	0.1 to 6.0	

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 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 the use of external readily observable market data such as future prices, interest rate yield curves, foreign exchange rates, quoted Canadian dollar swap rate as the discount rate for time value, counterparty credit risk and volatility when available. 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.

(Tabular amounts in millions of dollars)

20. Derivative instruments and hedge accounting, continued:

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

	Six months ended December 31, 2009	
	Unrealized gains (losses)	Realized gains (losses)
Energy cash flow hedges	$ 30	$ (34)
Energy non-hedges	18	2
Foreign exchange non-hedges	41	(2)

Realized gains and losses relate only to financial derivative instruments. Gains and losses on non-financial derivative instruments settlements are recorded in energy revenues or energy purchases and fuel, as appropriate.

If hedge accounting requirements are not met, unrealized and realized gains and losses on financial energy derivatives are recorded in energy 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 energy 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 energy revenues or foreign exchange gains and losses while such gains and losses on financial interest rate derivatives are recorded in net financing expenses.

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 six months ended December 31, 2009, the change in the fair value of the ineffective portion of hedging derivatives required to be recognized in the income statement was nil. Net losses of $5 million, net of income taxes of $2 million, related to derivative instruments designated as cash-flow hedges, are expected to settle and be reclassified to net income over the next twelve months. The Company's cash flow hedges extend up to 2016.

21. 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 balance sheet 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 cash and cash equivalents, 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 dollars)

21. 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 the discounted cash flow model or 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 table presents the Company's financial instruments measured at fair value on a recurring basis in the consolidated balance sheet, classified using the fair value hierarchy described above:

	December 31, 2009			
	Level 1	Level 2	Level 3	Total
Financial assets and liabilities:				
Cash	$ 52	$ -	$ -	$ 52
Derivative instrument assets				
Commodity derivatives	4	252	14	270
Foreign exchange derivatives	-	31	-	31
	$ 4	$ 283	$ 14	$ 301
Derivative instrument liabilities				
Commodity derivatives	(6)	(187)	(11)	(204)
Foreign exchange derivatives	-	(6)	-	(6)
	$ (6)	$ (193)	$ (11)	$ (210)

There were no significant transfers between Level 1 and 2 for the six months ended December 31, 2009.

21. Fair value hierarchy, continued:

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:

	December 31, 2009
Acquired from EPCOR [1]	$ 2
Unrealized and realized gains included in net income [2]	3
Settlements[3]	(2)
Balance, end of period	3
Total unrealized gains for the period included in net income	$ 1

[1] The fair value of derivative instruments is presented on a net basis.
[2] Gains and losses are recorded in energy 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.

22. 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.

Capital Power's Director, Risk Management and Internal Audit reports regularly to the Board of Directors on risk management activities of the executive team. 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 minimize volatility in earnings and cash flow.

Commodity price risk management and the associated credit risk management are carried out in accordance with financial 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 management, is carried out by a centralized Treasury function. 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.

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 market 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 earnings 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.

22. Risk management, continued:

Market risk, continued

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.
- When it is economically feasible, the Company purchases natural gas under long-term fixed-price supply contracts to reduce the exposure to fluctuating natural gas prices on its natural gas-fired generation plants and physical obligations arising from retail customers.
- 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 at December 31, 2009 that are required to be measured at fair value with the respective changes in fair value recognized in net income are disclosed in note 20.

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 VaR uses a statistical confidence interval of 95% over a twenty business day holding period. This measure reflects a 5% probability that, over the twenty 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.

22. Risk management, continued:

Market risk, continued

Commodity price risk, continued

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 95% confidence level, does not reflect the extent of potential losses beyond that percentile. Losses on the other 5% 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 5% of the time. As VaR is not a perfect measure of risk, the Company applies a safety factor to the calculated VaR amount to estimate total exposure (TE) which attempts to capture unaccounted for exposures due to the assumptions and limitations inherent in the calculation of VaR and to improve the confidence level beyond 95%.

The estimation of TE takes into account positions from all wholly-owned subsidiaries and subsidiaries in which the Company has controlling interest, and reflects the Company's aggregate commodity positions from its trading and asset portfolios. Capital Power's Board of Directors has established an aggregate TE limit, under their risk management policy, which 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, 2009, there is a higher than 95% probability that unfavorable daily market variations would not reduce the 12 month portfolio by more than $14 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.

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.

22. Risk management, continued:

Market risk, continued

Foreign exchange risk, continued

The Company primarily uses foreign currency forward contracts to fix the functional currency of its non-functional currency cash flows thereby reducing its anticipated U.S. dollar denominated transactional exposure. The Company looks to limit foreign currency exposures as a percentage of estimated future cash flows. The percentage amount to be fixed will generally be higher, the shorter the period into the future that the cash flows relate to. At December 31, 2009, US$395 million or approximately 102% of expected future net cash flows from CPILP's U.S. plants had been economically hedged for 2010 to 2015 at a weighted average exchange rate of $1.13 per U.S. dollar. At December 31, 2009, the Company has transactional exposure for US$16 million or approximately 90% of expected future net cash flows for capital expenditure commitments, which have been economically hedged for 2010 to 2011 at a weighted average exchange rate of $1.09 per U.S. dollar.

As at December 31, 2009, holding all other variables constant, a $0.10 strengthening or weakening of the Canadian dollar against the U.S. dollar would increase or decrease net income by approximately $1 million after tax. There would be no impact to other comprehensive income.

This sensitivity analysis excludes translation risk associated with the application of the current rate and temporal rate translation methods, 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 short-term and long-term loans and obligations. The Company is exposed to interest rate risk from the possibility that changes in the 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 short-term borrowings and other liquidity requirements. At December 31, 2009, the proportion of fixed rate debt was approximately 90% of total long-term debt outstanding. The Company may also use derivative instruments to manage interest rate risk. At December 31, 2009, the Company did not hold any interest rate derivative instruments.

Assuming that the amount and mix of fixed and floating rate loans and net debt remains unchanged from that held at December 31, 2009, a 100 basis point change to interest rates would decrease or increase full year net income by less than $1 million and would have no direct impact on other comprehensive income.

The effect on net income does not consider the effect of an overall change in economic activity that would accompany such an increase or decrease in interest rates. There would be no impact on net income for debt and long-term loan arrangements issued and held by the Company at fixed interest rates.

(Tabular amounts in millions of dollars)

22. Risk management, continued:

Market risk, continued

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 a transaction with the counterparty. Exposures and concentrations for commodity transactions are subsequently monitored and are regularly reported to the executive team. Creditworthiness continues to be evaluated after transactions have been initiated, at minimum, on an annual basis. To manage and mitigate credit risk, the Company employs various credit mitigation practices such as margining to reduce energy trading risks, credit derivatives and other forms of credit enhancements including cash deposits, parent company guarantees, and bank letters of credit.

Maximum credit risk exposure

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

	December 31, 2009
Cash and cash equivalents	$ 52
Accounts receivable [1]	275
Derivative instruments assets [1]	301
Loans and other long-term receivables	48
Net investments in leases	27
Loan commitments to third parties	6
	$ 709

[1] The Company's maximum exposures related to accounts receivable and derivative instruments assets by major credit concentration are comprised of maximum exposures of $173 million for generation and $403 million for wholesale.

This table does not take into account collateral held. At December 31, 2009, the Company held cash deposits of $3 million as security for certain counterparty accounts receivable 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. At December 31, 2009, the Company also held other forms of credit enhancement in the form of letters of credit of $29 million and parental guarantees of $733 million.

22. Risk management, continued:

Credit risk, continued

Credit quality and concentrations

The Company is exposed to credit risk on outstanding accounts receivable associated with its generation and energy sales activities including power purchase arrangements and agreements with independent system operators, power and steam sales contracts and on energy supply agreements with government sponsored entities and wholesale customers. The Company is also exposed to credit risk from its cash and cash equivalents (including short-term investments), financial and non-financial derivative instruments, and long-term financing arrangements.

The credit quality of the Company's 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 reputable banks, brokerage firms, and financial institutions, which may not have less than an "A" internal assigned rating.

Loans and long-term financing

At December 31, 2009, loans and long-term financing consists primarily of notes receivable attributable to three 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.

Accounts receivable and financial derivative instruments

Accounts receivable is substantially made up of receivables related to the generation and sale of electricity to counterparties and the settlement of financial derivative instruments related to merchant price risk mitigation and trading activities.

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 accounts receivable 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 agreements 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, netting amounts by legally enforceable set-off rights, and, when appropriate, taking back security from the counterparty. Credit risk with counterparties that are government-owned or sponsored entities and regulated public utility distributors is generally considered low.

(Tabular amounts in millions of dollars)

22. Risk management, continued:

Credit risk, continued

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. Credit risk exposure is mitigated by dealing with creditworthy counterparties, monitoring credit exposure limits, margining to reduce energy trading risks, parent company guarantees, and when appropriate taking back security from the counterparty. The majority of counterparty credit exposures are with counterparties considered to be investment grade or which have security structures in place to mitigate the credit risk.

Accounts receivable and allowance for doubtful accounts

Accounts receivable 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 contracts-for-differences provide for performance assurances including letters of credit if deemed appropriate. The Company also has credit exposures to large suppliers of electricity and natural gas. The Company mitigates these exposures by dealing with creditworthy counterparties and, when appropriate, taking back appropriate security from the supplier.

The aging of accounts receivable was:

	December 31, 2009		
	Gross accounts receivable	Allowance for doubtful accounts	Net accounts receivable
Current[1]	$ 271	$ -	$ 271
Outstanding 30 to 60 days	2	-	2
Outstanding 60 to 90 days	-	-	-
Outstanding greater then 90 days	3	1	2
Total	$ 276	$ 1	$ 275

[1] Current amounts represent accounts receivable outstanding zero to 30 days. Amounts outstanding more than 30 days are considered past due.

In conjunction with the acquisition of assets described in note 3, the Company assumed allowances for doubtful accounts of $2 million, which were reduced by $1 million in the six months ended December 31, 2009 due to a settlement agreement reached in the period. The Company has also assumed allowances for doubtful accounts of $2 million relating to long-term receivables which are recorded against the long-term receivable balance in other assets at December 31, 2009.

At December 31, 2009, the Company held $3 million of customer deposits for the purpose of mitigating the credit risk associated with accounts receivable from customers.

At December 31, 2009, there was no provision for credit losses associated with accounts receivable from treasury, trading and energy procurement counterparties as all balances are considered to be fully collectable.

(Tabular amounts in millions of dollars)

22. Risk management, continued:

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 capital debt markets and equity offerings by the Company or its CPLP or CPILP subsidiaries.

CPLP has a long-term debt rating of BBB, assigned by both Standard and Poor's (S&P) and DBRS Limited (DBRS). CPILP has a long-term debt rating of BBB+/negative outlook and BBB(high)/negative trend, assigned by S&P and DBRS respectively.

As at December 31, 2009, the Company had undrawn and committed bank credit facilities, including operating lines of credit and demand facilities, of $1,294 million, of which $600 million is committed for at least two years. In addition, CPILP has a Canadian shelf prospectus under which it may raise up to $1 billion in partnership units or debt securities, of which a maximum of $600 million can be medium-term notes. The Canadian shelf prospectus expires August 2010. As at December 31, 2009, CPILP has not drawn on the shelf prospectus.

The following are the undiscounted cash flow requirements and contractual maturities of the Company's financial liabilities, including interest payments, and financial assets that generate cash inflows to meet cash outflows on financial liabilities as at December 31, 2009:

	Due within 1 year	Due between 1 and 2 years	Due between 2 and 3 years	Due between 3 and 4 years	Due between 4 and 5 years	Due after more than 5 years	Total contractual cash flows
Non-derivative financial liabilities:							
Long-term debt	$ 247	$ 313	$ 127	$ 20	$ 214	$ 809	$ 1,730
Interest payments on long-term debt	97	86	69	65	64	384	765
Accounts payable and accrued liabilities [1]	301	-	-	-	-	-	301
Other current liabilities	8	-	-	-	-	-	8
Loan commitments	6	-	-	-	-	-	6
Derivative financial liabilities:							
Net forward foreign exchange contracts	1	1	1	-	2	-	5
Net commodity contracts-for-differences	79	49	4	-	-	-	132
Total	$ 739	$ 449	$ 201	$ 85	$ 280	$ 1,193	$ 2,947

[1] Excluding accrued interest on long-term debt of $20 million.

(Tabular amounts in millions of dollars)

23. Capital management:

The Company's primary objectives when managing capital are to safeguard the Company's ability to continue as a going concern, pay dividends to its shareholders in accordance with the Company's dividend policy, 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 short-term debt and long-term debt net of cash and cash equivalents, non-controlling interests (including preferred shares issued by subsidiary companies) and shareholder's equity. The following table represents the total capital of the Company:

	December 31, 2009
Long-term debt (including current portion) (note 10)	$ 1,719
Cash and cash equivalents	(52)
Net debt	1,667
Non-controlling interests (note 13)	2,064
Shareholders' equity	489
Total equity and non-controlling interests	2,553
Total capital	$ 4,220

The Company has no externally imposed requirements on its capital except as disclosed below.

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 0.90 to 1.0;
- Maintenance of consolidated senior debt to 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 earnings before interest, income taxes, depreciation and amortization to interest expense, as defined in the debt agreements, of not less than 2.5 to 1.0.

CPILP has the following externally imposed requirements on its capital:

- Maintenance of debt to total capitalization ratio, as defined in the debt agreements, of not more than 65%; and
- In the event that CPILP is assigned a rating of less than BBB+ by S&P and BBB(high) by DBRS, CPILP also would be required to maintain a ratio of earnings before interest, income taxes, depreciation and amortization to interest expense of not less than 2.5 to 1.

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

(Tabular amounts in millions of dollars)

23. Capital management, continued:

For the period ended December 31, 2009, CPLP and CPILP complied with all externally imposed capital restrictions.

To manage or adjust its capital structure, the Company can issue new debt, issue common or preferred shares, redeem preferred shares, issue new CPLP or CPILP units, repay existing debt or adjust dividends paid to its shareholders.

24. Related party balances and transactions:

Prior to the Reorganization described in note 3, 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. The following summarizes the Company's related party balances and transactions with EPCOR, EPCOR's subsidiaries and EPCOR's sole shareholder, the City of Edmonton. All transactions are in the normal course of operations, and are recorded at the exchange amount, which is the consideration established and agreed to by the parties.

		December 31, 2009
Balance sheet:		
Accounts receivable	(a)	$ 63
Other assets	(b)	8
Property, plant and equipment	(c)	20
Accounts payable and accrued liabilities	(d)	13
Long-term debt (including current portion) (note 10)		872
Share capital (note 14)		-
		Six months ended December 31, 2009
Income statement:		
Revenues – energy sales	(e)	219
Energy purchases and fuel	(f)	13
Operations, maintenance and direct administration		5
Net financing expenses	(g)	10

(a) Accounts receivable includes $51 million relating to energy sales to subsidiaries of EPCOR, $2 million relating to energy sales to the City of Edmonton and $10 million of amounts owed from EPCOR relating to operational cash transactions during the acquisition changeover period.

(b) Contributions made to subsidiaries of EPCOR for the construction of aerial and underground transmission lines.

(c) Interest on long-term debt to EPCOR capitalized to property, plant and equipment.

(d) Includes accrued interest on long-term debt to EPCOR of $9 million.

(e) Includes energy sales of $205 million to EPCOR and its subsidiaries and $14 million to the City of Edmonton.

(f) Includes energy distribution and transmission charges from subsidiaries of EPCOR.

(g) Net financing expenses on long-term debt to EPCOR.

In addition to the transactions disclosed above, the Company's subsidiary CPLP has paid distributions of $18 million to EPCOR in the six months ended December 31, 2009.

(Tabular amounts in millions of dollars)

25. Joint ventures:

The Company and the coal mine operator at the Genesee plant site each have a 50% interest in the Genesee Coal Mine Joint Venture. The joint venture partner operates the coal mine. Under agreements governing this joint venture, all coal mined is to be supplied to the Company's Genesee generation plant.

The Company holds 50% interests in the Genesee 3 Project, the Keephills 3 Project and the Taylor's Coulee Chute Hydro Project, and holds a 40% interest in the Joffre Cogeneration Project. The Company, through its CPILP subsidiary, also holds a 50.15% interest in the Frederickson power plant.

A financial summary of the Company's investments in joint ventures is as follows:

	December 31, 2009
Current assets	$ 44
Long-term assets	1,115
Current liabilities	57
Long-term liabilities	42
Revenues (1)	30
Expenses (2)	44
Net loss	(14)
Cash flows from operating activities	(17)
Cash flows used in investing activities	(109)
Cash flows from financing activities	115

(1) Excludes all revenues from Genesee 3, which are recorded as revenues by the Company but are not subject to the terms of the joint venture agreement.

(2) Excludes all costs of operating the Genesee Coal Mine Joint Venture which are recorded as fuel expenses by the Company.

Included in the Company's cash and cash equivalents at December 31, 2009 is its proportionate share of cash and cash equivalents which is restricted to use within joint ventures of $17 million.

Under the terms of the Company's interests in the Frederickson power plant, the Genesee 3 Project and the Keephills 3 Project, the Company and its respective partners have guaranteed financial and performance obligations under the joint venture agreements limited to $40 million, $50 million and $50 million respectively.

26. Employee future benefits:

Multiemployer defined benefit pension plan and defined contribution pension plan

Over 85% of the Company's employees are either members of the Local Authority Pension Plan or the Company's registered defined contribution plans. Accordingly, the majority of the Company's pension costs and obligations are accounted for as defined contribution plans.

(Tabular amounts in millions of dollars)

26. Employee future benefits, continued:

Defined benefit plans

The effective date for the latest actuarial valuation of the Company's registered pension plan was July 9, 2009. Prior to the transfer of employees resulting from the acquisition described in note 3, the effective date for the latest actuarial valuation of the Company's supplemental pension plan was December 31, 2007. The effective date of the next valuation for funding purposes is no later than December 31, 2011 for the registered pension plan. The effective date of the next valuation of the supplemental pension plan is no later than December 31, 2010. The date used to measure the plan assets and the accrued benefit obligation was December 31, 2009. The supplemental pension plan is a non-contributory plan that is unfunded at December 31, 2009.

As part of the Company's acquisition of its interest in CPILP from EPCOR, employees who transferred to Capital Power on July 1, 2009, and who were previously members of EPCOR's registered pension plan, became members of the Company's registered pension plan. The plan provides pension benefits based on an employee's years of service and their highest earnings over three consecutive years of employment. Retirement pensions will be increased annually by a portion of the increase in the Consumer Price Index. Under the terms of the pension transfer agreement between EPCOR and CPC, EPCOR transferred the pension liabilities and associated assets based on an actuarial valuation. At December 31, 2009, the actual transfer of assets has not yet occurred as regulatory approval required for the transfer of assets is outstanding.

Plan benefit costs, assets and obligations:

	2009
Costs recognized for the six months ended December 31:	
Service cost	$ 1
Actuarial gains	(1)
Difference between actuarial gain recognized and actual gain on accrued benefit obligation	1
Defined benefit plans cost	1
Defined contribution plans cost	3
Net expense	$ 4

	2009
Funded status as at December 31:	
Market value of plan assets	$ 9
Accrued benefit obligation	(17)
Funded status – plan deficit	(8)
Amounts not yet recognized in financial statements:	
Unamortized net losses	1
Accrued benefit liability recognized in financial statements	$ (7)
Expected average remaining service life in years – registered pension plan	11
Expected average remaining service life in years – supplemental pension plan	12

(Tabular amounts in millions of dollars)

26. Employee future benefits, continued:

The accrued benefit liability and other employee future benefit liabilities, totalling $10 million and assumed as part of the acquisition described in note 3, are included in other non-current liabilities. Other employee future benefit liabilities consist mainly of obligations for benefits provided to employees on long-term disability leaves.

		2009
Reconciliation of accrued benefit obligation:		
Accrued benefit obligation transferred from EPCOR	$	17
Service cost		1
Actuarial gain		(1)
Accrued benefit obligation, end of period	$	17

		2009
Plan assets:		
Market value of assets transferred from EPCOR and at end of period	$	9

Total cash payments for pension benefits in the six months ended December 31, 2009, consisting of cash contributed by the Company to the LAPP, other defined contribution and benefit plans and cash payments directly to beneficiaries for its unfunded pension plan, were $4 million.

Assumptions:

The significant actuarial assumptions adopted in measuring the corporation's accrued benefit obligations were as follows:

	2009
Accrued benefit obligation as at December 31	
Discount rate	6.00%
Rate of compensation increase	4.00%
Benefit cost for six months ended December 31	
Discount rate	5.75%
Rate of compensation increase	4.00%
Expected rate of return on plan assets	6.50%

Information concerning the Company's registered pension plan's target asset allocation and actual asset allocation is as follows:

	2009	
	Target asset allocation	Asset allocation
Fixed income securities	35%	35%
Equity securities	60%	63%
Other assets	5%	2%
Total	100%	100%

(Tabular amounts in millions of dollars)

27. 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 plants, comprised of Manchief, Mamquam, Moresby Lake, Southport, Roxboro, Kenilworth, Greeley, Williams Lake, Genesee units 1 and 2, Miller Creek, Brown Lake and Kingsbridge are accounted for as assets under operating leases. As at December 31, 2009, the carrying amount of such property, plant and equipment was $1,363 million, less accumulated depreciation of $26 million. The Company's revenue pursuant to the arrangements for the six months ended December 31, 2009 was $209 million.

28. Commitments and contingencies:

(a) The Company and TransAlta Corporation (TransAlta) are in the process of building Keephills 3, a 495 megawatt (MW) supercritical coal-fired generation plant at TransAlta's Keephills site. The construction is expected to be completed in 2011. As at December 31, 2009, the Company's 50% committed share of the estimated total remaining capital cost to be incurred is $281 million. The estimated total project cost is $1.9 billion and Capital Power's share is $955 million. As part of contractual arrangements, the Company and TransAlta have indemnified each other for up to $115 million during construction in the event that either party makes payments to the turbine supplier on behalf of the other party.

(b) CPILP has committed to the enhancement of the Southport facility to be completed over the first two quarters of 2010. As at December 31, 2009, the Company expects an additional $17 million (US$16 million) to be spent on the enhancement work. CPILP has committed to the upgrade of the gas turbine at the Oxnard facility, to be spent over the first two quarters of 2010. As at December 31, 2009, the Company expects an additional $16 million (US$15 million) to be spent on the upgrade of the Oxnard turbine.

(c) 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 2010 is $91 million. It is expected that the annual payments over the remaining terms of the Alberta PPAs, as described in note 2(k), will range from $91 million to $164 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.

(d) The Company has entered into a number of long-term energy purchase and transportation contracts and operating and maintenance contracts in the normal course of operations. Some of these energy purchase and transportation contracts are measured at their fair value and recorded on the consolidated balance sheet as derivative 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 these contracts and under operating leases for premises are as follows:

	Energy purchase and transportation contracts	Operating and maintenance contracts	Operating leases
2010	132	27	2
2011	91	27	1
2012	77	28	4
2013	64	28	4
2014	66	29	4
Thereafter	138	74	68
Total	$ 568	$ 213	$ 83

28. Commitments and contingencies, continued:

(e) The Company has committed to issue non-interest bearing notes receivable to the non-Capital Power syndicate members involved in the Sundance Swap transaction entered into by Capital Power subsidiaries prior to the acquisition of subsidiaries and assets from EPCOR as disclosed in note 3. The commitment relates to funding potential income tax liabilities incurred by the non-Capital Power syndicate members in relation to the transaction. The total estimated loan commitment is $19 million, with annual payments of principal commencing from the date the commitment is called by the non-Capital Power syndicate members through to December 2012. At December 31, 2009, the Company has $13 million extended under such notes and their carrying amount of $9 million, after fair value adjustments, is included in other assets.

(f) The Company and its subsidiaries are subject to various other 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.

29. Guarantees:

The Company has issued letters of credit for $119 million to meet the credit requirements of energy market participants, to meet conditions of certain service agreements, and to satisfy legislated reclamation requirements.

Prior to the acquisition of subsidiaries and assets from EPCOR disclosed in note 3, EPCOR issued parental guarantees on behalf of former EPCOR subsidiaries to meet the credit requirements of energy market participants, to meet conditions of certain service agreements, and to satisfy legislated reclamation requirements. At December 31, 2009, EPCOR continues to have outstanding parental guarantees on behalf of Capital Power totaling $1,295 million related to subsidiaries of Capital Power. In addition to this amount, EPCOR also has outstanding parental guarantees which do not have a defined limit, but which provide full support on any outstanding positions related to power purchase arrangements of Capital Power. Under the terms of the separation agreements described in note 3, the Company is required to transfer these parental guarantees from EPCOR by June 30, 2010. The Company will be required to pay market based rates on any parental guarantees that remain outstanding with EPCOR after that date.

30. Government assistance:

The Company is currently completing the front-end engineering and design (FEED) work on its pre-combustion carbon capture and storage project (the Genesee Integrated Gasification Combined Cycle (IGCC) power plant). The FEED project is being conducted in conjunction with the Canadian Clean Power Coalition, in partnership with the Province of Alberta and the Government of Canada. During the six months ended December 31, 2009, the Company accrued government assistance for this project from the Province of Alberta and the Government of Canada totaling $10 million as a reduction to indirect administration expenses and received contributions of $3 million. The Company acquired receivables of $2 million related to this government assistance as a part of the acquisition described in note 3 above. At December 31, 2009 the Company had accounts receivable related to this government assistance of $9 million. As a part of the agreements with the Province of Alberta and the Government of Canada, the Company is required to submit a final report in 2010 detailing the amounts spent on the project. As long as the project has been completed to the satisfaction of the government parties, none of the recorded amounts are repayable by the Company.

In addition to the above project, Capital Power is partnering with unrelated third parties to develop one of the world's largest carbon capture and storage (CCS) projects, Project Pioneer (Pioneer). In October 2009, a letter of intent was signed with the Province of Alberta under which Pioneer will be eligible to receive funding from the province's $2,000 million CCS fund. The Government of Canada will also be contributing toward the project through its Clean Energy Fund. Government funding for this project is expected to commence in 2010.

(Tabular amounts in millions of dollars)

31. Geographic information:

	Six months ended December 31, 2009			
	Canada	U.S.	Inter-area eliminations	Total
Revenues - external	$ 671	$ 337	$ -	$ 1,008
Inter-area revenues	7	1	(8)	-
Total revenues	$ 678	$ 338	$ (8)	$ 1,008
Property, plant and equipment	$ 2,734	$ 508	$ -	$ 3,242
Goodwill	$ 104	$ 36	$ -	$ 140

Inter-area transactions occur in the normal course of operations and are recorded at the exchange amount which is the consideration established and agreed to by the parties.

32. Subsequent events:

The Company’s interest in the Battle River PSA was disposed of on January 15, 2010 for proceeds of $64 million. The Company recognized a gain on disposal of $28 million less income taxes of $2 million in the first quarter of 2010. Since the final disposal occurred within one year of the balance sheet date, the remaining Battle River PSA assets on the consolidated balance sheet have been reclassified from power purchase arrangements to current assets held for sale for the six months ended December 31, 2009.