No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise. This prospectus constitutes a public offering of these securities only in those jurisdictions where they may be lawfully offered for sale and only by persons permitted to sell these securities.

These securities have not been and will not be registered under the United States Securities Act of 1933, as amended (the "U.S. Securities Act") or any state securities laws and may not be offered or sold in the United States or to U.S. persons (as defined in Regulation S under the U.S. Securities Act) except pursuant to an exemption from the registration requirements of those laws. See "Plan of Distribution".

SUPPLEMENTED PREP PROSPECTUS

Initial Public Offering June 25, 2009

$500,250,000
21,750,000 Common Shares

Capital Power Corporation ("Capital Power" or the "Company") is offering for sale 21,750,000 (the "Offering") of its common shares (the "Common Shares"). The Common Shares are being offered by TD Securities Inc., Goldman Sachs Canada Inc., RBC Dominion Securities Inc., CIBC World Markets Inc., BMO Nesbitt Burns Inc., Scotia Capital Inc., National Bank Financial Inc. and HSBC Securities (Canada) Inc. (collectively, the "Underwriters"). The final offering price of the Common Shares will be determined by negotiation among the Company, EPCOR Utilities Inc. ("EPCOR") and the Underwriters.

The Toronto Stock Exchange ("TSX") has conditionally approved the listing of the Common Shares under the symbol "CPX". Listing is subject to the Company fulfilling all of the original listing requirements of the TSX on or before August 31, 2009, including distribution of these Common Shares to a minimum number of public securityholders. **There is currently no market through which the Common Shares may be sold and purchasers may not be able to resell Common Shares purchased under this prospectus. This may affect the pricing of the Common Shares in the secondary market, the transparency and availability of trading prices, the liquidity of the Common Shares and the extent of issuer regulation. An investment in the Common Shares is subject to a number of risks. A prospective purchaser should review this document in its entirety and carefully consider the risk factors described under "Risk Factors" before purchasing the Common Shares.**

Price: $23.00 per Common Share

	Price to the Public	Underwriters' Commission	Net Proceeds to the Company[1]
Per Common Share	$23.00	$1.15	$21.85
Total Offering[2]	$500,250,000	$25,012,500	$475,237,500

(1) Before deducting the Company's expenses of the Offering estimated at $7,000,000 which, together with the Underwriters' commission, will be paid by the Company out of the proceeds of the Offering.

(2) The Company has granted to the Underwriters an option (the "Over-Allotment Option"), exercisable at their sole discretion at any time, in whole or in part, for a period of 30 days after the closing of the Offering, to purchase from the Company at the Offering price up to an additional 3,262,500 Common Shares for the purpose of covering over-allotments, if any. If the Over-Allotment Option is exercised in full, the total "Price to the Public", "Underwriters' Commission" and "Net Proceeds to the Company" before deducting the expenses of the Offering will be $575,287,500, $28,764,375 and $546,523,125, respectively. This prospectus also qualifies the grant of the Over-Allotment Option and the Common Shares issuable upon the exercise of the Over-Allotment Option. A purchaser who acquires Common Shares forming part of the Underwriters' over-allocation position acquires such Common Shares under this prospectus, regardless of whether the over-allocation position is ultimately filled through the exercise of the Over-Allotment Option or secondary market purchases. See "Plan of Distribution".

Underwriters' Position	Maximum Size or Number of Securities Available	Exercise Period	Exercise Price
Over-Allotment Option	Option to acquire up to 3,262,500 Common Shares	Exercisable for a period of 30 days after the closing of the Offering	$23.00 per Common Share

In connection with this distribution, the Underwriters have been granted the Over-Allotment Option and may, subject to applicable law, over-allocate or effect transactions which stabilize or maintain the market price of the Common Shares at levels other than those which otherwise might prevail on the open market. **The Underwriters may offer the Common Shares at a price lower than that stated above. See "Plan of Distribution — Price Stabilization, Short Positions and Passive Market Making".**

Each of TD Securities Inc., RBC Dominion Securities Inc., CIBC World Markets Inc., BMO Nesbitt Burns Inc., Scotia Capital Inc., National Bank Financial Inc. and HSBC Securities (Canada) Inc. is a subsidiary or an affiliate of a bank that is a lender to each of the Company and EPCOR. In addition, two directors of EPCOR are directors of a bank that is a lender to the Company and EPCOR. Consequently, the Company may be considered to be a "connected issuer" of such Underwriters under applicable Canadian securities laws. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and capital resources" and "Plan of Distribution — Relationship between the Company and Certain of the Underwriters".

(continued on next page)

(continued from cover)

The Underwriters, as principals, conditionally offer the Common Shares qualified under this prospectus, subject to prior sale, if, as and when issued by the Company and accepted by the Underwriters in accordance with the conditions contained in the underwriting agreement referred to under "Plan of Distribution" and subject to the approval of certain legal matters on behalf of the Company by Blake, Cassels & Graydon LLP and K&L Gates LLP, and on behalf of the Underwriters by Osler, Hoskin & Harcourt LLP.

Subscriptions will be received subject to rejection or allotment in whole or in part and the Underwriters reserve the right to close the subscription books at any time without notice. It is expected that certificates representing the Common Shares to be issued or sold in the Offering will be available for delivery on the date of the closing of the Offering, which is expected to occur on or about July 9, 2009 or such later date as the Company and the Underwriters may agree, but in any event not later than August 9, 2009.

Capital Power's vision is to become one of North America's most respected, reliable and competitive power generators

Capital Power has interests in 31 facilities across North America, with approximately 3,300 MW of owned and/or operated power generation capacity, 470 MW of capacity owned through PPAs and 448 MW of owned capacity under construction.

Capital Power Corporation

SELECTED ASSETS

1

The **Genesee Generating Station**, built and operated by Capital Power, hosts the Company's wholly-owned Genesee 1 and Genesee 2 units, as well as the Genesee 3 joint venture.

Keephills 3 builds on Capital Power's experience in power plant development and construction. The Keephills 3 joint venture is planned to achieve commercial operation in 2011 using supercritical technology.

2

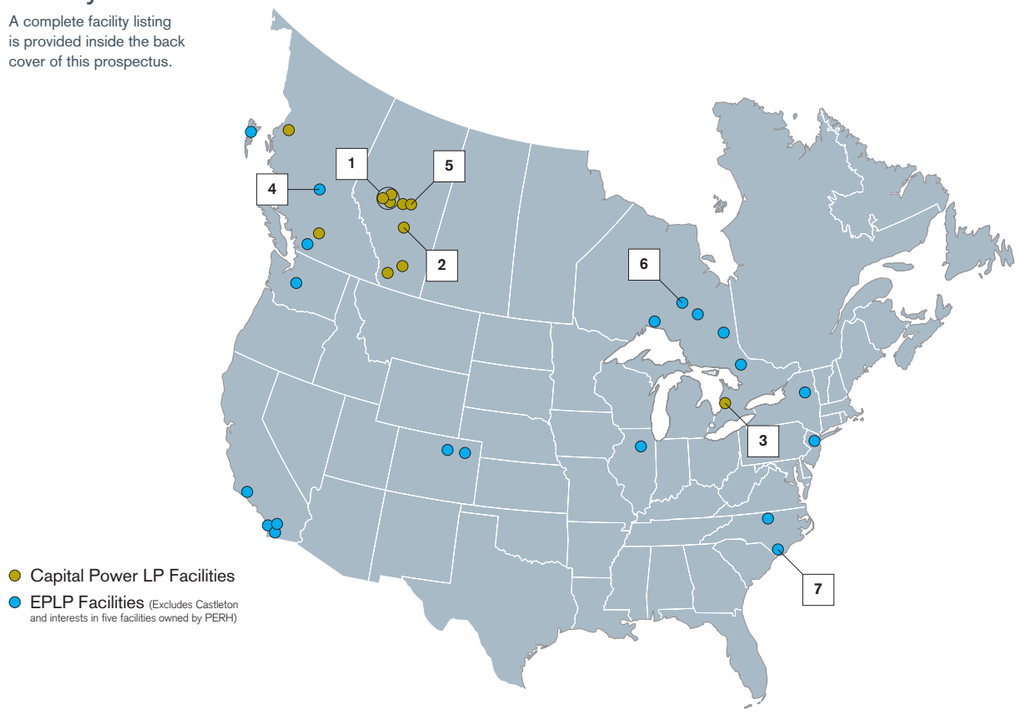
At 480 MW, **Joffre** is one of Canada's largest cogeneration facilities. Capital Power holds a 40% interest.

3

Kingsbridge is a 40 MW wind power project in Ontario, near Lake Huron, which has the highest capacity factor among Ontario wind farms.

Facility locations

A complete facility listing is provided inside the back cover of this prospectus.



Capital Power's Generation Portfolio

Alberta Contracted Plants

Genesee 1 and 2 are wholly-owned coal-fired units with 820 MW of combined generation capacity sold under long-term agreements.

Alberta Commercial Plants

Six facilities with 743 MW of owned and/or operated generation capacity from coal, natural gas, hydro, wind and landfill gas. Genesee 3, at 495 MW (gross), is among the most fuel-efficient coal-fired units in Canada.

Ontario and British Columbia Contracted Plants

Two hydro facilities in British Columbia with 40 MW of capacity and a 40 MW wind farm in Ontario; output sold to provincial entities under long-term contracts.

EPLP

Capital Power indirectly owns a 30.6% interest in this TSX-listed Canadian limited partnership with interests in 20 U.S. and Canadian plants, generating 1,688 MW of electricity and approximately 4.2 billion pounds of steam/hour. Fuels include: natural gas, waste heat, wood waste, hydro, coal, steam and tire-derived fuel. EPLP also holds a 15.4% interest in Primary Energy Recycling Holdings LLC.

Power Purchase Agreements

Capital Power maintains rights to 470 MW of capacity through its ownership interests in the Sundance and Battle River PPAs. The Company has agreed to sell its remaining interest in the Battle River PPA in January 2010.

Projects Under Construction and in Development

Keephills 3 – The Company is building a 50% owned 495 MW coal-fired generating facility using technology from Genesee 3; expected to be in operation in early 2011.

Clover Bar Energy Centre 2 and 3 – The Company is adding two 100 MW simple cycle natural gas-fired units, expected to be in service in 2009 and 2010.

Development – Includes projects across North America with approximately 1,300 MW of capacity; energy sources include: wind, biomass and natural gas.

SELECTED ASSETS (continued)

The 68 MW **Williams Lake** power facility, owned by EPLP, is one of Canada's largest biomass-fueled power generators.

4

Clover Bar Energy Centre is a 43 MW facility and Capital Power is currently constructing two more 100 MW units for service in 2009 and 2010. Each unit can reach full power minutes after start-up, giving the Company the flexibility to respond to meet market demand.

5

The 40 MW **Calstock** power plant, owned by EPLP, is fueled by both biomass and waste heat from a natural gas pipeline compressor station and operates under a long-term PPA.

6

Capital Power is significantly enhancing the operating and financial performance of EPLP's **Southport** facility by changing fuel type.

7

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NOTICE TO INVESTORS

About This Prospectus

An investor should rely only on the information contained in this prospectus (including information about Capital Power's facilities set forth in the Capital Power Facilities Summary Table at the end of this prospectus) and is not entitled to rely on parts of the information contained in this prospectus to the exclusion of others. The Company has not, and the Underwriters and EPCOR have not, authorized anyone to provide investors with additional or different information. The Company has not, and the Underwriters and EPCOR are not, offering to sell these securities in any jurisdictions where the offer or sale is not permitted. The information contained in this prospectus is accurate only as of the date of this prospectus, regardless of the time of delivery of this prospectus or any sale of the Common Shares. The Company's business, financial condition, results of operations and prospects may have changed since the date of this prospectus.

For investors outside Canada, neither the Company, EPCOR nor any of the Underwriters have done anything that would permit the Offering or possession or distribution of this prospectus in any jurisdiction where action for that purpose is required, other than in Canada. Investors are required to inform themselves about and to observe any restrictions relating to the Offering and the distribution of this prospectus.

Interpretation

Information contained in this prospectus gives effect to the Reorganization as described under "Relationship to EPCOR — Reorganization" and, unless otherwise stated, assumes that the Over-Allotment Option has not been exercised. Unless the context otherwise requires, all references in this prospectus to "Capital Power" and the "Company":

- refer to Capital Power Corporation, Capital Power L.P., and their respective subsidiary entities as constituted on the closing date of the Offering after giving effect to the Reorganization;
- in the case of references in "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the "Summary" to financial information relating to a period or as at a date prior to completion of the Offering and before giving effect to the Reorganization, refer to EPCOR Power Group, being the combination of certain EPCOR subsidiaries and interests as referred to in note 2(a) to the combined and consolidated financial statements of EPCOR Power Group contained in this prospectus; and
- in the case of references in this prospectus to matters undertaken by a predecessor in interest to Capital Power Corporation or its subsidiaries, include each such predecessor in interest.

Unless the context otherwise requires, all references in this prospectus to "EPCOR" refer to EPCOR Utilities Inc. and its subsidiaries.

Unless the context otherwise requires, all references in this prospectus to "EPLP" refer to EPCOR Power L.P. and its subsidiary entities.

References to "management" in this prospectus means the persons who will be the senior officers of the Company following the closing of the Offering and who are currently officers, management or employees of EPCOR. Any statements in this prospectus made by or on behalf of management are made in such persons' capacities as officers of the Company and EPCOR and not in their personal capacities.

The Company presents its combined and consolidated financial statements in Canadian dollars. In this prospectus, references to "$", "Cdn$", "dollars" or "Canadian dollars" are to Canadian dollars and references to "U.S.$" and "U.S. dollars" are to United States dollars. Amounts are stated in Canadian dollars unless otherwise indicated.

Certain terms used in this prospectus are defined under "Glossary".

Exchange Rate Data

The Company discloses certain financial information contained in this prospectus in U.S. dollars. The following table sets forth, for the periods indicated, the high, low, average and period-end noon spot rates of exchange for one U.S. dollar, expressed in Canadian dollars, published by the Bank of Canada.

	Year ended December 31			
	2008	2007	2006	2005
	C$	C$	C$	C$
Highest rate during the period	1.2969	1.1853	1.1726	1.2704
Lowest rate during the period	0.9719	0.9170	1.0990	1.1507
Average noon spot rate for the period[1]	1.0716	1.0666	1.1308	1.2085
Rate at the end of the period	1.2246	0.9881	1.1653	1.1659

(1) Determined by averaging the rates on the last business day of each month during the respective period.

On June 24, 2009, the noon rate of exchange posted by the Bank of Canada for conversion of U.S. dollars into Canadian dollars was U.S.$1.00 equals $ 1.1461.

Market Data

This prospectus contains statistical data, market research and industry forecasts that were obtained from government or other industry publications and reports (including the Canadian Electricity Association (the "CEA"), Natural Resources Canada ("NRCan"), the National Energy Board ("NEB"), Environment Canada, the Energy Information Administration ("EIA"), Cambridge Energy Research Associates ("CERA") and the North American Electric Reliability Corporation ("NERC")) or based on estimates derived from same and management's knowledge of, and experience in, the markets in which the Company operates. Government and industry publications and reports generally indicate that they have obtained their information from sources believed to be reliable, but do not guarantee the accuracy and completeness of their information. None of CEA, NRCan, NEB, Environment Canada, EIA, CERA or NERC has provided any form of consultation, advice or counsel regarding any aspect of, or is in any way whatsoever associated with, the Offering. Further, certain of these organizations are advisors to participants in the power industry, and they may present information in a manner that is more favourable to that industry than would be presented by an independent source. Actual outcomes may vary materially from those forecast in such reports or publications, and the prospect for material variation can be expected to increase as the length of the forecast period increases. While management believes this data to be reliable, market and industry data is subject to variations and cannot be verified due to limits on the availability and reliability of data inputs, the voluntary nature of the data gathering process and other limitations and uncertainties inherent in any statistical survey. Accordingly, the accuracy, currency and completeness of this information cannot be guaranteed. None of the Company, its affiliates, EPCOR or the Underwriters has independently verified any of the data from third party sources referred to in this prospectus or ascertained the underlying assumptions relied upon by such sources.

GAAP and Non-GAAP Measures

EPCOR Power Group's combined and consolidated financial statements included in this prospectus have been prepared in accordance with Canadian generally accepted accounting principles, or Canadian GAAP, as applied to its combined and consolidated financial statements. This prospectus makes reference to certain non-GAAP measures. These non-GAAP measures are not recognized measures under Canadian GAAP and do not have a standardized meaning prescribed by Canadian GAAP. Rather, these measures are provided as additional information to complement those Canadian GAAP measures by providing further understanding of the Company's results of operations from management's perspective. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Non-GAAP financial measures and — Results of Operations — non-GAAP financial measures".

Special Note Regarding Forward-Looking Statements

This prospectus contains forward-looking statements that relate to the Company's current expectations and views of future events. The forward-looking statements are contained principally in the sections titled "Prospectus Summary", "Business", "Management's Discussion and Analysis of Financial Condition and Results of Operations", "Use of Proceeds" and "Risk Factors".

In some cases, these forward-looking statements can be identified by words or phrases such as "may", "will", "expect", "anticipate", "aim", "estimate", "intend", "plan", "seek", "believe", "potential", "continue", "is/are likely to" or the negative of these terms, or other similar expressions intended to identify forward-looking statements. The Company has based these forward-looking statements on its current expectations and projections about future events and financial trends that it believes may affect its financial condition, results of operations, business strategy and financial needs (or, with respect to the first and second items noted below, on advice from EPCOR). These forward-looking statements include, among other things, statements relating to:

- EPCOR's intentions respecting its interest in the Company;
- EPCOR's intention to act only as an investor in and not as a manager of the Company;
- the Company's revenue, expenses, operations and prospects;
- the Company's strategy including growth for acquisition and development, return on existing assets, operational excellence and financial management;

- future cash flows, financial condition, operating performance, financial ratios, projected asset base, capital expenditures, and non-GAAP financial measures and pro forma and other unaudited financial information reflecting certain adjustments for the Company and its businesses;
- development and construction pipeline including potential projects for its various businesses;
- future legislative and regulatory developments and the regulatory environments in which the Company operates;
- the Company's use of net proceeds of the Offering;
- the Company's anticipated dividend policy;
- investment criteria and hedging activities;
- the Company's future financial strength and access to and terms of future financing;
- the Company's anticipated cash needs and its estimates regarding its capital expenditures, capital requirements, cash flow and its needs for and cost of additional financing;
- the availability and price of energy and other commodities and the Company's assessment of commodity and power markets;
- power plant availability and performance;
- the Company's future assets, including the possible sale of assets by the Company and EPLP and the exit from certain businesses and the discontinuation of certain operations;
- anticipated and unanticipated maintenance and other expenditures;
- demand for electricity and power generation facilities;
- weather and economic conditions;
- availability of labour and other resources;
- performance of counterparties, partners, contractors and suppliers in fulfilling their obligations;
- the acceptance of bids, the development and construction of projects and expansion of service and capacity;
- interest rates, related credit spreads and foreign exchange rates;
- the Company's competitive position and its expectations regarding competition from other energy providers; and
- anticipated trends and challenges in the Company's business and the markets in which it operates.

Forward-looking statements are based on certain assumptions and analysis 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. 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 and other factors, including those listed under "Risk Factors", that could cause the Company's actual results, performance, achievements and experience to differ materially from the Company's expectations, future results, performances or achievements expressed or implied by the forward-looking statements.

The forward-looking statements made in this prospectus relate only to events or information as of the date on which the statements are made in this prospectus. Except as required by law, the Company undertakes no obligation to update or revise publicly any forward-looking statements, whether as a result of new information, future event or otherwise, after the date on which the statements are made or to reflect the occurrence of unanticipated events.

An investor should read this prospectus and the documents to which the Company refers in this prospectus completely and with the understanding that the Company's actual future results may be materially different from what it expects.

Credit Rating Disclosure

This prospectus contains references to credit ratings of issuers, or their securities assigned by credit rating agencies. Set forth below is information in respect of the credit ratings assigned by these agencies.

The following description has been sourced from information made publicly available by DBRS. In general terms, DBRS ratings are opinions that reflect the creditworthiness of an issuer, a security, or an obligation. They are opinions based on forward-looking measurements that assess an issuer's ability and willingness to make timely payments on outstanding obligations (whether principal, interest, dividend, or distributions) with respect to the terms of an obligation. Ratings are opinions based on the quantitative and qualitative analysis of information sourced and received by DBRS, which information is not audited or verified by DBRS. The DBRS long-term debt rating scale is meant to give an indication of the risk that a borrower will not fulfill its full obligations in a timely manner, with respect to both interest and principal commitments. Whenever possible, DBRS assigns ratings to specific debt obligations or groups of obligations of an issuer, although there are cases though where DBRS chooses to assign an issuer rating that does not apply to individual securities. The long-term debt and issuer ratings scales consist of ten major rating categories, which range from a high of AAA to a low of D. With the exception of the AAA and D categories, DBRS uses "high" or "low" designations to indicate the relative standing of the securities being rated within a particular rating category, while the absence of either a high or low designation indicates the rating is in the "middle" of the category.

The following description has been sourced from information made publicly available by S&P. An S&P issue credit rating is a current opinion of the creditworthiness of an obligor with respect to a specific financial obligation, a specific class of financial obligations, or a specific financial program. It takes into consideration the creditworthiness of guarantors, insurers, or other forms of credit enhancement on the obligation and takes into account the currency in which the obligation is denominated. The opinion evaluates the obligor's capacity and willingness to meet its financial commitments as they come due, and may assess terms, such as collateral security and subordination, which could affect ultimate payment in the event of default. Issue credit ratings are based on current information furnished by the obligors or obtained by S&P from other sources it considers reliable. An S&P long-term issuer credit rating is a current opinion of an obligor's overall financial capacity (its creditworthiness) to pay its financial obligations and focuses on the obligor's capacity and willingness to meet its financial commitments as they come due, but does not apply to any specific financial obligation. The long-term issue ratings scales consist of ten major rating categories, which range from a high of AAA to a low of D. The long-term issuer ratings scales consist of nine major rating categories, which range from a high of AAA to a low of D, as well as rating categories for an issuer under regulatory supervision (R) and an issuer that has selectively defaulted (SD). The long-term issue and issuer ratings from AA to CCC may be modified by the addition of a plus (+) or minus (−) sign to show relative standing within the major rating categories.

The following description has been sourced from information made publicly available by Moody's. The purpose of Moody's ratings is to provide investors with a simple system of gradation by which relative creditworthiness of securities may be noted. Moody's long-term obligation ratings are opinions of the relative credit risk of fixed-income obligations with an original maturity of one year or more. They address the possibility that a financial obligation will not be honoured as promised. Such ratings reflect both the likelihood of default and any financial loss suffered in the event of default. Moody's issuer ratings are opinions of the ability of entities to honour senior unsecured financial obligations and contracts. The long-term obligation and issuer ratings scales consist of nine major rating categories, which range from a high of Aaa to a low of Caa. Moody's appends numerical modifiers 1, 2, and 3 to each major rating classification from Aa through Caa. The modifier 1 indicates that the obligation ranks in the higher end of its major rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that major rating category. Moody's ratings represent an opinion as to the relative creditworthiness of securities, and as such, should be used in conjunction with the descriptions and statistics appearing in Moody's publications.

The credit ratings assigned by DBRS, S&P or Moody's are not recommendations to buy, sell or hold a security inasmuch as such ratings do not comment as to market price or suitability for a particular investor. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised upward or downward or withdrawn entirely by the rating agency in the future if, in the judgment of either or both, circumstances so warrant. The credit ratings on a security may not reflect the potential impact of all risks related to the value of the security.

GLOSSARY

Certain terms used in this prospectus have the following meanings:

2009 Plan means the Company's 2009 long-term incentive plan, as more particularly described under "Management — Executive Compensation — Long-Term Incentive Compensation"

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

AESO means Alberta Electric System Operator, a corporation that acts as the Independent System Operator established by the *Electric Utilities Act* (Alberta)

amine scrubbing means a process for the removal of CO_2 from exhaust gases at fossil fuel power plants and other industrial facilities

Asset Purchase Agreement means the asset transfer agreement providing for the contribution by EPDC to Capital Power LP of certain of the assets of EPDC, as more particularly described under "Relationship to EPCOR — Agreements Between Capital Power and EPCOR — Asset Purchase Agreement"

ATCO means ATCO Power Canada Ltd., a corporation incorporated under the laws of Canada

Balancing Pool means the Alberta Balancing Pool, an Alberta provincial government entity established to, among other things, hold certain PPAs

baseload unit means a power generation facility that generally operates at or near full production capacity

Battle River means the Battle River power generation facility

BC Hydro means the British Columbia Hydro and Power Authority, a Crown corporation of the Province of British Columbia

btu/kWh means British thermal units per kilowatt hour

capacity factor means, for a power plant, a fraction equal to the actual amount of electricity produced over a given period of time divided by the amount of electricity that would have been produced if the power plant had operated at maximum output during 100% of the time

capacity payment means a fixed, periodic payment, typically monthly, from a PPA holder to a power generator under terms of a PPA that compensate the power generator for making its production capacity available to the PPA holder

Capital Power LP means Capital Power L.P., a limited partnership formed under the laws of Ontario by a limited partnership agreement

Capital Power LP General Partner means EMCC Limited immediately following completion of the Reorganization and any successor general partner of Capital Power LP

Capital Power Transitional Services Agreement means the transitional services agreement providing for the provision of certain services by Capital Power to EPCOR, as more particularly described under "Relationship to EPCOR — Agreements Between Capital Power and EPCOR — Transitional Services Agreements"

CEA means Canadian Electricity Association, an industry association for electricity producers in Canada

CERA means Cambridge Energy Research Associates, an energy consulting company

CfD means a contract-for-differences, a contractual arrangement whereby a payment is made by one party to the contract to the other, as the case may be, based on the difference between a reference price and the price of an underlying commodity

CGCN Committee means Capital Power's Corporate Governance, Compensation & Nominating Committee

Clover Bar means the Clover Bar Energy Centre

CO_2 means carbon dioxide

cogeneration natural gas-fired plant means a generation facility that produces both electricity and steam from the burning of natural gas, most commonly used on or near industrial sites where all or a portion of the products are purchased by the site host

combined-cycle means, in reference to a natural gas powered generation unit, plant or facility, using a natural gas turbine to generate electricity from the combustion of natural gas and using the waste heat resulting from the combustion process to make steam, which generates additional electricity via a steam turbine generator

Common LP Units means the common limited partner units of Capital Power LP

Common Shares mean the common shares in the capital of Capital Power Corporation

Cooperation Agreement means the cooperation agreement providing for among other things certain governance, tax and financial reporting matters by Capital Power to EPCOR, as more particularly described under "Relationship to EPCOR — Agreements Between Capital Power and EPCOR — Cooperation Agreement"

DBRS means DBRS Limited

ecoEnergy Renewable Power Program means the Government of Canada's ecoEnergy Renewable Power Program introduced in 2007 to support renewable power projects, as amended from time to time, and which replaced the Wind Power Production Incentive Program

Edmonton Social Objectives Agreement means the agreement dated as of May 5, 2009 between EPCOR, The City of Edmonton and Capital Power providing that Capital Power will, among other things, employ a certain number of employees in The City of Edmonton as more particularly described under "Relationship to EPCOR — Agreements Between Capital Power and EPCOR — Edmonton Social Objectives Agreement"

EIA means Energy Information Administration, the section of the United States Department of Energy providing statistics and data analysis on resources, supply, production and consumption for all energy sources in the United States

ENMAX means ENMAX Corporation, a corporation incorporated under the laws of Alberta

EPA means electricity purchase agreement

EPCOR Services Agreement means the services agreement providing for the provision of certain services by EPCOR to Capital Power, as more particularly described under "Relationship to EPCOR — Agreements Between Capital Power and EPCOR — Transitional Services Agreements"

EPCOR Transitional Services Agreement means the transitional services agreement providing for the provision of certain services by EPCOR to Capital Power, as more particularly described under "Relationship to EPCOR — Agreements Between Capital Power and EPCOR — Transitional Services Agreements"

EPDC means EPCOR Power Development Corporation, a corporation incorporated under the laws of Alberta

EPGSI means EPCOR Power Generation Services Inc., a corporation incorporated under the laws of Alberta

EPLP means EPCOR Power L.P., a limited partnership formed under the laws of Ontario by an amended and restated limited partnership agreement dated August 31, 2005

EPLP General Partner means EPCOR Power Services Ltd., a corporation incorporated under the laws of Canada which acts as the general partner of EPLP

EPLP Holdco means EPLP Investments Inc.

EPLP Holdco Shareholder Agreement means the agreement between the Company and EPCOR in their contemplated capacities as shareholders of EPLP Holdco, as more particularly described under "Relationship to EPCOR — Agreements Between Capital Power and EPCOR — EPLP Holdco Shareholder Agreement"

EPLP Manager means the subsidiary entities of Capital Power contracted by EPLP General Partner to provide management and administrative services to EPLP.

Equistar means Equistar Chemicals, LP, a limited partnership formed under the laws of Delaware by a limited partnership agreement dated October 17, 1997

Exchange Agreement means the exchange agreement providing the holders of Exchangeable LP Units the right to require the exchange of Exchangeable LP Units for Common Shares as more particularly described under "Relationship to EPCOR — Agreements Between Capital Power and EPCOR — Exchange Agreement"

Exchangeable LP Units means the exchangeable common limited partner units of Capital Power LP, exchangeable for Common Shares

Exelon means Exelon Generation Company, LLC, a corporation incorporated under the laws of Pennsylvania

FERC means the Federal Energy Regulatory Commission, the agency that regulates the transmission of electric energy in interstate commerce, the sale of electric energy at wholesale in interstate commerce, the transmission and sale of natural gas for resale in interstate commerce and that grants certificates for the construction and operation of interstate natural gas transmission facilities and that approves, and enforces compliance with, electric bulk power system reliability standards in the U.S.

FIT means "Feed-In-Tariff", which is a government program that encourages investment in renewable energy projects. Under a FIT program, electricity generated by a renewable energy project receives a fixed tariff price that is intended to be sufficient to compensate the power producer for a fixed term

FPA means the U.S. *Federal Power Act of 1935*, as amended

GEA means the Ontario *Green Energy and Green Economy Act, 2009*, S.O. 2009, c. 12

GHG means one or more of the greenhouse gases listed in Annex A to the Kyoto Protocol to the United Nations Framework Convention on Climate Change

GP Units means the general partner units of Capital Power LP

GW means gigawatt or one billion watts

GWh means gigawatt hour, or the amount of electricity generated by the power of one gigawatt operating for one hour

gross capacity means the total gross output that a power generation facility is capable of producing

heat rate means an arithmetic calculation of the amount of combustible fuel, typically natural gas or coal, that is used to produce a unit of electricity, often expressed in btu/kWh

IFRS means International Financial Reporting Standards

IGCC means Integrated Gasification Combined Cycle, a type of power generation plant configuration that converts coal into syngas for combustion in a combined cycle process

investment-grade credit rating means an issuer or long-term issue credit rating of BBB (low) or higher from DBRS, BBB− or higher from S&P, or Baa3 or higher from Moody's, unless the context requires otherwise

IPP means an independent power producer

IPSP means the proposed Integrated Power System Plan originally submitted by the OPA to the Ontario Energy Board, but which has not been approved and which is, as of the date of this prospectus, under revision by the OPA for resubmission to the Ontario Energy Board for approval

kWh means kilowatt hour, or the amount of electricity generated by the power of one kilowatt operating for one hour

Limited Partnership Agreement means the amended and restated limited partnership agreement relating to Capital Power LP as more particularly described under "Relationship to EPCOR — Limited Partnership Agreement of Capital Power LP"

LTI Plan means the Company's long-term incentive plan for the Company's 2010 fiscal year and onward

Master Separation Agreement means the master separation agreement dated as of June 25, 2009 providing for the separation of the business of Capital Power from EPCOR and contemplating the transfer of the business of EPCOR Power Group to Capital Power in connection with the Offering, as more particularly described under "Relationship to EPCOR — Agreements Between Capital Power and EPCOR — Master Separation Agreement"

Memorandum of Agreement means the memorandum of agreement dated June 7, 2009 between the Company, EPCOR and EPLP as more particularly described under "Business — Memorandum of Agreement"

mid-merit facility means a power generating facility that typically operates at between 30% and 70% of its annual production capacity, normally during periods of higher demand

Moody's means Moody's Investors Services

Morris means Morris Cogeneration LLC, a corporation incorporated under the laws of Delaware

Morris Facility means the Morris cogeneration facility

MW means megawatt, or one million watts

MWh means megawatt hour, or the amount of electricity generated by the power of one megawatt operating for one hour

Naval Facilities means three natural gas-fired generation facilities located on U.S. Naval bases in southern California

NEB means the National Energy Board, the agency of the Government of Canada that regulates international and interprovincial aspects of the oil, gas and electric utility industries

NEOs means the Chief Executive Officer, the Chief Financial Officer and the next three most highly compensated executive officers of Capital Power

NERC means the North American Electric Reliability Corporation, the not-for-profit corporation that created, and enforces compliance with, electricity transmission reliability standards in North America

NI 52-110 means National Instrument 52-110 — *Audit Committees*

NI 58-101 means National Instrument 58-101 — *Disclosure of Corporate Governance Practices*

NOVA means Nova Chemicals Corporation, a corporation incorporated under the laws of Canada

NO_x means nitrogen oxide

NRCan means Natural Resources Canada

NYMEX means the New York Mercantile Exchange, a physical commodity futures exchange and a trading forum for energy and precious metals

OEFC means the Ontario Electricity Financial Corporation, a Crown corporation of the Province of Ontario that is a successor of Ontario Hydro to manage the debt and administer the assets, liabilities, rights and obligations of Ontario Hydro not transferred to other successor entities

OPA means the Ontario Power Authority, an Ontario provincial government entity whose mandate includes conducting independent planning for electricity generation, demand management, conservation and transmission, developing integrated power system plans, and ensuring adequate, reliable and secure electricity supply and resources in Ontario

peaking facility means a power generating facility that generally operates only during peak demand and typically has the ability to start and stop on short notice

Pension Transfer Agreement means the pension transfer agreement as more particularly described under "Management — Executive Compensation — EPLP Component"

PERC means Primary Energy Recycling Corporation, a corporation incorporated under the laws of British Columbia

PERH means Primary Energy Recycling Holdings LLC, a limited liability company established under the laws of Delaware

PPA means power purchase arrangement or power purchase agreement, as applicable

PURPA means the U.S. *Public Utility Regulatory Policies Act of 1978*, as amended

QF means a qualifying cogeneration facility or a qualifying small power production facility, as defined under the FPA and FERC's regulations thereunder

Reorganization has the meaning ascribed thereto under "Relationship to EPCOR — Reorganization"

Registration Rights Agreement means the registration rights agreement as more particularly described under "Relationship to EPCOR — Agreements Between Capital Power and EPCOR — Registration Rights Agreement"

Regulations means the regulations under the Tax Act

reserve margin means the margin between power demand during peak usage periods versus the total supply of power available to meet this demand for a particular power market, generally expressed as a percentage that is calculated by taking total supply less the peak demand, and dividing by total supply

RFP means a request for proposals

S&P means Standard & Poor's Rating Services, a division of The McGraw-Hill Companies (Canada) Corporation

Secondment Agreement means the secondment agreement as more particularly described under "Management — Executive Compensation — Benefit and Pension Plans — Defined Benefit ("DB") Pension Plan"

Separation Agreements has the meaning ascribed thereto under "Relationship to EPCOR — Agreements Between Capital Power and EPCOR — Overview"

Share Purchase Agreement means the share transfer agreement providing for the purchase by Capital Power from EPCOR of all the issued and outstanding shares of EMCC Limited as more particularly described under "Relationship to EPCOR — Agreements Between Capital Power and EPCOR — Share Purchase Agreement"

simple-cycle means, in reference to a natural gas powered generation unit, plant or facility, using a natural gas turbine to generate electricity from the combustion of natural gas, without using the waste heat resulting from the combustion process to generate additional electricity. Simple-cycle facilities are generally used as peaking facilities as they have the ability to start and stop on short notice, but they have a higher heat rate than combined-cycle facilities

SO_2 means sulphur dioxide

spark spread means the theoretical difference between the price of electricity as the output and its energy cost of production

Special Limited Voting Share means the special limited voting share in the capital of Capital Power

Special Limited Voting GP Share means the special limited voting share in the capital of Capital Power LP General Partner

Special Voting Shares means the special voting shares in the capital of Capital Power

SRAC means short-run avoided costs

Sundance means units 5 and 6 of the Sundance power generation facility

supercritical coal-fired facility means a type of coal-fired power generation facility operating at very high temperatures and pressures and with higher efficiencies than other coal-fired facilities

syndicate members means the four companies with whom Capital Power acquired Alberta PPAs associated with Sundance and Battle River

Tax Act means the *Income Tax Act* (Canada)

tolling agreement means an agreement that allows one entity to have control of the electricity produced by the electricity generating assets owned by another entity, which usually requires the entity controlling the electricity produced to procure and pay for the fuel supply necessary to produce the electricity

TransAlta means TransAlta Corporation, a corporation incorporated under the laws of Canada

U.S. Securities Act means the *United States Securities Act of 1933*, as amended

Ventures means EPCOR USA Ventures LLC, formerly Primary Energy Ventures LLC, a corporation incorporated under the laws of Delaware

Vestas means Vestas Wind Systems A/S, the manufacturer of turbines for the Kingsbridge wind farm

WECC means the Western Electricity Coordinating Council

Wind Power Production Incentive Program means the Government of Canada Wind Power Production Incentive Program funded to support wind projects, which was replaced in 2007 by the ecoEnergy Renewable Power Program

PROSPECTUS SUMMARY

An investor should read the following summary together with the more detailed information regarding the Company contained elsewhere in this prospectus, including the risk factors and the combined and consolidated financial statements.

The Company

Overview

Headquartered in Edmonton, Alberta, Capital Power is among Canada's largest independent power generation companies (as measured by revenue, total assets and capacity), with interests in 31 facilities in Canada and the U.S. totalling approximately 3,300 MW of owned and/or operated power generation capacity, 470 MW of capacity owned through PPAs and 448 MW of owned capacity under construction. Drawing on a 118 year heritage of innovation and reliability, Capital Power has a well established history of developing, acquiring, operating and optimizing power generation from a range of energy sources. For ease of reference, information about Capital Power's facilities is summarized in a table at the end of this prospectus.

The Company's generation portfolio consists of the following:

Alberta contracted plants — The Alberta contracted plants, consisting of Genesee 1 and 2, are wholly-owned coal-fired generating units with 820 MW of combined generation capacity. The generation capacity of these plants is subject to a PPA, which provides Capital Power with a pre-determined return on invested capital and a formula based mechanism intended to recover operating costs.

Alberta commercial plants — The Alberta commercial plants consist of six facilities representing approximately 743 MW of owned and/or operated power generation capacity. These plants generate electricity principally from coal but also from natural gas, hydro, wind and landfill gas. Genesee 3, the largest of the Company's Alberta commercial plants with 495 MW of gross capacity, is among the most fuel-efficient coal-fired generating units in Canada. Capital Power operates Genesee 3 and owns 50% of the facility in a joint venture with TransAlta Corporation ("TransAlta").

Ontario and British Columbia contracted plants — The Company owns two hydro-electric generation facilities representing 40 MW of hydro-electric generation capacity in British Columbia and a 40 MW wind farm in Ontario. Output from these plants is sold under long-term contracts with provincial government entities in British Columbia and Ontario.

EPLP — EPLP is a Canadian limited partnership listed on the Toronto Stock Exchange. The Company indirectly holds a 30.6% interest in EPLP, and indirectly serves as its manager and general partner. EPLP has an ownership interest in a portfolio of 20 generation plants in the U.S. and Canada with generation capacity of 1,668 MW and thermal capacity of approximately 4,157 million pounds per hour. These plants generate electricity and steam principally from natural gas and, to a lesser extent, from waste heat, hydro, biomass, coal and tire-derived fuel. In addition, EPLP holds 17.0% of the common share interest and 14.2% of the preferred share interest in Primary Energy Recycling Holdings LLC ("PERH"), which in turn holds interests in four power generation facilities with an aggregate gross generation capacity of approximately 283 MW and one coal pulverizing facility. EPLP also indirectly acts as the manager for PERH.

Power purchase arrangements — Capital Power maintains rights to 470 MW of capacity through its ownership interest in PPAs, which entitle it to the output from five generating units at a price reflecting the cost of fixed and variable expenses associated with operating the facilities plus a pre-determined return on invested capital. The majority of this capacity is derived from the Company's 52% interest in the output from units 5 and 6 of the Sundance power generation facility ("Sundance"), a 710 MW coal-fired power plant in Alberta. The remaining balance comprises 99 MW of output from the coal-fired Battle River power generation facility ("Battle River"). The Company has agreed to sell its remaining interest in the Battle River PPA in January 2010.

Projects under construction and in development — In addition to its operating fleet, the Company has two significant projects under construction and a pipeline of projects in various stages of development. As part

of a 50/50 joint venture with TransAlta, the Company is constructing the 495 MW Keephills 3 supercritical coal-fired power plant in Alberta, which is expected to be in operation by early 2011. Keephills 3 will employ the same high-efficiency supercritical coal-fired technology that is currently in operation at Genesee 3 and will incorporate a number of innovative air emission reduction measures. TransAlta will operate the facility. The Company is also constructing units 2 and 3 to expand the Clover Bar Energy Centre ("Clover Bar"), adding a total of 200 MW of simple-cycle natural gas-fired peaking capacity. The units are expected to be in operation in 2009 and 2010, respectively. In addition, the Company is pursuing development projects and opportunities across Canada and the U.S. with an estimated 1,300 MW of capacity (based on current development plans) and employing various energy sources including wind, biomass and natural gas. The Company, in connection with the Canadian and Alberta governments, is also working on clean coal technology projects aimed at substantially reducing greenhouse gas ("GHG") emissions from coal-fired power generation.

Electricity generated from Capital Power's power generation portfolio is sold either under long-term contracts, short-term contracts or into the wholesale market in which the plant is located. Capital Power's objective is to contract a sufficient amount of production to maintain an investment-grade credit rating and stable dividends. The Company employs a "Networked Hub" strategy, whereby the Company seeks to optimize its assets by aggregating energy output from multiple facilities into a pool with non-unit-specific contracts. The Company believes that this strategy enhances its ability to manage output cost-effectively while reducing the economic risks associated with unforeseen outages at individual facilities. See "— Corporate Strategy — Regional footprint" and "— Networked Hub strategy".

Market Opportunity

Canada

On a national basis, the CEA forecasts Canadian electricity demand to grow at a 1.5% compound annual growth rate between 2005 and 2020.[(1)] In addition, the CEA expects 20% of the electricity generation capacity that was in operation in 2000 to be retired by 2020.[(1)] The combined effect of demand growth and facility retirements is expected to result in a significant need for new generation in the coming years. The CEA estimates that this need will equate to a required 60 GW in new generation capacity between 2006 and 2020,[(1)] or roughly $150 billion in investments in new power generation capacity between 2005 and 2025, according to Environment Canada.[(2)] Regionally, Capital Power's principal Canadian markets of Alberta, Ontario and British Columbia are expected to exhibit long-term GDP growth of 2.7%, 2.2% and 2.8% per annum, respectively.[(3)] The current economic downturn is expected to result in a near term slow-down in demand growth for electricity. Within Canada, Alberta is the only province with a deregulated electricity market, and one in which Capital Power holds a significant baseload position. The British Columbia and Ontario markets remain price regulated, and provincial regulatory bodies have continued to issue requests for proposals ("RFPs") or other procurements for new development.

United States

The current economic downturn in the U.S. is expected to result in a near term slow-down in energy demand growth. However, while Cambridge Energy Research Associates ("CERA") forecasts a decline in energy consumption from 2008 to 2009, CERA also expects that demand growth will become positive again beginning in 2010.[(4)] In the mid- to long-term, EIA, the statistical agency of the U.S. Department of Energy, forecasts 1% annual electricity demand growth from 2008 through 2020.[(5)] This projection is lower than the

(1) CEA's Power Generation in Canada: A Guide (2006)

(2) More Energy with Less Greenhouse Gas. Speaking notes for Stéphane Dion, then Minister of the Environment June 26, 2005

(3) NRCAN Canada's Energy Outlook Reference Case 2006

(4) CERA's US Power Market Fundamentals, dated January 19, 2009

(5) EIA's Annual Energy Outlook 2009, dated March 31, 2009

historical peak demand growth rate of over 2.0% seen in North America since 1990.[1] In combination with limited near-term capacity development, demand growth in the U.S. is expected to compress reserve margins and necessitate renewed development activity.[1] Regional power markets within the U.S. exhibit a high level of diversity, due in part to differing regulatory regimes, transmission constraints, supply and demand characteristics and environmental policies. Capital Power intends to focus on specific regions in the United States which, on average, are expected to have higher growth rates than the national norm. See "— Corporate Strategy — Regional footprint".

The U.S. market has solid growth potential for the Company due to its size relative to the Canadian market and because of its historical reliance on fossil fuel-based power generation which is an area of expertise for Capital Power.

Corporate Strengths

Large, high quality generation portfolio — Capital Power is one of Canada's largest independent power producers (as measured by revenue, total assets and capacity), with an existing portfolio of approximately 3,300 MW of owned and/or operated power generation capacity, 470 MW of capacity owned through PPAs and 448 MW of owned capacity under construction. The Company believes that Genesee 3, a supercritical coal facility, and Keephills 3, which will use the same supercritical coal technology utilized at Genesee 3, are among the highest-efficiency and most technologically advanced coal-fired plants in Canada. In addition, the Company believes that its significant baseload position, coupled with its portfolio of mid-merit and peaking power facilities, makes Capital Power well situated to capitalize on fluctuating market dynamics.

Modern fleet with excellent operating history — Capital Power's power generation fleet, with a capacity weighted average facility age of 13 years, is relatively young as compared with the average age of fleets larger than 1,000 MW in Canada. Coal-fired power generation facilities, which have historically represented the majority of the Company's portfolio, have useful lives up to 40 years. The Company's average facility age will decrease with the addition of 448 MW of owned capacity coming online between 2009 and 2011.

Capital Power's history of strong operating performance is exemplified by its fossil fuel facilities' most recent three year average availability of 94%, which compares favourably with the approximately 83% average availability of fossil fuel facilities in Canada as reported for 2006[2]. Moreover, the CEA has reported that Capital Power's Genesee 1 unit had the lowest incapability factor (the amount of power not produced relative to the plant's capability) of any Canadian fossil fuel plant in 2006, the latest year for which data is available. Solomon Associates, an energy industry advisor, also ranked the Genesee plant in the top quartile of a peer group (comprised of 99 coal units with capacity ranging from 210 MW to 549 MW) on the measure of forced outages in 2006, the latest year reported, consistent with prior years[3]. The Company believes that reliability is reflective of quality of assets and the Company's sound operating procedures and maintenance standards. The strong operating performance has been accomplished in conjunction with a culture of safe operations that stresses the health and safety of employees, contractors, customers and the public.

Diversified portfolio in attractive North American markets — The Company's portfolio is well diversified across three provinces and seven U.S. states, helping to mitigate exposure to regionally isolated declines, disruptions or changes in power markets. Capital Power believes that many of its generation facilities are located in growing markets with positive spark spreads that require new generation supply to meet market demand growth and/or anticipated plant retirements. For example, several of Capital Power's existing baseload facilities, including Genesee 1, 2 and 3, as well as the Keephills 3 development project, are located in Alberta, a region exhibiting some of the strongest market dynamics in Canada. Furthermore, the facilities are also diversified by fuel type including coal, natural gas, wind and hydro generation.

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(1) NERC's Electricity, Supply & Demand Report, dated January 21, 2009

(2) Based on CEA Generation Equipment Status Report 2006

(3) "Top Plants — Genesee 3 Edmonton, Alberta, Canada", Platts Power Magazine, Dr. Robert Peltier, PE, July/August 2005.

Long-term contracts including PPAs provide predictable cash flows and financial stability — Long-term contracts, which the Company considers to include power and steam purchase agreements, represent an important element of Capital Power's corporate strategy. The Company views these contracts as key in providing predictable cash flows and financial stability which support the Company's investment-grade credit rating and ability to pay dividends. Approximately 74% of Capital Power's generation capacity is sold forward through PPAs. Existing PPA contracts have an 11-year capacity weighted average remaining contract life, providing cash flows for a number of years. 96% of the Company's PPA counterparties have investment-grade credit ratings, helping to limit the Company's exposure to counterparty credit risk. In addition, approximately 70% of expected commercial generation in Alberta has been sold on a forward basis through 2009 and 2010, reducing the Company's short-term sensitivity to changes in power prices.

Environmental leadership — Capital Power is a leader in Canada in the development, construction, and operation of environmentally responsible power generation facilities, including supercritical coal technology, combined heat and power facilities, highly-efficient natural gas turbines used for both simple- and combined-cycle plants and recycled energy technology. In addition, the Company owns and/or manages a range of renewable energy facilities relying on fuels such as hydro, biomass, wind, waste heat and landfill gas. Examples of Capital Power's environmental leadership include:

- Capital Power was among the first to introduce commercial-scale supercritical technology to Canada. Using this technology, in March 2005, the coal-fired Genesee 3 unit entered operation with GHG emissions 18% lower than competing conventional coal-fired facilities in Alberta and significantly lower nitrogen oxide ("NO_x") and sulphur dioxide ("SO_2") emissions.
- Capital Power considers itself to be a leader in GHG emission offset project development and procurement, based on the volume of its purchase and retirement of offsets and diverse mix of offset projects. In 2007 and 2008, the first two years that emission reductions were mandated in Alberta, Capital Power applied 34% and 21%, respectively, of all GHG emission offset credits in the Province. Capital Power has a significant portfolio of GHG offsets developed or under contract from sources such as landfill gas, low tillage agriculture and acid gas injection.
- Capital Power actively participates in Canadian efforts to commercialize near-zero emission coal power technology. The Company is conducting front end engineering and design work on an Integrated Gasification Combined Cycle ("IGCC") power plant as well as pursuing the design of an amine scrubbing process to remove carbon dioxide from exhaust gas produced at generation facilities.

Outstanding platform for growth — Capital Power intends to continue to grow its generation capacity through construction and development, as well as acquisitions.

Capital Power is currently managing construction at both the 200 MW Clover Bar expansion and the 495 MW Keephills 3 facility which are expected to come online in 2009, 2010, and 2011 at a total combined capital cost of approximately $2.1 billion. In addition to the projects currently under construction, Capital Power is pursuing development opportunities for approximately 1,300 MW of power generation capacity.

To facilitate this growth, Capital Power actively engages in public consultation and building long-term positive relationships with communities, regulators, governments and other stakeholders. Capital Power has developed a public consultation and stakeholder engagement process that it considers a competitive advantage and the basis for sustainable relationships. Capital Power believes its reputation and engagement process have enabled it to achieve license renewals, facility expansions and closures and the permitting of new power generation projects on a timely basis.

Capital Power's acquisition program will initially be focused on opportunities in the U.S. within the regional footprint targeted by its "Networked Hub" strategy. This strategy will leverage expertise developed through management of EPLP and will rely primarily upon Capital Power's mergers and acquisitions ("M&A") and development team.

Capital Power has maintained a prudent growth strategy. Despite the significant capital requirements for the purchase of EPLP in 2005, the construction of Genesee 3 and the ongoing development of Clover Bar and

Keephills 3, EPCOR, the Company's predecessor, has consistently maintained an investment-grade credit rating. The Company believes that its focus on portfolio diversity represents additional evidence of its commitment to a disciplined, risk-conscious development strategy. The Company's presence in multiple markets, experience with multiple technologies and sound financial practices have provided Capital Power with a platform for further growth.

Experienced senior management team with a track record of disciplined growth — Capital Power's management team consists of eight key senior executives with 174 years of cumulative experience in the power and energy sectors (see "Management") and extensive experience with the Company's current power generation portfolio. Capital Power believes that its management team has a track record of strong operational performance, successful development across many fuel types, and successful completion of M&A and capital market transactions.

Capital Power has managed several development and construction projects and executed a number of acquisitions since its inception as part of a regulated utility in 1996, at which time the power portfolio consisted of 1,701 MW of generation regulated by the Alberta Energy and Utilities Board. During this period, Capital Power also decommissioned 881 MW of natural gas generation facilities in the Edmonton region that had reached the end of their economic lives. These facilities have been or are being replaced by newer and more cost effective power generation facilities. Capital Power's approximate 3,300 MW of owned and/or operated power generation capacity has been achieved through greenfield growth and M&A activity.

Capital Power has demonstrated expertise in construction management through its completion of six facilities since the beginning of 2002, including supercritical coal, combined-cycle natural gas, simple-cycle natural gas, wind, hydro and landfill gas facilities.

Capital Power's management team has experience in executing a number of M&A transactions, including the acquisition of its 30.6% interest in EPLP from TransCanada Corporation in 2005. Through the management of EPLP, the Capital Power team has also completed asset acquisitions including the Morris cogeneration facility (the "Morris Facility") and EPCOR USA Ventures LLC, formerly Primary Energy Ventures LLC ("Ventures"). Access to public and private capital markets has supported the Company's growth. As part of its M&A activities, the Company has completed a number of transactions including:

- the purchase of 1,373 MW of output under the Sundance and Battle River PPAs in 2000 and the sale and expected sale of 1,002 MW between 2006 and 2010 at an expected pre-tax gain on disposition of $515 million; and
- the purchase of Union Energy and Westcoast Capital in 2001 for $188 million and subsequent initial public offering of UE Waterheater in 2003 for a pre-tax and after-tax gain on disposition of $291 million.

Corporate Strategy

Capital Power's corporate strategy seeks to balance maintaining a strong financial position with the pursuit of targeted growth. The Company is committed to maintaining a stable dividend, operating as an entity with an investment-grade credit rating supported by contracted cash flows, and pursuing a prudent expansion strategy supported by its development pipeline and construction expertise.

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

Financial discipline — Capital Power is committed to a policy of financial discipline founded upon operational success, long-term contracting and targeted growth while seeking to maintain 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 and/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.

Capital Power L.P.'s ("Capital Power LP") preliminary corporate credit rating by S&P is BBB and its provisional senior unsecured debt rating provided by DBRS is BBB. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and capital resources".

Strong but sustainable growth — Capital Power has a pipeline of projects currently in construction or development. Building on the success of Genesee 3, the Company is expanding Clover Bar and building the Keephills 3 facility, representing 695 MW of new generation capacity under construction, of which Capital Power has a 448 MW ownership interest. Clover Bar and Keephills 3 are expected to be fully operational in 2010 and 2011, respectively. See "Business — Description of Capital Power Operating Facilities". The Company has a number of projects currently 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 will seek to capitalize on its experience to acquire high quality assets.

The U.S. and Canadian governments have identified a need for additional investment in power generation. These types of infrastructure investments have the potential to represent attractive growth opportunities for companies with experience and financial capacity. Capital Power believes it has the requisite background and ability to execute on these opportunities.

Technology preference — Capital Power plans to limit its selection of future power generation technologies 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. See "Regulatory Overview". 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 and/or maintain economic or environmental advantages over other power generators.

Regional footprint — Capital Power currently intends to confine its regional footprint to Canada and the U.S. The Company will seek 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. Based on these criteria, Capital Power initially intends to maintain its existing strong position in Alberta with initial focus on developing additional hubs in the following three regions: Mid-Atlantic U.S., including the PJM 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). To date, the Company has made a limited investment in each of these three regions. See "Power Industry Overview". In addition, if there are specific opportunities for development of contracted renewable facilities or for the replication of Capital Power's supercritical coal plant hubs with an attractive counterparty in a supportive regulatory environment, other markets will also be considered on a case-by-case basis. For example, Capital Power expects that long-term contracts from renewable projects will continue to be achievable in both the Ontario and British Columbia markets.

Continued focus on operational excellence, 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 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 are intended to 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.

Networked Hub strategy — The Company's "Networked Hub" strategy is an approach to managing power generation assets at the "hub" level rather than at the individual facility level 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 in the Company's markets. These plants best support hub efficiencies and electricity dispatch requirements. In order to reduce purchasing, warehousing, inventory and other costs, the Company seeks to standardize these plant types by fuel type and technology. The

Company then seeks to enter into non-unit-specific contracts to provide it with the most flexibility to deploy generation assets. The availability of physical generation from multiple generation sources in a market area provides flexibility to Capital Power to meet the requirements of customers from more than one generation plant. The proximity of generation allows the Company to optimize its portfolio of assets in the "Networked Hub" in response to factors such as heat rate, commodity, and inter-market optionality. The Company believes that its approach of managing assets at the hub level improves efficiency and reduces risk through portfolio diversification.

The Transaction

EPCOR currently owns, either directly or indirectly through its subsidiaries, all of the assets and operations of the Company. EPCOR will transfer those assets and operations to the Company and its subsidiaries through the Reorganization to be completed immediately following the closing of the Offering. See "Relationship to EPCOR — Reorganization".

Immediately following completion of the Reorganization, EPCOR will hold 56.625 million Exchangeable LP Units of Capital Power LP exchangeable for Common Shares of Capital Power (the "Exchangeable LP Units") and 56.625 million accompanying Special Voting Shares of Capital Power, representing in the aggregate approximately 72.2% of the total number of outstanding Common Shares after giving effect to the exchange of the Exchangeable LP Units. EPCOR will not be permitted to exchange Exchangeable LP Units if, following the exchange, EPCOR would own more than 49% of the outstanding Common Shares. See "Description of Share Capital and Exchangeable LP Units".

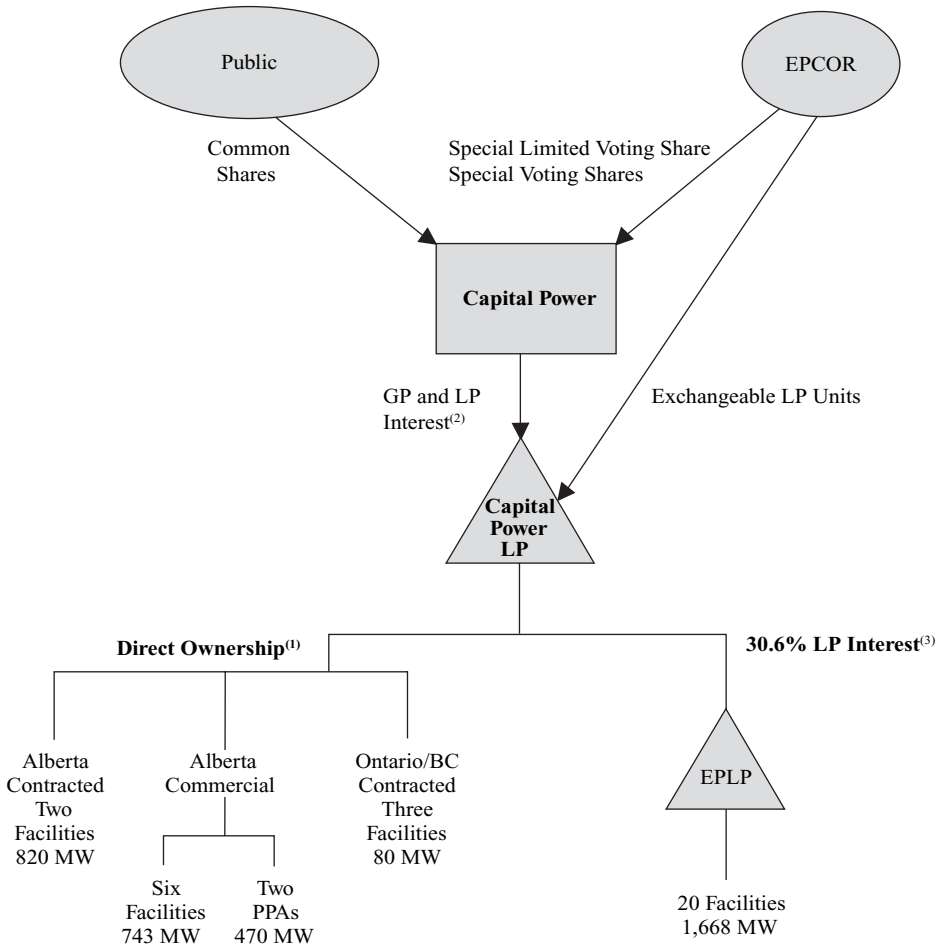
Each of the Exchangeable LP Units to be issued to EPCOR will be accompanied by a Special Voting Share of the Company that entitles the holder to not more than one vote per Special Voting Share (subject to customary anti-dilution adjustments), provided that the Special Voting Shares as a class shall not, at any time, entitle the holders to a number of votes greater than 49% of the votes attached to outstanding Common Shares and Special Voting Shares, taken together. So long as the holders of the Special Voting Shares hold in aggregate a certain minimum number of Exchangeable LP Units and/or Common Shares, the holders of Special Voting Shares will be entitled to nominate and elect, as a separate class, a maximum of four directors of the Company. Immediately following the closing of the Offering, four of the twelve directors of the Company will be directors or officers of EPCOR. Otherwise, the holders of the Special Voting Shares and Common Shares will vote together as a single class on all matters to be voted on by shareholders except as required by law. See "Description of Share Capital and Exchangeable LP Units — Capital Power — Special Voting Shares".

The articles of the Company will provide that the head office of the Company will be in The City of Edmonton. EPCOR has received a Special Limited Voting Share issued to it by the Company, designed to ensure that the head office of the Company remains in Edmonton. The Special Limited Voting Share is non-voting except with respect to its right to vote separately as a class in connection with any proposal to amend the articles of the Company to provide that the "Head Office" of the Company (as defined in the articles) will be in a location other than Edmonton, and certain related matters. The Company has also entered into the Edmonton Social Objectives Agreement with EPCOR and The City of Edmonton pursuant to which the Company has agreed to maintain its "Head Office" (as defined in the agreement) in The City of Edmonton, and to maintain at least 350 employees based in The City of Edmonton for a period of 25 years following completion of the Offering.

EPCOR has advised the Company 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.

The Company's Cooperation Agreement with EPCOR will provide for, among other things, financial reporting to EPCOR and certain other governance matters. The Cooperation Agreement will not in any way limit the ability of EPCOR to exercise its rights attached to the Special Voting Shares and Special Limited Voting Share. EPCOR has advised the Company that it intends to act only as an investor in and not as a manager of the Company. See "Relationship to EPCOR — Agreements Between Capital Power and EPCOR — Cooperation Agreement".

The following organization chart sets out the inter-corporate relationships of EPCOR, the Company and its material subsidiaries after giving effect to the completion of the Offering and the Reorganization:



(1) Stated capacity represents owned and/or operated capacity.

(2) Held through EMCC Limited, a subsidiary of Capital Power.

(3) Capital Power LP has a 49% voting interest and a 100% economic interest in EPLP Holdco, a holding company that owns a 30.6% interest in the limited partnership units of EPLP and 100% of the shares of EPLP General Partner, the general partner of EPLP. EPCOR owns the other 51% voting interest in EPLP Holdco. EPLP facilities are managed by indirect wholly-owned subsidiaries of Capital Power.

THE OFFERING

Total Gross Proceeds	$500,250,000
Offering Price per Common Share	$23.00
Common Shares Offered	21,750,000 Common Shares
Common Shares Outstanding Immediately After the Offering	21,750,000 Common Shares
Over-Allotment Option	The Underwriters have been granted the Over-Allotment Option exercisable for a period of 30 days after the closing of the Offering to purchase up to an additional 3,262,500 Common Shares (representing 15% of the Common Shares offered under the base Offering) at the initial public offering price to cover over-allotments, if any. See "Plan of Distribution".
Common Shares to be owned by EPCOR immediately after the Offering	56.625 million or approximately 72.2% of the outstanding Common Shares (68.1% if the Over-Allotment Option is exercised in full), after giving effect to the exchange of Exchangeable LP Units to be held by EPCOR. EPCOR's right to exchange Exchangeable LP Units is restricted. All of EPCOR's voting interest in Capital Power immediately after the Offering is expected to be held in the form of Special Voting Shares issued in tandem with the Exchangeable LP Units. See "Description of Share Capital and Exchangeable LP Units".
Use of Proceeds	It is estimated that the net proceeds to be received by the Company from the Offering will be approximately $468 million. The Company intends to use the net proceeds from the Offering to finance the acquisition of the assets and operations of the business of Capital Power pursuant to the Share Purchase Agreement described in "Relationship to EPCOR — Agreements Between Capital Power and EPCOR — Share Purchase Agreement". See "Use of Proceeds".
Risk Factors	An investment in the Common Shares is subject to a number of risks, including operational risks, PPA contract-related risks, risks relating to the Company's relationship with EPCOR, risks relating to the price and volume of electricity, environmental regulatory risks, risks relating to the cost and availability of fuel and other supplies, risks related to reliance on third party electrical transmission systems, risks related to the Company's relationship with EPLP, that no market for the Common Shares may develop and that the market price for the Common Shares may be volatile. See "Risk Factors" and the other information included in this prospectus for a discussion of the risks that an investor should carefully consider before deciding to invest in the Common Shares.
Dividend Policy	The board of directors (the "Board of Directors") of Capital Power has established a dividend policy pursuant to which

Capital Power will initially authorize the declaration and payment of a dividend of $1.26 per Common Share, to be paid on a quarterly basis. The payment of dividends is not guaranteed and the amount and timing of any dividends payable will be at the discretion of the Board of Directors. See "Dividend Policy".

It is anticipated that Capital Power LP will make quarterly cash distributions to holders of GP Units, Common LP Units and Exchangeable LP Units on a *pro rata* basis.

Unless otherwise indicated, the number of Common Shares outstanding after the Offering is based on 21,750,000 Common Shares outstanding after giving effect to the Offering and the Reorganization. It does not include:

- Common Shares issuable upon the exchange of Exchangeable LP Units to be held by EPCOR;
- Common Shares reserved for issuance under the 2009 long-term incentive plan (the "2009 Plan") or issuable upon the exercise of options granted under the 2009 Plan; and
- Common Shares reserved for issuance under the long-term incentive plan for the 2010 plan year onward (the "LTI Plan") or issuable upon the exercise of incentives granted under the LTI Plan.

Unless otherwise indicated, the information in this prospectus:

- gives effect to the Reorganization to be completed immediately following the closing of the Offering as described under "Relationship to EPCOR — Reorganization"; and
- assumes that the Underwriters do not exercise the Over-Allotment Option to purchase up to 3,262,500 additional Common Shares.

SUMMARY HISTORICAL AND PRO FORMA FINANCIAL AND OTHER DATA

The following tables present historical combined and consolidated financial data for EPCOR Power Group and pro forma consolidated financial data for the Company, in each case, for the periods ended and as at the dates indicated below. The historical combined and consolidated financial data for EPCOR Power Group as at December 31, 2008 and 2007 and for the years ended December 31, 2008, 2007 and 2006 have been derived from the audited combined and consolidated financial statements of EPCOR Power Group included in this prospectus. The historical combined and consolidated financial data for EPCOR Power Group as at March 31, 2009 and for the three months ended March 31, 2009 and 2008 have been derived from the unaudited combined and consolidated financial statements of EPCOR Power Group included in this prospectus. The pro forma combined financial data for the Company as at March 31, 2009 and for the three months then ended and the year ended December 31, 2008 have been derived from the unaudited pro forma consolidated financial information of the Company included in this prospectus, and give effect to the Offering, the Reorganization and other transactions as if they had occurred on January 1, 2008 for the unaudited pro forma consolidated statements of income and March 31, 2009 for the unaudited pro forma consolidated balance sheet. The pro forma data are unaudited, are for informational purposes only and are not necessarily indicative of what the Company's financial position or results of operations would have been had such transactions been completed as of such dates and had the Company operated as a separate, stand-alone public entity, and do not purport to represent what the financial position, results of operations or cash flows might be for any future period.

The data set forth below should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the combined and consolidated financial statements of EPCOR Power Group and the unaudited pro forma consolidated financial information of Capital Power included in this prospectus.

Selected Combined and Consolidated Financial Information and Other Data
(in $ millions)

	Year ended December 31			
Statements of Income Data	**Pro forma 2008**	**2008**	**2007**	**2006**
Revenues	$2,649	$2,649	$2,953	$2,246
Energy purchases and fuel	1,914	1,914	2,079	1,462
	735	735	874	784
Operations, maintenance and administration	374	370	287	248
Depreciation, amortization and asset retirement accretion	185	181	175	154
Foreign exchange losses (gains)	18	18	(56)	54
Gain on sale of power purchase arrangement and related transactions	(34)	(34)	(34)	(378)
Impairments	43	52	13	5
Net financing expenses	103	219	219	227
	689	806	604	310
Income (loss) before income taxes and non-controlling interests	46	(71)	270	474
Income taxes	(31)	(24)	113	(3)
Income (loss) before non-controlling interests	77	(47)	157	477
Non-controlling interests	47	(51)	23	44
Net income	**$ 30**	**$ 4**	**$ 134**	**$ 433**

Statements of Income Data	Three months ended March 31		
	Pro forma 2009	2009	2008
Revenues	$709	$709	$633
Energy purchases and fuel	510	510	397
	199	199	236
Operations, maintenance and administration	83	82	83
Depreciation, amortization and asset retirement accretion	47	46	45
Foreign exchange losses (gains)	—	—	13
Gain on sale of power purchase arrangement and related transactions	(30)	(30)	(34)
Net financing expenses	35	64	51
	135	162	158
Income before income taxes and non-controlling interests	64	37	78
Income taxes	(8)	5	5
Income before non-controlling interests	72	32	73
Non-controlling interests	53	(22)	38
Net income	**$ 19**	**$ 54**	**$ 35**

Selected Balance Sheet Data	Pro forma March 31, 2009	March 31, 2009	December 31, 2008	December 31, 2007
Cash and cash equivalents	$ 80	$ 80	$ 69	$ 51
Total assets	4,953	5,048	5,002	4,922
Long-term debt (including current portion)	1,781	3,064	3,027	2,485
Total liabilities	2,622	4,105	4,081	3,453
Non-controlling interests	1,863	507	540	740
Total shareholders' equity	468	436	381	729

Other Financial Data	Three months ended March 31		Year ended December 31		
	2009	2008	2008	2007	2006
Gross margin[1]	$199	$236	$735	$874	$784
Adjusted EBITDA[1]	117	153	365	587	536
Funds from operations[1]	81	70	265	279	281
Funds from operations excluding non-controlling interests in EPLP[1]	62	44	182	194	177
Capital additions	108	76	439	235	49
Net income net of certain items[1]	17	26	79	111	72
Adjusted EBITDA net of certain items[1]	136	142	549	552	543

(1) The Company uses gross margin, earnings before foreign exchange, interest, income taxes, depreciation and amortization, and impairments ("adjusted EBITDA"), funds from operations, funds from operations excluding non-controlling interests in EPLP, net income net of certain items, and adjusted EBITDA net of certain items as financial performance measures. These terms are not defined financial measures according to Canadian generally accepted accounting principles ("GAAP") and do not have any standardized meanings prescribed by GAAP. Therefore, these measures may not be comparable to similar measures used by other enterprises. Rather, these measures are provided as additional information to complement those Canadian GAAP measures by providing further understanding of the Company's results of operations from management's perspective. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Results of operations — non-GAAP financial measures" for a reconciliation of these measures to the most closely comparable GAAP measures.

The following table presents certain power generation and plant availability data of the Company for the periods indicated.

	Three months ended March 31		Year ended December 31		
	2009	2008	2008	2007	2006
Electricity generation (GWh)					
Alberta commercial plants	691	625	2,206	2,477	2,555
Alberta contracted plants	1,628	1,423	5,923	6,350	6,250
Ontario/British Columbia contracted plants	49	53	271	288	223
	2,368	2,101	8,400	9,115	9,028
EPLP plants[1]	1,299	1,253	4,955	5,229	3,272
Total	**3,667**	**3,354**	**13,355**	**14,344**	**12,300**

(1) Excludes Castleton, the sale of which closed on May 26, 2009.

	Three months ended March 31		Year ended December 31		
	2009	2008	2008	2007	2006
Generation plant availability (%)[1]					
Alberta commercial plants	99	98	85	95	97
Alberta contracted plants	100	88	91	97	95
Ontario/British Columbia contracted plants	89	99	94	91	93
EPLP plants	94	97	94	93	95
Overall Average[2]	**97**	**95**	**91**	**95**	**95**

(1) Plant availability represents the percentage of time in the period that the plant is available to generate power, whether actually running or not and is reduced by planned and unplanned outages.

(2) Overall average generation plant availability is an average of individual plant availability weighted by owned and/or operated capacity.

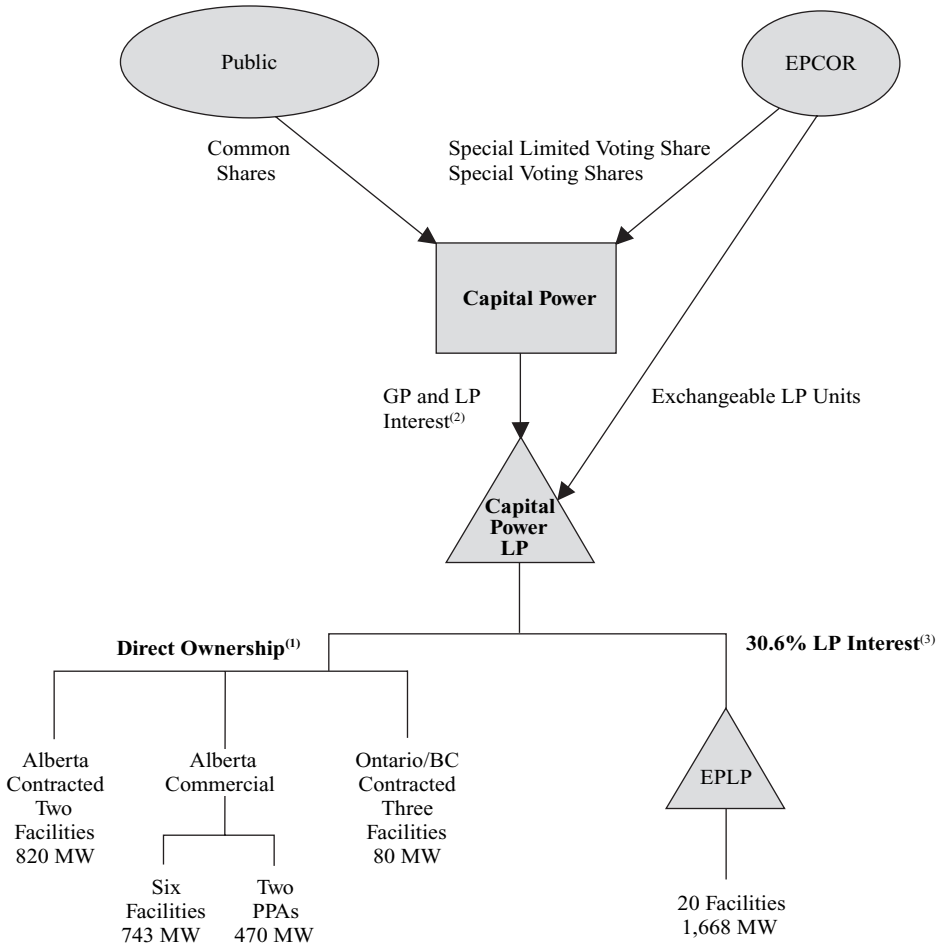
CORPORATE STRUCTURE

Capital Power

Capital Power Corporation was incorporated under the *Canada Business Corporations Act* on May 1, 2009 as 7166575 Canada Inc. The Company's name was changed to Capital Power Corporation pursuant to articles of amendment dated May 6, 2009. The Company's articles were further amended on June 16, 2009 to, among other things, create the classes of shares described in this prospectus. The principal business office and registered office of the Company is located at TD Tower, 10188-102 Avenue, Edmonton, Alberta, Canada, T5J 2Z1.

EPCOR currently owns, either directly or indirectly through its subsidiaries, all of the assets and operations of the Company. EPCOR will transfer those assets and operations to the Company and its subsidiaries through the Reorganization to be completed immediately following the closing of the Offering as described under "Relationship to EPCOR — Reorganization". Immediately following the completion of the Reorganization, EPCOR will hold 56.625 million Exchangeable LP Units of Capital Power LP and 56.625 million accompanying Special Voting Shares, representing approximately 72.2% of the total number of outstanding Common Shares after giving effect to the exchange of the Exchangeable LP Units. The votes attached to the Special Voting Shares may not, however, exceed 49% of the votes attached to all outstanding Common Shares and Special Voting Shares, taken together. In addition, EPCOR will not be permitted to exchange Exchangeable LP Units if following the exchange, EPCOR would own more than 49% of the then outstanding Common Shares. See "Description of Share Capital and Exchangeable LP Units".

The following organization chart indicates the intercorporate relationships of EPCOR, the Company and its material subsidiary entities after giving effect to the completion of the Offering and the Reorganization:



(1) Stated capacity represents owned and/or operated capacity.

(2) Held through EMCC Limited, a subsidiary of Capital Power.

(3) Capital Power LP has a 49% voting interest and a 100% economic interest in EPLP Holdco, a holding company that owns a 30.6% interest in the limited partnership units of EPLP and 100% of the shares of EPLP General Partner, the general partner of EPLP. EPCOR owns the other 51% voting interest in EPLP Holdco. EPLP facilities are managed by indirect wholly-owned subsidiaries of Capital Power.

Capital Power LP

Capital Power LP is a limited partnership established under the laws of the Province of Ontario. Immediately following the completion of the Reorganization, Capital Power LP will directly and indirectly, hold the Company's assets and investments in the electrical power generation business, EPCOR will hold 56.625 million Exchangeable LP Units of Capital Power LP and 56.625 million Special Voting Shares of Capital Power. In addition, Capital Power will hold indirectly 21,750,001 GP Units of Capital Power LP and indirectly one Common LP Unit of Capital Power LP representing approximately 27.8% and zero % respectively of the total number of outstanding partnership interests in Capital Power LP. See "Relationship to EPCOR — Limited Partnership Agreement of Capital Power LP — Partnership Units".

EPLP

EPLP is a limited partnership formed under the laws of the Province of Ontario with interests in 20 power generation facilities in Canada and the U.S. that generate electricity and steam. See "Business — EPLP". EPLP is a reporting issuer in each of the provinces and territories of Canada with limited partnership units listed on the Toronto Stock Exchange. Immediately following the completion of the Reorganization, EPCOR will hold 51 Class A Shares of EPLP Holdco representing 51% of the votes and Capital Power LP will hold 49 Class B Shares of EPLP Holdco representing 49% of the votes. The Class B Shares will entitle Capital Power LP to all dividends declared and paid by EPLP Holdco. EPLP Holdco will hold an approximate 30.6% interest in EPLP and 100% of the shares of EPCOR Power Services Ltd., the general partner of EPLP ("EPLP General Partner"). See "Relationship to EPCOR — Reorganization" and "Description of Share Capital and Exchangeable LP Units — EPLP Holdco".

BUSINESS

Overview

Headquartered in Edmonton, Alberta, Capital Power is among Canada's largest independent power generation companies (as measured by revenue, total assets and capacity), with interests in 31 facilities in Canada and the U.S. totalling approximately 3,300 MW of owned and/or operated power generation capacity, 470 MW of capacity owned through PPAs and 448 MW of owned capacity under construction. Drawing on a 118 year heritage of innovation and reliability, Capital Power has a well established history of developing, acquiring, operating and optimizing power generation from a range of energy sources. For ease of reference, information about Capital Power's facilities is set forth in the Capital Power Facilities Summary Table at the end of this prospectus, which forms part of this prospectus.

The Company's generation portfolio consists of the following:

Alberta contracted plants — The Alberta contracted plants, consisting of Genesee 1 and 2, are wholly-owned coal-fired generating units with 820 MW of combined generation capacity. The generation capacity of these plants is subject to a PPA, which provides Capital Power with a pre-determined return on invested capital and a formula based mechanism intended to recover operating costs.

Alberta commercial plants — The Alberta commercial plants consist of six facilities representing approximately 743 MW of owned and/or operated power generation capacity. These plants generate electricity principally from coal, but also from natural gas, hydro, wind and landfill gas. Genesee 3, the largest of the Company's Alberta commercial plants with 495 MW of gross capacity, is among the most fuel-efficient coal-fired generating units in Canada. Capital Power operates Genesee 3 and owns 50% of the facility in a joint venture with TransAlta.

Ontario and British Columbia contracted plants — The Company owns two hydro-electric generation facilities representing 40 MW of hydro-electric generation capacity in British Columbia and a 40 MW wind farm in Ontario. Output from these plants is sold under long-term contracts with provincial government entities in British Columbia and Ontario.

EPLP — EPLP is a Canadian limited partnership listed on the Toronto Stock Exchange. The Company indirectly holds a 30.6% interest in EPLP, and indirectly serves as its manager and general partner. EPLP has an ownership interest in a portfolio of 20 generation plants in the U.S. and Canada with generation capacity of 1,668 MW and thermal capacity of approximately 4,157 million pounds per hour. These plants generate electricity and steam principally from natural gas and, to a lesser extent, from waste heat, hydro, biomass, coal and tire-derived fuel. In addition, EPLP holds 17.0% of the common share interest and 14.2% of the preferred share interest in PERH, which in turn holds interests in four power generation facilities with an aggregate gross generation capacity of approximately 283 MW and one coal pulverizing facility. EPLP also indirectly acts as the manager for PERH.

Power purchase arrangements — Capital Power maintains rights to 470 MW of capacity through its ownership interest in PPAs, which entitle it to the output from five generating units at a price reflecting the cost of fixed and variable expenses associated with operating the facilities plus a pre-determined return on invested capital. The majority of this capacity is derived from the Company's 52% interest in the output from Sundance. The remaining balance comprises 99 MW of output from Battle River. The Company has agreed to sell its remaining interest in the Battle River PPA in January 2010.

Projects under construction and in development — In addition to its operating fleet, the Company has two significant projects under construction and a pipeline of projects in various stages of development. As part of a 50/50 joint venture with TransAlta, the Company is constructing the 495 MW Keephills 3 supercritical coal-fired power plant in Alberta, which is expected to be in operation by early 2011. Keephills 3 will employ the same high-efficiency supercritical coal-fired technology that is currently in operation at Genesee 3 and will incorporate a number of innovative air emission reduction measures. TransAlta will operate the facility. The Company is also constructing units 2 and 3 to expand Clover Bar, adding a total of 200 MW of simple-cycle natural gas-fired peaking capacity. The units are expected to be in operation in 2009 and 2010, respectively. In addition, the Company is pursuing development projects and opportunities across Canada and the U.S. with an estimated 1,300 MW of capacity (based on current development plans) and employing various energy sources including wind, biomass and natural gas. The Company, in connection with the Canadian and Alberta governments, is also working on clean coal technology projects aimed at substantially reducing GHG emissions from coal-fired power generation.

Electricity generated from Capital Power's power generation portfolio is sold either under long-term contracts, short-term contracts or into the wholesale market in which the plant is located. Capital Power's objective is to contract a sufficient amount of production to maintain an investment-grade credit rating and stable dividends. The Company employs a "Networked Hub" strategy, whereby the Company seeks to optimize its assets by aggregating energy output from multiple facilities into a pool with non-unit-specific contracts. The Company believes that this strategy enhances its ability to manage output cost-effectively while reducing the economic risks associated with unforeseen outages at individual facilities. See "— Corporate Strategy — Regional footprint" and "— Networked Hub strategy".

Market Opportunity

Canada

On a national basis, the CEA forecasts Canadian electricity demand to grow at a 1.5% compound annual growth rate between 2005 and 2020.[1] In addition, the CEA expects 20% of the electricity generation capacity that was in operation in 2000 to be retired by 2020.[1] The combined effect of demand growth and facility retirements is expected to result in a significant need for new generation in the coming years. The CEA estimates that this need will equate to a required 60 GW in new generation capacity between 2006 and 2020,[1] or roughly $150 billion in investments in new power generation capacity between 2005 and 2025, according to Environment Canada.[2] Regionally, Capital Power's principal Canadian markets of Alberta, Ontario and British Columbia are expected to exhibit long-term GDP growth of 2.7%, 2.2% and 2.8% per annum, respectively.[3] The current economic downturn is expected to result in a near term slow-down in demand growth for electricity. Within Canada, Alberta is the only province with a deregulated electricity market, and one in which Capital Power holds a significant baseload position. The British Columbia and Ontario markets remain price regulated, and provincial regulatory bodies have continued to issue RFPs or other procurements for new development.

United States

The current economic downturn in the U.S. is expected to result in a near term slow-down in energy demand growth. However, while CERA forecasts a decline in energy consumption from 2008 to 2009, CERA also expects that demand growth will become positive again beginning in 2010.[4] In the mid- to long-term, EIA, the statistical agency of the U.S. Department of Energy, forecasts 1% annual electricity demand growth from 2008 through 2020.[5] This projection is lower than the historical peak demand growth rate of over 2.0% seen in North America since 1990.[6] In combination with limited near-term capacity development, demand growth in the U.S. is expected to compress reserve margins and necessitate renewed development activity.[6] Regional power markets within the U.S. exhibit a high level of diversity, due in part to differing regulatory regimes, transmission constraints, supply and demand characteristics and environmental policies. Capital Power intends to focus on specific regions in the United States which, on average, are expected to have higher growth rates than the national norm. See "— Corporate Strategy — Regional footprint".

The U.S. market has solid growth potential for the Company due to its size relative to the Canadian market and because of its historical reliance on fossil fuel-based power generation which is an area of expertise for Capital Power.

Corporate Strengths

Large, high quality generation portfolio — Capital Power is one of Canada's largest independent power producers (as measured by revenue, total assets and capacity), with an existing portfolio of approximately 3,300 MW of owned and/or operated power generation capacity, 470 MW of capacity owned through PPAs and 448 MW of owned capacity under construction. The Company believes that Genesee 3, a supercritical coal facility, and Keephills 3, which will use the same supercritical coal technology utilized at Genesee 3, are among the highest-efficiency and most technologically advanced coal-fired plants in Canada. In addition, the Company believes that its significant baseload position, coupled with its portfolio of mid-merit and peaking power facilities, makes Capital Power well situated to capitalize on fluctuating market dynamics.

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(1) CEA's Power Generation in Canada: A Guide (2006)

(2) More Energy with Less Greenhouse Gas. Speaking notes for Stéphane Dion, then Minister of the Environment June 26, 2005

(3) NRCAN Canada's Energy Outlook Reference Case 2006

(4) CERA's US Power Market Fundamentals, dated January 19, 2009

(5) EIA's Annual Energy Outlook 2009, dated March 31, 2009

(6) NERC's Electricity, Supply & Demand Report, dated January 21, 2009

Modern fleet with excellent operating history — Capital Power's power generation fleet, with a capacity weighted average facility age of 13 years, is relatively young as compared with the average of fleets larger than 1,000 MW in Canada. Coal-fired power generation facilities, which have historically represented the majority of the Company's portfolio, have useful lives up to 40 years. The Company's average facility age will decrease with the addition of 448 MW of owned capacity coming online between 2009 and 2011.

Capital Power's history of strong operating performance is exemplified by its fossil fuel facilities' most recent three year average availability of 94%, which compares favourably with the approximately 83% average availability of fossil fuel facilities in Canada as reported for 2006[(1)]. Moreover, the CEA has reported that Capital Power's Genesee 1 unit had the lowest incapability factor (the amount of power not produced relative to the plant's capability) of any Canadian fossil fuel plant in 2006, the latest year for which data is available. Solomon Associates, an energy industry advisor, also ranked the Genesee plant in the top quartile of a peer group (comprised of 99 coal units with capacity ranging from 210 MW to 549 MW) on the measure of forced outages in 2006, the latest year reported, consistent with prior years[(2)]. The Company believes that reliability is reflective of quality of assets and the Company's sound operating procedures and maintenance standards. The strong operating performance has been accomplished in conjunction with a culture of safe operations that stresses the health and safety of employees, contractors, customers and the public.

Diversified portfolio in attractive North American markets — The Company's portfolio is well diversified across three provinces and seven U.S. states, helping to mitigate exposure to regionally isolated declines, disruptions or changes in power markets. Capital Power believes that many of its generation facilities are located in growing markets with positive spark spreads that require new generation supply to meet market demand growth and/or anticipated plant retirements. For example, several of Capital Power's existing baseload facilities, including Genesee 1, 2 and 3, as well as the Keephills 3 development project, are located in Alberta, a region exhibiting some of the strongest market dynamics in Canada. Furthermore, the facilities are also diversified by fuel type including coal, natural gas, wind and hydro generation.

Long-term contracts including PPAs provide predictable cash flows and financial stability — Long-term contracts, which the Company considers to include power and steam purchase agreements, represent an important element of Capital Power's corporate strategy. The Company views these contracts as key in providing predictable cash flows and financial stability which support the Company's investment-grade credit rating and ability to pay dividends. Approximately 74% of Capital Power's generation capacity is sold forward through PPAs. Existing PPA contracts have an 11-year capacity weighted average remaining contract life, providing cash flows for a number of years. 96% of the Company's PPA counterparties have investment-grade credit ratings, helping to limit the Company's exposure to counterparty credit risk. In addition, approximately 70% of expected commercial generation in Alberta has been sold on a forward basis through 2009 and 2010, reducing the Company's short-term sensitivity to changes in power prices.

Environmental leadership — Capital Power considers itself to be a leader in Canada in the development, construction, and operation of environmentally advanced power generation facilities, including supercritical coal technology, combined heat and power facilities, highly-efficient natural gas turbines used for both simple- and combined-cycle plants and recycled energy technology. In addition, the Company owns and/or manages a range of renewable energy facilities relying on fuels such as hydro, biomass, wind, waste heat and landfill gas. Examples of Capital Power's environmental leadership include:

- Capital Power was among the first to introduce commercial-scale supercritical technology to Canada[(2)]. Using this technology, in March 2005, the coal-fired Genesee 3 unit entered operation with GHG emissions 18% lower than competing conventional coal-fired facilities in Alberta and significantly lower NO_x and sulphur dioxide SO_2 emissions.
- Capital Power considers itself to be a leader in GHG emission offset project development and procurement, based on the volume of its purchase and retirement of offsets and diverse mix of offset projects. In 2007 and 2008, the first two years that emission reductions were mandated in Alberta, Capital

(1) Based on CEA Generation Equipment Status Report 2006

(2) "Top Plants — Genesee Phase 3, Edmonton, Alberta, Canada", Platts Power Magazine, Dr. Robert Peltier, PE, July/August 2005.

Power applied 34% and 21%, respectively, of all GHG emission offset credits in the Province. Capital Power has a significant portfolio of GHG offsets developed or under contract from sources such as landfill gas, low tillage agriculture and acid gas injection.

- Capital Power actively participates in Canadian efforts to commercialize near-zero emission coal power technology. The Company is conducting front end engineering and design work on an IGCC power plant as well as pursuing the design of an amine scrubbing process to remove carbon dioxide from exhaust gas produced at generation facilities.

Outstanding platform for growth — Capital Power intends to continue to grow its generation capacity through construction and development, as well as acquisitions.

Capital Power is currently managing construction at both the 200 MW Clover Bar expansion and the 495 MW Keephills 3 facility which are expected to come online in 2009, 2010, and 2011 at a total combined capital cost of approximately $2.1 billion. In addition to the projects currently under construction, Capital Power is pursuing development opportunities for approximately 1,300 MW of power generation capacity.

To facilitate this growth, Capital Power actively engages in public consultation and building long-term positive relationships with communities, regulators, governments and other stakeholders. Capital Power has developed a public consultation and stakeholder engagement process that it considers a competitive advantage and the basis for sustainable relationships. Capital Power believes its reputation and engagement process have enabled it to achieve license renewals, facility expansions and closures and the permitting of new power generation projects on a timely basis.

Capital Power's acquisition program will initially be focused on opportunities in the U.S. within the regional footprint targeted by its "Networked Hub" strategy. This strategy will leverage expertise developed through management of EPLP and will rely primarily upon Capital Power's M&A and development team.

Capital Power has maintained a prudent growth strategy. Despite the significant capital requirements for the purchase of EPLP in 2005, the construction of Genesee 3 and the ongoing development of Clover Bar and Keephills 3, EPCOR, the Company's predecessor, has consistently maintained an investment-grade credit rating. The Company believes that its focus on portfolio diversity represents additional evidence of its commitment to a disciplined, risk-conscious development strategy. The Company's presence in multiple markets, experience with multiple technologies and sound financial practices have provided Capital Power with a platform for further growth.

Experienced senior management team with a track record of disciplined growth — Capital Power's management team consists of eight key senior executives with 174 years of cumulative experience in the power and energy sectors (see "Management") and extensive experience with the Company's current power generation portfolio. Capital Power believes that its management team has a track record of strong operational performance, successful development across many fuel types, and successful completion of M&A and capital market transactions.

Capital Power has managed several development and construction projects and executed a number of acquisitions since its inception as part of a regulated utility in 1996, at which time the power portfolio consisted of 1,701 MW of generation regulated by the Alberta Energy and Utilities Board. During this period, Capital Power also decommissioned 881 MW of natural gas generation facilities in the Edmonton region that had reached the end of their economic lives. These facilities have been or are being replaced by newer and more cost effective power generation facilities. Capital Power's approximate 3,300 MW of owned and/or operated power generation capacity has been achieved through greenfield growth and M&A activity.

Capital Power has demonstrated expertise in construction management through its completion of six facilities since the beginning of 2002, including supercritical coal, combined-cycle natural gas, simple-cycle natural gas, wind, hydro and landfill gas facilities.

Capital Power's management team has experience in executing a number of M&A transactions, including the acquisition of its 30.6% interest in EPLP from TransCanada Corporation in 2005. Through the management of EPLP, the Capital Power team has also completed asset acquisitions including the Morris Facility and

Ventures. Access to public and private capital markets has supported the Company's growth. As part of its M&A activities, the Company has completed a number of transactions including:

- the purchase of 1,373 MW of output under the Sundance and Battle River PPAs in 2000 and the sale and expected sale of 1,002 MW between 2006 and 2010 at an expected pre-tax gain on disposition of $515 million; and
- the purchase of Union Energy and Westcoast Capital in 2001 for $188 million and subsequent initial public offering of UE Waterheater in 2003 for a pre-tax and after-tax gain on disposition of $291 million.

Corporate Strategy

Capital Power's corporate strategy seeks to balance maintaining a strong financial position with the pursuit of targeted growth. The Company is committed to maintaining a stable dividend, operating as an entity with an investment-grade credit rating supported by contracted cash flows, and pursuing a prudent expansion strategy supported by its development pipeline and construction expertise.

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

Financial discipline — Capital Power is committed to a policy of financial discipline founded upon operational success, long-term contracting and targeted growth while seeking to maintain 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 and/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.

Capital Power LP's preliminary corporate credit rating by S&P is BBB and its provisional senior unsecured debt rating provided by DBRS is BBB. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and capital resources".

Strong but sustainable growth — Capital Power has a pipeline of projects currently in construction or development. Building on the success of Genesee 3, the Company is expanding Clover Bar and building the Keephills 3 facility, representing 695 MW of new generation capacity under construction, of which Capital Power has a 448 MW ownership interest. Clover Bar and Keephills 3 are expected to be fully operational in 2010 and 2011, respectively. See "Business — Description of Capital Power Operating Facilities". The Company has a number of projects currently 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 will seek to capitalize on its experience to acquire high quality assets.

The U.S. and Canadian governments have identified a need for additional investment in power generation. These types of infrastructure investments have the potential to represent attractive growth opportunities for companies with experience and financial capacity. Capital Power believes it has the requisite background and ability to execute on these opportunities.

Technology preference — Capital Power plans to limit its selection of future power generation technologies 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. See "Regulatory Overview". 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 and/or maintain economic or environmental advantages over other power generators.

Regional footprint — Capital Power currently intends to confine its regional footprint to Canada and the U.S. The Company will seek 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. Based on these criteria, Capital Power initially intends to maintain its existing significant position in Alberta with initial focus on developing additional hubs in the following three regions: Mid-Atlantic U.S., including the PJM 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). To date, the Company has made a limited investment in each of these three regions. See "Power Industry Overview". In addition, if there are specific opportunities for development of contracted renewable facilities or for the replication of Capital Power's supercritical coal plant hubs with an attractive counterparty in a supportive regulatory environment, other markets will also be considered on a case-by-case basis. For example, Capital Power expects that long-term contracts from renewable projects will continue to be achievable in both the Ontario and British Columbia markets.

Continued focus on operational excellence, 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 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 are intended to 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.

Networked Hub strategy — The Company's "Networked Hub" strategy is an approach to managing power generation assets at the "hub" level rather than at the individual facility level 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 in the Company's markets. These plants best support hub efficiencies and electricity dispatch requirements. In order to reduce purchasing, warehousing, inventory and other costs, the Company seeks to standardize these plant types by fuel type and technology. The Company then seeks to enter into non-unit-specific contracts to provide it with the most flexibility to deploy generation assets. The availability of physical generation from multiple generation sources in a market area provides flexibility to Capital Power to meet the requirements of customers from more than one generation plant. The proximity of generation allows the Company to optimize its portfolio of assets in the "Networked Hub" in response to factors such as heat rate, commodity, and inter-market optionality. The Company believes that its approach of managing assets at the hub level improves efficiency and reduces risk through portfolio diversification.

Description of Capital Power Facilities

Summary of Capital Power Operating Facilities

Capital Power's current portfolio consists of interests in 31 facilities in Canada and the U.S., totalling approximately 3,300 MW of owned and/or operated power generation capacity (excluding the Castleton facility, the sale of which closed on May 26, 2009). Capital Power's asset portfolio includes direct ownership in operating facilities, ownership of PPAs where Capital Power is entitled to the electricity output from the facilities but does not own the facilities themselves, and indirect ownership of a 30.6% interest in EPLP. For ease of reference, Capital Power's plants are summarized in a flip-out table at the end of this prospectus.

Genesee Units 1 & 2

Overview

Genesee 1 and 2 are coal-fired generating facilities with a total gross capacity of 820 MW. These facilities are located west of Edmonton near Warburg, Alberta and are baseload units, meaning they regularly run at or near full production capacity. Genesee 2, which was the first Genesee unit to be completed, was commissioned in October 1989, with a capacity of 410 MW. Genesee 1 was commissioned 5 years later in May 1994, using similar coal-fired steam turbine equipment and has an identical capacity of 410 MW. Both units have excellent

operating histories, as measured by their high availabilities. The Genesee 1 and 2 facilities are 100% owned and operated by Capital Power and are located on land owned by Capital Power.

Genesee 1 and 2 are identical pulverized coal-fired units that can operate on sliding-pressure allowing for more rapid start up and shutdown times. The boilers are subcritical and were supplied by ALSTOM SA ("ALSTOM"). The three-stage turbines were also supplied by ALSTOM. Each unit has its own cooling systems, but they share coal crushing and feeding equipment and a water treatment plant.

Genesee 1 and 2 are core assets in Capital Power's existing fleet. Their PPA ensures a base rate of return, with defined operating parameters that allow for incentives earned or penalties incurred by Capital Power. Management believes that Genesee 1 and 2 provide Capital Power with long-term, contracted cash flows from a highly creditworthy counterparty. This, together with low fuel supply risks associated with operating Genesee 1 and 2, contributes to the overall financial stability of the Company's portfolio of assets. Costs associated with compliance with changes in environmental regulation are passed through to the PPA holder under a change of law provision.

Commercial Arrangement: Power Purchase Arrangement

Genesee 1 and 2 are subject to a PPA with an Alberta provincial government entity (the "Balancing Pool"), which is in effect until December 31, 2020. Under terms of the PPA, the Balancing Pool is entitled to the power produced by the generating units, up to their committed capacity, in return for compensating Capital Power through amounts determined as follows:

- a formula-based provision intended to recover fixed and variable costs of operating the generating units;
- a formula-based provision for income taxes;
- a return on rate base formulation which includes a return on equity and cost of debt component; and
- incentive payments for maintaining plant availability above set target availability levels in the PPA and penalties to the extent the target availability levels in the PPA are not met. When the PPA was established, the target availability levels were set with the expectation that plant availability would equal target availability over the term of the PPA, although the plant owner is free to better that performance.

Availability incentives and penalties are determined on a monthly basis, and while there have been months where Genesee 1 and 2 have paid penalties, on an average annual basis they have earned net incentive payments in all but one year between 2001 and 2008.

The PPA contains termination provisions covering destruction of the unit, default of the owner with respect to performance, and default of the buyer or owner with respect to payments, credit proceedings, or bankruptcy. There is also a provision allowing the buyer to elect to terminate the PPA. The PPA specifies the calculation of termination payments, which considers the net present value of the PPA over the balance of its effective term.

The Alberta government has a credit rating of AAA as determined by both S&P and DBRS.

Fuel Supply

Coal required for Genesee 1, 2 and 3 is supplied by the adjacent Genesee Coal Mine, making Genesee a mine-mouth operation. Coal is supplied under long-term agreements with the Genesee Coal Mine joint venture, a 50/50 joint venture between Capital Power and Prairie Mines and Royalty Ltd. Prairie Mines and Royalty Ltd. is the operator of the mine and owns approximately 50% of the coal rights within the Genesee Coal Mine permit area. The remaining 50% of the coal rights is owned by the Alberta Government, but is leased to both the Genesee Coal Mine joint venture and Capital Power under 15-year renewable lease terms. Capital Power owns substantially all surface rights within the Genesee Coal Mine permit area.

Capital Power believes the recoverable coal reserves contained in the Genesee Coal Mine to be sufficient to supply the estimated requirements for the Genesee facilities, as currently configured, for the next 40 years, which exceeds the remaining useful lives of the Genesee 1, 2 and 3 units. The explored portions of the coal rights held by the Genesee Mine joint venture are surface mineable, which reduces extraction costs. In addition,

long-term geological modeling suggests predictable coal thickness within joint venture-controlled areas to be mined in the future. Environmental work to date at Genesee Coal Mine has returned 600 hectares of previously-mined area into productive farm land and wildlife habitat. In February 2009, Capital Power and Prairie Mines and Royalty Ltd. received the 2009 Alberta Chamber of Resources' Major Reclamation Award for its efforts at the Genesee Coal Mine.

Coal is supplied by the Genesee Coal Mine to the Genesee plant on a cost-of-service basis. The coal price is determined under a fixed formula having various components, including a regulated utility-like return on investment, depreciation, tax, royalty, management fee, annual inflation and interest rate adjustments and an annually negotiated capital operating and maintenance amount. Capital Power has the deciding vote on the joint venture management committee, which must approve the final budget each year. Prairie Mines and Royalty Ltd. can earn an incentive fee if it is able to reduce the actual annual operating costs below the operating costs included in the approved final budget each year while also sustaining mine output.

The proximity of the mine to the units as well as the relatively low cost of extracting the coal, provides a cost-competitive and secure fuel source for the Genesee facilities.

Operating History

The following tables present a summary of the Genesee 1 and 2 historical operating data for the years 2006 through 2008.

	Genesee Unit 1 Historical Operating Data			
	2008[1]	2007	2006	Average
Total Net Generation, GWh	2,961	3,125	3,218	3,101
Capacity Factor, %	88.8	94.2	96.8	93.3
Coal, tonnes (000s)	1,625	1,690	1,777	1,697
Availability Factor, %	89.8	95.7	97.8	94.4
Forced Outage, %	2.9	2.5	1.8	2.4

	Genesee Unit 2 Historical Operating Data			
	2008[1]	2007	2006	Average
Total Net Generation, GWh	2,962	3,225	3,032	3,073
Capacity Factor, %	90.4	97.1	90.9	92.8
Coal, tonnes (000s)	1,626	1,744	1,675	1,681
Availability Factor, %	91.9	98.0	92.0	94.0
Forced Outage, %	3.1	1.7	2.0	2.3

(1) Genesee 1 and 2 had major planned maintenance shutdowns in 2008. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Significant Events — Other Genesee plant outages".

Genesee Unit 3

Overview

Genesee 3 is located adjacent to Genesee 1 and 2 on the Genesee plant site. It is 50% owned by Capital Power and 50% owned by TransAlta and has a gross generation capacity of 495 MW. It commenced commercial operations in March 2005 and, the Company believes, remains among the most technologically advanced coal-fired power plants in North America. It was featured in its commissioning year by Platts Power Magazine as one of its "Top Plants in 2005".

Genesee 3 is one of the most fuel efficient coal-fired generating units in Canada. The supercritical technology combines higher boiler temperatures and pressures with a high-efficiency turbine to achieve greater efficiency and lower carbon dioxide, NO_x and SO_2 emissions per MW than conventional subcritical pulverized coal technologies. Genesee 3 is approximately 10% more fuel efficient than the older Genesee units, and

produces carbon dioxide ("CO_2") emissions that are approximately 18% lower than the average conventional Alberta coal generation unit on a per MW basis.

Genesee 3 uses a supercritical sliding-pressure, Babcock-Hitachi K.K. boiler and clean air technology that reduce its resulting air emissions beyond the requirements of current provincial and federal environmental standards.

The Company believes Genesee 3 to be one of the lowest variable cost, baseland generators in Alberta. It enjoys a competitive position in a market with shrinking reserve margins and planned coal unit retirements. The Company believes that Genesee 3 provides it with the ability to participate prudently in the upside potential of Alberta's wholesale power market.

Commercial Arrangement: Merchant Facility

Capital Power's share of Genesee 3's generation contributes to Capital Power's internal pool of electricity available to sell through the wholesale market. See "— Portfolio Optimization". Genesee 3 does not have a PPA with a third party buyer.

Fuel Supply

See "— Genesee Units 1 & 2 — Fuel Supply".

Operating History

The following table presents a summary of Genesee 3's historical operating data for the years 2006 through 2008.

	Genesee Unit 3 Historical Operating Data			
	2008[1]	**2007**	**2006**	**Average**
Total Net Generation, GWh	2,994	3,584	3,673	3,417
Capacity Factor, %	78.4	93.1	96.6	89.4
Coal, tonnes (000s)	1,494	1,727	1,758	1,660
Availability Factor, %	80.9	96.2	98.8	92.0
Forced Outage, %	12.30	0.62	0.31	4.41

(1) Genesee 3 had a major planned maintenance shutdown and a forced outage due to a turbine blade failure in 2008. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Significant Events — Genesee 3 turbine failure".

Joffre

Overview

Joffre is a 480 MW cogeneration natural gas-fired plant, commissioned in 2000, located at the Nova Chemicals Corporation ("NOVA") petrochemical complex near Red Deer, Alberta. NOVA's Joffre manufacturing complex is a large ethylene and polyethylene production facility.

The cogeneration plant at NOVA's Joffre complex is owned by a joint venture that includes Capital Power, ATCO Power Canada Ltd. ("ATCO") and NOVA with respective interests of 40%, 40% and 20%. It began commercial operations in May 2001. On February 23, 2009, International Petroleum Investment Company announced that it had entered into an agreement providing for the acquisition of all of NOVA's outstanding common shares. International Petroleum Investment Company is wholly-owned by the Government of the Emirate of Abu Dhabi, which has a credit rating from S&P of AA. Completion of the acquisition is subject to receiving regulatory approvals. NOVA shareholders approved the transaction on April 14, 2009.

ATCO is the operator of the Joffre cogeneration plant. The plant produces both steam and electricity. All of the steam and a portion of the electricity are used by the host petrochemical complex. Of the net electricity output from the plant, approximately 110 MW to 115 MW is used at the petrochemical complex with the balance

being sold to the Balancing Pool. ATCO markets the power that is surplus to the needs of the petrochemical complex. The Joffre plant is one of the largest cogeneration plants in Canada, as measured by capacity.

The plant utilizes two Siemens-Westinghouse 501F combustion turbines, two Nooter Erickson Heat Recovery Steam Generators, one Toshiba steam turbine and a Rentech vapour high pressure boiler. A long-term service agreement with Siemens Westinghouse covers non-routine maintenance through to 2015 or upon completion of the 12th scheduled outage.

Joffre is Capital Power's largest cogeneration and combined-cycle facility and it provides the Company with a significant position as a mid-merit participant in the Alberta market.

Commercial Arrangement: Energy Supply Agreement and Merchant Facility

An energy supply agreement dated June 30, 1999 among a subsidiary of Capital Power, ATCO and NOVA, in their respective capacities as sellers of energy, and NOVA also in its capacity as buyer, sets forth the terms regarding the sale of electricity, steam and feedwater to NOVA. The energy supply agreement is a tolling agreement. NOVA makes cost-of-service payments comprised primarily of a natural gas tariff, an operating maintenance tariff and a capital tariff based on a return-on-rate basis.

The energy supply agreement contains termination provisions that apply upon the decommissioning of the site by NOVA, upon agreement by the parties, upon default of the buyer or seller with respect to payments or performance, or upon default of the buyer with respect to credit proceedings or bankruptcy.

Capital Power also entered into a contract-for-differences ("CfD") with the joint venture partners for 50 MW of electricity at a contracted floating price calculated monthly. The purpose of the CfD, which expires in December 2010, is to minimize the joint venture's exposure to spot electricity prices and guarantee a level of cash flow to support the financing of the asset. The combination of the energy supply agreement and the Capital Power CfD result in the joint venture having tolling arrangements in place for approximately 160 MW of its electrical capacity. The uncommitted capacity of the plant is bid into the Alberta power pool.

Fuel Supply

Natural gas for the facility is procured and managed by NOVA under agreement with the three joint venture partners. Natural gas purchased from NOVA under the agreement is purchased at spot market prices. The agreement terminates upon decommissioning of the site by NOVA.

Operating History

The following table presents a summary of Joffre's historical operating data for the years 2006 through 2008.

	Joffre Historical Operating Data			
	2008[1]	**2007**	**2006**	**Average**
Total Net Generation, GWh	1,542	1,542	1,517	1,534
Capacity Factor, %	39.1	39.1	38.5	38.9
Availability Factor (weighted average of three units), %	90.1	94.3	90.9	91.8
Forced Outage, %	0.20	1.12	2.27	1.20

(1) Joffre experienced forced outages in 2008 to fix problems identified in its turbines.

Clover Bar Energy Centre

Overview

The Clover Bar Energy Centre is located in Edmonton, Alberta and currently utilizes one natural gas turbine that was commissioned in February 2008. Two natural gas turbines are expected to be operational in the third quarter of 2009 and in the third quarter of 2010, respectively. See "— Projects in Construction and

Development". The simple-cycle units will cycle on and off to take advantage of price volatility in the Alberta electricity market. The current capacity of the LM6000 unit at the facility is 43 MW. The two new units will consist of General Electric LMS 100 turbines that are each expected to add 100 MW for a total plant capacity of 243 MW in 2010.

The new units are being installed at the location of a previous generation plant owned by a subsidiary of Capital Power that was decommissioned in 2007. Certain infrastructure, like the water pump house, was retained from the previous facility resulting in reduced capital costs for the project. In addition, the retention of the current zoning, historical use and associated licenses have substantially reduced the lead time and complexities of obtaining regulatory approvals for the new facility.

Clover Bar's peaking units provide Capital Power with additional flexibility to optimize its Alberta power portfolio. The higher efficiency of the General Electric LMS 100s will help Capital Power offer peaking capacity competitively, and capture greater margins from peak power prices.

Commercial Arrangement: Merchant Facility

Clover Bar's output contributes to Capital Power's internal pool of electricity available to sell through the wholesale market. See "— Portfolio Optimization". Clover Bar does not have a PPA with a third party buyer.

Fuel Supply

Natural gas for Clover Bar is purchased on the spot market in Alberta to meet dispatch requirements. A natural gas transportation agreement with ATCO Pipelines, a division of ATCO Gas and Pipelines Ltd., provides firm service delivery to the Clover Bar site. The current nominated demand is 30,090 GJ/day. Commencing on November 1, 2009, the nominated demand will be 50,038 GJ/day, which is sufficient to meet the needs of all units operating at maximum capacity.

Operating History

The following table presents a summary of Clover Bar's historical operating data for 2008.

	Clover Bar Energy Centre (Unit 1) Historical Operating Data
	2008[1]
Total Net Generation, GWh	29
Capacity Factor, %[2]	12.0
Net Heat Rate btu/kWh	10,112
Availability Factor, %	96.6
Forced Outage, %	4.5

(1) For period from commissioning in February 2008.

(2) Operating factor used to approximate capacity factor for the first year of operations, when the capacity factor was not calculated.

Other Alberta Facilities

Capital Power also has interests in three other power generation facilities in Alberta, being:

- a 50% joint venture interest in Taylor Coulee Chute, a 13 MW hydro facility in Southern Alberta, co-owned with Canadian Hydro Developers, Inc. and commissioned in 2000;
- a 100% interest in Clover Bar Landfill Gas Plant, a 5 MW facility located in Edmonton that extracts methane from an adjacent landfill for its fuel source and that was commissioned in 2005; and
- a 99% interest in Weather Dancer, a 1 MW wind turbine located in Southern Alberta that was commissioned in 2001.

The total net investment in these other Alberta generation facilities is under $20 million. While they each have reliable operating histories and contribute to Capital Power's experience with clean energy sources, they make up a small overall contribution to the Capital Power generation fleet.

Since January 1, 2004, EPCOR has operated its Rossdale facility as a commercial generation plant. As the ancillary services contract with the AESO for continued operation of the Rossdale plant expired on December 31, 2008, Rossdale will be decommissioned in 2009. As a result, Rossdale will not be transferred to Capital Power pursuant to the Reorganization.

Kingsbridge

Overview

Kingsbridge is a 40 MW wind farm, owned by Capital Power, located near Goderich, Ontario. It consists of 22 1.8 MW Vestas V-80 turbines and one 0.7 MW Vestas turbine. The Vestas V-80 turbines were commissioned in March 2006 and have been very reliable, with annual availability for the 2007 and 2008 operating years exceeding 98.6%. For these years, the Kingsbridge facility was the best performing wind farm in Ontario based on capacity factor, as measured from data received by the Independent Electric System Operator. The Kingsbridge wind farm serves the electricity requirements in the region, has favourable wind conditions from Lake Huron and is strategically located within 200 kilometres from major load centers in the Greater Toronto Area.

The Kingsbridge wind turbines are located on land leased from 10 area landholders (some of which are related) pursuant to 14 leases. These leases have terms that can be renewed to cover the full term of the energy supply contract relating to the 22 turbines, although one landowner has the right to terminate its lease in the last year of the energy supply contract 8½ months before the energy supply contract expires. While the Company considers the likelihood of termination to be low, it will be seeking amendments to these leases to ensure they do not expire before the end of the energy supply contract. Some or all of the leases may require that consent under the *Planning Act* (Ontario) be obtained so that their respective terms including renewals can exceed 21 years less a day. If *Planning Act* (Ontario) consent is not obtained, the terms of the affected leases typically expire between 2023 and 2025. A subsidiary of Capital Power has secured additional leases on sites close to the existing wind farm which may provide further growth opportunities. See "— Projects in Construction and Development".

Kingsbridge receives wind power production incentive payments under the Wind Power Production Incentive Program of the Government of Canada. Under the program, Capital Power receives from the Canadian Federal Government $0.010 per kilowatt-hour up to a maximum of approximately $1.1 million annually and a total of approximately $10.8 million through to March 2016.

Capital Power has a long-term service agreement with Vestas which provides for a comprehensive warranty on all replacement parts and major components and all maintenance through to March 2011. The Company is currently reviewing various options for the continued provision of long term operation and maintenance services after March 2011, but expects that prices for such services will increase.

Kingsbridge provides Capital Power with long-term, contracted, stable cash flows in an area having favourable wind conditions in Ontario. It also provides Capital Power with the market presence to help the Company pursue larger wind development projects, such as the neighbouring Kingsbridge Phase II project and wind projects in British Columbia. See "— Projects in Construction and Development".

Commercial Arrangement: Energy Supply Contracts

Kingsbridge operates under the terms of two energy supply contracts with the Ontario Power Authority ("OPA"): one for the 22 turbines commissioned in 2006 and the other for the 0.7 MW turbine commissioned in 2007. The primary energy supply contract has a term of 20 years that terminates in March 2026. The smaller energy supply contract is a standard offer agreement under the OPA's "Renewable Energy Standard Offer Program" which terminates in March 2027. The terms of the primary Kingsbridge energy supply contract are relatively similar to other renewable energy supply contracts that the OPA administers with other Ontario renewable energy power producers. This energy supply contract has 3 key components:

- For each MWh of electricity that is delivered, a fixed price is paid. Fifteen percent of the initial fixed energy price is indexed to the Consumer Price Index in relation to Ontario and the balance remains fixed through the contract term. If the market price exceeds the fixed price, the fixed price applies.
- In the event the production-weighted average market price exceeds the average electricity price in the energy supply contract, Capital Power is entitled to a performance incentive payment based on a specified formula. Based on current market prices in Ontario and the electricity price in the energy supply contract, it is not expected that this incentive will be earned in the near future.
- When production exceeds the "Maximum Contract Energy", which is 125% of the expected annual energy output of the facility, Capital Power is entitled to be paid the prevailing market price for the

excess production, subject to an obligation to share with the OPA 50% of the gross profit for the excess production over the Maximum Contract Energy. Capital Power does not expect to earn incentives under this term of the energy supply contract.

The primary energy supply contract contains termination provisions including for default of the supplier or buyer with respect to payments, performance, credit proceedings or bankruptcy. In the event of such a default by Capital Power, the energy supply contract specifies the calculation for an early termination payment, which considers the net present value to the OPA of the energy supply contract over the balance of its effective term, and provides for a right of set-off.

Both energy supply contracts state that all contract related products, including GHG credits, are transferred and assigned to the OPA.

The OPA has a AA(low) credit rating from DBRS.

Energy Supply

Since 1999, the average wind speeds recorded at the Goderich airport weather station over the key months from October to March (when typically over 70% of annual production is achieved) have resulted in satisfactory capacity factors.

Operating History

The following table presents a summary of Kingsbridge's historical operating data for the years 2006 through 2008.

	Kingsbridge Historical Operating Data			
	2008[1]	2007	2006[2]	Average (2 year)
Total Net Generation, GWh	115.4	118.5	75.0	117.0
Capacity Factor, %	33.1	34.3	25.8	33.7
Availability Factor, %	98.9	98.6	96.6	98.8

(1) Capital Power does not track forced outage rates for wind facilities.

(2) For period from commissioning in March 2006.

Miller Creek

Overview

The Miller Creek facility is a 33 MW, two unit run-of-river hydroelectric power plant located on Miller Creek, near Pemberton, British Columbia. It is wholly-owned by Capital Power and consists of a 30 MW main unit and a 3 MW unit for peaking and use during the low water creek flow season, both of which were commissioned in 2003. The facility is located on Crown land that is leased by Capital Power. Capital Power pays water rental fees to the Province of British Columbia for the use of water from Miller Creek as well as royalty payments to four separate parties. One of the royalty payments ends in 2013, the second one ends in 2083 and the balance continues for the life of the facility.

The Miller Creek powerhouse contains one 29.5 MW vertical axis Pelton Wheel turbine and one 3.3 MW horizontal axis Pelton Wheel auxiliary turbine. The facility has an automated control system to allow unattended operation, remote monitoring and remote control of the project, which helps reduce its operating costs.

Water flows on Miller Creek peak from May through August, with relatively low flows in the winter months.

Commercial Arrangement: Electricity Purchase Agreement

There is a 20-year term electricity purchase agreement ("EPA") between British Columbia Hydro and Power Authority ("BC Hydro") and EPCOR Power Development (British Columbia) Limited Partnership ending May 2023, for all of the power output from the Miller Creek facility. EPCOR's interest in EPCOR Power

Development (British Columbia) Limited Partnership, as well as its interest in the general partner of the limited partnership, will be transferred to Capital Power LP. As a result, a consent to the change of control of the limited partnership from BC Hydro, in accordance with the terms of the EPA, is required.

At the end of the initial term of the EPA, BC Hydro has the option to renew the EPA for up to two 5-year terms. In addition, BC Hydro has, under separate agreement, a right of first refusal over the facility and the option to purchase a 25% joint venture interest in the facility or 25% of the electricity output from the facility for a fixed amount. Pricing under the EPA is based on the "Dow Jones Mid-C" daily index, adjusted for various factors including Canadian/U.S. foreign exchange rates and transportation adjustments depending on whether BC Hydro is importing or exporting power during the period. The EPA calls for certain environmental criteria to be met relating to construction, operation and maintenance (the "Green Resource Criteria"). In addition, the EPA provides for sharing with BC Hydro of any GHG emission credits arising from the Miller Creek facility.

The EPA termination provisions include the right for BC Hydro to refuse to accept deliveries and/or terminate the EPA for breach of power supply quality, reliability and for Green Resource Criteria, under defined circumstances. Either party is entitled to terminate the EPA if a force majeure event has not been cured within one year.

BC Hydro is a Crown corporation of the Province of British Columbia and has the same credit rating as the province, which is AAA as rated by S&P.

Operating History

The following table presents a summary of Miller Creek's historical operating data for the years 2006 through 2008.

	Miller Creek Historical Operating Data			
	2008	**2007**	**2006**	**Average**
Total Net Generation, GWh	98.5	114.4	98.9	103.9
Capacity Factor, %	40.9	46.8	41.2	43.0
Availability Factor, %	87.2	84.2	86.1	85.8
Forced Outage, %	8.4	8.9	11.1	9.5

Brown Lake

Overview

Brown Lake is a 7 MW hydroelectric power plant located on the Ecstall River, near Brown Lake and Prince Rupert, British Columbia. The plant was commissioned in 1996 and purchased by Capital Power in 2000. Water rental fees are paid to the Province of British Columbia as well as a royalty payment to one of the original developers which ends in 2034. Power generation from the facility is generally consistent throughout the year, with the exception of July and August when water flows and the resulting electricity generated are generally lower. The facility is located on land leased from the Crown.

The Brown Lake plant uses water flow from two lakes: Brown Lake and McKnight Lake. The powerhouse contains a single horizontal Francis turbine-generator.

Commercial Arrangement: Electricity Purchase Agreement

Capital Power is a party to a 20-year term EPA with BC Hydro, ending December 2016, for all of the power output from the facility, unless terminated by either party on six months' notice. The agreement automatically renews on a year-to-year basis on the same terms. The pricing under the contract is at a fixed amount per MWh, escalating annually by 3%.

The EPA also contains termination provisions that apply in the event of a disconnection by BC Hydro without corrective action by Capital Power within six months or for forced outages that continue for more than 18 months.

Operating History

The following table presents a summary of Brown Lake's historical operating data for the years 2006 through 2008.

	Brown Lake Historical Operating Data			
	2008	2007	2006	Average
Total Net Generation, GWh	56.0	56.1	46.9	53.0
Capacity Factor, %	93.9	91.5	77.6	87.7
Availability Factor, %	97.4	94.8	90.7	94.3
Forced Outage, %	1.3	3.9	7.3	4.2

PPAs Owned by Capital Power

In 2000, Capital Power, with four other companies (the "syndicate members"), acquired PPAs associated with two thermal power plants (Sundance and Battle River) having a total committed power capacity of approximately 1,373 MW.

Coincident with the purchase of these PPAs, Capital Power entered into sales and supply arrangements with its syndicate members under which 29.9% (410 MW) of Capital Power's rights and obligations under the acquired PPAs were effectively passed through to the other four syndicate members. Under these arrangements, the syndicate members are entitled to a proportionate interest in, and proceeds from, the PPAs. If an owner of a PPA generating unit is unable to deliver power, Capital Power has no obligation to any of the syndicate members. The syndicate members are obliged to pay their proportionate share of the PPA facilities costs. If any of the other syndicate members are unable to meet a payment obligation, Capital Power is entitled to receive the power and has the option to buy out any defaulting syndicate member's interest in the PPAs at a discount to the current market value of the PPAs.

Commencing in May 2006, Capital Power began selling down its interest in the Battle River PPA over a four-year period. See "Management's Discussion and Analysis of Financial Condition and Results of Operation — Outlook". As part of the commercial arrangements in respect of the sale of the Battle River PPA to ENMAX Corporation ("ENMAX"), each of the syndicate members sold to ENMAX their respective allocated capacity (aggregate total of 197 MW) in the Battle River PPA. In addition, Capital Power entered into swap and/or purchase agreements with three of the four original PPA syndicate members, under which these members purchased in the aggregate an additional 17.9% (127 MW) of Sundance capacity. The swap agreements were to replace the Battle River capacity that was sold. This arrangement became effective May 1, 2006 and will continue in effect until the expiry of the Sundance PPA on December 31, 2020. Capital Power's current interest in the Battle River PPA is 15%. This interest has been contracted to be sold to ENMAX in January 2010 for expected proceeds of approximately $64 million.

The following table provides details of the generation represented by these PPAs:

Plant and Location	Type of Generating Plant	Year of Commission	MW Committed Capacity	MW Net to Capital Power[1]
Battle River	Coal-fired steam turbine	Unit 3 - 1969	147.3	22.1
Forestburg, Alberta		Unit 4 - 1975	147.3	22.1
		Unit 5 - 1981	368.2	55.3
Sundance	Coal-fired steam turbine	Unit 5 - 1978	353.0	184.4
Lake Wabamun, Alberta		Unit 6 - 1980	357.0	186.5
Total			1,372.8	470.4

(1) After deduction of power sold by Capital Power LP under sales and supply arrangements with three of the four original PPA syndicate members (MW net to Capital Power LP in respect of Battle River units 3, 4 and 5 represent the residual share of the Battle River PPA for the period January 1, 2009 to December 31, 2009).

Production from Sundance is governed by its PPA until December 31, 2020. During the remaining term of the Sundance PPA, and while Capital Power has an ownership interest in the Battle River PPA, Capital Power is entitled to the power produced by the facilities up to Capital Power's interest in its committed capacity. Capital Power is obligated to pay the owners of the facilities amounts intended to cover the fixed and variable costs of operating the facilities, including a return on the owner's equity in the facilities. Coal for each plant is obtained from nearby coal mines. Currently, the coal supply for Battle River is contracted until 2013 while that for Sundance is contracted for the full 20 years of the PPA period. Capital Power can sell the power acquired under the PPAs through direct sales to power customers or into the Alberta power pool.

Although Capital Power is reducing its interest, the PPAs will remain an important component of Capital Power's portfolio and provide it with additional baseload capacity to offer the Alberta market.

Portfolio Optimization

Portfolio optimization includes activities undertaken primarily to manage the Company's exposure to electricity and natural gas price movements. Capital Power purchases and sells electricity and natural gas under physical and financial transactions with the objective of matching volumes and terms, or taking positions in electricity or natural gas within limits established under the Company's risk management policies. The primary objective of Capital Power's portfolio optimization activities is to maximize wholesale revenues while minimizing risk associated with power price volatility. Capital Power manages its output from its Alberta commercial plants and acquired PPAs (with the exception of Joffre, which is managed by ATCO) as a "Networked Hub", meaning that it sells forward contracts that are non-unit specific, reducing its exposure to plant availabilities. From time to time, Capital Power also takes specific and limited positions in the electricity or natural gas markets to generate trading profits as opportunities present.

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

- Determines the scheduling of output from generation assets to meet contractual obligations and to optimize returns while managing generation and transmission risks, including unplanned outages;
- Manages Capital Power's commodity portfolio and counterparty risks;
- Acquires and schedules deliveries of natural gas supplies used to generate electricity, in particular with respect to the EPLP plants and Clover Bar; and
- Derives earnings from wholesale trading of electricity and natural gas, and by participating in Alberta's ancillary services (electricity reserves) market.

The commodity portfolio management team has been in place for more than seven years. The team has experience in major North American electricity markets, including the Alberta, Ontario, the New York Independent System Operator, New England Power Pool, Midwest Independent Transmission System Operator, California Independent System Operator, and California-Oregon Border power markets. The team also has experience in the NYMEX and AECO natural gas markets.

Capital Power considers itself to be a leader in Canada's emerging GHG offset market place and believes it has one of Canada's largest portfolios of GHG offset projects through purchases and project development and Capital Power's Commercial Environment group is responsible for ensuring its compliance with existing and emerging market-based environmental regulations. The GHG offset investments and purchases are designed to proactively manage potential compliance risks associated with GHG regulations.

Capital Power has entered into bilateral commercial arrangements for the purchase of credits that have proven consistent with the Alberta Specified Gas Emitters Regulation, and is pursuing projects that it expects will be recognized under the forthcoming Canadian Federal GHG regulations. Capital Power has more than 5 million tonnes of GHG offsets under contract.

Capital Power's portfolio management and trading activities are subject to oversight by Capital Power's Risk Oversight Council ("ROC"), a senior executive group including the Vice President, Risk Management, which in turn reports to the Board of Directors. ROC develops and implements procedures and practices consistent with the Company's Energy Commodity Risk Management Policy and Counterparty Credit Risk Management Policy. Capital Power controls its trading activities by measuring and reporting risk, validating transactions, valuing the trading portfolio and managing and reporting credit. Capital Power uses

mark-to-market valuation and a Value-at-Risk ("VaR") determination to assess the risk of its trading activities, and actively manages its aggregate VaR exposure within approved limits as set out in the risk management policies.

General oversight, policy review and recommendation, and reviews of commodity risk compliance are undertaken by the ROC. The Vice President, Risk Management is generally responsible for monitoring compliance with risk management policies. The responsibilities of that office include oversight of the enterprise risk management program and leadership of commodity risk management function. The commodity portfolio management team is responsible for carrying out the risk management and mitigation activities associated with the commodity portfolio.

Capital Power believes that risk management is a key component of the Company's culture. The Company's internal audit team also performs testing of the design and effectiveness of internal controls associated with the Company's commodity portfolio management. In 2005, the Company engaged third party experts to evaluate its commodity risk management governance model. The Company employs a thorough set of principles, rules, controls and limits, which management believes conform to industry practice.

Capital Power employs VaR as the basic component to measure the risk in its energy commodity portfolio. VaR is the maximum expected loss over a given period of time at a given level of confidence. Capital Power's VaR is calculated at a 95% statistical confidence level over a holding period of 20 business days. In other words, over the 20 business day period commencing with the point in time that the VaR is measured, there is a one in 20 likelihood that the fair value of the commodity portfolio could change by an amount in excess of the VaR amount. The VaR calculation incorporates positions, forward prices, price volatilities and correlations as major input variables. As VaR is not a perfect measure of risk, Capital Power applies a factor to the calculated VaR amount to attempt to capture unaccounted for exposures. The resulting measure is referred to as the total exposure of the portfolio. Capital Power's one year energy commodities total exposure, which considers one year's cash flows from the portfolio on a net basis, as at December 31, 2008, was $22 million (2007 — $8 million).

To supplement its VaR estimates, Capital Power uses stress-testing and scenario analysis on the electricity and natural gas portfolio by applying plausible but unlikely extreme adverse market conditions and movements. This testing is used to determine the resulting financial effects on the portfolio in relation to Capital Power's VaR limits. Capital Power employs operational limits for its energy trading operations, including position limits, transaction limits and stop loss limits. Key risk measures in relation to the applicable limits are reported daily to ROC and quarterly to the Board, with any incidences of limits having been exceeded being required to be reported to the Board of Directors.

Projects in Construction and Development

Capital Power has a pipeline of projects that are at various stages of development. Capital Power has two major projects under construction and is also managing major upgrades to two EPLP facilities. See "— EPLP". Capital Power also has several development opportunities that it is currently pursuing. In addition to development projects, Capital Power continues to review acquisition opportunities for assets that fit with its strategic objectives. Capital Power's focus in the U.S. will be primarily on acquisition opportunities; however, it will consider greenfield developments as opportunities present.

Capital Power's current construction projects and major development opportunities include the following:

Keephills 3

Keephills 3 is a 495 MW coal-fired power plant that is being built on TransAlta's Keephills site just west of Edmonton, Alberta. Capital Power and TransAlta are equal partners in the plant. Capital Power has overall responsibility for construction while TransAlta will be responsible for operations once the plant is commissioned. The capital cost of the project, including mine capital, is expected to be approximately $1.8 billion, half of which is the responsibility of Capital Power. Construction is expected to be completed by the end of the first quarter of 2011. The plant is a sister plant to the Genesee 3 facility, utilizing similar Hitachi supercritical boiler technology.

Capital Power has spent approximately $481 million to the end of March 2009 on its share of the projected costs. Of the estimated remaining $421 million to spend, $244 million is expected to be spent during the balance of 2009, $167 million in 2010 and $10 million in 2011. Capital Power believes that the project will materially add

to Capital Power's cash flow beginning in 2011. Despite slower regional economic conditions, construction costs remain under pressure as project work packages are finalized in the normal course of construction.

The addition of new generating capacity is occurring at a slower rate than the expected rate of increase in demand in Alberta. Capital Power expects that the quantity of baseload, coal-fired generation capacity will remain essentially constant as the completion of Keephills 3 and capacity increases to existing coal plants are offset by retirements of smaller and older units. Capital Power anticipates that Keephills 3, based on its similar technology and feedstock, will perform similarly to Genesee 3 once fully operational, and will generate comparable operating cash flows under common power prices.

Keephills 3 is being designed to meet the 2006 new unit emission limits for SO_2, NO_x, mercury, and particulate matter under the 2006 Alberta Air Emissions Standards for Electricity Generation. The Company estimates that the plant will emit 24% less CO_2 per MWh than four coal plant units that are expected to be retired in the near future by another power producer in the province.

Capital Power and TransAlta will independently dispatch and market their share of the unit's electrical output.

Clover Bar Energy Centre

Clover Bar continues to be developed. In addition to the General Electric LM6000 natural gas turbine that began commercial operations in 2008 (see "— Description of Capital Power Operating Facilities"), two 100 MW General Electric LMS 100 natural gas turbines are being installed. The first General Electric LMS 100 turbine is scheduled to begin producing electricity during the third quarter of 2009, and the second General Electric LMS 100 turbine is scheduled to begin producing electricity in the third quarter of 2010. The LMS 100 turbines will add 200 MW of peaking capacity at the site.

Capital costs for the project are projected to be $284 million, including the costs of the first unit. Capital Power has spent approximately $215 million to March 31, 2009 on the project, and plans to spend $58 million in the remainder of 2009 and $11 million in 2010. Except for commissioning costs, most of the remaining capital costs are contracted at fixed prices under firm contracts. Capital Power believes the project will materially add to Capital Power's cash flow once the additions are complete.

According to General Electric Company, the LMS 100 turbines are more efficient than other turbines of a similar size, and are well-suited for peaking generation since they require ten minutes from start-up to reach full capacity. The comparatively low start-up emissions and high efficiency of the General Electric LMS 100 turbine result in an estimated 30,000 ton reduction in CO_2 emissions when compared to a typical simple-cycle natural gas turbine of the same size (based on an average peaking season of 2,184 hours).

This additional peaking capacity will further optimize Capital Power's portfolio of power generation assets in Alberta and provide it with additional flexibility to meet market demand. In particular, it will allow Capital Power to respond quickly to price volatility in the Alberta electricity market. The Alberta electricity market is expected to require additional peaking generation as a result of changing power demand and the addition of wind power generation to the Alberta transmission grid.

Clean Coal Technology Projects

Capital Power is currently developing two separate projects aimed at significantly reducing GHG emissions from coal-fired power generation. Capital Power, on behalf of and in collaboration with the Canadian Clean Power Coalition, the Alberta Energy Research Institute and NRCan, is working towards developing by 2015 a low emission IGCC power plant located at the Genesee site. The plant is proposed to be in the 270 MW net output range, utilizing sub-bituminous coal from the Genesee coal mine. The proposed plant will be configured for CO_2 capture and utilization for enhanced oil recovery or sequestration. Siemens Fuel Gasification Technology GmbH and Co. KG has been selected as the coal gasifier technology supplier for the project. The project is currently in the first phase of the front-end engineering design.

Capital Power is also working on the potential commercialization of amine scrubbing technology to capture CO_2 emissions post combustion from coal-fired generation plants. Capital Power is assessing the feasibility of comparing the cost for a coal plant with post-combustion CO_2 capture versus pre-combustion CO_2 reduction. If the opportunity for CO_2 capture is found to be viable, Capital Power plans to proceed with a full-scale project. A

service agreement has been executed for the feasibility study. The configuration for the study is for a 200 MW facility.

Both projects have been selected by the Government of Alberta as potential candidates for participation in its $2 billion carbon capture storage funding program under its climate change action plan. The Alberta Government's final selection of projects is expected at the end of the second quarter of 2009. Both projects require some form of government support to make them economic and if either project proceeds, Capital Power would intend to have one or more third party partners participate in the ownership of the facility.

Quality Wind

Capital Power has submitted a comprehensive bid in response to BC Hydro's 2008 Clean Power Call. See "Regulatory Overview — British Columbia". The project, Quality Wind, is proposed to be a 142 MW wind farm located near Tumbler Ridge, British Columbia. Favourable wind conditions, nearby road access and available transmission capacity in the area make it a good candidate for future development. A complete environmental assessment is expected to be completed by the third quarter of 2009. BC Hydro is expected to announce the selection of projects under its 2008 Clean Power Call in the second quarter of 2009. Construction of Quality Wind will be subject to successful participation in BC Hydro's bid process, regulatory approvals, final economic and engineering assessments and negotiation of an EPA with BC Hydro.

British Columbia Biomass

The Government of British Columbia, in conjunction with BC Hydro, have identified the need to develop biomass based power in the province as a response to the mountain pine beetle kill and the provincial government's commitment to be electricity self-sufficient by 2016. BC Hydro is planning to release Phase II of the Bioenergy Call (a competitive call for larger scale biomass projects) in the third quarter of 2009, with results expected to be announced in early 2010. Capital Power and West Fraser Timber Co. Ltd. are working together to jointly review development opportunities for a 50 MW to 70 MW biomass facility in either the Quesnel, British Columbia or Houston, British Columbia areas. A project pre-development agreement has been executed between Capital Power and West Fraser Timber Co. Ltd. and initial cost estimates for a boiler and its associated emission control equipment have been received from a third party manufacturer. The initial fuel supply studies have been prepared and are currently being reviewed by an independent consultant.

British Columbia Wind Projects

Capital Power entered into a joint development agreement with Chinook Power Corp. to work together on certain proposal activities and develop four wind projects in British Columbia. Capital Power is actively evaluating a site, Klo, near Houston, British Columbia, and has identified two others for possible future evaluation.

Capital Power currently holds 50% of the rights to the Klo site under its joint venture agreement with Chinook Power Corp. Capital Power expects to further evaluate and possibly develop this project in anticipation of the next BC Hydro call for power.

Cambridge Natural Gas Peaking Facility

The OPA has identified a number of locations for natural gas-fired peaking plants within their proposed Integrated Power System Plan ("IPSP"), including the Kitchener-Waterloo-Cambridge-Guelph area. See "Regulatory Overview — Ontario". The Company anticipates that the OPA will receive a directive from the Minister of Energy and Infrastructure to conduct an RFP process for peaking capacity in either late 2009, or sometime through the second quarter of 2010. The timing of the RFP is likely to be affected by the impact of the economic downturn on Ontario's manufacturing sector and the conclusion of the OPA's filing of a revised IPSP with the Ontario Energy Board in response to a directive from the Minister of Energy and Infrastructure for the OPA to consider the amount and diversity of renewable energy sources in the proposed power supply mix. Also affecting the timing of the RFP is the final legal implementation of key provisions of the *Green Energy and Green Economy Act, 2009* ("GEA"). While the GEA was passed by the Ontario Legislature on May 14, 2009, the vast majority of the legislative changes included in the GEA will only come into force upon proclamation by the Lieutenant Governor of Ontario. The OPA had previously announced that it would not be able to complete its

revision of the IPSP until the summer of 2009, following final implementation of the GEA. (For more details on the GEA, see "Regulatory Overview — Ontario"). In anticipation of a natural gas generation facility being needed to support the power system in the Cambridge area, Capital Power has secured a site for construction and operation of such a peaking facility. The selected site has several positive attributes including close proximity to the high pressure natural gas pipeline of Union Gas Limited, reasonable proximity to transmission station interconnection, favourable zoning, and positive stakeholder support. Capital Power is currently evaluating technology alternatives for meeting a requirement of 450 MW to 500 MW of capacity. Engineering, stakeholder communications and environmental assessments are currently underway with the expectation that a complete bid package will be developed in advance of the RFP deadline. Construction of the Cambridge Natural Gas Peaking Facility will be subject to a number of factors, including the OPA initiating an RFP process for the Kitchener-Waterloo-Cambridge-Guelph area pursuant to a directive of the Minister of Energy and Infrastructure, the Company's satisfaction with the OPA's final form of peaking energy supply contract, selection of the Company as the successful proponent in the OPA's competitive procurement process and receipt of regulatory approvals and final economic and engineering assessments.

Kingsbridge Wind — Phase II

In addition to its Kingsbridge 40 MW operating wind farm, Capital Power has 13,128 acres of land currently under lease with approximately a further 4,000 acres having parties who have expressed an interest to enter into a lease, although not all of the latter acres are usable. All of the acreage is in close proximity to Goderich, Ontario and could support phase II of the Kingsbridge development. Previously, Capital Power entered into a PPA with the OPA to develop and operate a 160 MW wind farm on this site. However, protracted delays and opposition in receiving municipal, provincial and other related approvals for environmental and zoning of the proposed project resulted in Capital Power and the OPA mutually agreeing to terminate the PPA in October 2008. Following termination of the PPA, Capital Power has continued to work to obtain these approvals. On May 14, 2009, the Ontario legislature passed the GEA, an Act designed to, among other things, streamline and facilitate the approval process for renewable energy projects. The implementation of the vast majority of the legislative amendments contained in the GEA will be delayed, however, until the related Schedules to the GEA are proclaimed into force, and the Ontario government passes the necessary regulations to implement the legislative changes. There are a few key amendments in the GEA that will likely affect Kingsbridge II, assuming that they are proclaimed into force and become law in the future. First, Schedules to the GEA contain provisions that amend the *Planning Act* to exempt renewable energy projects such as Kingsbridge II, from various by-law and permit requirements (including official plan and zoning) and that amend the *Environmental Protection Act* and *Ontario Water Resources Act* to streamline the environmental approval process. Second, one of the Schedules to the GEA amends the *Electricity Act, 1998*, to allow for the design of a Feed-In-Tariff ("FIT") program for procurement of energy from renewable sources. Under FIT, it is expected that the OPA will provide standard program rules, contracts and pricing for classes of renewable energy projects; prices will be differentiated by energy source, generator capacity, and the manner by which the generation facility is used, deployed, installed and located. It is expected that implementation of these provisions in the GEA will address many of the delays encountered previously on Kingsbridge II. (For more details on the GEA, see "Regulatory Overview — Ontario"). Based on its evaluations and assessments to date, Capital Power believes it is well positioned to participate in the next OPA renewable energy supply process. Capital Power is currently in the process of assessing wind turbine equipment that is most suitable for the site with the expectation that final selection of an equipment manufacturer will be made in a manner which would be consistent with the FIT rules.

It is not expected that Kingsbridge II will be in a position to generate environmental attributes or credits for the benefit of the Company, as the current draft FIT program rules suggest that such credits will be assigned to the OPA.

EPLP

EPLP's General Partner has contracted for management and administrative services of EPLP to be provided by subsidiaries of Capital Power (collectively, the "EPLP Manager"). The EPLP Manager or its affiliates also operate and maintain the power plants and employ substantially all personnel carrying out duties for EPLP.

Capital Power holds a 30.6% interest in the limited partnership units of EPLP, a limited partnership with interests in power generation businesses in Canada and the U.S. that generate electricity and steam. EPLP currently has a total generating capacity (electricity) of 1,668 MW and a thermal energy (steam) capacity of approximately 4,157 pounds per hour. Capital Power estimates that over 60% of EPLP's gross margin is attributable to EPLP plants that have PPAs with counterparties with a credit rating of A or better.

At present, EPLP's portfolio consists of 19 wholly-owned power generation assets located in both Canada (in British Columbia and Ontario) and in the U.S. (in California, Colorado, Illinois, New Jersey, New York, and North Carolina); a 50.15% interest in a power generation asset in Washington State, and 17.0% of the common share interest and 14.2% of the preferred share interest in PERH. PERH wholly-owns four power plants and a 50% interest in a pulverized coal facility, all located in the state of Indiana. The PERH power plants have an aggregate gross generation capacity (electricity) of approximately 283 MW and a thermal energy (steam) capacity of approximately two million pounds per hour. EPCOR USA Ventures LLC, an indirect wholly-owned subsidiary of EPLP, which indirectly holds EPLP's 17.0% common share interest and 14.2% preferred share interest in PERH, has contracted to provide management and administrative services to PERH and PERH's subsidiaries under a management agreement. In turn, EPCOR USA Ventures LLC has subcontracted these management and administrative services to indirect wholly-owned subsidiaries of the Company. PERC, a publicly-traded entity, holds the remaining 84.6% interest in PERH. EPLP is currently in a process to refinance and restructure its interest in PERH.

The roles and relationships of Capital Power and EPLP are synergistic. EPLP provides an investment vehicle for Capital Power's growth in lower risk, contracted power opportunities. EPLP's diverse geographic footprint and fuel mix combined with counterparties, the majority of which have investment grade credit ratings and long-term contract arrangements offer an attractive lower risk, yield-oriented vehicle for Capital Power. Furthermore, on a normalized basis, EPLP's cost of capital may be lower than Capital Power's and thereby provide an opportunity to crystallize value created by developments or investments made at the Capital Power level by the sale of such assets to EPLP. Conversely, Capital Power expects to be more growth-oriented through a combination of development of large power generation assets, expansion of existing capacity and acquisitions. This combination of more aggressive development and growth in Capital Power with stable predictable yield-oriented growth contemplated for EPLP provides complementary growth strategies that are in the best interest of both entities.

Summary of EPLP Operating Facilities

Operating performance for EPLP's facilities is shown below. The lower generation in 2008 versus 2007 is primarily due to higher scheduled maintenance in 2008 and because the Ontario plants elected to resell natural gas when natural gas prices were high and reduce electricity generation. The increase in generation in 2007 reflects EPLP's acquisition of Ventures.

	2008	2007	2006
Electricity generation (GWh)			
Ontario	1,263	1,412	1,368
Williams Lake	499	545	553
Mamquam and Queen Charlotte	245	267	232
Northwest U.S.	872	910	456
California	941	1,004	170
Curtis Palmer	328	307	416
Northeast U.S.[1]	253	171	26
North Carolina	554	613	51
Total	**4,955**	**5,229**	**3,272**

	2008	2007	2006
Generation plant availability (%)[2]			
Ontario	97	95	98
Williams Lake	90	96	95
Mamquam and Queen Charlotte	87	81	83
Northwest U.S.	95	95	96
California	91	90	94
Curtis Palmer	86	96	97
Northeast U.S.[1]	99	92	97
North Carolina	92	94	91
Overall Average[3]	**94**	**93**	**95**

(1) Excludes Castleton, the sale of which closed on May 26, 2009.

(2) Plant availability represents the percentage of time in the period that the plant is available to generate power, whether actually running or not and is reduced by planned and unplanned outages.

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

EPLP combines certain of its operating facilities for reporting purposes. A summary of these facilities is as follows:

Ontario Facilities

EPLP has four natural gas-fired facilities and one biomass facility located in Ontario. All five facilities are located on the Northern Canadian TransCanada Mainline natural gas pipeline and utilize waste heat from TransCanada Corporation natural gas compressor stations for a portion of their energy requirements. The Ontario Electricity Financial Corporation ("OEFC") is the sole purchaser of power from EPLP's five Ontario power plants. The power is purchased under long-term PPAs originally entered into by Ontario Hydro in the 1990s and assumed by OEFC as the continuation of Ontario Hydro and which expire between 2012 and 2020. The term of the PPAs may be extended upon mutual agreement. Payment under the PPAs is based upon a formula that generally includes a fixed capacity rate applicable in that year, or adjusted annually for that year, seasonal and peak/off-peak electricity rates that are indexed and other adjustments.

EPLP purchases fuel — natural gas and/or waste heat for each of the Ontario power plants under natural gas and waste heat supply agreements, the earliest of which expires in 2010. Firm capacity for the transportation of fuel natural gas to the Ontario power plants has been contracted for on the TransCanada Corporation natural gas transmission system under transportation agreements, the earliest of which expires in 2011. For the biomass facility, wood waste and the related transportation services are purchased under contracts with four local mills for the majority of the fuel requirements at the Calstock plant, with the balance supplemented by waste heat purchased from TransCanada Corporation. The supply agreement with an additional local mill has expired, although EPLP is currently able to continue to purchase wood waste from the mill on a spot basis. Wood waste handling costs include the cost of wood waste, the transportation of wood waste, fuel and management costs and the disposal of wood ash. However, the continued availability of wood waste under such long-term contracts depends on the continued operation of the local mills, which continue to be negatively impacted by economic conditions which has resulted in the renegotiation of aspects of such arrangements. In 2008, waste heat contributed to approximately 16% of power revenue at EPLP's Ontario Plants. Declining waste heat availability that began in 2007 continued in 2008 due to lower throughput on the TransCanada pipeline system. This decrease was due to lower natural gas demand in Northern Ontario in part due to lower forestry industry activity, lower natural gas volumes leaving Alberta due to lower levels of natural gas supply from the Western Canadian Sedimentary Basin because of lower drilling activity combined with increasing demand in Alberta, structural changes in the underlying long-haul transportation agreements with shippers, the conversion of an upstream high pressure natural gas line to oil and the addition of looping in and around the North Bay shortcut.

Williams Lake

Williams Lake is one of the largest biomass facilities in Canada (as measured by capacity), with 68 MW of capacity. The plant went into service in April 1993. It sells power to BC Hydro under a 25-year contract with the initial term expiring in 2018. BC Hydro has an option to extend the EPA for two consecutive five-year terms at significantly reduced EPA prices. The plant pays no royalty to any third party.

Energy rates are established for a firm energy tranche, representing approximately 80% of total energy produced, and a surplus energy tranche, representing approximately 20% of total energy produced. The firm energy tranche price consists of a fixed energy component, an operations and maintenance component, and a reimbursable cost component which covers essentially all fuel costs and other operating and maintenance costs. The surplus energy tranche price is adjusted annually for changes in the Dow Jones California-Oregon Border Index.

Wood waste is purchased for the facility from several local mills under long-term contracts. Under terms of the EPA, 80% of fuel costs for the plant are passed through to BC Hydro, reducing the long-term exposure to supply price changes.

In February 2009, one of the two main suppliers to the Williams Lake facility idled their mills and the second major supplier reduced its production. Capital Power has identified other sources of supply, but these sources are more expensive. Approximately 82% of the higher costs are expected to be borne by BC Hydro. Capital Power has not been able to obtain sufficient wood waste supplies at economic prices and as a result, it has curtailed its operations starting April 23, 2009. BC Hydro will continue to make firm energy payments while the plant is offline and Capital Power does not expect a decline in the operating margin from firm energy as a result of the curtailment. Capital Power expects that Williams Lake will be dispatched to optimize available wood waste supplies until its major suppliers return to normal operation or are replaced with new sources of economically viable supply.

Mamquam

Mamquam is a 52 MW hydroelectric facility that sells all of its electricity generated to BC Hydro under a long-term contract which will expire in October 2027. It commenced operation in November 1996. BC Hydro has an option, exercisable in 2021 and every five years thereafter, to either purchase the Mamquam facility or extend the Mamquam contract. Energy rates consist of a fixed energy component, an operations and maintenance component, and a reimbursable cost component. No royalty payment is made by the Mamquam plant.

Queen Charlotte

Queen Charlotte is a 6 MW hydroelectric facility that sells substantially all its electricity to BC Hydro under a long-term contract which will expire in August 2022. The plant went into service in September 1990. The balance, approximately 1% of its power generation, is sold to NAV Canada and The Department of Fisheries and Oceans (Canada) under long-term PPAs. Energy rates payable by BC Hydro consist of a fixed energy component adjusted annually for inflation. No royalty payment is made by the plant.

Northwest U.S. Facilities

EPLP owns three natural gas-fired facilities in the U.S. Northwest, including the 301 MW Manchief facility and the 101 MW Greeley facility both located in Colorado, and a 50.15% interest in the 249 MW Frederickson power plant located in Washington State.

The Manchief power plant operates under energy supply agreements with Public Service Company of Colorado ("PSCo") that expire in 2022. PSCo is an electricity and natural gas distribution company that primarily serves Northern Colorado. Under terms of the agreements, PSCo makes capacity payments and energy payments. Energy payments include tolling fees and natural gas transportation fees. PSCo has an option during the latter part of the contracted term, to acquire the plant. Manchief is operated and maintained by Colorado Energy Management L.L.C.

The Greeley facility provides all of its electrical output to the PSCo under a PPA that expires in August 2013. PSCo pays the Greeley facility a capacity payment and an energy payment. The Greeley facility also sells hot water to the University of Northern Colorado pursuant to a thermal supply agreement, which expires in August 2013. The charge for thermal energy is based on the University of Northern Colorado's avoided natural gas-fired boiler costs. Natural gas supply purchased for the Greeley facility is financially fixed through November 2011. Physical natural gas is purchased from DCP Midstream Marketing LP or Tenaska Power Services Co. at an indexed price.

EPLP's portion of the Frederickson power plant's generating capacity has been sold under PPAs to three Washington State Public Utility Districts ("PUDs") for a term of 20 years ending in 2022. Under the PPAs, the PUDs pay a capacity charge, a fixed operations and maintenance charge, a variable operations and maintenance charge and a fuel charge. The PUDs must supply their proportionate share of natural gas to EPLP.

California Facilities

EPLP owns four natural gas-fired generation facilities in California including three located on U.S. Naval bases (the "Naval Facilities"). The Naval Facilities are comprised of the Naval Station, North Island and Naval Training Center, and have a combined capacity of 133 MW. The Naval Facilities sell substantially all their electrical output to San Diego Gas and Electric Company ("SDG&E") under PPAs, which expire in 2019. SDG&E is an electricity and natural gas distribution company primarily serving the San Diego area. The Naval Facilities receive a capacity payment and an energy payment based on SDG&E's short-run avoided costs ("SRAC"). The Naval Facilities also sell steam to the U.S. Navy pursuant to contracts, each of which expires in February 2018. The Navy is obligated to pay a termination payment if it breaches an agreement or causes the loss of a Naval Facility's status as a qualifying cogeneration facility or a qualifying small power production facility, as defined under the *U.S. Federal Power Act* (the "FPA") and the U.S. Federal Energy Regulatory Commission's ("FERC") regulations thereunder (a "QF"). EPLP has repowered the North Island facility with a new General Electric LM6000 PD turbine, which is expected to improve the efficiency of the natural gas turbine and reduce maintenance costs in comparison to the existing General Electric LM5000 turbine.

Oxnard is a 49 MW facility that provides all of its natural gas turbine electrical output to Southern California Edison Company ("SCE") under a PPA that expires in 2020. SCE is an electricity and natural gas distribution company primarily serving areas of Southern California outside Los Angeles and San Diego. The Oxnard facility receives a capacity payment and an energy payment based on SCE's SRAC. Capacity payments are based on achieving availability performance targets. The Oxnard facility supplies steam to its Anhydrous Ammonia Absorption Refrigeration Plant, which then provides refrigeration services to Boskovich Farms at no charge, thereby maintaining the Oxnard facility's regulatory treatment as a QF.

Natural gas for the Naval Facilities and Oxnard is purchased through natural gas contracts with RBS Sempra Energy Trading at monthly index prices similar to those used in the utility SRAC calculations. Energy payments received by these facilities are derived from SRAC, which enables them to largely recover natural gas costs.

On September 20, 2007, the California Public Utilities Commission accepted an alternative decision regarding reversing the SRAC cost formulae. These changes are expected to become effective later in 2009 and are not expected to have a material impact. The essence of the decision is to provide a 50/50 split between market and alternative heat rates for the calculation of the overall heat rate used in the compensation calculation, to increase the compensation for the operating and maintenance fee adder, and use a 12-month forward-looking market heat rate rather than the historical south California pricing.

Curtis Palmer

Curtis Palmer is a 60 MW hydroelectric facility located in New York that sells all power generated to Niagara Mohawk Power Corporation under a long-term contract. The PPA ends after the earlier of 42 years or delivery of a cumulative 10,000 GWh of electricity, both of which are expected to occur in 2027. The PPA sets out multiple prices for electricity sold, which are a function of the cumulative total of electricity delivered. Over the remaining term of the PPA, the pricing blocks increase on average by 10% with each additional 1,000 GWh of electricity delivered. The plant requires approximately three years to deliver 1,000 GWh.

Under certain circumstances, Niagara Mohawk Corporation has the ability to relocate, rearrange, retire or abandon its transmission system which would potentially give rise to material future capital cost outlays by Curtis Palmer to maintain its interconnection.

Northeast U.S. Facilities

EPLP owns two natural gas-fired facilities in the North Central and Northeast U.S.: the Kenilworth 30 MW cogeneration facility located in New Jersey, and the 177 MW Morris Facility located in Illinois.

The Kenilworth facility sells electrical and steam energy to a subsidiary of Schering-Plough Corporation ("Schering-Plough"), under an energy contract that expires in July 2012. Schering-Plough pays an energy rate that escalates annually. The contract imposes a minimum take or pay obligation on Schering-Plough of 125,000 MWh per year. Any power produced in excess of Schering-Plough's requirements is sold to Jersey Central Power & Light Company ("JCP&L") under a PPA ending in June 2009. There are no plans to extend the PPA with JCP&L as Schering-Plough is expected to continue to consume the full capacity of the plant. Any excess power provided to JCP&L is delivered by Public Service Electric and Gas Company under a transmission service and interconnect agreement. Upon the expiry of the PPA in June 2009, any future surplus energy sales will be made to the Public Service Electric and Gas Company. Natural gas for the facility is purchased from Sempra Energy Trading LLC with that price used in the steam pricing.

The Morris Facility sells electrical and steam energy to Equistar Chemicals LP ("Equistar"), a wholly-owned subsidiary of LyondellBasell AF S.C.A., under an energy services agreement that expires in 2023. Equistar pays a tiered energy rate based on the amount of electricity and steam consumed to a maximum of 77 MW. Equistar also pays capacity fees, comprised of both a non-escalating fixed fee and an escalating variable fee that expires in 2013 and 2023, respectively. Morris also has a PPA with Exelon Generation Company, LLC ("Exelon") covering 100 MW of electrical capacity. Exelon pays a capacity charge and an energy charge, as well as an availability-based "performance bonus". The energy charge is comprised of fuel costs and a per MWh variable operating and maintenance charge. The Exelon PPA expires in 2011. Excess capacity and energy above the needs of Equistar and Exelon can be sold into markets in the PJM Interconnection. The Morris Facility obtains natural gas from Tenaska Power Services Co. at a price indexed to the Chicago City Gate.

On January 6, 2009, Equistar, along with LyondellBasell AF S.C.A.'s other North America operating entities, filed a voluntary petition for reorganization under Chapter 11 of the U.S. Bankruptcy Code. Under provisions in the U.S. Code, Equistar obtained approval to make payments for post-petition services. As a result, the Equistar facility continues to operate and Equistar has made payments for post-petition services.

North Carolina Facilities

EPLP's two facilities in North Carolina burn a mixture of coal, tire-derived fuel and wood waste. The Roxboro facility is a 54 MW plant and the Southport facility is a 109 MW plant. Both facilities are undergoing substantial capital improvements in 2009 designed to significantly reduce their NO_x and SO_2 emissions. The improvements will also change their fuel handling capabilities to reduce the amount of coal, and increase the amount of wood waste and tire derived fuel utilized, with the anticipated effect of reducing their cost of fuel. The cost of the capital improvements is estimated at U.S.$80 million.

Both facilities provide all of their electrical output to Carolina Power & Light Company ("CP&L") under PPAs which expire on December 31, 2009. CP&L is an energy company serving North Carolina and South Carolina, and is a subsidiary of Progress Energy, Inc. PPA extensions for both plants are currently being negotiated. The price paid under the existing PPAs includes a capacity payment, an energy payment that reflects the price of coal, and a cycling charge. If this pricing does not result in a dispatch order for the facility, EPLP has the right, but not the obligation, to bid an alternate price based upon its own pricing strategies to obtain a dispatch order. The Southport facility also sells steam pursuant to a contract that expires in December 2014.

Approximately 70% of the Roxboro and Southport facilities' fuel requirements are satisfied with coal, with the balance from tire derived fuel and waste wood. The anticipated coal requirements for 2009 for each facility are sourced with regional coal suppliers. Tire derived fuel and waste wood are sourced from multiple local

suppliers. Tire derived fuel is procured under fixed-price contracts, and waste wood is procured at fixed prices indexed to the transport distance from the facility and subject to a fuel surcharge.

CFIUS Approval

Pursuant to Section 721 of the Defense Production Act of 1950, as amended (the "Defense Act"), the President of the United States may act to suspend or prohibit the acquisition of control of a U.S. business by a non-U.S. person if the President determines that the transaction will impair U.S. national security. The President has delegated his authority to review transactions in this regard to the federal inter-agency Committee on Foreign Investment in the United States ("CFIUS"). As certain of EPLP's facilities are located in the United States, the Company has made a voluntary notification of the Offering and the Reorganization to CFIUS. If after such notice CFIUS determines to take no further action, the Offering and the Reorganization will not be subject to future challenge under the Defense Act except in very limited circumstances involving any material misrepresentations made to CFIUS. CFIUS is expected to complete its review of the notice on or about July 8, 2009. No assurance can be given that CFIUS will determine to take no further action and/or will not require a modification of terms of the Offering and the Reorganization.

Memorandum of Agreement

Pursuant to the Memorandum of Agreement, Capital Power has agreed to disclose on a monthly basis the power acquisition and business development opportunities that Capital Power is considering or pursuing to the independent directors of EPLP General Partner, so that Capital Power and EPLP may work together to find and implement opportunities for power acquisition and business development projects that would be appropriate for EPLP to invest in. Capital Power retains the rights to all development projects unless they relate to existing EPLP facilities.

Capital Power has also agreed to disclose all power generating acquisitions on which Capital Power plans to bid to the independent directors of EPLP General Partner, so that EPLP may be afforded the opportunity to become the bidder/acquirer of such opportunities. In addition, Capital Power has agreed to disclose all power generation assets that Capital Power proposes to dispose of to the independent directors of EPLP General Partner, so that EPLP may be afforded the opportunity to become the acquiring vehicle of such assets. EPLP is obliged to respond to such opportunities having regard to the fact that such opportunities may be time sensitive. Capital Power does not anticipate that this right of first look will materially affect Capital Power's ability to execute its plans to achieve growth through acquisitions.

Capital Power and EPLP have agreed to a standstill whereby Capital Power is not able to increase its ownership in EPLP without the consent of the independent directors of EPLP General Partner until July 1, 2010.

Insurance

The Company maintains property, business interruption, liability and other insurance of the type and in the amounts that it considers to be appropriate for such risks. Such insurance is subject to deductibles and limits that the Company considers reasonable and not excessive given the current insurance market environment.

Properties

The Company's corporate headquarters are located in Edmonton, Alberta, where the Company leases office space. The Company's directly owned facilities are located on land owned or leased by the Company or joint ventures to which the Company is a party.

Employees

Capital Power employs approximately 1,000 full-time, part-time, temporary and casual employees of which approximately 750 are in Canada and 250 are in the U.S.

Capital Power enjoys positive work relations with its five Canadian labour unions, which together represent approximately 350 union members. None of the U.S. operations are unionized. The Canadian labour unions are:

- The Civic Service Union 52 ("CSU"), which represents administrative, technical and some professional employees.
- The International Brotherhood of Electrical Workers ("IBEW"), which represents electrical and mechanical tradesmen, coal plant operators, equipment operators, labourers and related employees at the Genesee power plant.
- The Communication, Energy and Paperworkers Union of Canada ("CEP"), which represents shift engineers at the Genesee power plant.
- The United SteelWorkers ("USW"), which represents shift engineers, electrical and mechanical tradesmen, labourers, and some administrative support positions at the Williams Lake power plant.
- The Power Workers Union ("PWU"), which represents shift engineers, electrical and mechanical tradesmen, labourers, and some administrative support positions at the Calstock, Kapuskasing, Nipigon and Tunis power plants in Northern Ontario. The North Bay plant is not unionized.

The following table provides a summary of the status of collective agreements in force.

Bargaining Unit	Location	CBA start date	CBA expiry date
CSU 52	Edmonton, Alberta	July 22, 2007	December 25, 2010
IBEW Local 1007	Edmonton, Alberta	December 24, 2006	December 26, 2009
CEP Local 829	Edmonton, Alberta	December 24, 2006	December 25, 2010
USW 1-425	Williams Lake, British Columbia	January 1, 2008	December 17, 2011
PWU	Ontario	February 1, 2007	December 19, 2009

Collective bargaining with PWU is expected to commence in the fall of 2009. Capital Power has not experienced any labour disruptions or work stoppages since 1978, and believes its relations with its employees are good.

Following the completion of the Offering, some of the services required by Capital Power, including certain information technology, legal, tax, treasury, administration and human resources services, will be provided to Capital Power pursuant to the EPCOR Transitional Services Agreement. See "Relationship to EPCOR — Agreements Between Capital Power and EPCOR — Transitional Services Agreements".

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

This management's discussion and analysis of financial condition and results of operations has been prepared as at the date of this prospectus and should be read in conjunction with the combined and consolidated financial statements of EPCOR Power Group that appear elsewhere in this prospectus. Included herein are certain forward-looking statements that involve various risks, uncertainties and other factors. See "Special Note Regarding Forward-Looking Statements". This management's discussion and analysis has been prepared for the years ended December 31, 2008, 2007 and 2006 and for the quarters ended March 31, 2009 and 2008 and is based on financial statements prepared in accordance with Canadian GAAP.

The financial condition and results of operations under the ownership and management of EPCOR will not necessarily be indicative of future performance of the Company, as the Company will have a different capital structure, its access to and cost of capital will be different and corporate functions historically provided by EPCOR such as executive oversight, risk management, information technology, finance, legal, treasury, audit, tax, human resources, procurement and environment will be staffed by Company personnel. See "Risk Factors".

Completion of the Offering and the Reorganization are reflected in the unaudited pro forma consolidated financial information of the Company. See "Unaudited Pro Forma Consolidated and Other Financial Information".

Overview

The Company is among Canada's largest independent power generation companies (as measured by revenue, total assets and capacity), and owns and/or operates approximately 3,300 MW of power generating capacity in North America. The Company's facilities consist of 31 high-quality power plants with geographic, fuel source and counterparty diversification. Many of these facilities have been built and commissioned by the Company over the last decade, providing the Company with development and construction experience and capability. The Company is currently constructing 695 MW of additional generation capacity at two locations with approximately 1,300 MW of projects in various stages of development.

Significant events

Genesee 3 turbine failure

In the fourth quarter of 2008, there was an unplanned outage at the Company's Genesee 3 facility due to a turbine rotor blade failure which kept the unit offline for 39 days. Revenues were negatively impacted during this period by an estimated $23 million. The 39-day outage represents the longest unplanned outage at a Genesee facility since 1994. See "— Results of operations — non-GAAP financial measures".

Other Genesee plant outages

In 2008, the AESO upgraded the high-voltage transmission lines in the Genesee and Keephills area, requiring all of the Genesee plant units to take outages during the year to accommodate the upgrades. The Company used the outage period to perform major maintenance on each of its Genesee facilities, thereby increasing its maintenance expenses, reducing its revenue and gross margin and reducing its overall plant availability. Total Genesee 1, 2, and 3 maintenance costs increased by $26 million before income taxes ($18 million after income taxes) in 2008 compared with the prior year. Of this total increase, maintenance expenses related to the planned Genesee plant outages were $22 million before income taxes ($16 million after income taxes). The Company incurred availability incentive penalties of $41 million ($29 million after income taxes) from Genesee 1 and 2 under the terms of the PPA and revenues were not earned on Genesee 3 during the outage period.

Goodwill impairment

The Company's recognized goodwill was primarily acquired with the purchase of its interest in EPLP in 2005 and EPLP's purchase of Ventures in 2006. Goodwill represents the difference between the purchase price and the fair value of the underlying net assets. In the fourth quarter of 2008, as determined by annual impairment testing, the estimated fair value of the goodwill decreased $28 million below its carrying amount. Accordingly, goodwill was written down by $28 million and the impairment loss was recognized in net income.

The fair value of goodwill was estimated using discounted cash flow techniques and estimated future cash flows considering the impact of inflation, re-contracting of power plants, foreign exchange and the continued maintenance of the assets to keep them in good operating condition over their useful lives. The Company's estimates of the future cash flows from EPLP's plant operations did not change materially from the previous year as EPLP's fleet of power generation assets is generally supported by long-term contracts that provide stable cash flows. However, based on deteriorating equity and credit market conditions, particularly over the last quarter of 2008, the discount rate increased significantly, thereby decreasing the estimate of fair value. In assessing the reasonableness of the results of the discounted cash flow analysis, the Company also considered the year-end EPLP unit price, which had decreased along with capital markets generally. Since the fair value estimate is subject to significant risks and uncertainties, it could change materially in the future.

EPLP non-cash charges

EPLP's contracted plants generate relatively stable cash flows with low fuel cost exposure. EPLP's cash provided by operating activities increased to $160 million in 2008 from $133 million in 2007 primarily due to operating working capital changes. However, EPLP recorded a net loss of $68 million in 2008 versus net income of $31 million in 2007. EPLP recorded negative unrealized fair value changes of $98 million on its foreign

exchange and natural gas contracts in 2008 and unrealized foreign exchange losses of $28 million on translation of its U.S. dollar denominated debt. These specific accounting non-cash charges are not reflective of economic changes in value when considering these financial instruments in conjunction with the risk exposures they are intended to hedge. EPLP also recorded a $24 million impairment loss on its investment in PERH in 2008 which was reflective of a decline in value of this investment. Because the Company consolidates EPLP in its financial statements, the foregoing amounts are recorded on a gross basis in the financial statements.

Sale of percentage interest in PPA

On each of January 15, 2009 and 2008, the Company sold a 10% interest in the Battle River PPA for cash proceeds of $47 million and $53 million, respectively, resulting in pre-tax gains of $30 million and $34 million, respectively. The associated income taxes on the 2009 sale were $4 million (2008 — $4 million) of expense with an additional $5 million (2008 — $6 million) of refundable taxes related to the sale charged to retained earnings. This sale was pursuant to a purchase and sale agreement entered into in June 2006 whereby the Company agreed to sell its Battle River PPA and related interest in the Battle River PSA to ENMAX over a four-year period ending in January 2010. An initial interest of 55% was sold for cash proceeds of $343 million on June 5, 2006 followed by the sale of a 10% interest 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 after-tax gain on the sale in the current quarter was $26 million compared with $30 million in the first quarter of 2008. The year-over-year decrease in proceeds and after-tax gain were due to the one year shorter-term to maturity for the Battle River PPA.

EPLP acquisition of Illinois cogeneration facility

On October 31, 2008, EPLP acquired 100% of the equity interest in Morris from Diamond Generating Corporation and MIC Nebraska Inc., both wholly-owned subsidiaries of Mitsubishi Corporation. Morris owns a 177 MW natural gas-fired cogeneration facility located on the Equistar chemical plant site. The total consideration paid was $89 million (U.S.$74 million) in cash which was financed under EPLP's existing credit facilities.

Non-GAAP financial measures

The Company uses (i) gross margin, (ii) adjusted EBITDA, (iii) funds from operations, (iv) funds from operations excluding non-controlling interests in EPLP, (v) net income net of certain items, and (vi) adjusted EBITDA net of certain items 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 an alternative to net earnings, cash flow from operating activities or other measures of financial performance calculated in accordance with Canadian GAAP. Rather, these measures are provided as additional information to complement those Canadian GAAP measures by providing further understanding of the Company's results of operations from management's perspective. See "— Results of operations — non-GAAP financial measures".

The Company uses gross margin and adjusted EBITDA to measure the operating performance of plants and groups of plants from period to period.

The Company uses funds from operations as its primary cash flow measure because changes in non-cash operating working capital are primarily made up of intercompany payables and receivables between the Company and EPCOR and are not representative of how working capital would be managed by the Company on a stand-alone basis. The Company uses funds from operations excluding non-controlling interests in EPLP to measure its interest in cash flow by excluding non-controlling interest in EPLP's cash flow.

The Company uses net income net of certain items and adjusted EBITDA net of certain items since they are meant to show the impact to net income and adjusted EBITDA of certain items that management believes are not in the normal course of operations or that are unrealized fair value changes in derivative instruments and natural gas inventory held for trading or foreign exchange gains and losses. The Company adjusts for the

unrealized fair value changes and foreign exchange gains and losses since the changes do not consider the items that these items economically hedge and they are not considered predictors of future economic performance.

Summary of combined and consolidated financial information

The Company reports operational results summarized into the following categories: (i) Alberta commercial plants and portfolio optimization, (ii) Alberta contracted plants, (iii) Ontario/British Columbia contracted plants, (iv) EPLP plants, and (v) other portfolio activities.

Alberta commercial plants and portfolio optimization

Alberta commercial plants and portfolio optimization consists of generation facilities for which the Company has not contracted substantially all power and capacity of the facility to third parties. This category includes the Company's directly-owned facilities located in Alberta consisting of Genesee 3, Joffre, Clover Bar, Taylor Coulee Chute, Clover Bar Landfill Gas Plant and Weather Dancer and the Company's interests in the Battle River and Sundance PPAs (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 trading activities in the Alberta market undertaken primarily to manage the Company's exposure to electricity price movements, selling power contracts to competitive wholesale commercial and industrial ("C&I") customers and managing the supply for rate regulated tariff customers of EPCOR. The Company has been gradually exiting the competitive wholesale C&I power contract market over the last several years and is considering winding this business down as the remaining contracts expire over the next four years. This C&I portion of the business has represented a very small component of earnings for the Company.

The Company seeks to maximize earnings from Alberta commercial plants and portfolio optimization by achieving high production levels from the facilities when it is economic to do so and by actively managing the portfolio's commodity price risk of its assets and contracts by using a variety of financial and non-financial derivative instruments. Trading counterparties in the Alberta market include other power generators, large load bearing entities and market trading counterparties. Credit limits are established and monitored for these counterparties.

Alberta contracted plants

Alberta contracted plants consist of generation facilities for which the Company has contracted substantially all power and capacity of the facility to third parties. Alberta contracted plants are comprised of the Genesee 1 and 2 generation facilities whose capacity and output are sold under a long-term PPA with the Balancing Pool which expires in 2020. Under the PPA, the Balancing Pool has the right to dispatch the output from the generation facilities. The Balancing Pool pays capacity payments, consisting of fixed operating and maintenance charges, and incentive and 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/British Columbia contracted plants

Ontario/British Columbia contracted plants includes the Kingsbridge wind farm in Ontario and the Brown Lake and Miller Creek hydro facilities in British Columbia. Revenues from these plants consist of firm energy sales and excess energy sales under power sales contracts with the OPA and BC Hydro.

EPLP plants

EPLP plants consist of a fleet of 20 facilities located in Canada and the U.S. with long-term PPAs and fuel supply contracts that provide stable cash flows. The Company owns 30.6% of the limited partnership units of EPLP and consolidates EPLP in its financial statements. This management's discussion and analysis of financial condition and results of operations discusses the EPLP facilities on a consolidated basis unless otherwise stated. All of the EPLP plants are contracted.

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 electricity markets. The Company also holds retail and commercial natural gas customer contracts in Alberta. However, as the Company exits the competitive market, the impact on revenues will decrease as these natural gas contracts are wound down or expire. See "— Outlook".

The Company's results reflect unrealized fair value changes on derivative instruments and natural gas inventory held for trading related to the Alberta commercial plants and EPLP plants. The Company believes that unrealized fair value changes recognized in the financial statements in derivative instruments and natural gas inventory held for trading are not representative of the instruments' underlying economic value without considering them in conjunction with associated economically hedged items to which they relate, such as natural gas required for plant operations, future power sales, and future expected cash flows denominated in foreign currencies. While the derivatives used to hedge the associated exposures are measured at fair value, the changes in the fair value of the associated economically hedged exposures are not recognized in income. Derivative instruments that are recorded at fair value can produce volatility in net income as a result of fluctuating forward commodity prices, foreign exchange rates and interest rates which are not offset by the unrealized fair value changes of the exposure being hedged economically. As a result, the recording of gains or losses for changes in fair values of derivative instruments for accounting purposes does not necessarily represent the underlying economics of the hedging transactions.

Accordingly, 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. Management views funds from operations as a key performance indicator since it highlights the key sources of cash generation and liquidity of the Company.

Summarized volume and financial information

	Three months ended March 31		Year ended December 31		
	2009	2008	2008	2007	2006
Electricity generation (GWh)					
Alberta commercial plants[1]	691	625	2,206	2,477	2,555
Alberta contracted plants	1,628	1,423	5,923	6,350	6,250
Ontario/British Columbia contracted plants	49	53	271	288	223
	2,368	2,101	8,400	9,115	9,028
EPLP plants[2]	1,299	1,253	4,955	5,229	3,272
Total	**3,667**	**3,354**	**13,355**	**14,344**	**12,300**

(1) Alberta commercial plants excludes acquired PPAs.

(2) Excludes Castleton, the sale of which closed on May 26, 2009.

Output increased in 2007 due to EPLP's acquisition of Ventures in November 2006. The decrease in 2008 generation reflects the outages at the Genesee facilities.

	Three months ended March 31		Year ended December 31		
	2009	2008	2008	2007	2006
Generation plant availability (%)[1]					
Alberta commercial plants	99	98	85	95	97
Alberta contracted plants	100	88	91	97	95
Ontario/British Columbia contracted plants	89	99	94	91	93
EPLP plants	94	97	94	93	95
Overall Average[2]	**97**	**95**	**91**	**95**	**95**

(1) Plant availability represents the percentage of time in the period that the plant is available to generate power, whether actually running or not, and is reduced by planned and unplanned outages.

(2) Overall average generation plant availability is an average of individual plant availability weighted by owned and/or operated capacity.

The overall average availability of the Company's facilities, as indicated in the above table, was 97% for the three months ended March 31, 2009 compared with 95% for the same period in the prior year, due to lower planned outages at the Genesee facilities.

The overall average availability of the Company's facilities, as indicated in the above table, was 91% in 2008, 95% in 2007 and 95% in 2006. The lower availability of the Company's generation units in 2008 compared with 2007 and 2006 was primarily due to planned and unplanned outages at Genesee facilities.

Summary of combined and consolidated financial results

	Three months ended and as at March 31		Year ended and as at December 31		
	2009	2008	2008	2007	2006
			($ millions)		
Revenues	$ 709	$633	$2,649	$2,953	$2,246
Gross margin[1]	199	236	735	874	784
Adjusted EBITDA[1]	117	153	365	587	536
Net income[2][3]	54	35	4	134	433
Cash provided by operating activities	27	67	165	130	139
Capital expenditures	108	76	439	235	49
Long-term debt including current portion	3,064	—	3,027	2,485	—
Total assets	5,048	—	5,002	4,922	—

(1) The combined and consolidated financial results have been prepared in accordance with Canadian GAAP except for gross margin and adjusted EBITDA. See "— Results of operations — non-GAAP financial measures".

(2) There are no discontinued operations or extraordinary items in the periods indicated.

(3) Net income on a per share basis cannot be calculated because the financial statements of the EPCOR Power Group are prepared on a combined and consolidated basis which includes share capital of multiple entities that do not equally share in the net income.

Combined and consolidated net income

	($ millions)
Net income for the three months ended March 31, 2008	**$ 35**
Unrealized fair value changes in derivative instruments, excluding EPLP	38
Higher revenue from Genesee 1 and 2 PPA availability	11
Lower Genesee 1 maintenance expenses	7
Lower gain on sale of the Battle River PPA	(4)
Higher financing expenses, excluding EPLP	(8)
Lower income from EPLP	(19)
Other	(6)
	19
Net income for the three months ended March 31, 2009	**$ 54**

Net income increased by $19 million for the three months ended March 31, 2009 compared with the three months ended March 31, 2008, primarily due to the net impact of the following items:

- Fair value changes from the Company's Alberta electricity derivative positions not designated as hedges for accounting purposes were favourable due to a decrease in forward Alberta power prices on a net short position in 2009 compared with an increase in power prices in 2008.
- In the three months ended March 31, 2009, availability incentive income was earned under the terms of the Genesee 1 and 2 PPA compared with net availability penalty incurred in the same period in 2008. The net penalty in the three months ended March 31, 2008 was due to a major maintenance turnaround at Genesee 1.
- Maintenance expenses for Genesee 1 were lower due to the major planned maintenance turnaround in the three months ended March 31, 2008 compared with no outages in the three months ended March 31, 2009.
- Financing expenses were higher in the three months ended March 31, 2009 primarily due to an increase in guarantee fees and other credit enhancement costs for credit services provided by EPCOR. Credit fees increased due to higher amounts of issued guarantees, higher interest rate spreads, and from the impact of foreign exchange translation on guarantees related to the Company's U.S. dollar denominated activities compared with 2008. The increase in credit costs reflects the general tightening of the credit market in the latter part of 2008 and the three months ended March 31, 2009. Financing expenses were also higher due to lower cash balances in the three months ended March 31, 2009 resulting from the payment of dividends to EPCOR in the third quarter of 2008.
- Net income from EPLP was lower in the three months ended March 31, 2009 compared with the same period in the prior year primarily due to unfavourable changes in the fair value of EPLP's natural gas supply and foreign exchange contracts as a result of decreases in the future market prices for natural gas in the three months ended March 31, 2009 compared with increases in the three months ended March 31, 2008.

	($ millions)
Net income for the year ended December 31, 2006	**$ 433**
Foreign exchange losses on Frederickson plant previously deferred until the 2006 transfer to EPLP	43
Unrealized fair value changes in derivative instruments, excluding EPLP	24
Impact of 2006 and 2007 income tax rate reductions on future income tax assets and liabilities, excluding EPLP	21
Lower financing expenses, excluding EPLP	20
Impact of recording a net future income tax asset associated with the restructuring of EPCOR Generation Inc. in 2006	(117)
Gain on sale of the Battle River PPA and related transactions	(297)
Other	7
	(299)
Net income for the year ended December 31, 2007	**$ 134**
Higher Alberta electricity margin	18
Impact of 2007 income tax rate reductions on future income tax assets and liabilities, excluding EPLP	17
Higher gain on sale of venture capital investment	9
Higher Genesee 1 and 2 fuel costs	(7)
Higher administration expenses, excluding EPLP	(15)
Fair value changes on EPLP's foreign exchange, natural gas supply, and interest rate contracts	(16)
Higher Genesee 1, 2 and 3 maintenance costs	(18)
Foreign exchange losses from EPLP in 2008 compared with gains in 2007[1]	(22)
Write-down of EPLP goodwill in 2008	(28)
Lower revenue from Genesee 1 and 2 PPA availability and capacity payments	(29)
Unrealized fair value changes in derivative instruments and natural gas inventory held for trading, excluding EPLP	(35)
Other	(4)
	(130)
Net income for the year ended December 31, 2008	**$ 4**

(1) Excluding changes in the fair value of foreign exchange and interest rate contracts.

Net income decreased by $130 million for the year ended December 31, 2008 compared with the previous year primarily due to the net impact of the following items:

- Alberta electricity margins were higher primarily due to higher Alberta spot electricity prices received on a net long position held in the Company's electricity portfolio. The net length held was a result of more electricity generated from the Company's commercial power plants than the Company had contracted to sell in 2008. This was partly offset by contracted power sold at lower contract prices relative to the Alberta power prices.
- In the second and third quarters of 2008, the Company sold shares in venture capital investments and recognized after-tax gains of $11 million compared with $2 million in 2007.
- The increase in fuel costs for the Genesee 1 and 2 facilities were higher primarily due to higher coal mining costs in 2008 compared with 2007. The higher coal mining costs result from the initial adoption of an accounting policy in 2007 that capitalizes coal mine stripping costs. In 2008, the amortization expense approximates the amount of new stripping costs capitalized in the period.
- Administration expenses increased by $15 million after tax, excluding administration for EPLP, due to business project development costs, more information technology projects and initiatives, higher costs related to environment and supply chain management, and higher bad debt provisions.

- Fair value changes on EPLP foreign exchange, natural gas supply, and interest rate contracts were unfavourable in 2008 primarily due to fair value losses recognized on the foreign exchange contracts used to hedge cash flows denominated in U.S. dollars compared with fair value gains in 2007. These fair value changes on the foreign exchange contracts were due to an appreciation in the U.S. dollar forward price relative to the Canadian dollar of $0.192 in 2008 compared with a declining U.S. dollar forward price relative to the Canadian dollar of $0.135 in 2007.
- The increase in maintenance expenses reflects three major planned outages for Genesee 1, 2 and 3 due to AESO requirements and an unplanned outage for Genesee 3 in 2008 compared with one unit outage for Genesee in 2007.
- EPLP recognized unrealized foreign exchange losses in 2008 on the translation of U.S. dollar net monetary liabilities, primarily long-term debt, compared with foreign exchange gains in 2007. These changes were due to a strengthening U.S. dollar relative to the Canadian dollar in 2008 compared with a weakening U.S. dollar in 2007.
- A net availability penalty was incurred under the terms of the Genesee 1 and 2 PPA in 2008 compared with availability incentive income recognized in 2007. The net penalty in 2008 was due to the AESO required plant outages in the first two quarters of 2008. Capacity payment revenue under this PPA also decreased due to a lower return from a declining PPA rate-base related to amortization of the PPA calculated asset base and reduced tax recoveries related to lower federal income tax rates.
- Unfavourable unrealized fair value changes on derivative financial contracts for the forward sales of power in Alberta (financial sales), which are used to hedge anticipated energy revenues but were not designated as hedges for accounting purposes, were due to an increase in the forward Alberta power prices in 2008. In 2007, unrealized fair value changes were favourable due to a decrease in forward Alberta power prices on financial sales contracts.

Net income decreased by $299 million for the year ended December 31, 2007 compared with the previous year primarily due to the net impact of the following items:

- On August 1, 2006, the Company sold its interest in the Frederickson power plant to EPLP. The Company recognized a reduction in its net investment in the Frederickson power plant operations to the extent of the non-controlling interests in EPLP of approximately 69.4%. In addition, with the sale to EPLP, foreign exchange losses on translation of the Company's net investment in the Frederickson power plant, which were previously deferred in a separate component of equity, were recognized in income in 2006.
- Favourable fair value changes in derivative instruments, excluding EPLP, are primarily due to significantly reduced trading activity in the Ontario power market compared with the prior year, partly offset by lower fair value gains on the Joffre CfD due to less significant changes in Alberta natural gas and power forward prices in 2007 compared with the prior year.
- In 2007, the Government of Canada substantially reduced general corporate income tax rates resulting in an income tax expense for the Company of $17 million, excluding the impact from EPLP as the rate decrease reduced the value of its net future income tax assets on its balance sheet. In 2006, the Government of Alberta and the Government of Canada both reduced corporate income tax rates resulting in an income tax expense of $38 million, excluding the impact from EPLP.
- Financing expenses, excluding financing for EPLP, decreased primarily due to the repayment in the third quarter of 2006 of the loan issued under a three-year credit facility and scheduled repayments of obligations to The City of Edmonton and non-recourse debt. Capitalized interest was higher in 2007 due to the commencement of construction for the Keephills 3 and Clover Bar generation projects.
- The January 3, 2006 reorganization of certain subsidiaries resulted in the recognition of a future income tax asset associated with additional deductions available for income tax purposes, partly offset by the write-off of future income tax balances associated with the Government of Alberta's Payment in Lieu of Tax Regulation, thereby increasing income in 2006 by $117 million.

- In 2006, the Company recognized an after-tax gain of $327 million on the initial sale of a 55% interest in the Battle River PPA and a 17.8% interest in the Sundance PPA to other syndicate members compared with an after-tax gain of $30 million in 2007 on the sale an additional 10% interest in the Battle River PPA.

Comparison of results by plant category

	Three months ended March 31		Year ended December 31		
	2009	2008	2008	2007	2006
			($ millions)		
Revenues					
Alberta commercial plants and portfolio optimization	$336	$337	$1,314	$1,339	$1,287
Alberta contracted plants	72	60	242	282	283
Ontario/British Columbia contracted plants	4	4	19	20	14
EPLP plants	145	136	578	545	359
Other portfolio activities	115	148	600	708	303
Inter-plant category transaction eliminations	(3)	(3)	(11)	(13)	(16)
	669	682	2,742	2,881	2,230
Unrealized fair value changes in derivative instruments and natural gas inventory held for trading	40	(49)	(93)	72	16
	$709	**$633**	**$2,649**	**$2,953**	**$2,246**
Gross margin[1]					
Alberta commercial plants and portfolio optimization	$ 68	$ 71	$ 278	$ 250	$ 253
Alberta contracted plants	61	50	198	243	244
Ontario/British Columbia contracted plants	4	4	19	20	14
EPLP plants	76	78	313	314	256
Other portfolio activities	9	4	47	22	35
Inter-plant category transaction eliminations	—	—	(4)	(10)	(11)
	218	207	851	839	791
Unrealized fair value changes in derivative instruments and natural gas inventory held for trading	(19)	29	(116)	35	(7)
	$199	**$236**	**$ 735**	**$ 874**	**$ 784**
Adjusted EBITDA[1]					
Alberta commercial plants and portfolio optimization	$ 47	$ 52	$ 173	$ 160	$ 171
Alberta contracted plants	40	18	92	167	157
Ontario/British Columbia contracted plants	3	3	13	13	9
EPLP plants	39	48	160	188	184
Other portfolio activities	7	2	43	26	26
Inter-plant category transaction eliminations	—	1	—	(2)	(4)
	136	124	481	552	543
Unrealized fair value changes in derivative instruments and natural gas inventory held for trading	(19)	29	(116)	35	(7)
	$117	**$153**	**$ 365**	**$ 587**	**$ 536**

(1) The comparison of results by plant category has been prepared in accordance with Canadian GAAP except for gross margin and adjusted EBITDA. See "— Results of operations — non-GAAP financial measures".

Comparison of results — Three months ended March 31, 2009 versus March 31, 2008

Alberta commercial plants and portfolio optimization

Revenues and expenses from Alberta commercial plants and portfolio optimization decreased by $1 million and increased by $2 million, respectively, in the first three months of 2009 compared with the same period in 2008 and gross margin decreased by $3 million. Revenues decreased primarily due to the reduced interest in the Battle River PPA and lower Alberta spot prices, partly offset by favourable settlements on financial power sales contracts. Expenses increased primarily due to unfavourable settlements on financial power purchases resulting from higher volumes and lower Alberta spot prices.

Alberta power prices averaged $70/MWh in the first three months of 2009 compared with the $77/MWh in the first three months of 2008. The decrease in Alberta spot prices was primarily due to the scheduled outages from the AESO's upgrade of the high-voltage transmission lines in the Genesee and Keephills area in 2008 and lower natural gas prices in the three months ended March 31, 2009 compared with the three months ended March 31, 2008.

Gross margin and adjusted EBITDA from Alberta commercial plants and portfolio optimization decreased by $3 million and $5 million, respectively, in the first three months of 2009 compared with the same period in 2008, primarily due to reduced portfolio length, partly offset by favourable settlements on financial power sales and margins from commercial power supply contracts due to lower Alberta spot electricity prices.

Alberta contracted plants

Revenues from Alberta contracted plants increased by $12 million and gross margin increased $11 million primarily due to increased availability incentive income payments in the first three months of 2009 compared with net availability penalty incurred in the three months ended March 31, 2008. The net penalty in the first three months of 2008 was due to a major planned maintenance turnaround on Genesee 1. Expenses increased by $1 million due to higher fuel costs for the Genesee facilities. Higher fuel costs are due to the initial adoption of an accounting policy in 2007 that capitalizes coal mine stripping costs. In 2008, the amortization expense approximates the amount of new stripping costs capitalized in the period.

Adjusted EBITDA increased $22 million in the first three months of 2009 as compared with the first three months of 2008 primarily due to higher availability income in 2009 and higher maintenance expenses in the first three months of 2008 on the Genesee 1 facility resulting from the major maintenance turnaround in that period.

EPLP plants

EPLP's revenues and expenses increased by $9 million and $11 million, respectively, and gross margin decreased by $2 million in the first three months of 2009 as compared with the first three months of 2008. Revenues and expenses increased primarily due to the acquisition of Morris on October 31, 2008. The higher revenues were partly offset by a decrease in revenues from the other U.S. plants primarily due to lower electricity prices for the California plants and lower generation at the North Carolina plants. The higher expenses were partly offset by lower fuel costs at the California facilities due to lower natural gas prices and lower consumption resulting from planned outages for inspections at the Naval Station.

EPLP's adjusted EBITDA was $9 million lower in the first three months of 2009 compared with the first three months of 2008 primarily due to lower margins at the North Carolina facilities as a result of higher planned maintenance costs related to enhancement projects, lower margins at the California facilities due to the inspections work at the Naval facility and lower margins at the Ontario facilities due to higher waste heat optimization costs.

Other portfolio activities

Revenues and expenses from other portfolio activities decreased by $33 million and $38 million, respectively, and gross margin increased by $5 million in the first three months of 2009 compared with the first three months of 2008. Decreases in revenues and expenses were primarily due to lower natural gas trading activity, lower natural gas consumption as a result of fewer wholesale and merchant customers in keeping with

the Company's strategy to exit this segment of the business, and decreased electricity trading activity in the Western U.S. compared with the first quarter of 2008.

Adjusted EBITDA from other portfolio activities increased primarily due to lower natural gas costs reflecting lower natural gas prices and volumes compared with the corresponding period in 2008.

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

Unrealized fair value changes in financial derivative electricity contracts increased revenues and expenses by $89 million and $137 million, respectively, and decreased gross margin and adjusted EBITDA by $48 million in the first three months of 2009 compared with the corresponding period of 2008. Unrealized fair value adjustments increased revenues in the first three months of 2009 primarily due to a net short position arising from financial electricity contracts that were not designated as hedges for accounting purposes combined with a decrease in forward Alberta power prices, compared with increasing forward power prices in the three months ended March 31, 2008. Unrealized fair value adjustments increased expenses primarily due to a decrease in the fair value of EPLP's natural gas supply contracts due to a decrease in forward natural gas prices in the three months ended March 31, 2009 compared with an increase in forward prices in the corresponding period of 2008.

Comparison of annual results — 2008 versus 2007

Alberta commercial plants and portfolio optimization

Revenues and expenses from Alberta commercial plants and portfolio optimization decreased by $25 million and $53 million, respectively, resulting in a gross margin increase of $28 million in 2008 compared with 2007. Revenues decreased due to unfavourable settlements on financial derivative electricity contracts sold due to higher Alberta spot prices in 2008 and lower generation due to the reduced interest in the Battle River PPA and the Genesee 3 plant outage. Expenses decreased due to favourable settlements from financial derivative electricity purchased electricity due to higher Alberta spot prices in 2008. Revenues and expenses also decreased primarily due to a reduction in wholesale power contracts with C&I customers reflecting the Company's strategy to exit the competitive retail electricity business.

Alberta power prices averaged $90/MWh in 2008 compared with the $67/MWh in 2007. This was primarily due to the AESO's upgrade which required the Genesee and Keephills coal units to be offline or operating at a reduced output in the first and second quarters of 2008 and a number of forced outages from coal plants in the fourth quarter of 2008. The gross margin for Alberta commercial plants and portfolio optimization increased by $28 million primarily due to the higher power prices received in 2008 on a net long position held in the Company's electricity portfolio. The financial derivative contracts which sold electricity decreased energy revenues, while the length created from both the physical generation and financial derivative electricity contracts to purchase financial power at higher power pool prices resulted in lower expenses and higher gross margin in 2008 compared with the prior year.

Despite the year-over-year increase, gross margins and adjusted EBITDA were lower than anticipated, in significant part due to the higher maintenance expenses related to the turnaround of Genesee 3 in the second quarter of 2008 and the unplanned outage of Genesee 3 in the fourth quarter of 2008, which together are estimated to have reduced revenues by $28 million and adjusted EBITDA by $34 million in 2008. As a result of the planned and unplanned outages, availability from the Company's commercial plants decreased from 95% in 2007 to 85% in 2008. Genesee 3 contributed approximately $109 million to gross margin and $77 million to adjusted EBITDA in 2008 compared with $107 million and $82 million, respectively, in 2007.

With the commissioning of the first Clover Bar unit in the first quarter of 2008, Clover Bar contributed approximately $8 million to gross margin and $6 million to adjusted EBITDA in 2008, as compared with nil in 2007.

Alberta contracted plants

Revenues from Alberta contracted plants decreased by $40 million, expenses increased by $5 million and gross margin decreased by $45 million in 2008 compared with 2007. Revenues from the Genesee PPA decreased primarily due to a net availability penalty for 2008 compared with net availability incentives in 2007. The

penalties were due to the major planned outages at Genesee 1 and 2 in the first six months of 2008 and an unscheduled outage at Genesee 2 in the third quarter of 2008, all of which coincided with periods of high Alberta power prices. As a result of the planned and unplanned outages, plant availability from Genesee 1 and 2 decreased from 97% in 2007 to 91% in 2008.

Fuel expense for the Genesee facilities also increased in 2008 compared with 2007 as discussed previously above.

Adjusted EBITDA decreased by $75 million in 2008 compared with the prior year primarily due to the factors noted above and higher maintenance and operations costs. Administration expenses increased in 2008 due to strategic business project development costs and information technology projects and initiatives and higher community and sponsorship costs.

EPLP plants

EPLP contributed $313 million of gross margin in 2008 compared with $314 million in 2007. Revenues and expenses increased by $33 million and $34 million, respectively, in 2008 compared with 2007. The increase in revenues was primarily due to higher plant revenues from the Morris Facility which was acquired in the fourth quarter of 2008, and from the California facilities where the higher cost of natural gas supply was passed on to the PPA counterparties.

EPLP gross margin before fair value changes was slightly lower in 2008 compared with 2007, due to higher cost of natural gas supply for the Ontario plants, California plants, and Northeast U.S. natural gas plants. Fuel costs were higher at the Northeast U.S. plants due to the acquisition of Morris. Fuel costs of Ontario plants were higher due to settlement of natural gas supply contract disputes for the Tunis facility and an increase in the fuel supply price in the natural gas supply contracts at Kapuskasing and North Bay. EPLP's adjusted EBITDA was lower by $28 million in 2008 compared with 2007 primarily due to higher planned maintenance at the Northwest U.S. plants, Ontario facilities, Castleton plant, California plants, Curtis Palmer facility and higher operating and higher administration costs. In particular, a $5 million milestone payment was incurred in 2008 under the terms of a long-term service agreement with the turbine manufacturer at the Frederickson plant.

Other portfolio activities

Revenues from other portfolio activities decreased by $108 million and gross margin increased by $25 million in 2008 compared with 2007. Revenues from trading physical natural gas were lower in 2008 due to lower volumes of trading physical delivery contracts and lower revenues from the marketing and sale of natural gas to retail and wholesale customers in Alberta reflecting the Company's strategy to exit the competitive retail and wholesale natural gas business. Revenues from energy trading in the U.S. Pacific Northwest also decreased due to a decrease in export sales of electricity from the Pacific Northwest power market to the Alberta power market. The impact of these activities on gross margin was not significant.

In 2008, gross margin on other portfolio activities increased by a $13 million pre-tax gain on sale of venture capital investments and by $11 million from favourable energy trading activities in Ontario and the U.S. Northeast compared with 2007. The higher gross margins from energy trading activities in Ontario and the U.S. Northeast were due to higher payments received from purchased financial transmission rights resulting from higher transmission congestion occurring on specific interconnection tie-lines between the Ontario and New York electricity markets and an increase in exports of electricity between the Ontario and New York electricity markets resulting from higher natural gas prices in 2008 which created a widening of electricity price spreads between the Ontario and New York electricity markets.

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

Unrealized fair value changes in financial derivative electricity contracts decreased revenues and expenses by $165 million and $14 million, respectively, and decreased gross margin by $151 million in 2008 compared with 2007. The majority of the decline in unrealized fair value adjustments on revenues and gross margin was due to the effect of a weakening of the Canadian dollar relative to the U.S. dollar in 2008 compared with 2007 on EPLP's forward foreign exchange contracts used to economically hedge U.S. denominated revenues. Unrealized fair value changes in financial derivative electricity contracts that were not designated as hedges for accounting purposes relate primarily to a net short position held in both 2008 and 2007. In 2008, forward Alberta power prices increased which reduced the fair value of the financial derivatives, whereas in 2007 forward Alberta power prices decreased which increased the fair value of the financial derivatives.

Comparison of annual results — 2007 versus 2006

Alberta commercial plants and portfolio optimization

Revenues and expenses from Alberta commercial plants and portfolio optimization increased $52 million and $55 million, respectively, in 2007 compared with 2006 and gross margin decreased by $3 million. Revenues from Alberta commercial plants and portfolio optimization increased primarily due to a higher volume of contracted financial power which was sold at higher contract prices compared with lower Alberta power spot prices which averaged $67/MWh in 2007. The increase in revenues was partly offset by lower Alberta power prices and lower generation from the Company's commercial plants in 2007 compared with 2006. The decrease in generation was due to the Company's reduced interest in the Battle River PPA, the 2006 fourth quarter expiry of the short-term tolling arrangement and lower generation from Genesee 3 resulting from an October 2007 outage.

Alberta power prices averaged $67/MWh in 2007 compared with $80MW/hr in 2006. In 2006, Alberta power prices were higher due to a significant number of forced plant outages in Alberta in the third and fourth quarters. In 2007, generation from Alberta's baseload coal fleet was relatively stable. The stable generation supply in the province resulted in lower Alberta power prices compared with the prior year.

The Company sells forward power contracts to mitigate the risk and volatility of Alberta spot prices on the generation activities of the portfolio. The impact of lower Alberta spot prices and reduced generation were offset by the Company's portfolio optimization and risk management activities, whereby the Company sold power forward at higher contracted prices relative to the Alberta spot prices in 2007 compared with the prior year.

Adjusted EBITDA decreased by $11 million in 2007 compared with the prior year due to higher administration costs primarily from increased business development expenses. Maintenance expenses in 2007 were lower on the Joffre facility due to a major inspection in 2006.

Genesee 3 contributed approximately $107 million to gross margin and $82 million to adjusted EBITDA in 2007 compared with $136 million and $110 million, respectively, in 2006.

Alberta contracted plants

Revenues and gross margin decreased by $1 million in 2007 compared with the prior year. In accordance with the PPAs for Genesee 1 and 2, the Company receives capacity payments from the Balancing Pool. Income taxes based on statutory rates and the PPA base rate are two factors in the formula for determining capacity payments. In 2007, reductions in both of these variables resulted in lower payments compared with 2006.

Adjusted EBITDA increased $10 million in 2007 compared with the prior year due to lower maintenance and operations costs. Maintenance on Genesee 2 was lower compared with the prior year as there was a 24 day outage for Genesee 2 in 2006 compared with a seven day outage on Genesee 1 in 2007.

Ontario/British Columbia contracted plants

In 2007, the revenues and gross margin on Ontario/British Columbia contracted plants were higher than the previous year primarily due to Kingsbridge I wind farm which commenced operations in March 2006. Plant availability decreased from 93% in 2006 to 91% in 2007 primarily due to an increase in planned outages at the Miller Creek hydro facility in 2007.

EPLP plants

EPLP contributed $545 million in revenues and $314 million in gross margin in 2007 compared with $359 million in revenues and $256 million in gross margin in 2006. The increase in revenues, expenses, and gross margin is primarily due to the impact of the Ventures and Frederickson power plant acquisitions on November 1, 2006 and August 1, 2006, respectively. The sale of the Frederickson power plant from the Company to EPLP had no impact on consolidated revenues. The offsetting decrease is included in other portfolio activities revenues. The higher revenues were partly offset by the non-recurrence of a settlement payment received from the OEFC and recognized in the first quarter of 2006, and lower revenues from the Curtis Palmer plant in 2007. EPLP's

plant availability decreased from 95% in 2006 to 93% in 2007 primarily due planned outages at the Curtis Palmer and Mamquam hydro plants in 2007.

Other portfolio activities

Revenues from other portfolio activities increased $405 million and gross margin decreased $13 million compared with the prior year. Revenues from trading physical natural gas were higher in 2007 primarily due to higher volume of physical delivery contracts compared with 2006. In addition, electricity trading activities were entered into for the first time in the U.S. Northeast and California electricity markets which also contributed higher energy revenues. The impact from both these activities on gross margin was insignificant. The higher revenues were partly offset by lower electricity sales to wholesale customers in Ontario resulting from contract expiries in 2007.

Other portfolio activities revenues and gross margin were also impacted by the Company's sale of its interest in the Frederickson power plant to EPLP on August 1, 2006. Although the sale decreased gross margins under this category, the sale of the Frederickson power plant to EPLP had no impact on consolidated results.

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

Unrealized fair value changes in financial derivative electricity contracts increased revenues and expenses by $56 million and $14 million, respectively, resulting in an increase in gross margin and adjusted EBITDA of $42 million in 2007 compared with 2006. Revenues increased due to a strengthening Canadian dollar relative to the U.S. dollar on EPLP's forward foreign exchange contracts and from lower fair value losses on the Joffre CfD in 2007 compared with 2006. Expenses increased due to unfavourable fair value changes in EPLP's natural gas supply contracts resulting from a decrease in forward natural gas prices, partly offset by lower fair value losses from reduced trading activity in the Ontario power market in 2007 compared with 2006.

Consolidated other expenses

	Three months ended March 31		Year ended December 31		
	2009	2008	2008	2007	2006
			($ millions)		
Depreciation, amortization and asset retirement accretion	$46	$45	$181	$175	$154
Foreign exchange losses (gains)	—	13	18	(56)	54
Impairments	—	—	52	13	5
Net financing expenses	64	51	219	219	227

Depreciation, amortization and asset retirement accretion

In 2008, depreciation, amortization and asset retirement accretion increased by $6 million compared with the prior year due to capital asset additions related to the completion of Clover Bar Unit 1 in February 2008 and the acquisition of the Morris Facility in October 2008.

In 2007, depreciation, amortization and asset retirement accretion increased by $21 million compared with the prior year primarily due to the acquisition of Ventures in November 2006.

Foreign exchange losses

In the first quarter of 2008, the Company recognized net foreign exchange losses of $13 million related to the foreign currency translations on EPLP's U.S. dollar-denominated debt due to a weakening of the Canadian dollar by $0.035 relative to the U.S. dollar. In the first quarter of 2009, EPLP reported net foreign exchange losses in other comprehensive income.

The Company reported net foreign exchange losses of $18 million for the year ended December 31, 2008 compared with gains of $56 million in 2007. The foreign exchange losses recorded in 2008 were the result of a

weakening of the Canadian dollar over the first nine months of $0.045 relative to the U.S. dollar on the translation of U.S. dollar-denominated debt, compared with a strengthening of $0.174 for the twelve months to December 31, 2007.

In 2007, the Company recognized foreign exchange gains compared with foreign exchange losses in 2006. In 2007, the foreign exchange gains were primarily due to a strengthening Canadian dollar relative to the U.S. dollar on the translation of EPLP's U.S. dollar denominated monetary assets and liabilities, partly offset by realized losses of $15 million on settlement of foreign exchange contracts entered into in anticipation of the issuance of Canadian equity by EPLP to replace a portion of the U.S. dollar bridge acquisition facility during the first two quarters of 2007. In 2006, upon the sale of Frederickson to EPLP, the Company recognized in net income foreign exchange losses of $42 million related to translations of the net investment which were previously deferred in a separate component of equity.

Impairments

Impairments for the year ended December 31, 2008 include $28 million for the goodwill impairment on the Company's investment in EPLP and $24 million for the write-down of EPLP's investment in PERH. In 2007, impairments consist of $13 million for the write-down of the management agreement acquired as part of the Ventures acquisition.

Net financing expenses

Financing expenses increased by $13 million in the three months ended March 31, 2009 compared with the three months ended March 31, 2008 primarily due to an increase in the cost of guarantee fees and other credit enhancement services to EPCOR. Credit fees increased due to higher amounts of issued guarantees, higher interest rate spreads, and the impact of foreign exchange translation on guarantees related to the Company's U.S. denominated activities. Financing expenses were also higher due to lower cash balances in the three months ended March 31, 2009 resulting from the payment of dividends to EPCOR in the third quarter of 2008.

Financing expenses decreased by $8 million in 2007 compared with the prior year primarily due to interest earned on higher cash balances throughout the first half of 2007, the 2006 third quarter repayment of the borrowings under a three-year credit facility, and scheduled repayments of long-term debt. Capitalized interest on commercial construction activities was higher in 2007 for the Keephills 3 and Clover Bar generation projects. The lower financing expenses were partly offset by interest on short-term debt and long-term debt used to finance the Ventures and Frederickson acquisitions by EPLP in 2006, interest on capital lease obligations assumed in the Ventures acquisition, and realized losses and declines in the fair value of interest rate contracts compared with the prior year.

Results of operations — non-GAAP financial measures

The Company uses (i) gross margin, (ii) adjusted EBITDA, (iii) funds from operations, (iv) funds from operations excluding non-controlling interests in EPLP, (v) net income net of certain items, and (vi) adjusted EBITDA net of certain items 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 an alternative to net earnings, cash flow from operating activities or other measures of financial performance calculated in accordance with Canadian GAAP. Rather, these measures are provided as additional information to complement those Canadian GAAP measures by providing further understanding of the Company's results of operations from management's perspective.

Gross margin and adjusted EBITDA

The Company uses gross margin and adjusted EBITDA to measure the operating performance of plants and groups of plants from period to period. A reconciliation of gross margin and adjusted EBITDA to net income is as follows:

	Three months ended March 31		Year ended December 31		
	2009	2008	2008	2007	2006
			($ millions)		
Revenues	**$709**	**$633**	**$2,649**	**$2,953**	**$2,246**
Deduct (add):					
Energy purchases and fuel	510	397	1,914	2,079	1,462
Gross margin	**199**	**236**	**735**	**874**	**784**
Deduct (add):					
Operations, maintenance, and administration	82	83	370	287	248
Adjusted EBITDA	**117**	**153**	**365**	**587**	**536**
Deduct (add):					
Depreciation, amortization, and asset retirement accretion	46	45	181	175	154
Foreign exchange losses (gains)	—	13	18	(56)	54
Gain on sale of power purchase arrangement and related transactions	(30)	(34)	(34)	(34)	(378)
Impairments	—	—	52	13	5
Net financing expenses	64	51	219	219	227
Income taxes (reductions)	5	5	(24)	113	(3)
Non-controlling interests	(22)	38	(51)	23	44
Net income	**$ 54**	**$ 35**	**$ 4**	**$ 134**	**$ 433**

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

The Company uses funds from operations to measure the Company's ability to generate funds from current operations and measures the Company's interest in cash flows by excluding the non-controlling interest in EPLP's cash flows. A reconciliation of funds from operations and funds from operations excluding non-controlling interests in EPLP to cash provided by operating activities is as follows:

	Three months ended March 31		Year ended December 31		
	2009	2008	2008	2007	2006
			($ millions)		
Funds from operations excluding non-controlling interests in EPLP	**$ 62**	**$44**	**$ 182**	**$ 194**	**$ 177**
Funds from operations due to non-controlling interests in EPLP	19	26	83	85	104
Funds from operations	**81**	**70**	**265**	**279**	**281**
Change in non-cash operating working capital	(54)	(3)	(100)	(149)	(142)
Cash provided by operating activities	**$ 27**	**$67**	**$ 165**	**$ 130**	**$ 139**

The change in non-cash operating working capital for the year ended December 31, 2008 compared with the year ended December 31, 2007 is due to a decrease in notes receivable from EPCOR partly offset by the payment of the tax on capital gains arising from the initial sale of the Company's 55% interest in the Battle River PPA and Sundance PPA in June 2006.

Changes in working capital are primarily made up of intercompany payables and receivables between the Company and EPCOR and are not representative of how working capital would be managed by the Company on a stand-alone basis. Therefore, the Company uses funds from operations as its primary operating cash flow measure.

	($ millions)
Funds from operations for the three months ended March 31, 2008	**$ 70**
Higher adjusted EBITDA from Alberta contracted plants	22
Lower current income taxes	10
Lower adjusted EBITDA from EPLP	(9)
Higher financing expenses	(13)
Other	1
	11
Funds from operations for the three months ended March 31, 2009	**$ 81**

The $11 million increase in funds from operations in the three months ended March 31, 2009 compared with the same period in 2008 was primarily due to the following items:

- Alberta contracted plants adjusted EBITDA was higher due to availability incentive income of $11 million in the three months ended March 31, 2009 compared with availability penalties of $4 million in the same period in 2008 and higher maintenance expenses from Genesee 1 of $10 million due to the major maintenance turnaround in the three months ended March 31, 2008.
- Current income taxes decreased primarily due to losses carried forward from prior periods and utilized in the three months ended March 31, 2009.

Increases in funds from operations were partly offset by the following items:

- Adjusted EBITDA from EPLP was lower due to lower generation and higher maintenance costs from the North Carolina plants related to plant outages of $3 million, higher waste heat optimization costs and lower waste heat availability from the Ontario plants of $2 million and lower settlements on foreign exchange contracts of $2 million due to lower contract prices compared with the same period in 2008.
- Financing expenses were higher primarily due to an increase in the cost of guarantee fee and other credit enhancement services to EPCOR. Credit fees increased due to higher amounts of issued guarantees, higher interest rate spreads, and the impact of foreign exchange translation on guarantees related to the Company's U.S. dollar denominated activities. Financing expenses were also higher due to lower cash

balances in the three months ended March 31, 2009 resulting from the payment of dividends to EPCOR in the third quarter of 2008.

	($ millions)
Funds from operations for the year ended December 31, 2006	**$281**
Higher adjusted EBITDA from Alberta contracted plants	28
Lower financing expenses	13
Higher adjusted EBITDA from EPLP	5
Higher adjusted EBITDA from Ontario/British Columbia contracted plants	4
Lower adjusted EBITDA from Alberta commercial plants and portfolio optimization	(11)
Net realized losses upon settlement of foreign exchange and interest rate contracts	(18)
Higher current income taxes	(27)
Other	4
	(2)
Funds from operations for the year ended December 31, 2007	**279**
Lower current income taxes	45
Lower net realized losses upon settlement of foreign exchange and interest rate contracts	18
Higher adjusted EBITDA from other portfolio activities	17
Higher adjusted EBITDA from Alberta commercial plants and portfolio optimization	13
Lower adjusted EBITDA from EPLP	(29)
Lower adjusted EBITDA from Alberta contracted plants	(74)
Other	(4)
	(14)
Funds from operations for the year ended December 31, 2008	**$265**

The $14 million decrease in funds from operations in 2008 compared with 2007 was primarily due to the following items:

- Adjusted EBITDA from Alberta contracted plants was lower in 2008 primarily due to a net availability penalty incurred under the terms of the Genesee 1 and 2 PPAs compared with availability incentive income recognized in 2007 and higher maintenance expenses from the Genesee 1 and 2 facilities due to planned and unplanned maintenance outages.
- EPLP contributed lower adjusted EBITDA primarily due to higher planned maintenance expenses at the Northwest U.S. plants of $9 million, Ontario facilities of $9 million, Castleton of $4 million, California plants of $4 million, and Curtis Palmer of $3 million. In particular, a $5 million milestone payment was incurred in 2008 under the terms of a long-term service agreement with the manufacturer of the turbine at the Frederickson plant.

Decreases in funds from operations were partly offset by the following items:

- Current income taxes decreased primarily due to the tax associated with the sale of the Company's interest in the Battle River PPA and interest in the Sundance PPA in June 2006.
- In 2007, net realized losses upon settlement of foreign exchange and interest rate contracts were primarily due to the strengthening of the Canadian dollar relative to the U.S. dollar, as discussed below.
- Adjusted EBITDA from other portfolio activities were higher primarily due to gains on the sale of venture capital investments and from favourable energy trading activities in Ontario and the U.S. Northeast compared with the prior year.
- Adjusted EBITDA from Alberta commercial plants and portfolio optimization was higher primarily due to higher Alberta spot electricity prices received on a net long position held in the Company's electricity portfolio, partly offset by lower production and higher maintenance costs from the Genesee 3 facility due

to a major turnaround in the second quarter of 2008 and an unplanned outage in the fourth quarter of 2008.

The $2 million decrease in funds from operations in 2007 compared with 2006 was primarily due to the following items:

- Current income taxes increased primarily due to the tax associated with the sale of the Company's interest in the Battle River PPA and interest in the Sundance PPA in June 2006 and from the full utilization of non-capital loss carry forwards from the Company's subsidiaries in 2006.
- In 2007, foreign exchange and interest rate contracts were used to hedge changes in foreign exchange rates on U.S. dollar credit and bridge facilities that were repaid with the proceeds from Canadian dollar equity offerings and to hedge changes in interest rates on the portion of the credit facilities and bridge facilities that were replaced by long-term fixed rate debt, respectively. Net realized losses of $18 million were recognized primarily due to the strengthening of the Canadian dollar relative to the U.S. dollar.
- Adjusted EBITDA from Alberta commercial plants and portfolio optimization was lower primarily due to higher administration costs mainly from increased new business development spending.

Decreases in funds from operations were partly offset by the following items:

- Alberta contracted plants adjusted EBITDA increased due to higher incentives income earned on Genesee 1 and 2 due primarily to higher availability and lower maintenance expenses on Genesee 2 resulting from a shorter duration of plant outages in 2007 compared with the prior year.
- Financing expenses increased for EPLP due to financing for the Ventures acquisition which was more than offset by decreases in interest due to scheduled repayments of the obligation to The City of Edmonton and non-recourse debt as well as an increase in capitalized interest in 2007 related to the construction of Keephills 3 and Clover Bar facilities.
- EPLP contributed higher adjusted EBITDA primarily due to the impact of the Ventures and Frederickson power plant acquisitions commencing on their respective purchase dates of November 1, 2006 and August 1, 2006.
- Adjusted EBITDA from Ontario/British Columbia contracted plants increased in 2007 due to a full year of operations from the Kingsbridge I wind farm which commenced operations in March 2006.

The Company uses funds from operations excluding non-controlling interests in EPLP to measure its interest in cash flow.

	Three months ended March 31		Year ended December 31		
	2009	2008	2008	2007	2006
			($ millions)		
Funds from operations	$81	$70	$265	$279	$281
Less: funds from operations due to non-controlling interests in EPLP	19	26	83	85	104
Funds from operations excluding non-controlling interests in EPLP	**$62**	**$44**	**$182**	**$194**	**$177**

Net income net of certain items and adjusted EBITDA net of certain items

The adjustments for certain items in the tables below are meant to show the impact to net income and adjusted EBITDA of certain items that management believes are not in the normal course of operations or that are unrealized fair value changes in derivative instruments and natural gas inventory held for trading at the reporting dates or foreign exchange gains and losses. The Company adjusts for these unrealized fair value changes and foreign exchange gains and losses since the changes do not consider the items that these items economically hedge and they are not considered predictors of future economic performance. These adjustments should not be considered to be predictive of future performance. The effect of a change in a particular variable

to the impact of certain items on net income and adjusted EBITDA is calculated without considering interrelationships between the various market related variables or mitigating actions that would be taken by the Company.

	Three months ended March 31		Year ended December 31		
	2009	2008	2008	2007	2006
	($ millions)				
Net income as reported	$ 54	$ 35	$ 4	$134	$ 433
Add back (deduct) other items after tax:					
Gain on sale of Battle River PPA and related transactions[1]	(26)	(30)	(30)	(30)	(327)
Gain on sale of venture capital investments[2]	—	—	(11)	(2)	—
Unrealized fair value changes in derivative instruments and natural gas inventory held for trading, including the Company's 30% interest in EPLP[3]	(11)	5	33	(23)	1
Foreign exchange losses (gains), including the Company's 30% interest in EPLP[4]	—	3	—	(12)	31
Impact of income tax rate reductions on future income tax assets and liabilities, excluding EPLP[5]	—	—	—	17	38
Impact of EPLP future tax due to enactment of SIFT[6]	—	—	—	24	—
Impact of recording a net future income tax asset associated with the restructuring of Power Company's Generation segment[7]	—	—	—	—	(117)
Discontinuation of Clover Bar generation facility[8]	—	—	—	—	10
Impairments, including the Company's 30% interest in EPLP[9]	—	—	35	3	3
Estimated impact of Genesee 3 planned and unplanned plant outages[10]	—	—	24		
Estimated impact of Genesee 1 and 2 plant outages adjusted to historical experience[11]	—	13	24	—	
Net income net of certain items	**$ 17**	**$ 26**	**$ 79**	**$111**	**$ 72**

(1) Reflects the after-tax gains on the sale of the Company's interest in the Battle River PPA to ENMAX. The gains reflect the sale of a 10% interest in each of January, 2009, 2008 and 2007 and a 55% interest in June 2006. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Significant events — Sale of percentage interest in PPA", "— Comparison of annual results — 2008 versus 2007 — Other portfolio activities", and "— Outlook".

(2) Reflects the sale of certain venture capital portfolio investments focused on strategic elements of the energy value chain in 2008 and 2007. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Summary of combined consolidated financial information — Combined and consolidated net income".

(3) Reflects the impact of unrealized fair value changes in derivative instruments and natural gas inventory held for trading (for the quarters ended 2009 and 2008 — $19 million and $(29) million respectively, and for the years ended 2008, 2007 and 2006 — $116 million, $(35) million and $7 million respectively) less the non-controlling portion of unrealized fair value changes related to EPLP (for the quarters ended 2009 and 2008 — $(35) million and $36 million respectively, and for the years ended 2008, 2007 and 2006 — $(69) million, $1 million and $(4) million respectively) less income tax expense recorded (for the quarters ended 2009 and 2008 — $5 million and $(2) million respectively, and for the years ended 2008, 2007 and 2006 — $(14) million, $11 million and $(2) million respectively).

(4) Reflects the impact of foreign exchange losses (gains) (for the quarters ended 2009 and 2008 — $— million and $13 million respectively, and for the years ended 2008, 2007 and 2006 — $18 million, $(56) million and $54 million respectively) less the non-controlling portion of foreign exchange losses (gains) related to EPLP (for the quarters ended 2009 and 2008 — $— million and $(9) million respectively, and for the years ended 2008, 2007 and 2006 — $(18) million, $39 million and $(8) million respectively) less income tax expense recorded (for the quarters ended 2009 and 2008 — $— million and $(1) million respectively, and for the years ended 2008, 2007 and 2006 — $— million, $5 million and $(15) million respectively).

(5) In 2007, the Government of Canada substantially reduced general corporate income tax rates resulting in an income tax expense for the Company of $17 million, excluding the impact from EPLP, as the rate decrease reduced the value of its net future income tax assets on its balance sheet. In 2006, the Government of Alberta and the Government of Canada both reduced corporate income tax rates resulting in an income tax expense of $38 million, excluding the impact from EPLP.

(6) Reflects the impact of the Company's 30% interest of EPLP future tax recognized due to the enactment of SIFT legislation.

(7) Reflects the net future income tax assets recognized on reorganization.

(8) Reflects the net income included from the Clover Bar generation facility which was discontinued.

(9) Reflects impairment losses recognized in net income (for the years ended 2008, 2007 and 2006 — $52 million, $13 million and $5 million respectively) less the non-controlling interest related to impairments recognized by EPLP $(17) million and $(10) million for the years ended 2008 and 2007 respectively) less income tax recovery (2006 — $(2) million). See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Significant events — Goodwill impairment", and "— Consolidated other expenses — Impairment".

(10) Reflects management's estimate of the net income impact ($34 million less income taxes of $10 million) of an unplanned outage at the Company's Genesee 3 facility in the fourth quarter of 2008 due to a turbine rotor blade failure which kept the unit offline for 39 days, being the longest unplanned outage at a Genesee facility since 1994 and management's estimate of the impact of a planned outage at the Company's Genesee 3 facility in 2008 required to accommodate the upgrades by AESO of high voltage transmission lines in the Genesee and Keephills area in excess of normal course of operations. Management used historical plant planned and unplanned outages for the period from Genesee 3 commissioning in 2005 to 2008 in estimating the production levels and maintenance costs that would normally be incurred in a given year. For Genesee 3, whose output is not under contract and is sold into the Alberta power market, the Company has multiplied this average historical output by 2008 Alberta pool prices to determine the adjustment. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Significant events — Genesee 3 turbine failure" and "— Other Genesee plant outages", and "— Outlook".

(11) Reflects management's estimate of the net income impact (for the quarter ended 2008 — $18 million less income taxes of $5 million and for the year ended 2008 — $34 million less income taxes of $10 million) of planned outages at the Company's Genesee 1 and 2 facilities in 2008 required to accommodate the upgrades by AESO of the high-voltage transmission lines in the Genesee and Keephills area in excess of normal course of operations. Management used average historical plant planned and unplanned outages for the past six years through the end of 2008 in estimating the production levels and maintenance costs that would normally be incurred in a given year. For Genesee 1 and 2, which are under contract, the Company used the six year average of availability incentive income on an earned basis and excess energy receipts to determine the adjustment. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Significant events — Other Genesee plant outages", and "— Outlook".

Gains on sale and impairments are primarily the result of investing activities of the business and not operations and therefore have been excluded from the net income net of certain items. Unrealized fair value changes and foreign exchange gains and losses do not consider the items that these items hedge economically and therefore have also been added back in the above measure. Changes in income tax rates, income tax legislation due to enactment of SIFT and significant tax benefits from reorganizations have been adjusted as they again do not reflect operational performance of the business. The Genesee plant outages have also been adjusted in 2008 to reflect the unusual circumstances of having an AESO requirement to take outages at all

three units in one year as well as the length of the Genesee 3 outage which was the longest Genesee unit outage in fifteen years.

	Three months ended March 31		Year ended December 31		
	2009	2008	2008	2007	2006
			($ millions)		
Revenues	$709	$633	$2,649	$2,953	$2,246
Less energy purchases and fuel	510	397	1,914	2,079	1,462
Less operations, maintenance and administration	82	83	370	287	248
Adjusted EBITDA as previously stated in "Management's Discussion and Analysis of Financial Condition and Results of Operations"	117	153	365	587	536
Unrealized fair value changes in derivative instruments and natural gas inventory held for trading including the Company's interest in EPLP[1]	19	(29)	116	(35)	7
Estimated impact of Genesee 3 planned and unplanned plant outages[2]	—	—	34	—	—
Estimated impact of Genesee 1 and 2 plant outages adjusted to historical experience[3]	—	18	34	—	—
Adjusted EBITDA net of certain items	**$136**	**$142**	**$ 549**	**$ 552**	**$ 543**

(1) Reflects the impact of unrealized fair value changes in derivative instruments and natural gas inventory held for trading.

(2) Reflects management's estimate of the impact of an unplanned outage at the Company's Genesee 3 facility in the fourth quarter of 2008 due to a turbine rotor blade failure which kept the unit offline for 39 days, being the longest unplanned outage at a Genesee facility since 1994 and management's estimate of the impact of a planned outage at the Company's Genesee 3 facility in 2008 required to accommodate the upgrades by AESO of high voltage transmission lines in the Genesee and Keephills area in excess of normal course of operations. Management used historical plant planned and unplanned outages for the period from Genesee 3 commissioning in 2005 to 2008 in estimating the production levels and maintenance costs that would normally be incurred in a given year. For Genesee 3, whose output is not under contract and is sold into the Alberta power market, the Company has multiplied this average historical output by 2008 Alberta pool prices to determine the adjustment. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Significant events — Genesee 3 turbine failure" and "— Other Genesee plant outages", and "— Outlook".

(3) Reflects management's estimate of the impact of planned outages at the Company's Genesee 1 and 2 facilities in 2008 required to accommodate the upgrades by AESO of the high-voltage transmission lines in the Genesee and Keephills area in excess of normal course of operations. Management used average historical plant planned and unplanned outages for the past six years through the end of 2008 in estimating the production levels and maintenance costs that would normally be incurred in a given year. For Genesee 1 and 2, which are under contract, the Company used the six year average of availability incentive income on an earned basis and excess energy receipts to determine the adjustment. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Significant events — Other Genesee plant outages", and "— Outlook".

Liquidity and capital resources

It is anticipated that on closing of this Offering, Capital Power LP will have credit facilities of approximately $1,200 million, of which $500 million may be utilized for issuing letters of credit. In addition, Capital Power LP will have $1,781 million of long-term debt outstanding as follows:

	Amount ($ millions)	Maturity Dates	Effective Interest Rate
Long-term debt payable to EPCOR	$ 894	Ranging from 2009 to 2018	Ranging from 5.01% to 9.00%
Joffre Cogeneration and Brown Lake project non-recourse financing	$ 45	2020 and 2016	9.57% and 8.08%
EPLP long-term debt	$ 842	Ranging from 2009 to 2036	Ranging from 1.09% to 11.02%
	$1,781		

Capital Power LP will be required to make principal payments of $41 million in 2009 and $365 million in 2010 under terms of the long-term debt agreements.

The long-term debt payable to EPCOR will be issued in connection with the Reorganization pursuant to a credit agreement entered into by Capital Power LP with EPCOR. See "Relationship to EPCOR — Agreements Between Capital Power and EPCOR — Asset Purchase Agreement" and "Relationship to EPCOR — Reorganization". The indebtedness of Capital Power LP to EPCOR will mirror existing indebtedness of EPCOR under debt issued by EPCOR to the public, which is to be repaid on the originally-scheduled maturity dates of such mirrored debt, and shall bear interest at rates corresponding to the interest rates of each component of the mirrored debt. The indebtedness of Capital Power LP to EPCOR will also include an amount sufficient to meet existing obligations of EPCOR related to indebtedness of The City of Edmonton assumed by EPCOR, which 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 in Capital Power LP, then EPCOR may, by written notice to Capital Power LP, require repayment of all or any portion of the outstanding principal amount under the credit agreement and accrued interest thereon (but, for certainty, no yield maintenance amount). If the principal amount specified in such repayment notice is less than $200,000,000, then such principal amount and accrued interest thereon shall be payable 180 days after delivery of notice (such principal amount shall be calculated without reference to any scheduled payment of principal during such 180-day period). If the principal amount specified in such repayment notice is $200,000,000 or more, then such principal amount and accrued interest thereon shall be payable 365 days after delivery of notice. Only one repayment notice may be outstanding at any time. The long-term debt payable to EPCOR requires Capital Power LP to meet certain financial covenants under the credit agreement. The credit agreement contemplates certain events of default including the acquisition of more than 50% of the voting equity of the Company or of the general partner of Capital Power LP.

The Company anticipates that Capital Power LP will enter into bank credit agreements pursuant to commitments EPCOR has received from two lenders acting as lead arrangers for the related credit facilities that are conditional on completion of the Offering and the Reorganization and satisfaction of other usual closing conditions. The first commitment provides for an extendible revolving credit facility of up to $700,000,000 with an initial term of three years (the "Syndicated Facility"), and the second provides for an extendible revolving credit facility of up to $500,000,000 with an initial 364 day revolving period following which any drawn portion of the facility will convert into a non-revolving facility for a one year term-out period (the "Club Facility") if not extended. The lead arrangers have made commitments of an aggregate of $300,000,000 and $200,000,000 in respect of the Syndicated Facility and the Club Facility, respectively, and have received commitments as to the balance of each of these facilities from additional lenders. It is contemplated that drawdowns and repayments under the Club Facility may be made by Capital Power LP with each lender on an individual basis up to that lender's commitment, and not on a pro rata basis.

The commitment in respect of the Syndicated Facility provides that Capital Power LP will not make any partnership distributions if a default or event of default has occurred and is continuing or would reasonably be expected to result from such a distribution. The commitment also contemplates that Capital Power LP will be required to meet certain financial covenants under the credit agreement. The commitment further provides that in the event that a "Change of Control" occurs, then if (i) immediately thereafter the long term senior unsecured and unsubordinated debt rating of Capital Power LP ("Debt Rating") is BBB− or higher from S&P and BBB(low) or higher from DBRS (in each case with a stable outlook) (defined in the commitment as "Investment Grade"), the Majority Lenders (as defined in the commitment) will have the option, exercisable within 60 days after the Change of Control, 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 Capital Power LP is not Investment Grade, it shall constitute an event of default unless the Change of Control is consented to by the Majority Lenders within 30 days after the occurrence thereof. "Change of Control" is defined in the commitment to mean (i) a change in the general partner of Capital Power LP (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 or the general partner of Capital Power LP 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, EPCOR or their affiliates).

The commitment in respect of the Club Facility similarly provides that Capital Power LP will not make any partnership distributions if a default or event of default has occurred and is continuing or would reasonably be expected to result from such a distribution. The commitment contemplates that Capital Power LP will be required to meet the same financial covenants under the credit agreement as contemplated by the commitment in respect of the Syndicated Facility. The commitment further provides that in the event that a "Change of Control" (as defined above) occurs, then if (i) immediately thereafter the Debt Rating of Capital Power LP is Investment Grade, each lender will have the option, exercisable within 60 days after the Change of Control, to elect to shorten the term applicable to such lender to the lesser of 364 days and the then current maturity date, and (ii) immediately thereafter the Debt Rating of Capital Power LP is not Investment Grade, it shall constitute an event of default unless the Change of Control is consented to by each lender within 60 days after the occurrence thereof.

It is contemplated that the committed bank credit facilities will be used principally for the purpose of providing funds for capital expenditures and letters of credit, as well as for 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.

Capital Power LP's preliminary corporate credit rating provided by S&P is BBB. This preliminary rating assumes the successful completion of the Offering.

This rating from S&P, however, while addressing credit quality subsequent to completion of the Offering, makes no comment on the likelihood or risk of default upon failure of such completion. Investors should exercise their own judgment with respect to such likelihood and risk. Credit ratings are intended to provide investors with an independent assessment of the credit quality of an issue or issuer of securities and do not speak to the suitability of particular securities for any particular investor. 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. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be withdrawn or revised entirely by a rating agency at any time if in its judgment circumstances so warrant.

Capital Power LP's provisional senior unsecured debt rating provided by DBRS is BBB. This rating from DBRS is a provisional rating pending the satisfaction of certain conditions and in the event that conditions are met, a final rating will be assigned.

This rating from DBRS is a provisional rating pending the satisfaction of certain conditions and in the event that conditions are not met, a final rating will be assigned. The conditions typically relate to the review of the financial documentation, but may also include the closing of a plan of arrangement or the completion of a purchase or merger. A provisional rating is not a final rating in respect of the security, it may change or be discontinued, and the final rating issued in respect of the security may be different from the provisional rating.

Capital Power's full year 2009 projected cash requirements include an estimated $560 million for capital expenditures, $41 million for scheduled debt repayments, and dividends that may be declared by the Board of Directors. The major project expenditures in 2009 will be on Keephills 3 and Clover Bar which are estimated at $375 million for the year and EPLP's Roxboro, Southport and North Island facilities which are estimated at $100 million.

If total cash requirements for 2009 remain as planned, the sources of capital will be cash on hand, cash provided by operating activities, and the use of existing credit facilities. If required, other sources of capital for 2009 could include additional new public or private debt borrowings and additional public equity market offerings.

Capital Power's cash flow will be partly dependent on distributions from EPLP. On June 7, 2009, the general partner of EPLP announced a reduction in distributions on EPLP's units from $0.63 per unit per quarter to $0.44 per unit per quarter effective with the June 2009 distribution. If future distributions from EPLP decline, it could indirectly and negatively impact the cash flow available to Capital Power.

If ongoing 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 potentially 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 counterparties, its trading counterparties and its supplier counterparties. While the Company continues to monitor its exposure to its significant counterparties, there can be no assurance, particularly in light of recent economic events, that all counterparties will be able to meet their commitments.

Capital expenditures

	Three months ended March 31		Year ended December 31		
	2009	**2008**	**2008**	**2007**	**2006**
	($ millions)				
Alberta commercial plants	$ 91	$67	$390	$213	$ 5
Alberta contracted plants	2	7	27	17	15
Ontario/British Columbia contracted plants	1	1	2	1	17
EPLP plants	14	1	20	4	12
	108	76	439	235	49
Investment in Ventures	—	—	—	—	354
Investment in Morris	—	—	89	—	—
Total capital expenditures	$108	$76	$528	$235	$403

Capital expenditures for property, plant and equipment were higher in 2008 compared with 2007 primarily due to increased construction activity on the Keephills 3 and Clover Bar generation projects.

The Company's capital expenditures on Keephills 3 were $259 million in 2008 and $155 million in 2007. The current estimated final cost for the project is approximately $0.9 billion for the Company's 50% interest in the facility.

The first Clover Bar unit was commissioned in the first quarter of 2008, the second unit is expected to be commissioned in the third quarter of 2009 and commissioning of the third unit is expected in the third quarter of 2010. The current estimated final cost for the project is $284 million. Capital expenditures on Clover Bar Energy Centre were $119 million in 2008 and $61 million in 2007.

Effects of economic downturn and market uncertainty

If the world-wide economic recession and credit and financial instability continue, particularly as they relate to Canada and the U.S., there may be an adverse effect on the Company's future ability to raise equity or

arrange long-term financing for its capital expenditure programs and acquisitions, and to refinance outstanding indebtedness on its maturity dates. Furthermore, these conditions have resulted in an increase in interest rates and a decline in equity markets in general, which may make finding accretive acquisitions for the Company and EPLP more difficult.

Should market conditions worsen, the Company may suffer a credit rating downgrade and be unable to renew its credit facilities or access the public debt or equity markets. While the probability of such events may be relatively low, management is mindful of how quickly market conditions changed in 2008. Management has reviewed the Company's capital and operating programs and is ensuring that the appropriate level of diligence is applied and plans are in place to minimize the risk that the Company becomes short of cash or unable to honour its obligations. Some of these plans include the preservation of capital through capital expenditure reduction or deferral, operating cost reductions and sale of non-strategic assets.

Contractual obligations

	Payments due by period					
	2009[5]	2010	2011	2012	2013 and thereafter	Total
	($ millions)					
Acquired PPA obligations[1]	$ 135	$ 93	$ 96	$ 99	$1,089	$1,512
Capital projects[2]	501	179	10	—	—	690
Energy purchase/transportation contracts[3][4]	156	122	93	77	256	704
Asset retirement obligations	8	8	9	13	352	390
Long-term debt	41	365	234	28	1,130	1,798
Interest on long-term debt	102	99	80	70	499	850
Forward foreign exchange contracts and commodity contracts-for-differences	106	59	18	12	15	210
Total contractual obligations	$1,049	$925	$540	$299	$3,341	$6,154

(1) The Company'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 volumes and scheduled plant outages.

(2) The Company's obligations for capital projects include obligations for Keephills 3, Clover Bar Energy Centre, and enhancements of the Southport, Roxboro and North Island facilities.

(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.

(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) Assumes payments for a 12-month period.

EPLP has committed up to $119 million (U.S.$98 million) for the enhancement of the Southport, Roxboro and North Island facilities, to be spent through 2009, of which $18 million (U.S.$15 million) was incurred in 2008.

There were no other material guarantee obligations outstanding in respect of third parties.

Off-balance sheet arrangements

As at December 31, 2008, the Company had no off-balance sheet arrangements required to be disclosed in accordance with applicable securities regulations.

Related party transactions

The Company has entered into various transactions with EPCOR and EPCOR's sole shareholder, The City of Edmonton. These 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.

Energy sales relating to the Company's portfolio supply management of EPCOR's rate regulated customers included $663 million for the year ended December 31, 2008 (2007 — $596 million; 2006 — $525 million). Sales from the Company to The City of Edmonton included electricity and miscellaneous services totalling $24 million in 2008 (2007 — $23 million; 2006 — $23 million).

The Company recorded net financing expenses of $139 million for the year ended December 31, 2008 (2007 — $118 million; 2006 — $143 million) on its short-term and long-term notes payable to EPCOR offset by short-term notes receivable from EPCOR. The decrease in net financing expense in 2007 from 2006 and the increase in 2008 from 2007 reflect the changed intercompany debt balances as the components of the Company's financing profile changed throughout these years.

The Company recorded financing expenses of $40 million for the year ended December 31, 2008 (2007 — $50 million; 2006 — $51 million) on its debt obligation to The City of Edmonton. This debt obligation relates to financing provided by The City of Edmonton prior to 1996 when EPCOR and the Company commenced raising capital directly. The decrease in interest expense in 2008 corresponds to the decrease in the net obligation. The outstanding balance of the net obligation to The City of Edmonton was $154 million at December 31, 2008 (2007 — $199 million; 2006 — $248 million).

The Company recorded operations, maintenance and administration expenses of $52 million for the year ended December 31, 2008 (2007 — $44 million; 2006 — $38 million) representing executive, legal, finance, treasury, audit, human resources, procurement, information technology and pension services provided by EPCOR.

The Company recorded dividends to EPCOR of $370 million for the year ended December 31, 2008 (2007 — $122 million; 2006 — $19 million). The variability in dividends was in part due to the timing of repatriations of earnings from the Company to EPCOR from gains on the Battle River and Sundance PPA sales. These dividends are not indicative of what may be declared and paid by the Company in the future.

Included in the Company's revenues for the year ended December 31, 2008 is $4 million (2007 — $3 million; 2006 — $1 million) for the provision of management services by EPLP to PERH under a long-term management agreement. As at December 31, 2008, there were no accounts receivable due from PERH (2007 — $1 million; 2006 — nil).

Outlook

Funds from operations in 2006 and 2007 were consistent with management's expectations based on the assets owned for those periods. Net income for all reported years was impacted by gains on the sale of the Battle River PPA, the changes in future income taxes related to tax legislation changes and restructuring, unrealized fair value changes on derivative instruments and unrealized foreign currency gains and losses. The Company believes that the impact of these items was not necessarily representative of the performance of the assets of the business. It is expected that Capital Power, after reflecting the changes resulting from recapitalization of the business pursuant to the Offering and the Reorganization, will incur lower financing expenses.

2008 financial and operating performance of the business was negatively impacted by the AESO requirement that all three Genesee units be shut-down to accommodate AESO's upgrade of the high-voltage transmission lines in the Genesee and Keephills areas. The Company expects that on an ongoing basis, Genesee 1, 2 and 3 will have major turnarounds approximately every 24 to 36 months. The estimated impact of these shutdowns on 2008 income before income taxes and net income was $45 million and $31 million respectively compared with what would be expected to normally occur in a given year. In addition, the Genesee 3 unit experienced an unplanned outage of 39 days in the fourth quarter of 2008 due to blade failure in the low pressure turbine. While unplanned failures are expected to occur at the facilities, and there can be no assurance that a failure similar to the outage in 2008 will not be experienced in the future, the period of this outage was the longest experienced at a Genesee unit in 15 years and coincided with relatively high Alberta power pool prices. Any failure of this magnitude is expected by management to be infrequent, and therefore is considered to be outside the normal course of operations for the reporting periods under discussion. Total reduced revenue is estimated at $23 million ($17 million after income taxes) as a result of this unplanned outage. These items

combined represent the impact of both planned and unplanned outages relative to what would normally occur in a given year.

For 2009, the Company has planned one outage at Genesee 1. There will also be outages in 2009 at EPLP's North Island, Southport and Roxboro plants to accommodate major upgrades.

In order to realize certain power generation growth opportunities in Alberta in 2006, the Company identified that it needed to reduce the number of MW under its control and generate additional capital to fund such opportunities. Accordingly, in 2006, the Company decided to sell its Battle River PPA and a portion of its interest in the Sundance PPA and to replace this electricity output with power produced from its own new physical facilities. In January 2010, the Company expects to sell its final remaining 15% interest in the Battle River PPA for proceeds of $64 million. In 2007, the Company commenced construction of both Keephills 3 and Clover Bar Energy Centre as part of this strategy. The Company recognized that there would be an interim period during which it would no longer receive funds from operations from the Battle River PPA and a portion of the Sundance PPA nor from the new facilities until operational. Funds from operation of Keephills 3 are expected to be received once the unit is in operation in 2011. Clover Bar funds from operations are expected to increase from 2008 levels as units 2 and 3 are commissioned in 2009 and 2010. Electricity consumption by C&I customers is expected to decrease in the near term as their businesses slow down. This decline in demand is expected to translate into lower prices in the spot and forward markets for electricity in the short-term.

The Company also holds a block of retail natural gas contracts acquired in 2000 and the initial term of the contracts expired in late 2004. The customers under these contracts had an option to renew at the original contracted price and approximately 56% did so with terms expiring by the end of 2009. Due to the relatively low embedded contract price, the Company will experience losses on servicing these contracts. The Company will also have exposure to losses from another five-year renewal period expiring in 2014, to the extent customers choose to renew. This potential loss could be material depending on the renewal rate and the difference between the contract price and future natural gas prices. As the Company no longer participates in the competitive retail natural gas market, the Company will continue to seek opportunities to exit from these contracts.

Some of the Company's trading counterparties have been affected by the economic conditions which have resulted in a decrease in forward market liquidity. Banks, hedge funds and utility companies have curtailed forward trading as credit costs have increased and their willingness to take on credit risk declined. With the decrease in demand by end users for power contracts and the decline in the Company's trading counterparties' activity, the Company's ability to hedge its commodity portfolio and execute trading strategies has been restricted. The Company remains focused on dealing only with creditworthy counterparties and has implemented position management strategies to mitigate the effects of low market liquidity and price volatility.

The Company expects the following factors to impact its 2009 results:

- Only one minor outage is planned at the Genesee site in 2009 for scheduled equipment repairs and maintenance whereas three scheduled and two unplanned outages occurred in 2008;
- The 2009 sale of an additional 10% interest in the Battle River PPA; and
- A full year of earnings from Morris and the first unit of Clover Bar in 2009 compared with three months and ten months, respectively, in 2008 and earnings from the second unit of Clover Bar after commissioning in 2009.

Earnings for 2010 are expected to be lower than 2009 as the final remaining portion of the Battle River PPA is sold. This decrease is expected to be partly offset by higher earnings from Clover Bar. Keephills 3 is expected to contribute to earnings when it becomes operational in 2011.

Sensitivity to specific risk factors

The following table outlines the Company's estimated sensitivity to specific risk factors as at December 31, 2008. Each sensitivity factor 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 sensitivity factors will not be held constant but rather, will change at the same time as other factors are changing. In addition, these sensitivities are presented at December 31, 2008 and the degree of sensitivity to each factor will

change as the Company's mix of assets and operations subject to these factors changes or the degree of commodity hedge coverage changes.

Factor	Change	Annual funds from operations ($ millions)	Annual net income ($ millions) ($ millions)
Wholesale price of electricity — Alberta[1]	+$5/MWh	$ —	$ 11
Wholesale price of natural gas[1]	+$1/Gj	+1	+15
U.S. exchange rate — strengthening CDN dollar	+$0.10 (CDN to U.S. dollar)	−1	+7
Short-term interest rates	+1.0%	−1	−1
Canadian federal and provincial income tax rates	−1.0%	+1	+1

(1) Sensitivities to wholesale prices of electricity and natural gas include the impact of fair value changes in derivative financial instruments that are not hedges for accounting purposes.

The above sensitivities are for 2009. For 2010 and particularly for 2011 and onward, less of the Company's expected Alberta power generation is sold forward at fixed rates. As a result, sensitivities to Alberta power prices will increase.

Changes in the fair value of EPLP's natural gas contracts have limited economic impact on the Company as the majority of the natural gas supplied under long-term contracts is used for power generation. Changes in the value of the foreign exchange contracts are offset by changes in the value of expected foreign currency cash flows. Therefore, readers should be cautious in assessing the disclosed sensitivities.

Disclosure controls and procedures and internal controls over financial reporting

The Company will be required to meet the standards as outlined in Canadian Securities Administrators' (CSA) National Instrument 52-109 — *Certificate of Disclosure in Issuers' Annual and Interim Filings* ("NI 52-109") once it becomes a public issuer. As part of EPCOR, management has conducted an evaluation of the design and effectiveness of disclosure controls and procedures as well as internal controls over financial reporting. In addition, EPLP is a public issuer and management has experience in meeting the requirements of NI 52-109. Based on the systems, processes, policies, documentation and controls in place, management expects that it will be able to meet the requirements of NI 52-109 once it becomes a public issuer.

Accounting changes in 2009

Commencing January 1, 2009, the Company adopted new accounting standards as issued by the Canadian Institute of Chartered Accountants ("CICA") for goodwill and intangible assets and credit risk and fair value of financial assets and liabilities. The new accounting standards have been applied prospectively and the comparative financial statements have not been restated.

Goodwill and intangible assets

In February 2008, the CICA issued Handbook Section 3064 — Goodwill and Intangible Assets and consequential amendments to Section 1000 — Financial Statement Concepts. The new section establishes standards effective January 1, 2009 for the recognition, measurement and disclosure of goodwill and intangible assets. The provisions relating to the definition and initial recognition of intangible assets, including internally generated intangible assets, are equivalent to the corresponding provisions in the International Financial Reporting Standards ("IFRS"). The Company has reviewed its capitalization policies and practices for compliance with the new standard and has reclassified approximately $11 million (2007 — $8 million) of assets from property, plant and equipment to contract and customer rights and other intangible assets effective January 1, 2009. The Company does not expect the new standard to have any other material impacts on the Company's combined and consolidated financial statements in the future.

Credit risk and fair value of financial assets and liabilities

On January 20, 2009, the Emerging Issues Committee of the CICA issued EIC-173 Credit Risk and the Fair Value of Financial Assets and Liabilities, which clarifies that an entity's own credit risk and the credit risk of its counterparties should be taken into account in determining the fair value of financial assets and liabilities, including derivative instruments. EIC-173 is to be applied retrospectively without restatement of prior periods in interim and annual financial statements for periods ending on or after January 20, 2009. The Company has adopted this recommendation in its fair value determinations as at March 31, 2009. The inclusion of counterparty credit risk in the estimate of fair value of EPLP's natural gas and foreign exchange contracts on January 1, 2009 had the following impact on the balance sheet of EPCOR Power Group on that date:

	Increase (decrease)
	($ millions)
Derivative instruments assets — non-current	$ (1)
Derivative instruments liabilities — non-current	(6)
Future income tax liabilities — non-current	1
Non-controlling interests	3
Opening retained earnings	1

The adoption of the recommendations of EIC-173 had no other material impact on the Company's interim consolidated financial statements.

Future accounting changes

International Financial Reporting Standards

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

In January 2008, EPCOR, including the Company, established a core team to develop a plan which will result in the first interim report for 2011 being in compliance with IFRS.

The diagnostic phase of the project was completed in April 2008. For each international standard, the Company 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. In making the assessment, the number of businesses impacted, the potential magnitude of the financial statement adjustment, the availability of policy choices, the impacts on systems and the impacts on internal controls were all considered.

Based on the results of the diagnostic phase, the following standards were identified as most likely to have a significant impact. Certain IFRS standards which may have a significant impact and are expected to change before January 1, 2011, such as joint ventures, will be addressed by the Company in the future depending on the expected timing of the revised standards.

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

For each standard, the Company will determine the quantitative impacts to its financial statements, system requirements, accounting policy decisions, and changes to internal controls and business policies.

Consolidated financial statements and non-controlling interests

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 Capital Power's 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 will be assessed as part of the IFRS project.

Business combinations

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 Capital Power's 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 will be assessed as part of the IFRS project.

Significant accounting policies

Revenue recognition under PPAs

The Company's Genesee power generation units 1 and 2 operate under a PPA. Under the terms of the PPA, the target levels of generation availability set out in the PPA recognize that the generation units will experience planned and forced outages over the terms of the PPA. The Company records the electricity revenue from the generation units under PPAs at the price embedded in the PPAs, including expected incentives and penalties for operating above or below specified availability targets set out in the PPA. Under this approach, incentives for the current period may be deferred and included in non-current liabilities on the balance sheet if they are not expected to be sustained over the full term of the PPA. As penalties are incurred, any balance of deferred incentive will be drawn down. If cumulative penalties exceed cumulative incentives, the excess will be charged to income and no deferred charge will be created.

The degree to which incentives are recognized or deferred will change due to revisions to the long-term outlook of plant performance, which is based on historical performance, planned maintenance, reliability and generation availability, and due to revisions in the estimated long-term price embedded in the PPA.

Revenues from the Company's power generation plants located outside of Alberta are recognized upon delivery of output or upon availability of 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 cumulative billable contract price per MWh and (2) an amount determined by the MW made available during the period, multiplied by the average price per MWh over the term of the contract. Any excess of the contract price over the average price is recorded as deferred revenue.

Foreign currency translation

EPLP has operations in the U.S., the functional currency of which is 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.

During the fourth quarter of 2008, changes in economic circumstances including an increase in U.S. dollar denominated borrowings, the reduction of Canadian dollar intercompany borrowings and a significant increase in U.S. dollar capital expenditures substantially reduced the U.S. subsidiaries exposure to Canadian dollar transactions. It also significantly reduced the cash flow from the U.S. operations to the reporting entity as the operating cash flow was required to fund the U.S. dollar debt and new capital expenditures. Accordingly, the Company re-evaluated the functional currency of EPLP's indirectly-owned U.S. subsidiaries. As a result, the functional currency of these U.S. subsidiaries was determined to be the U.S. dollar. Accordingly, these operations are being translated prospectively using the current rate method.

Consolidation of EPLP

While the Company owns only 30.6% of the outstanding units of EPLP, it controls EPLP under generally accepted accounting principles. Accordingly, EPLP is consolidated in the financial statements of the Company.

Critical accounting estimates

In preparing the combined and consolidated financial statements, management necessarily made estimates in determining transaction amounts and financial statement balances. The following are the items for which significant estimates were made in the financial statements.

Fair values

The Company is required to estimate the fair value of certain assets or obligations for determining the valuation of certain financial instruments, asset impairments, asset retirement obligations and purchase price allocations for business combinations, and for determining certain disclosures.

Fair values of financial instruments are based on quoted market prices when these instruments are traded in active markets. In illiquid or inactive markets, the Company uses appropriate price modeling to estimate 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.

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 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.

Estimates of fair value for purchase price allocations, and goodwill and other asset impairments as described above, are mainly 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.

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.

Useful lives of 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 common life characteristics of common assets.

Income taxes

The Company follows the asset and liability method of accounting for income taxes and amounts in lieu of income taxes. Income taxes and amounts in lieu of income taxes are determined based on estimates of current income taxes and 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. 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 income taxes and amounts in lieu of income taxes, future income tax assets and liabilities and any related valuation allowance might vary from actual amounts incurred.

Fair values and useful lives are used in determining potential impairments for each long-lived asset, which will vary with each asset and market conditions at the particular time. Similarly, income taxes and amounts in lieu of income taxes will vary with taxable income and, under certain conditions, with fair values of assets and liabilities.

PPA availability incentives

Electricity revenue from the Genesee 1 and 2 units includes an estimate of availability incentives as described above under "— Significant accounting policies". Availability incentive payments received are deferred in non-current liabilities and recognized in energy sales when they are expected to be sustained over the full term of the PPA. Accordingly the amount deferred can vary from no amount to the full amount of availability incentive payments received.

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 March 31, 2009 are as follows:

	Carrying amount					
	Held for trading	Available for sale	Loans and receivables	Other financial liabilities	Total	Total fair value
	($ millions)					
Other assets	$ —	$23	$86	$ —	$ 109	$ 106
Long-term debt (including current portion)	—	—	—	3,064	3,064	2,969

Long-term debt includes The City of Edmonton debentures which are offset by the payments made by the Company into the sinking fund. Although the accumulated contributions to the sinking fund are classified as available for sale, they are included as an offset to long-term debt under financial liabilities in the table above, consistent with their presentation on the balance sheet. The Company's interest in the PERH preferred shares is included in available for sale other assets. The accumulated contributions to the sinking fund and the Company's interest in the PERH preferred shares are measured at cost as they are not quoted in an active market. The Company is undertaking a sales process that could lead to the sale of the PERH preferred share interest.

The fair values of the Company's net investments in leases are 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 March 31, 2009.

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 utilizing the effective interest method.

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. The derivative instruments assets and liabilities used for risk management purposes consist of the following:

	Energy		Foreign exchange	
	Cash flow hedges	Non-hedges	Non-hedges	Total
	($ millions)			
Total derivative instruments net assets (liabilities) as at March 31, 2009	$(18)	$38	$(50)	$(30)

The Company uses various open-market derivative instruments with arm's-length parties, including CfDs, to manage its exposure to risks associated with electricity and natural gas prices, foreign exchange rates and interest rates. 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.

Energy derivatives designated as accounting hedges

At March 31, 2009, the net fair value of energy financial derivative instruments designated and qualifying for hedge accounting was a liability of $18 million and is included in derivative instruments assets and derivative instruments liabilities on the combined and consolidated balance sheet. This derivative liability was due to a net short position for the portfolio combined with increases in the forward Alberta electricity prices, relative to the contract prices. Unrealized gains and losses for fair value changes on financial derivatives that qualify for hedge accounting are recorded in other comprehensive income and reclassified to net income as energy revenues or energy purchases when realized.

Energy derivatives not designated as accounting hedges

At March 31, 2009, the net fair value of energy financial derivative instruments not designated as hedges for accounting was a net asset of $38 million and is included in derivative instruments assets and derivative instruments liabilities on the consolidated balance sheet. This derivative asset position was primarily due to unrealized gains on the Company's natural gas supply contracts resulting from increased forward natural gas prices relative to the contract prices.

For the period ended March 31, 2009, the fair value of the Company's forward foreign currency contracts was a net liability of $50 million. The net liability is due to the impact of a weakening Canadian 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 March 31, 2009 was $1.13 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. Unrealized and realized gains and losses on interest rate derivatives that are not designated as hedges for accounting purposes are recorded in financing expenses.

All non-financial derivative instruments are required to be 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. The Company holds certain physical power and natural gas purchase and sales contracts that are used to meet power generation and retail customer requirements. Certain of the natural gas purchase contracts were not designated as contracts used in accordance with the Company's expected purchase requirements, as defined by accounting standards, since the natural gas can at times be re-sold in the market and not entirely used to produce electricity or to sell to end-use consumers. These contracts were, therefore, recorded at fair value in the balance sheet.

As the Company's natural gas supply contracts extend beyond the active period of the market for natural gas, their fair value is determined by reference in part to published price quotations where there is observable market data. With respect to EPLP's long-term natural gas supply contracts, the Company has determined that the market is active to the end of the contract terms, a change from the previous assessment that the market was active within five years. The Company considered market activity and the short period of time that the contracts extend beyond five years when changing its assessment.

Risk management and hedge accounting

Primarily for risk management purposes, the Company uses various financial and non-financial derivatives. Unrealized changes in the fair value of financial and non-financial derivatives that either do not qualify for 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. 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 economically. As a result, the recording of gains or losses for changes in fair values of derivative instruments for accounting purposes does not necessarily represent the underlying economics of the hedging transaction.

For example, the Company has more physical supply of power in Alberta from the Company's generating stations and power purchased under PPAs than the Company has contracted to physically sell. The Company utilizes financial sells 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 sells. However, financial sells 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 economic gains on the physical supply. This economic gain will be recognized in later periods when 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 March 31, 2009, an unrealized gain, net of income taxes, of $9 million (December 31, 2008 — $26 million unrealized loss net of income taxes) was recorded in other comprehensive income for the effective portion of cash flow hedges, and an unrealized loss net of income taxes, of $8 million (December 31, 2008 — $7 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 $13 million (December 31, 2008 — $29 million) in net losses related to derivative instruments designated as cash flow hedges included in accumulated other comprehensive income at March 31, 2009, net losses of $9 million (December 31, 2008 — $15 million), net of taxes of $4 million (December 31, 2008 — $7 million) are expected to settle and be reclassified to net income over the next twelve months.

Unrealized gains on financial instruments designated as available for sale are related to certain venture capital portfolio investments which are focused on strategic elements of the energy value chain. Some of the shares held are not typically traded on an exchange and therefore are difficult to value.

During the fourth quarter of 2008, changes in economic circumstances caused EPLP to re-evaluate the functional currency of its indirectly-owned U.S. subsidiaries. Accordingly, commencing October 1, 2008, these operations are translated using the current rate method whereby gains and losses resulting from foreign currency translation are recorded as a component of shareholders' equity within accumulated other comprehensive income. The loss for the fourth quarter of 2008 was $62 million and was recognized in other comprehensive income. Prior to the fourth quarter of 2008, EPLP's foreign currency translation gains and losses were recognized in net income.

UNAUDITED PRO FORMA CONSOLIDATED AND OTHER FINANCIAL INFORMATION

Unaudited Pro Forma Consolidated Financial Information

The unaudited pro forma consolidated financial information of Capital Power has been prepared by management based on the unaudited interim combined and consolidated financial statements of EPCOR Power Group as at and for the three months ended March 31, 2009 and the audited combined and consolidated financial statements of EPCOR Power Group for the year ended December 31, 2008. The pro forma consolidated financial information of Capital Power includes Capital Power LP on a consolidated basis. See accompanying note 1b). The pro forma consolidated financial information presents the effects of the completion of the Offering and the Reorganization and the related use of the net proceeds as if the completion of the Offering and Reorganization occurred on March 31, 2009 for the purpose of the pro forma consolidated balance sheet and on January 1, 2008 for the purpose of the pro forma consolidated statements of income for the year ended December 31, 2008 and for the three months ended March 31, 2009. See "Relationship to EPCOR — Reorganization" and "Use of Proceeds".

The notes to the unaudited pro forma consolidated financial information have been prepared by management based on EPCOR Power Group's unaudited combined and consolidated balance sheet as at March 31, 2009 and the unaudited combined and consolidated statements of income for the year ended December 31, 2008 and for the three months ended March 31, 2009. These notes should be read in conjunction with EPCOR Power Group's audited combined and consolidated financial statements for the year ended December 31, 2008 and EPCOR Power Group's unaudited interim combined and consolidated financial statements as at and for the three months ended March 31, 2009 included elsewhere in this prospectus.

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 EPCOR Power Group's audited combined and consolidated financial statements for the year ended December 31, 2008.

The unaudited pro forma combined financial information reflects pro forma adjustments that are described in the accompanying notes and are based on currently available information and assumptions that management believes provide a reasonable basis for presenting the significant effects of the completion of the Offering 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 informational purposes only and is not necessarily indicative of what the financial position and results of operations would have been had the completion of the Offering 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.

Unaudited Pro Forma Consolidated Statement of Income

($ millions)
Year ended December 31, 2008

		Pro forma adjustments					
	Historical	Capital structure	Fair values	Public entity costs	Total	Notes	Pro forma
Revenues	$2,649				$ —		$2,649
Energy purchases and fuel	1,914						1,914
	735						735
Operations, maintenance and administration	370			4	4	3d	374
Depreciation, amortization and asset retirement accretion	181		4		4	3a	185
Foreign exchange losses	18						18
Gain on sale of power purchase arrangement and related transactions	(34)						(34)
Impairments	52		(9)		(9)	3b	43
Net financing expenses	219	(116)			(116)	3c	103
	806	(116)	(5)	4	(117)		689
Income (loss) before income taxes and non-controlling interests	(71)	116	5	(4)	117		46
Income taxes (reductions)	(24)	(7)	—	—	(7)	3e	(31)
Income (loss) before non-controlling interests	(47)	123	5	(4)	124		77
Non-controlling interests	(51)	104	(3)	(3)	98	3f	47
Net income	$ 4	$ 19	$ 8	$(1)	$ 26		$ 30

See accompanying notes to unaudited pro forma consolidated financial information.

Unaudited Pro Forma Consolidated Statement of Income

($ millions)
Three months ended March 31, 2009

		Pro forma adjustments					
	Historical	Capital structure	Fair values	Public entity costs	Total	Notes	Pro forma
Revenues	$709						$709
Energy purchases and fuel	510						510
	199						199
Operations, maintenance and administration	82			1	1	3d	83
Depreciation, amortization and asset retirement accretion	46		1		1	3a	47
Foreign exchange losses	—						—
Gain on sale of power purchase arrangement and related transactions	(30)						(30)
Impairments	—						—
Net financing expenses	64	(29)			(29)	3c	35
	162	(29)	1	1	(27)		135
Income (loss) before income taxes and non-controlling interests	37	29	(1)	(1)	27		64
Income taxes (reductions)	5	(13)	—	—	(13)	3e	(8)
Income (loss) before non-controlling interests	32	42	(1)	(1)	40		72
Non-controlling interests	(22)	77	(1)	(1)	75	3f	53
Net income	$ 54	$(35)	$ —	$ —	$(35)		$ 19

See accompanying notes to unaudited pro forma consolidated financial information.

Unaudited Pro Forma Consolidated Balance Sheet

($ millions)
March 31, 2009

		Pro forma adjustments			
	Historical	Offering	Reorganization	Notes	Pro forma
Assets					
Current assets:					
Cash and cash equivalents	$ 80	$468	$ (468)	1a	$ 80
Notes receivable	—				—
Accounts receivable	257				257
Income taxes recoverable	9				9
Inventories	55				55
Prepaid expenses	5				5
Future income taxes	—		2	2e	2
Derivative instruments assets	139				139
	545	468	(466)		547
Property, plant and equipment	3,274		(83)	2a, 2b	3,191
Power purchase agreements	549		121	2a, 2b	670
Contract and customer rights and other intangible assets	188		(39)	2a, 2b	149
Derivative instruments assets	88		—	2a, 2b	88
Future income tax assets	96		(75)	2a, 2b, 2e	21
Goodwill	161		(32)	2a, 2b	129
Other assets	122		—	2a, 2b	122
Assets held for sale	25		11	2a, 2b	36
	$5,048	$468	$ (563)		$4,953
Liabilities and Shareholders' Equity					
Current liabilities:					
Notes payable	$ 179	$ —	$ (179)	2d	$ —
Accounts payable and accrued liabilities	363				363
Income taxes payable	8				8
Derivative instruments liabilities	155				155
Future income tax liabilities	50		(37)	2e	13
Current portion of long-term debt	20		21	2d	41
	775	—	(195)		580
Long-term debt	3,044		(1,304)	2d	1,740
Derivative instruments liabilities	102		—	2a, 2b	102
Other non-current liabilities	91		28	2a, 2b, 2c	119
Future income tax liabilities	93		(12)	2a, 2b, 2e	81
	4,105		(1,483)		2,622
Non-controlling interests	507		1,356	1b	1,863
Shareholders' equity	436	468	(436)	1a, 1b	468
	$5,048	$468	$ (563)		$4,953

See accompanying notes to unaudited pro forma consolidated financial information.

1. Transactions:

a) Offering: As described in this prospectus under "Use of Proceeds", Capital Power expects to issue 21,750,000 Common Shares for estimated gross cash proceeds of $500 million less estimated underwriting commissions of $25 million and estimated offering expenses of $7 million. The net proceeds of the Offering will be used to acquire the shares of EMCC Limited. See "Relationship to EPCOR — Reorganization".

b) Reorganization: Through a series of reorganization steps, the assets and liabilities used to carry on the business of EPCOR Power Group will be transferred to Capital Power LP. This involves a number of reorganization and acquisition transactions that will take place immediately prior to and following the completion of the Offering. For full description of the Reorganization, see "Relationship to EPCOR — Reorganization".

The effect of the Reorganization will be that Capital Power LP will acquire from EPCOR and its subsidiaries, directly or indirectly, the assets and liabilities used to carry on EPCOR Power Group's business in exchange for an equity interest in Capital Power LP, voting interests in Capital Power and debt in the aggregate principal amount of $896 million. The assets and liabilities, directly or indirectly owned by Capital Power LP, will be recorded at fair value (except EPLP, see note 2b) resulting in an adjustment to the carrying amounts (note 2a) in Capital Power's consolidated financial statements. Capital Power is expecting to consolidate the assets, liabilities and operations of Capital Power LP on the basis of control. As EPCOR will hold an economic interest in Capital Power LP, a non-controlling interest of approximately 73% of the assets and liabilities is reflected in the unaudited pro forma consolidated financial information of Capital Power after giving effect to completion of the Reorganization.

2. Notes to unaudited pro forma consolidated balance sheet:

The adjustments included in the unaudited pro forma consolidated balance sheet assumed the following events occurred on March 31, 2009.

a) Fair value adjustments to assets and liabilities: Fair value adjustments, as determined by an independent third party valuation, are preliminary and subject to change. The actual fair values of assets and liabilities will be determined as of the closing date of the transactions, not the dates used in the preparation of the pro forma financial information. The amount of the fair value adjustments may differ materially from the amounts disclosed in the future purchase price allocation. Any such changes in the determination and allocation of the fair value adjustments could also result in material changes to operating results in subsequent periods.

b) Fair value adjustments on the assets and liabilities of EPLP: Capital Power expects to consolidate EPLP. The non-controlling interest in EPLP continues to be recorded at carrying amounts. Adjustments from carrying amounts at the date of acquisition to fair values of the assets and liabilities have been recorded to the extent of Capital Power Corporation's effective 8.1% ownership interest. These fair value adjustments will be determined in accordance with, and are subject to, note 2a.

c) Assumption of net pension liability: Other non-current liabilities were adjusted to record the estimated net pension liability of $20 million associated with employees formerly employed by EPCOR and expected to transfer to Capital Power.

d) Adjustments to notes payable and long-term debt: As part of the Reorganization, existing third party debt with unrelated parties will be assumed by Capital Power LP and has been recorded at fair value. Notes payable and long-term debt with related parties will not be transferred to Capital Power. Capital Power LP will incur indebtedness in the aggregate principal amount of $896 million as part of the consideration payable to EPCOR under the Reorganization.

e) Future income tax assets and liabilities have been adjusted to exclude those assets and liabilities recorded historically with respect to EPCOR's 73% interest which will not be included in Capital Power's financial statements.

3. Notes to unaudited pro forma consolidated statements of income:

The assumptions and adjustments made to the unaudited pro forma consolidated statements of income are as follows:

(a) Increase in depreciation, amortization and asset retirement accretion expense: Incremental depreciation and amortization expense arises from fair value changes on property, plant and equipment, power purchase agreements and contract and customer rights and other intangible assets.

(b) Reversal of impairment expense: The impairment expense consists of two components: (i) an impairment of the goodwill originally recognized on the purchase of EPLP and (ii) an impairment of EPLP's investment in PERH. The income statements have been adjusted to reflect the Reorganization as if it had occurred on January 1, 2008 which results in the assets and liabilities being recorded at fair value as at that date for the 27% acquired by Capital Power, thereby eliminating an impairment expense in 2008 related to that portion. Due to the non-controlling interest, 91.9% of the EPLP assets and liabilities continue to be the carrying amount and only 8.1% of the impairment of PERH was reversed.

(c) Reduction of interest expense: The decrease in long-term debt, as described in note 2(d), results in lower interest expense.

(d) Incremental costs associated with the creation of a new public entity: Represents estimated incremental costs for financial reporting and compliance, corporate governance, legal, treasury, investor relations activities and professional fees to external service providers.

(e) Changes to income tax provision: Represents the change to income tax expense as a result of the other pro forma adjustments.

(f) EPCOR's non-controlling interest: Represents the proportion of income and pro forma adjustments that relate to EPCOR's non-controlling interest.

Unaudited Other Financial Information

The table below presents net income for the year ended December 31, 2008 and for the three months ended March 31, 2009 and net income net of certain items for the corresponding periods, adjusted to reflect the pro forma adjustments discussed above giving effect to the completion of the Offering and the Reorganization.

The adjustments to net income net of certain items in the table below are meant to show the impact of certain items that management believes are not in the normal course of operations or that are unrealized fair value changes in derivative instruments and natural gas inventory held for sale for the reporting periods indicated and are more fully described under "Management's Discussion and Analysis of Financial Condition and Results of Operations — Results of operations — non-GAAP financial measures". The effect of a change in a particular variable on the impact of certain items on net income is calculated without considering interrelationships between the various market related variables or mitigating actions that would be taken by the Company.

EPCOR has advised the Company that it may eventually sell all or a substantial number of the Common Shares underlying its Exchangeable LP Units. The pro forma adjustments below are designed to reflect Capital Power's ownership structure assuming EPCOR had sold its ownership interest. Accordingly, the data in the following table have been presented on the basis that the results of Capital Power LP are consolidated with the Company, and therefore excludes any non-controlling interest in Capital Power LP.

The information set out in the table below does not purport to be indicative of actual results for any future period or to be an alternative to net income.

	Three months ended March 31, 2009	Year ended December 31, 2008
	($ millions)	
Net income	$ 54	$ 4
Gain on sale of Battle River PPA and related transactions[1]	(26)	(30)
Gain on sale of venture capital investments[2]	—	(11)
Unrealized fair value changes in derivative instruments and natural gas inventory held for trading, including the Company's 30% interest in EPLP[3]	(11)	33
Impairments, including the Company's 30% interest in EPLP[4]	—	35
Estimated impact of Genesee 3 planned and unplanned plant outages[5]	—	24
Estimated impact of Genesee 1 and 2 plant outages adjusted to historical experience[6]	—	24
Net income, net of certain items[7]	17	79
Pro forma adjustments[8]:		
Operations, maintenance and administration	(1)	(4)
Depreciation, amortization and asset retirement accretion	(1)	(4)
Net financing expenses	29	116
Income taxes	(8)	(31)
	19	77
	$ 36	$156

(1) Reflects the after-tax gains on the sale of 10% of the Company's interest in the Battle River PPA to ENMAX on January 15, 2009 and January 15, 2008. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Significant events — Sale of percentage interest in PPA", "— Comparison of annual results — 2008 versus 2007 — Other portfolio activities", "— Results of operations — non-GAAP financial measures", and "— Outlook".

(2) Reflects the sale of certain venture capital portfolio investments focused on strategic elements of the energy value chain. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Results of operations — non-GAAP financial measures".

(3) For the three months ended March 31, 2009, reflects the impact of a net short position arising from financial electricity contracts that were not designated as hedges for accounting purposes combined with a decrease in forward Alberta power prices which increased the fair value of the financial derivatives, and a decrease in the fair value of EPLP's natural gas supply contracts due to a decrease in forward natural gas prices. For the year ended December 31, 2008, reflects a weakening of the Canadian dollar relative to the U.S. dollar on EPLP's forward foreign exchange contracts used to economically hedge U.S. denominated revenues, as well as the impact of a net short position arising from financial electricity contracts that were not designated as hedges for accounting purposes combined with an increase in forward Alberta power prices, which reduced the fair value of the financial derivatives. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Comparison of results — Three months ended March 31, 2009 versus March 31, 2008", "— Comparison of annual results — 2008 versus 2007 — Unrealized fair value changes in derivative instruments and natural gas inventory held for trading" and "— Results of operations — non-GAAP financial measures".

(4) Reflects an impairment loss recognized in net income as a result of a write down in goodwill. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Significant events — Goodwill impairment", "— Consolidated other expenses — Impairment" and "— Results of operations — non-GAAP financial measures".

(5) Reflects management's estimate of the impact of an unplanned outage at the Company's Genesee 3 facility in the fourth quarter of 2008 due to a turbine rotor blade failure which kept the unit offline for 39 days, being the longest unplanned outage at a Genesee facility since 1994 and management's estimate of the impact of a planned outage at the Company's Genesee 3 facility in 2008 required to accommodate the upgrades by AESO of high voltage transmission lines in the Genesee and Keephills area in excess of normal course of operations. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Significant events — Genesee 3 turbine failure" and "— Other Genesee plant outages", "— Results of operations — non-GAAP financial measures" and "— Outlook".

(6) Reflects management's estimate of the impact of planned outages at the Company's Genesee 1 and 2 facilities in 2008 required to accommodate the upgrades by AESO of the high-voltage transmission lines in the Genesee and Keephills area in excess of normal course of operations. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Significant events — Other Genesee plant outages", "— Results of operations — non-GAAP financial measures" and "— Outlook".

(7) See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Results of operations — non-GAAP financial measures.

(8) See "— Unaudited Pro Forma Consolidated Financial Information".

POWER INDUSTRY OVERVIEW

Capital Power owns and/or operates a portfolio of power generation facilities that spans various markets in Canada and the U.S. and that offers growth, with a focus on areas where it expects to be able to effectively compete both against incumbents and other developers. The following section provides a brief overview of the power industry in those jurisdictions in which the Company currently has significant operations.

Canada

Supply and demand in Canada's power generation markets are largely segmented along provincial lines principally due to limited interconnection capacity between provinces. Consequently, each province has a unique power industry structure that features varying availability of resources, demand, energy policies, and regulatory bodies. Over time, this variance between markets has resulted in differing power generation development and procurement regimes. With the exception of Alberta, Canada's only fully competitive power generation market, the provincial power markets are still largely price regulated by provincial power authorities. See "Regulatory Overview". The current economic downturn is expected to result in a near term slow-down in demand growth for electricity.

The main national institutions that forecast and monitor Canada's energy markets are the CEA, the NEB and NRCan. Although Canada is currently a net exporter of electricity, all three institutions anticipate that there will be a significant need for new generation over the next two decades.[(1)(2)(3)] This represents a significant growth opportunity for independent power producers ("IPPs") with the capabilities to expand to meet such growing demand. According to Environment Canada, on a national basis, electricity demand will grow at a compound annual rate of 1.5% between 2005 and 2020.[(1)] Furthermore, the CEA expects 20% of the capacity in operation in 2000 to be retired by 2020.[(1)] The combined effect of demand growth and the retiring of aging facilities is expected to result in a significant need for additional capacity in the coming years. The CEA estimates that, commencing in 2006, an additional 60 GW of capacity[(1)] (of an expected total capacity of 131 GW)[(2)] will be necessary by 2020. Based on Environment Canada estimates, in order to keep pace with such demand growth, approximately $150 billion will need to be invested[(5)] in new power generation facilities from 2005 to 2025, much of this investment provided by the private sector.[(1)(2)]

Given Canada's diverse economy, natural resources and geographic make up, power generation portfolio mixes and market characteristics vary widely between regions. British Columbia, Manitoba, Quebec and Newfoundland primarily depend upon hydro power, whereas Alberta, Saskatchewan and Nova Scotia primarily depend upon coal power generation. Ontario, New Brunswick and Prince Edward Island use a mix of nuclear, coal and hydro, with Ontario attempting to further diversify as it retires and refurbishes a significant portion of its fleet in the coming years.

According to NRCan, Canada's power generation portfolio mix will shift towards cleaner generation sources[(4)] in response to increasing GHG emission costs and government clean power initiatives.[(2)] See "Environmental Regulation and Initiatives — Regulation". Given the limitations of economic scalability inherent in many renewable energy alternatives, and the significant requirement for new power generation in Canada, in the near to medium term, the Company expects that much of this new demand will be met by clean fossil fuel alternatives like cleaner coal technologies (such as IGCC or amine scrubbing combined with carbon sequestration and storage) and natural gas.[(6)] The forecasted shift in Canada's power generation portfolio can be seen in the following charts.

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(1) CEA's Power Generation in Canada: A Guide (2006)

(2) NRCan Canada's Energy Outlook Reference Case 2006

(3) National Energy Board (www.neb.gc.ca/Home›Pricing›Crude Oil and Petroleum Products›The Canadian Industry)

(4) Turning the Corner: Canada's energy and GHG Emissions Projections Reference Case: 2006-2020

(5) More Energy with Less Greenhouse Gas. Speaking notes for Stéphane Dion, then Minister of the Environment June 26, 2005

(6) NRCan Canada's Clean Coal Technology Roadmap

Electricity Generation Capacity in Canada — Projected Shift in Portfolio from 2005 - 2020

Source: NRCan

While power generation supply and demand are expected to continue to be driven at the provincial level, several federal initiatives have had a significant impact on new generation. For example, the federal ecoEnergy Renewable Power Program has committed to invest $1.48 billion on projects that are commissioned between April 1, 2007 and March 31, 2011 (although it is expected that the initial funding for the mandate will be fully allocated by the end of 2009) by providing incentives of $10/MWh for qualified renewable generation projects for up to a 10 year term, including wind, solar, and low-impact hydro. See "Environmental Regulation and Initiatives — Regulation — Canadian Federal Government — ecoEnergy for Renewable Power Program".

Furthermore, federally mandated GHG emissions standards are expected to indirectly affect the type of generation that is developed to meet future power needs, with future legislation mandating significant GHG emission reductions by specific target dates by various industrial sectors. See "Environmental Regulation and Initiatives — Regulation — Canadian Federal Government — Regulation of GHG Emissions and Air Pollution". As part of this platform, high intensity emitters such as coal plants may incur significant additional costs through measures that are yet to be introduced, but may include a cap and trade system.(1) A cap and trade system would be expected to involve limits on emissions and the issuance of allowances representing the right to emit certain amounts of GHG. The allowances could be traded by emitters whose emissions were less than their permitted limits to those that exceeded their respective limits. If a cap and trade system is adopted, it is unclear if such allowances would be allocated without cost, if they would be sold or auctioned or if it would be a combination of the two approaches.

However, despite the increased emphasis on GHG reduction, given the scalability limitations of renewable energy alternatives such as wind, GHG reduction initiatives for the foreseeable future are expected to focus increasingly on the development of cleaner fossil fuel power technology development such as CO_2 sequestration, supercritical coal and natural gas cogeneration.

Alberta

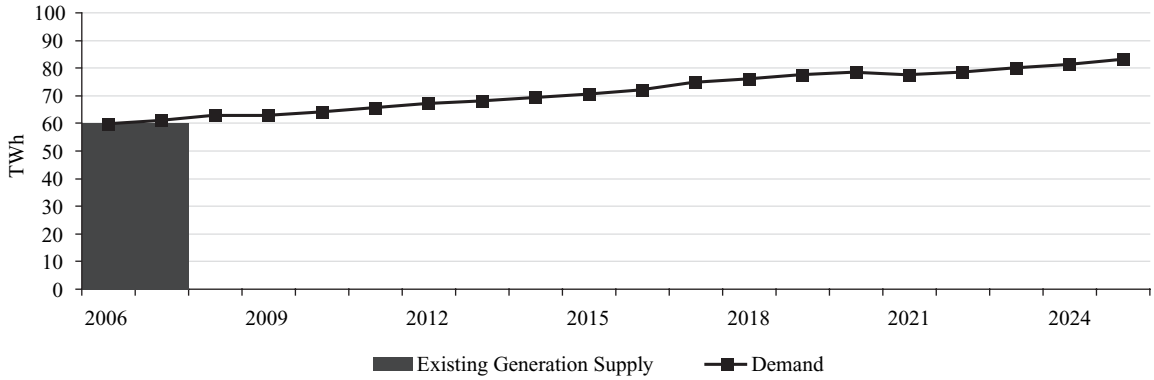
Alberta is Canada's fourth most populous province and home to the country's third largest economy with a gross domestic product ("GDP") of $259 billion in 2007. According to NRCan, Alberta is expected to be Canada's second fastest growing provincial economy (only behind Ontario) over the long-term with its GDP forecast to grow at an annual average rate of 2.7% from 2005 through to 2020.(2) Consequently, demand growth is expected to remain robust in the near and intermediate term with a 6% increase in capacity necessary to meet demand.(3) The following chart illustrates the projected growth in demand in Alberta.

(1) Government of Canada, Canada's Clean Air and Climate Change Act

(2) NRCan Canada's Energy Outlook Reference Case 2006

(3) NRCan and AESO's *20 Year Outlook* Document (2005-2024)

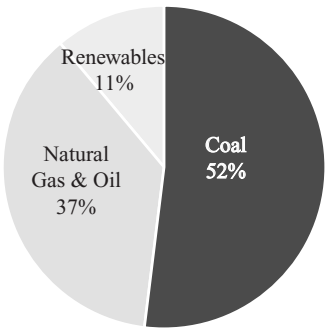
Alberta Power Supply and Demand Growth



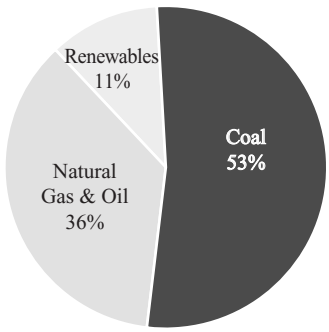
Source: AESO. Note that AESO does not project power generation supply growth

Electricity Generation Capacity in Alberta — Projected Shift in Portfolio from 2005 to 2020

2005



Projected for December 31, 2020



Sources: NRCan

Alberta's incremental new capacity is expected to primarily be in the form of clean power projects,[1] as the cost of GHG emissions improves the relative economics of cleaner power. See "Environmental Regulation and Initiatives — Regulation — Alberta". While Alberta has an abundance of wind resources, the provincial transmission system's inability to handle large amounts of new wind capacity serves as an obstacle to developing incremental wind capacity. In 2006, AESO, in response to potential grid instability, placed a cap of 900 MW on new wind generation just as some 11,000 MW of new projects were proposed by IPPs. While the cap was removed in 2007, the development of new wind capacity is still impacted by the availability of transmission infrastructure. As a result, it is expected that the primary contributor to new generation in Alberta will be natural gas plants and clean coal technologies.[1]

Ontario

Ontario is Canada's most populous province and the country's largest economy with a population of 13.0 million and a GDP of $584 billion in 2007. According to NRCan, Ontario is expected to be Canada's fastest growing provincial economy over the long-term with its GDP forecast to grow at an annual average of 2.8% from 2005 through to 2020.[2] The resulting demand growth is expected to be accompanied by a dramatic decrease in supply resulting from the Government of Ontario's planned retirements of several coal plants, and resulting from aging nuclear plants with an aggregate generating capacity of approximately 18,000 MW. According to the

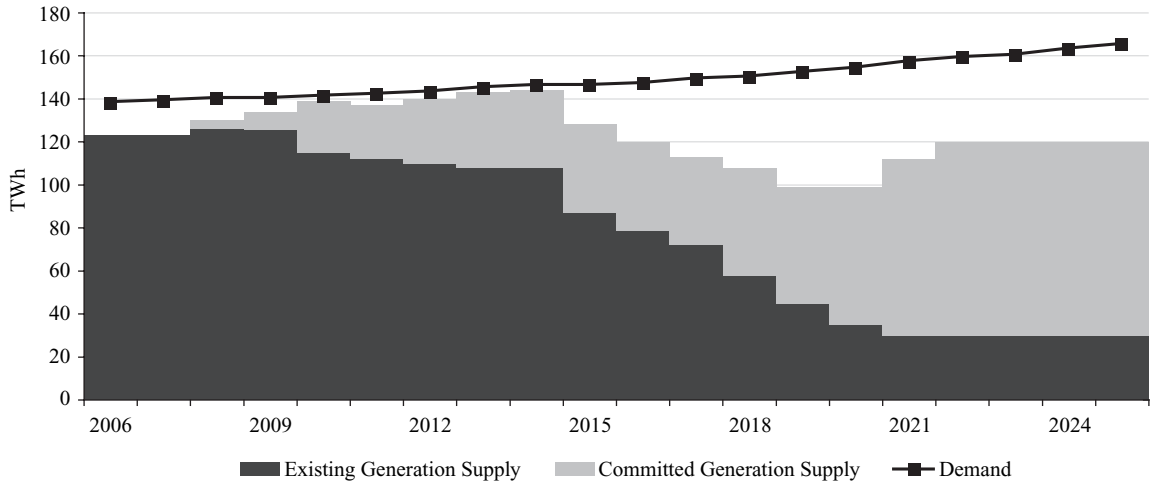
(1) AESO's 20 Year Outlook (2005-2024)

(2) NRCan Canada's Energy Outlook Reference Case 2006

OPA, the combination of demand increasing 20% and supply decreasing 60% over the next 20 years is expected to leave Ontario with a need for 24,000 MW of new generation.[1]

The following chart illustrates the OPA's projected growth in demand and supply (existing and committed) in Ontario. Additional capacity is forecast such that total capacity is expected to grow approximately 12% by 2020.[2]

Ontario Power Supply and Demand Growth

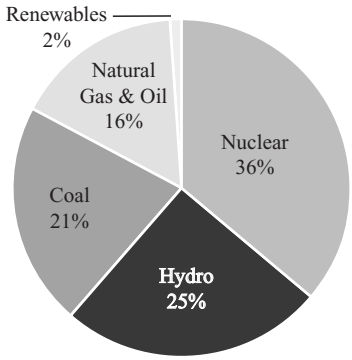


Source: OPA

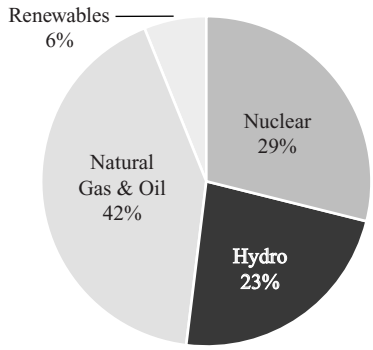
While the OPA expects that nuclear power will continue to be a major component of Ontario's generation mix, reduced dependence on coal power generation is expected to be met largely by new natural gas generation.[3] The expected shift in power generation portfolio can be seen in the following charts.

Electricity Generation Capacity in Ontario — Projected Shift in Portfolio from 2005 to 2020

2007



Projected for December 31, 2020



Sources: OPA and NRCan

It is the OPA's responsibility to award PPAs to both IPPs and to Ontario's generation Crown corporation, Ontario Power Generation Inc. (see "Regulatory Overview — Ontario") primarily through RFPs as part of the

(1) OPA, *Supply Mix Analysis Report* — December 9, 2005

(2) NRCan Canada's Energy Outlook Reference Case 2006

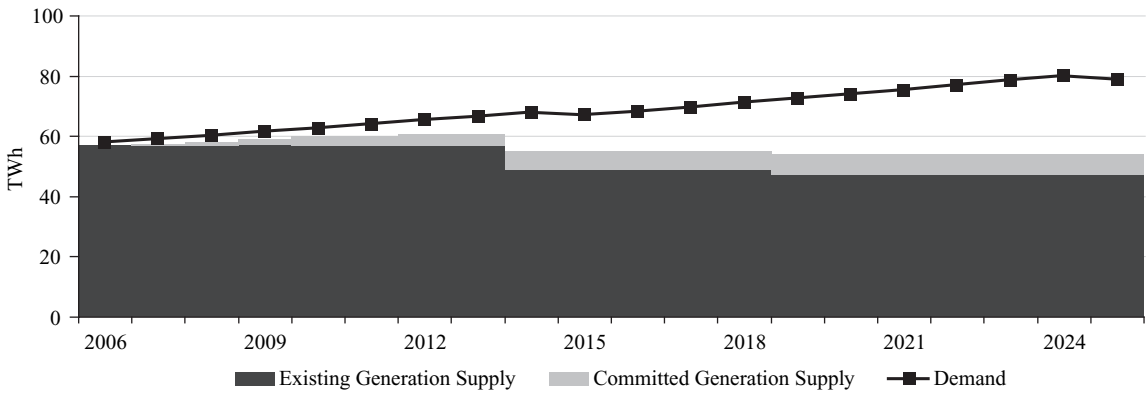
(3) OPA, The Integrated Power System Plan for the Period 2008-2027

OPA's procurement process for future power resources. As of September 2008, the OPA had 11,290 MW of electricity supply under contract with IPPs with more recent targets to award PPAs to cleaner power projects, primarily natural gas, and to a lesser extent, wind and solar. One of the Schedules to the GEA provides for the necessary amendments to the *Electricity Act, 1998* to permit Ontario's Minister of Energy and Infrastructure to direct the OPA to develop a FIT program to promote a more open and secure environment in Ontario, for the procurement of renewable energy projects, such as wind and solar power. On May 14, 2009, the Ontario legislature passed the GEA, however the section providing for the development of a FIT program has not yet come into force. On March 13, 2009, the OPA issued its draft Program Rules and Price Schedule for FIT. Assuming that the FIT program is implemented, it is expected that the FIT program will provide standard program rules, contracts and pricing for classes of renewable energy projects; and prices will be differentiated by energy source, generator capacity, and the manner by which the generation facility is used, deployed, installed and located.

British Columbia

British Columbia is Canada's third most populous province and fourth largest economy with GDP of $192 billion in 2007. NRCan expects British Columbia's GDP to steadily grow at a compound annual growth rate of 2.2% until 2020 and expects power demand to grow at an average of 1.9% per year between 2005 and 2020.(1) According to BC Hydro, a combination of demand growth and retiring of aging facilities is forecast to leave British Columbia with a need for a 9% increase in capacity between 2009 and 2020, from 11,300 MW to 12,300 MW.(2) BC Hydro is a Crown corporation and public utility regulated by the BC Utilities Commission, and is required to file long-term planning documentation with the BC Utilities Commission. The following chart illustrates BC Hydro's projected growth in supply and demand in British Columbia.

British Columbia Power Supply and Demand Growth



Source: BC Hydro

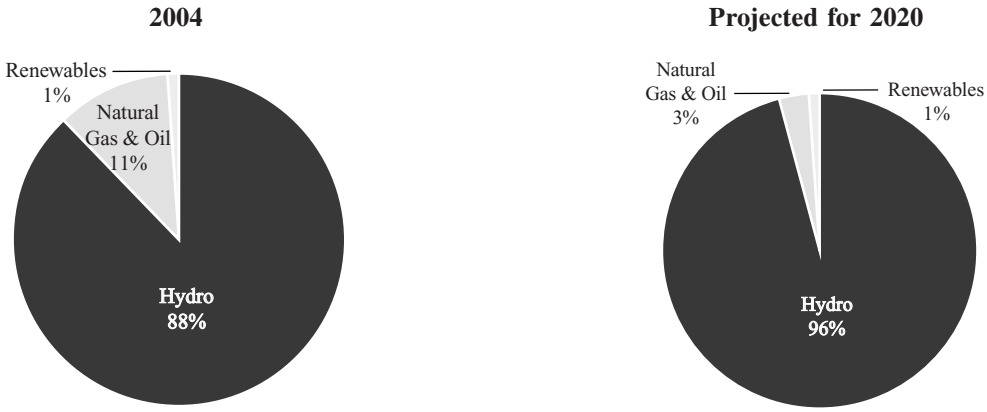
While BC Hydro forecasts hydro power generation to continue to be the major contributor to British Columbia's generation portfolio, the relative dependence on natural gas power generation (primarily used for peaking power) is expected to decline.(3) The expected shift in power generation portfolio can be seen in the following charts.

(1) NRCan Canada's Energy Outlook Reference Case 2006

(2) BC Hydro's 2008 Long Term Acquisition Plan

(3) BC Hydro's Lighting the Way for Generations (2008)

Electricity Generation Capacity in British Columbia — Projected Shift in Portfolio from 2004 to 2020



Source: NRCan

BC Hydro accounts for about 85% of British Columbia's generating capacity and it utilizes available hydro storage facilities to its commercial advantage by importing electricity from the U.S. and Alberta when prices are low, and exporting when market prices are high. As recently as 2004, British Columbia was a net exporter of electricity (primarily to California, Washington State and, to a lesser extent, Alberta). Currently, however, British Columbia is a net importer of power, importing as much as 15% of its demand with expectations[(1)] to increase imports in the near term. Much of these imports come from coal-fired plants in Alberta, a practice in direct opposition to the province's desire to decrease dependence on fossil fuels. As a result, in 2007, the British Columbia provincial government announced the B.C. Energy Plan, which stipulates that 90% of British Columbia's energy must come from renewable sources and that the province must be energy self-sufficient by 2016. See "Regulatory Overview — British Columbia". Part of the reason for the shortfall is that, while British Columbia has historically enjoyed a strong and growing economy, only one major project with 305 MW of incremental capacity has been added since 1984.

BC Hydro determines its power generation development strategy with the stated goal of achieving the portfolio mix targets set forth in the B.C. Energy Plan. Although there has been, and continues to be, a growing requirement for new generation, very little capacity has been built in the last 20 years. In recognition of the province's supply shortage, in 2003, the British Columbia Government fostered the development of new generation sources by IPPs by directing BC Hydro to purchase some electricity supply from IPPs. As a result, BC Hydro issued competitive bidding "open calls" for electricity supply in 2003 and 2005. Most recently, BC Hydro held another open call for power, referred to as the "Clean Power Call", which closed for proposals in late November 2008 and is expected to have EPA results announced in June 2009. In addition, during 2008, BC Hydro developed a "Standing Offer Program" calling for projects of fewer than 10 MW to apply for a PPA. A related call for power, the "Bioenergy Call for Power", released its Phase I RFP in February 2008 and was aimed at utilizing wood waste, roadside logging debris and, in particular, trees that have been affected by the pine beetle infestation. The results of the Phase I Bioenergy Call for Power were released on December 8, 2008 with BC Hydro announcing four successful proposals. BC Hydro expects to conduct a Phase II of the Bioenergy Call for Power during 2009.

(1) BC Hydro's 2008 Long Term Acquisition Plan

United States

Fundamentals for the U.S. non-utility generation industry are expected to track long-term GDP growth. Continued declines in the U.S. economy will likely result in a slow-down in demand growth. As the economy recovers and U.S. energy demand grows, however, significant investments in energy will be necessary to meet these emerging needs. The EIA, the statistical agency of the U.S. Department of Energy, expects aggregate electricity consumption in the U.S. to grow at a compound annual rate of about 1.0%.[(1)] The North American Electric Reliability Corporation ("NERC"), a self-regulatory organization dedicated to ensuring the reliability of the bulk power system in North America, suggests a 1.8% growth in peak demand in the U.S. from 2008-2017.[(2)] In either of these scenarios, between 10,000 MW and 18,000 MW per year of net new capacity would be needed to meet demand, not including the additional capacity that would be needed to replace plants that are retired during that period. Even with current economic conditions, a 1% to 1.8% long-term growth in demand would be historically low. Specifically, since 1990, the compound annual growth rate of the U.S. peak demand has averaged over 2.0% across both shorter- and longer-term time periods.[(2)] While overall electricity demand has slowed significantly during the current economic downturn, demand growth, coupled with the challenges to increasing supply, are likely to lead to continued tightening of reserve margins.[(2)]

The U.S. fuel mix by energy production consists of approximately 49% coal, 21% natural gas, 20% nuclear and 10% of other resources. Due to the relatively inexpensive nature of coal, consumption of power from coal-fired plants is projected to increase in the decades to come and will continue to be the single largest source of generation in the next two decades.[(1)] Energy production from renewable resources, while smaller in absolute terms, is expected to increase dramatically in light of new legislation and an expected shift towards cleaner technologies.[(1)] See "Regulatory Overview — United States".

CERA, a leading advisor to international energy companies, has predicted that across the U.S., 2009 annual energy consumption will decline from 2008 levels before recovering in early 2010.[(3)] Wholesale spot power prices are also expected to be lower as a result of the sharp decline in power prices from 2008 levels.[(3)]

In its 2009 Electricity Supply and Demand report, NERC indicated that the industry is working off excess capacity with U.S. average reserve margins (the amount by which power generation capacity exceeds peak demand) continuing to decline from 2004 peak levels. Given the recent market turmoil, however, while capacity is expected to be adequate to meet demand in the near-term, the long-term outlook suggests that more capacity will be needed as growth in demand is expected to surpass growth in supply.

With respect to generation supply, there are challenges related to construction and expansion. Factors such as increasing construction costs and regulatory uncertainty, mixed with more recent market concerns surrounding difficult credit markets, exacerbate the difficulties in construction of new generation facilities.

Environmental considerations also continue to influence generation choices. See "Environmental Regulation and Initiatives — Regulation — United States".

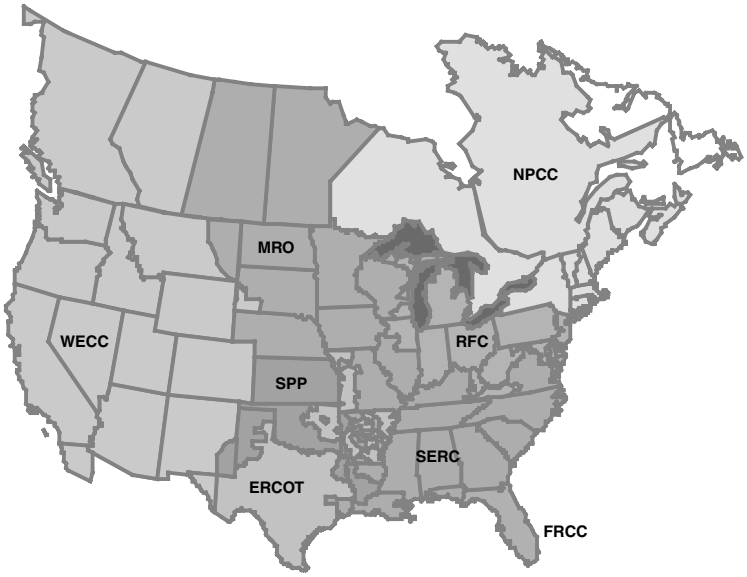
Electric reliability, as evaluated by NERC, is based on eight regional areas as shown on the map below. Within the majority of these regions, multiple subregions exist. Because of the geographic and regulatory differences of the various regions and subregions, it is difficult to evaluate the U.S. on anything but a regional basis as each region has unique transmission, distribution, and regulatory issues, among other distinguishing features. The regional discussions to follow detail the U.S. portion of regions and subregions which Capital Power intends to focus on in the near- and medium-terms. See "Business — Corporate Strategy — Regional footprint".

(1) EIA's Annual Energy Outlook 2009, dated March 31, 2009

(2) NERC's Electricity Supply &Demand Report, dated January 21, 2009

(3) CERA's US Power Market Fundamentals, dated January 19, 2009

NERC Map — North American Power Markets



Source: NERC's 2008 Long-Term Reliability Assessment dated March 26, 2009

WECC

The Western Electricity Coordinating Council ("WECC") region is the largest geographic electric reliability region in the U.S., covering approximately 1.8 million square miles in 14 Western states, Western Canada and Northern Mexico. WECC is comprised of four sub-regions, including (i) California-Northern Baja; (ii) Desert Southwest; (iii) Rocky Mountains; and (iv) Northwest Power Pool. A further description of California-Northern Baja and Desert Southwest is provided below.

California-Northern Baja

California is the world's sixth largest economy and one of the largest electricity markets in the U.S. The California market is a net importer of electricity from its surrounding regions and typically reaches peak levels of demand in the summer months. The California Independent System Operator power market recently adopted a nodal-based congestion management system based on locational prices that is very similar to the other regions such as the PJM Interconnection, ISO New England and the New York Independent System Operator. While much of the U.S. is still working off excess capacity, California is not experiencing overbuild to the same extent. Consequently, California power producers are expected to benefit from a favourable supply-demand balance.

California's electricity markets have historically been dominated by vertically integrated regulated utilities. During the late 1990s, California began implementation of a new wholesale power market and retail customer choice program, paving the way for non-vertically integrated IPPs to play a more dominant role in the market. Shortly thereafter, in mid-2000, retail electricity prices in California achieved all-time highs due to generation capacity shortages, flaws in the market design then in effect, and the financial instability/bankruptcy of major investor-owned utilities. This period, often referred to as the "California Energy Crisis", lead to a partial return to the vertically integrated business model with the utilities satisfying their own generation needs.

Steady demand growth in the California market is gradually reducing the state's reserve margin as the region's surplus generation capacity decreases and the state's current electricity supply fails to keep pace with demand. Construction of new power plants has lagged and the number of new plants applying for permits has also decreased. New construction has consisted predominantly of combined-cycle natural gas-fired plants which have less flexibility to meet peak demand than simple-cycle or conventional steam facilities. Due to the scarcity of new facilities well-adapted to California's load, the state's aging plants continue to operate despite their relatively high heat rates. California receives a majority of its power from natural gas-fired facilities. With planned capacity additions forecast to be largely combined-cycle gas units, natural gas is expected to play a

pivotal role in setting wholesale power prices in WECC.[1] Changes in the price of natural gas will have a large impact on power prices within this region.

Desert Southwest

The Desert Southwest consists of the states of Arizona, New Mexico, and South Nevada. Within the U.S. portion of WECC, the Desert Southwest is expected to face the most dramatic tightening of supply-demand balance.[1] The marked change in the region's market balance will be the result of rapid demand growth and higher commitments to export electricity to California. As a result, excess supply is quickly disappearing and the need for additional capacity is significant.

NPCC

The Northeast Power Coordinating Council (the "NPCC") has a large and diverse footprint spanning seven U.S. States and includes market operators such as the New York Independent System Operator and ISO New England. The NPCC continues to serve as the blueprint for changes being considered and implemented in other portions of the U.S.

A combination of slowing demand growth, the expected addition of substantial amounts of new capacity, and an anticipated increase in imports is likely to keep NPCC power markets oversupplied through at least 2013.[1] Forward capacity auctions in New England have attracted capacity and demand resources. If these committed resources come online as planned, New England could be oversupplied for a number of years. In coming years, natural gas-fired generation will grow significantly with some support from increasing nuclear supply and wind generation.[1] In addition, downward pressure on spark spreads has been experienced in NPCC since early July 2008 as the impact of falling natural gas prices has been coupled with a lack of buying interest in the power markets.

New York Independent System Operator

The New York power market is one of five sub regions within the NPCC and covers the state of New York. When deregulation in New York occurred about a decade ago, the New York Independent System Operator was established to operate New York's bulk electricity grid, administer the state's wholesale electricity markets, and provide reliability planning.

Growth in energy consumption in New York is forecast to decrease slightly as a result of a weaker long-term economic outlook and new energy conservation initiatives.[1] Traditionally, the New York area generation mix has been dependent on fossil fuels for the largest portion of installed capacity. Recent capacity additions or enhancements, however, utilize natural gas as the primary fuel. The state's dependence on fossil fuels is shifting with the majority of planned additions consisting of combined-cycle natural gas-fired plants and the remaining in various renewable resources. Certain areas of New York State, including New York City and Long Island, are severely limited by transmission constraints, thus leading to prices being determined on a zone-by-zone basis and often leading to higher spark spreads relative to nearby regions.

ISO New England

Since 1999, ISO New England has operated wholesale electric power markets which they describe as some of the nation's most innovative. ISO New England trades both physically and financially, with pricing varying widely as a result of transmission constraints and capacity disparities in the region. ISO New England's generation is more heavily natural gas-based than the PJM Interconnection, but less so than the Electric Reliability Council of Texas.

RFC

Three former councils combined to form Reliability First Corp.: the East Central Area Reliability Council; the Mid-Atlantic Area Council; and the Mid-America Interconnected Network. Reliability First Corp., after being approved as the regional council by NERC, began operation on January 1, 2006. The new region spans an area from the Mid-Atlantic across the Midwest, including parts of Wisconsin and Illinois. Reliability First Corp.

(1) NERC's 2008 Long-Term Reliability Assessment

serves part of the territory of two Regional Transmission Organizations, the PJM Interconnection and Midwest Independent Transmission System Operator.

PJM Interconnection

The PJM Interconnection is the most mature U.S. power market and traditionally the most liquid. PJM Interconnection Western Hub is one of the most transparent pricing locations in the U.S., and is often used as a benchmark for pricing in other markets. PJM Interconnection has a diverse generation fuel mix and thus is more insulated from changes in natural gas than other more natural gas-driven markets. Forward capacity auctions suggest that PJM Interconnection is likely to be oversupplied in coming years.

SERC

The SERC Reliability Corporation ("SERC") is the regional reliability organization for 16 central and Southeastern states. SERC is divided into five sub-regions: Central, Delta, Gateway, Southeastern, and the Virginia-Carolinas, supplying power to nearly a quarter of the U.S. electric customers. Most electric utilities within SERC are vertically integrated. SERC does not suffer from the same transmission constraints that many other regions within the U.S. have and enjoys extensive transmission interconnections between its sub-regions and neighbouring regions including MRO, RFC and SPP.

Parts of SERC did, however, go through a period with significant development in generation facilities which led to severe overbuild. The region is currently working off this excess capacity as demand is projected to steadily increase over the long-term.(1) Generation with coal and nuclear fuels continues to lead the region's fuel mix, accounting for just above half of net operable capacity in 2008.

The Virginia-Carolinas subregion within SERC is the least overbuilt within SERC. Load growth is expected to necessitate construction of new generation facilities.(1) Over 90% of the Virginia-Carolinas' generating capacity is from coal and nuclear generation, reflecting the Virginia-Carolinas' reliance on baseload facilities. Planned additions are a mix of baseload coal facilities and combined-cycle natural gas-fired plants, as those will offer much needed operational flexibility.

REGULATORY OVERVIEW

Set forth below is an overview of the principal electrical power regulatory regimes to which the Company's operations are subject. Environmental regulations affecting the Company's operations are discussed under "Environmental Regulation and Initiatives".

Alberta

Commencing January 1, 1996, the Government of Alberta, through the *Electric Utilities Act* (Alberta) took significant steps toward deregulation of the power industry in Alberta. Under the *Electric Utilities Act* (Alberta), the power pool, a competitive spot market for power generation, was created and access to the provincial transmission grid was opened to allow all eligible persons access to trade energy through the power pool. The *Electric Utilities Act* (Alberta), and subsequent updates and legislation, established the basic features of the Alberta market as follows:

- Since January 1, 1996, new generating capacity initiatives in Alberta have been undertaken by IPPs (including municipally owned entities) and have been subject to market forces, rather than rate regulation.
- Regulated generating units, including those owned and operated by the Company, became subject to PPAs that were auctioned by the Alberta Government to buyers in 2000. The Balancing Pool also assumed the responsibilities of "PPA Buyer" for those generating units that were subject to a PPA but were not acquired in the initial 2000 auction.
- Power from both PPA generating units and commercial generation is cleared through a power pool. Power is dispatched in accordance with an economic merit order determined by the power pool operator

(1) NERC's 2008 Long-Term Reliability Assessment

based upon offers by generators to sell power. All energy traded through the power pool is financially settled each hour at a single spot market price.

- Under the *Electric Utilities Act*, municipalities and their subsidiaries must generally meet certain "level playing field" rules in order to hold a direct or indirect interest in a power generation unit. On this basis, pursuant to the *Electric Utilities Act*, EPCOR requires an authorization from the Alberta Minister of Energy, who must be satisfied that the structure prevents any tax advantage, subsidy, or financing advantage or any other direct or indirect benefit as a result of the generating unit's association with EPCOR. EPCOR currently has the necessary authorization from the Minister for all of the Alberta power generation units being transferred to Capital Power LP in the Reorganization and intends to provide the Minister with notice of the Reorganization. As Capital Power is not, and will not be, a subsidiary of The City of Edmonton, it does not require a similar authorization.
- In 2003, the power pool and transmission administrator were merged into a single entity, the independent system operator, being AESO.
- Also in 2003, the Market Surveillance Administrator was established as an independent entity responsible for monitoring the market behaviour and conduct of market participants, including AESO and the Balancing Pool, which seeks compliance with all applicable legislation, regulations, market rules and/or guidelines.

Ontario

Market Design

The wholesale and retail electricity markets in Ontario were opened to competition on May 1, 2002, following a period of legislative and regulatory changes, beginning in 1998, to restructure the industry in preparation for competition. Changes included breaking up the incumbent electricity monopoly, Ontario Hydro, into five successor entities and changing the status of municipal distribution utilities from entities created by statute to companies under the *Business Corporations Act* (Ontario) owned by the municipalities. This latter change also resulted in a reduction in the number of municipal distribution utilities from approximately 300 to 95 due to mergers, amalgamations and sales. However, generation outages, along with above-normal temperatures during the summer of 2002, resulted in volatility and high prices. To mitigate the effects of high prices, price caps were implemented for small consumers, which has had the effect of deterring investment in new facilities. In December 2004, *An Act to amend the Electricity Act, 1998 and the Ontario Energy Board Act, 1998 and to make consequential amendments to other Acts* ("Bill 100") received Royal Assent. Bill 100 created the framework for broad regulatory reform of the energy sector in Ontario. The major components of Bill 100 included the restructuring of the Independent Market Operator to the Independent Electricity System Operator, the creation of the OPA, significant amendments to the *Ontario Energy Board Act, 1998* and the creation of a "hybrid" market requiring the regulation of certain Ontario Power Generation assets.

On May 14, 2009, the Ontario legislature passed the GEA, an Act aimed at encouraging renewable energy projects and energy conservation measures in Ontario. The GEA acts as a framework for the legislative amendments; the substantive aspects of the GEA are contained in 12 Schedules attached to the GEA. Schedule A to the GEA introduces a new *Green Energy Act, 2009*, and Schedules B to L amend a host of other Ontario statutes, including the *Electricity Act, 1998*, the *Planning Act* and the *Environmental Protection Act*. These more substantive aspects of the GEA, that are contained in the Schedules, will only become law on the date or dates that they are proclaimed into force. Implementation will also be delayed until such time as the necessary regulations (that are yet to be issued by the Ontario government), are passed. No proposed proclamation dates for the legislative changes contained in the Schedules have been publicly announced. One of the main objectives of the GEA is to facilitate and streamline the approval process for renewable energy projects. Toward that end, changes to Ontario's *Environmental Protection Act* and the Ontario *Water Resources Act*, under Schedules G and H, respectively, will, when proclaimed in force, exempt renewable energy projects from existing environmental approval and permitting requirements, and provide that such projects will instead be required to obtain a new comprehensive "renewable energy approval" from the Ontario Ministry of the Environment. Once the relevant legislative provisions come into force, it is expected that renewable energy permit approvals will be processed more efficiently than under the existing array of individual air, waste and water taking approvals.

Further, when Schedules A and K of the GEA come into force, renewable energy generation facilities and renewable energy projects will be exempted from existing by-law, zoning and other municipal requirements (including those under an official plan). The impact of these changes will be to reduce local municipal control over the approval process for qualifying renewable energy facilities and projects. Other Schedules to the GEA when implemented will give the Minister of Energy and Infrastructure the power to provide grants and loans to encourage energy conservation, renewable energy projects and to help establish a 'smart grid' in Ontario. Lastly, it is anticipated that the Ontario Ministry of the Environment will, in the future, issue standardized requirements for the location of wind turbines, that will apply province-wide and will replace the current situation where location is governed by municipal zoning requirements, unique to each municipality.

Ontario Power Authority

One of the key responsibilities of the OPA has been to develop the IPSP and procure power on a competitive basis. The proposed IPSP submitted to the Ontario Energy Board for review in 2007, and which has not yet been approved, represents the first long-term plan for Ontario's electrical system in more than a decade. It is a blueprint for the development of conservation, supply and transmission infrastructure over the next 20 years. Based on the work completed at the direction of the Ontario Minister of Energy, the IPSP incorporates the recommendations found in the OPA's Supply Mix Advice Report to the Minister (December 2005) and the formal response to the recommendations made by the Minister following public consultations with various stakeholders in June 2006. The key objectives of the IPSP are to: (i) reduce peak electricity demand by 6,300 MW by 2025 through conservation based programs; (ii) eliminate coal-fired generation capacity; (iii) replace or refurbish 10,000 MW of nuclear generation; (iv) increase the total capacity of renewable energy sources used in Ontario to 15,700 MW by 2025; and (v) install up to 12,000 MW of natural gas-fired generation by 2014. In September 2008, Ontario's Minister of Energy and Infrastructure directed the OPA to file a revised IPSP with the Ontario Energy Board by March 17, 2009. However, the OPA has previously announced that it will not be able to complete its revision of the IPSP until the summer of 2009, following final implementation of the GEA.

Given the Ontario government's commitments on renewable energy, conservation and coal plant phase-out (see also "Environmental Regulation and Initiatives — Regulation — Ontario"), the OPA has estimated that 80% of Ontario's current generating capacity will need to be replaced by 2028 with a combination of reduced demand and new or refurbished generating capacity.(1) The OPA also estimated that Ontario will need $60 billion in new investment over the next 20 years to meet its electricity needs; of this total, the OPA estimated that $46 billion will be required for new generation capacity, $10 billion will be needed to meet conservation targets, and $4 billion will be required for the new transmission infrastructure needed to link these elements.(2)

While the OPA is not a Crown corporation, it has a strong self standing credit rating (DBRS: AA(low); Moody's: Aa1) based on its legislated right to recover its costs from Ontario's energy consumers, providing a strong counterparty for prospective investors. It is expected that, through the objectives of the IPSP, the OPA will continue to provide significant opportunities for private sector companies to build new generation in Ontario. Since the initial two Ontario RESs RFPs and one clean energy RFP by the Ontario Ministry of Energy, the OPA has completed numerous power procurement initiatives which includes one combined heat and power procurement initiative, two sole source procurements for large natural gas facilities in Toronto and Brampton, an RFP for a large natural gas facility in the western Greater Toronto Area and one RFP for a peaking generation facility in Northern York Region. In addition, while a second combined heat and power RFP that concluded in April 2009 did not yield successful proponents, due in part, according to the OPA, to the current unfavourable economic climate for large scale cogeneration projects in Ontario, the OPA is currently soliciting proposals in a third combined heat and power procurement for cogeneration projects using renewable fuel. To date, the OPA has surpassed 11,000 MW of new contracted supply of all types of generation (renewable, natural gas and nuclear refurbishment). At this time, and in addition to the initiatives described above, the OPA has also initiated a procurement process for an additional 850 MW of natural gas-fired combined-cycle generation to be

(1) Speech by John Beck (Chairman, OPA) to the Ontario Energy Association entitled "Get Ready For Ontario's Surge", February 29, 2008

(2) Speech by Ian Carr (then President and CEO, OPA) to the Canadian Manufacturer's and Exporters Energy Forum, February 20, 2008

in service no later than the end of 2013 to serve the southwest Greater Toronto Area. Other RFPs are expected to occur for natural gas-fired generation out to 2015.

British Columbia

British Columbia's electricity is provided primarily by the Crown corporation BC Hydro, which in turn, is regulated by the British Columbia Utilities Commission. Electricity is transmitted throughout the province through British Columbia Transmission Corporation ("BCTC"), which is a separate Crown corporation. BCTC, also regulated by the British Columbia Utilities Commission, is responsible for the planning, management and operation of BC Hydro's transmission assets. Electricity is traded with other markets through BC Hydro's trading arm and wholly-owned subsidiary, Powerex.

While British Columbia is not a deregulated market like Alberta, the BC Government has taken steps since 2003 to diversify the market and to promote new generation by IPPs. In particular, BC Hydro was directed by the BC Government to acquire electricity supply on a competitive basis from IPPs thus resulting in the various open calls for power held over the last five years. See "Power Industry Overview — Canada — British Columbia".

As a result of BC Hydro effectively controlling the market (generation, distribution and trading activities), the opportunity for IPPs in British Columbia has been limited. IPPs can bid into RFPs from BC Hydro, which, if successful, result in long-term PPAs with BC Hydro.

On February 27, 2007, the Government of British Columbia released its most recent B.C. Energy Plan. The B.C. Energy Plan outlines various measures to address the challenge of global warming including that all electricity produced in British Columbia will be required to have zero net GHG emissions by 2016. They further announced in this B.C. Energy Plan that 90% of British Columbia's electricity will come from renewable resources and that British Columbia will require zero greenhouse gas emissions from any coal-fired electricity project. The B.C. Energy Plan places a great deal of responsibility on British Columbians to conserve energy. The target is to acquire 50% of the province's incremental resource needs through conservation by 2020. During 2008, various amendments were made to the *Utilities Commission Act* (British Columbia) to enable BC Hydro and BCTC to achieve some of the B.C. Energy Plan goals, including a requirement to commence, by no later than March 31, 2009, an inquiry to make determinations with respect to BC's infrastructure and capacity needs for electricity transmission.

In order to encourage greater development and use of wood-fired electricity in the Province, and to help address the effects of the mountain pine beetle infestation, BC Hydro released in March 2007 a Request for Expressions of Interest to assess and identify potential bioenergy projects and proponents for using residual wood, including sawmill residues, logging debris and a growing supply of timber killed by mountain pine beetle, for power production. Following a strong interest from the industry, BC Hydro designed a two phase power procurement process. Phase I focused on projects that were immediately viable. The successful proponents for Phase I were announced on December 8, 2008. The process for the Phase II of the Bioenergy Call has been planned for second and third quarters of 2009.

United States

U.S. Energy Industry Regulatory Matters

FERC Jurisdiction

Unless otherwise exempt, any person that owns or operates facilities used for the wholesale sale or transmission of electric energy in interstate commerce is a public utility subject to FERC's jurisdiction. FERC has extensive ratemaking jurisdiction and other authority with respect to interstate wholesale sales and transmission of electric energy under the FPA and with respect to certain interstate sales, transportation and storage of natural gas under the *U.S. Natural Gas Act of 1938*, as amended ("NGA") and the *U.S. Natural Gas Policy Act of 1978*, as amended ("NGPA"). FERC also maintains certain reporting requirements for public utilities and regulates, among other things, the disposition and acquisition of certain assets and securities, the holding of certain interlocking directorate positions, and the issuance of securities by public utilities.

Transmission Service

Issued in 1996, FERC Order No. 888 mandated the unbundling of utilities' transmission and generation services and required such utilities to offer eligible entities open access to utility transmission facilities on a basis comparable to the utilities' own use of the facilities. FERC Order No. 888 required public utility transmission owners to file open access transmission tariffs containing the terms and conditions under which they would offer transmission service, enabling independent generators and marketers to schedule and reserve capacity on those transmission facilities. In 2007, FERC Order No. 890 made a number of changes to open access implementation, including requiring an open, transparent and coordinated transmission planning process on both a local and regional basis.

In 1999, FERC issued Order No. 2000, which set out standards for Independent System Operators ("ISOs") and Regional Transmission Organizations ("RTOs"). These organizations are operated by an entity that is independent of market participants, and planning, operations, and transmission services are performed on a regional, instead of utility specific, basis. In addition, most ISOs and RTOs administer liquid day-ahead and real-time spot markets. Examples are PJM Interconnection, ISO New England, New York ISO, Midwest Independent Transmission System Operator and California Independent System Operator. In 2008, FERC Order No. 719 made incremental reforms to such markets, including requiring scarcity pricing to encourage demand response and other new resources.

Market-Based Rate Authority

Under the FPA and FERC's regulations (subject to certain exceptions for entities such as municipal utilities that are not public utilities under the FPA), an entity seeking to make wholesale sales of power at market-based or cost-based rates must obtain authorization from FERC. FERC grants market-based rate authorization if it finds that the seller and its affiliates lack market power in generation and transmission, that the seller and its affiliates cannot erect other barriers to market entry and the seller and its affiliates comply with certain affiliate restrictions. All of the Company's affiliates that own power plants in the U.S. (except for those power plants that are QFs), as well as the Company's power marketer affiliates, are currently authorized by FERC to make wholesale sales of power at market-based rates. This authorization is subject to revocation by FERC if such companies fail to continue to satisfy FERC's current or future criteria for market-based rate authority, or to modification if FERC restricts the ability of wholesale sellers of power to make sales at market-based rates.

Mergers and Acquisitions

FERC has FPA jurisdiction over certain sales, mergers, consolidations and acquisitions of public utility assets or securities, and over certain mergers and acquisitions involving holding companies and transmitting utilities or electric utility companies. In reviewing such matters, FERC reviews the effect of the transaction on competition, rates and regulation and ensures that there is no unlawful cross subsidization of affiliates by entities with captive customers.

Reliability Standards

Pursuant to the *U.S. Energy Policy Act of 2005*, FERC finalized in February 2006 new rules regarding the certification of an Electric Reliability Organization and the procedures for the establishment, approval and enforcement of mandatory electric reliability standards. In July 2006, FERC certified NERC as the Electric Reliability Organization to establish and enforce reliability standards applicable to all owners, operators and users of the bulk power system. NERC relies on regional reliability entities to enforce FERC and NERC standards with bulk power system owners, operators, and users through approved delegation agreements. Such regional entities are responsible for monitoring compliance of the registered entities within their regional boundaries, assuring mitigation of all violations of approved reliability standards and assessing penalties and sanctions for failure to comply.

FERC Enforcement Authority

FERC has the authority to enforce the statutes it is responsible for implementing and the regulations it issues under those statutes. The *U.S. Energy Policy Act of 2005* conferred substantial enforcement authority on FERC, allowing it to impose civil penalties of up to U.S.$1 million per day per violation for violations of the NGA, NGPA and Part II of the FPA. This expanded penalty authority also applies to any entity that manipulates wholesale natural gas or electric markets by engaging in fraud or deceit in connection with jurisdictional transactions. These laws also allow for the assessment of criminal fines and imprisonment for violations.

The Public Utility Regulatory Policies Act of 1978

The *Public Utility Regulatory Policies Act of 1978*, as amended ("PURPA") and FERC's regulations under PURPA provide certain incentives for the development of combined heat and power facilities and small power production facilities using alternative or renewable fuels, in part by establishing certain exemptions from the FPA and the U.S. *Public Utility Holding Company Act of 2005* for owners of QFs.

PURPA provides two primary benefits to QFs. First, all cogeneration facilities, geothermal and biomass small power production facilities, and small power production facilities 30 MW or smaller that are QFs are exempt from certain provisions of the FPA, the regulations of FERC thereunder and the *U.S. Public Utility Holding Company Act of 2005*. Second, the FERC regulations promulgated under PURPA require that electric utilities purchase electricity generated by QFs that are directly, or under certain circumstances indirectly, connected to such electric utilities at a price based on the purchasing utility's avoided cost and that such utilities sell back up power to such QFs on a non-discriminatory basis. An electric utility may be entitled to relief from these mandatory purchase and sale obligations if, in the case of the mandatory purchase obligation, the utility can show that the QF has non-discriminatory access to a market that meets certain competitive conditions and, in the case of the mandatory sale obligation, if the utility can show that that there are competing retail electric suppliers willing and able to sell and deliver electricity to the QF and there is no obligation under state law for the utility to make such power sales. The provisions for relief from the mandatory purchase and sale obligations do not affect contracts entered into or pending approval on or before August 8, 2005.

Under FERC's regulations, QFs are subject to FERC's rate making authority under the FPA and are required to obtain market-based rate authority in order to sell power at market-based rates, except for sales of energy or capacity (i) made by QFs that have a generating capacity of 20 MW or less, (ii) made pursuant to a contract executed on or before March 17, 2006, or (iii) made pursuant to state-approved avoided cost rates.

Public Utility Holding Company Act of 2005

In August 2005, the passage of U.S. *Energy Policy Act of 2005* repealed the *Public Utility Holding Company Act of 1935* and enacted the *U.S. Public Utility Holding Company Act of 2005*, effective February 2006, which primarily addresses FERC's access to the books and records of holding companies. Any entity that is a holding company solely with respect to QFs, exempt wholesale generators or foreign utility companies, such as the Company, is exempt from FERC's books and records requirements and any accounting, record-retention and reporting requirements contained in the U.S. *Public Utility Holding Company Act of 2005* and FERC's regulations promulgated thereunder.

ENVIRONMENTAL REGULATION AND INITIATIVES

This section provides an overview of the environmental regulations and related initiatives applicable to the Company and its operations.

Permitting, Engineering, Construction and Operation

The permitting, engineering, construction and operation of power projects are subject to extensive federal, provincial, state and municipal laws and regulations, and in many cases, result in a lengthy and complex process for obtaining licenses, permits and approvals, with sometimes uncertain outcomes. The Company must adhere to engineering, environmental, construction and operations codes and standards, local building codes, regulations

pertaining to the discharge of emissions into water and air, water use, waste disposal, noise regulations, protection of endangered species and land conservation.

Land-Use Policies

The construction and operation of power projects are subject to provincial, state and municipal land-use policies. Such policies include adherence to local and regional land-use plans and zoning by-laws. If a power project does not qualify as a permitted use under a local and/or regional land-use plan and/or zoning by-law, the developer must seek an exemption, amendment or other form of approval under a public process.

Regulation

The Company is subject to federal, provincial, state and local environmental laws, regulations and guidelines concerning its businesses. The Company complies with or surpasses regulatory requirements while reducing environmental impact. The Company also works with stakeholders with a view to protecting the environment and, at the same time, encouraging and sustaining economic development. Compliance with new regulatory requirements may require Capital Power to incur significant capital expenditures or additional operating expenses. See "Risk Factors — Risks Relating to the Company's Business — Environmental Regulatory Risk".

Canadian Federal Government

Regulation of GHG Emissions and Air Pollution

On April 29, 2009, the Canadian Environment Minister announced in a media interview that the Canadian Federal Government is planning new climate change regulations aimed at coal-fired power in Canada's electricity sector. The anticipated regulations were described as requiring all newly constructed coal generation plants to significantly reduce GHG emissions, which could include the use of technology to capture GHG and inject it underground for permanent storage. The Minister also stated that absolute emission caps on existing coal-fired generation plants are planned and that a market-based credit system would be established to permit such plants to purchase credits to enabled them to meet such emission limits. The limits would be designed to permit existing plants to operate until they reach the end of their useful, fully-amortized lives.

This announcement is expected to build on the proposed federal regulatory framework known as "Turning the Corner", which was proposed on April 26, 2007 and March 10, 2008 to reduce GHG emissions and air pollution, including CO_2, NO_x, and SO_2 emissions. The proposed framework recommended an 18% reduction in GHG emissions intensity starting in 2010 and increasing by 2% per year thereafter resulting in a 20% absolute reduction in GHG emissions from 2006 levels by 2020, and a 50% reduction in air pollution by 2015. Subsequently released government information indicates that some or all of these proposed compliance dates will be extended, starting in 2012 as opposed to 2010.

The Canadian Federal Government also indicated in late 2008 that it intends to work closely with the U.S. to establish a North American-wide GHG emission cap and trade system.

Federal Wind Power Production Incentive Program

The Wind Power Production Incentive Program is a Canadian Federal Government program that provides incentive payments to producers of wind energy. The 2001 federal budget provided an initial $260 million for the program, to be paid by way of a per kWh incentive to eligible wind energy projects commissioned between March 31, 2002 and April 1, 2007. The goals of this incentive were to stimulate the installation of 1,000 MW of wind power capacity and to encourage complementary provincial support for renewable power. The 2005 federal budget provided an additional $200 million over five years and a total of $920 million over 15 years to expand the Wind Power Production Incentive Program to 4,000 MW. This is equivalent to the amount of power needed by approximately one million average Canadian homes. Under the program, projects were eligible to receive an incentive payment of between $0.008 per KWh and $0.012 per kWh for the first 10 years of operation, depending upon the commissioning date. The Wind Power Production Incentive Program was replaced by the ecoEnergy

Renewable Power Program described below, but does not affect any existing entitlement of projects to receive the Wind Power Production Incentive Program.

ecoEnergy for Renewable Power Program

On January 19, 2007, the Canadian Federal Government announced the ecoEnergy Renewable Power Program. The objective of this $1.48 billion program (although it is expected that the initial funding for the mandate will be fully allocated by the end of 2009) is to encourage the development of clean power generation projects in Canada and to bring electricity prices from such projects more in line with those of conventional sources of electricity. An incentive of one cent per kWh for up to ten years will be offered to eligible projects commissioned within the four year program. The program is intended to support up to 4,000 MW of new renewable electricity capacity by 2011. The program is open to all low-impact renewable-energy technologies, including wind, small hydro, biomass, solar photovoltaic, geothermal, tidal and wave technologies that generate few or no harmful emissions.

Alberta

The Province of Alberta passed the *Climate Change and Emissions Management Act* in 2003. It includes a goal to reduce emissions intensity to at least 50% of 1990 levels by 2020. 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 ("CO2Es"), per year. The Alberta Government recognizes three mechanisms for compliance with this regulation: (1) operational or plant changes to reduce emission intensity; (2) pay 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 2008 compliance period was March 31, 2009. The SGER imposes a CO2E intensity reduction of 12% from the average CO2E emissions intensity based on the 2003 to 2005 period.

Accordingly, the Company's Genesee 1, 2 and 3 generating stations, the Sundance 5 and 6 units and the Battle River 3, 4 and 5 units are subject to the SGER. The SGER imposes a CO2E intensity reduction of 12% from the average CO2E emissions intensity for the 2003 to 2005 period. The costs associated with compliance with the SGER for Genesee 1 and 2 were approximately $4.7 million for 2008 and are estimated to be approximately $5 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 and Battle River PPAs will be passed on to the Company, as the PPA buyer, in proportion to its ownership interest until the PPA reaches its expiry date or is sold.

The Company has been purchasing offsets for over four years. It has entered into more than 12 offset purchase agreements, and has taken delivery of or has contracted approximately 9.0 million tonnes of offsets. Approximately $4 million worth of offsets were purchased in 2008 (compared with $1 million of purchases in 2007) and approximately 550,000 tonnes worth 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 the Company of approximately $4.5 million.

The Company will bear any related costs imposed on commercial generation plants that it owns.

In 2008, the Company 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 is scheduled to culminate in mid-2009 with recommendations to the Alberta Minister of the Environment on new air pollutant emission standards for coal and natural gas-fired electricity generating plants approved after 2010. These new standards will be based on a concept known as "Best Available Technology Economically Achievable" and will cover emissions of NO_x, SO_2, particulate matter and mercury. These standards will likely require the installation of additional, more expensive emission controls on generation facilities permitted and built after 2010. Existing generating units will not be affected by these standards unless they continue to run past

the defined end of their life and are replaced. The electricity framework requires a review of the particulate matter emissions from existing coal-fired units in 2009 that may result in additional control costs in future years. However, there is insufficient information at this time to determine the financial implications.

After detailed consultation with both industry and public stakeholders, the Government of Alberta imposed requirements to reduce mercury emissions from coal-fired power plants in the *Mercury Emissions from Coal-Fired Power Plants Regulation* which came into force in March 2006. The regulation requires coal-fired plant operators, including the Company, to monitor mercury emissions and capture at least 70% of the mercury in the coal starting January 1, 2011. In 2008, the Company completed full scale activated carbon injection demonstration testing on Genesee 3. The results from the testing indicate that the Company will be able to meet the 70% mercury capture requirements. Engineering and design is on-going at Genesee to determine the optimal configuration for the site-wide installation of mercury removal systems. Permanent installation is expected to be completed prior to the January 1, 2011 deadline including testing and commissioning the equipment. Estimates of the costs of installing mercury removal equipment are approximately $2 million per unit, but these estimates are subject to change based on the engineering and design work to be done in 2009. The Company anticipates this will apply to its Sundance and Battle River PPAs.

Ontario

On June 20, 2007, the Premier of Ontario announced a short-term target of reducing GHG emissions by 6% from 1990 levels by 2014. Half of this reduction is to be achieved through closure of Ontario's remaining coal-fired power plants. Ontario's mid-term target is to achieve a 15% reduction of GHGs below 1990 levels by 2020, and its long-term goal is to reduce emissions by 80% below 1990 levels by 2050.

Ontario Regulations 397/07 and 194/05 set limits on emissions of NO_x and SO_2 from electricity generating facilities that use fossil fuels and seven industrial sectors, being iron and steel, cement, petroleum refining, pulp and paper, glass and carbon black. These regulations further provide for an allowance and emissions trading system. Under these regulations, cleaner sources of power generation, such as natural gas-fired or renewable energy are eligible to receive and sell emission allowances with respect to NO_x and SO_2.

On May 27, 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 and will continue to work with its partners in the Western Climate Initiative ("WCI"), which is playing an important role in the development of a U.S. federal and broader North American cap and trade system. Ontario will also continue to work with the Government of Canada to develop a national system that reflects Ontario's interests and avoids duplicate federal and provincial regulations. However, the timing and specifics of such a GHG cap and trade system are not known at this time, although public consultation will occur into the fall of 2009 and final regulations may not be implemented until 2012.

British Columbia

On February 27, 2007, the British Columbia Provincial Government released the 2007 B.C. Energy Plan, which provides direction as to how the electricity generation sector will have to manage GHG emissions going forward. In addition, the B.C. Energy Plan calls for British Columbia to be electricity self-sufficient by 2016 in order to ensure the province's energy security. In November 2007, the British Columbia Provincial Government introduced the *Greenhouse Gas Reduction Targets Act* ("GGRTA"), which came into force on January 1, 2008. The GGRTA establishes GHG targets for British Columbia for 2020 and 2050, requires that interim targets be set for 2012 and 2016, and requires that the British Columbia Government, including all public sector organizations and Crown corporations, become carbon neutral by 2016.

All new electricity generating projects in British Columbia will be subject to the B.C. Energy Plan requirement to completely offset GHG emissions. While a new electricity generation plant in British Columbia would be subject to applicable requirements and targets under the Federal emissions intensity program, those requirements would likely be met through compliance with British Columbia requirements, which are more

stringent. In April 2008, the British Columbia Provincial Government passed legislation to create a cap-and-trade system for GHG emissions. As a member of the WCI, British Columbia will develop its cap-and-trade program in conjunction with the WCI's regional cap-and-trade system, which is expected to start trading on January 1, 2012. The WCI has set a regional emissions reduction target of 15% below 2005 levels by 2020. In September 2008, the WCI released the draft design for its regional cap-and-trade system. Under the draft design, a multi-sector cap-and-trade program is proposed with a limit on emissions from all major sources of GHG emissions. The cap will include all electricity imported from outside WCI member jurisdictions. However, the exact timing and effect of the provincial regime is uncertain given the fact that the federal regulations have not been finalized and may be part of a continental system.

United States

Regulation of GHG and Other Air Emissions

The Company continually assesses the potential impact on EPLP's assets of future legislation and regulatory requirements in the U.S. for certain air emissions regulations including those related to climate change.

In 2007, the U.S. Supreme Court, in the case of *Massachusetts v. U. S. Environmental Protection Agency*, held that CO_2 and other GHG emissions are pollutants subject to regulation under the new motor vehicle provisions of the U.S. *Clean Air Act* ("CAA"). The case was remanded to the U.S. Environmental Protection Agency (the "Environmental Protection Agency") to determine whether GHG emissions may reasonably be anticipated to endanger public health or welfare. In response, on April 17, 2009, the Environmental Protection Agency issued a proposed finding that emissions of carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride contribute to air pollution that may endanger public health or welfare. The proposed finding is subject to a 60-day public comment period. If adopted, the finding would not would not by itself automatically trigger regulation under the CAA, but it could lead to regulation of GHG emissions from motor vehicles and also from manufacturing plants, including electric generation, pursuant to Environmental Protection Agency rule or federal or state legislation. Both President Obama and the Administrator of the Environmental Protection Agency have expressed a preference for federal legislation. In July 2008, the Environmental Protection Agency issued an Advance Notice of Proposed Rulemaking ("ANPR") and is currently considering public comments made on analyses and policy alternatives regarding GHG effects and regulation under the CAA. It is very likely that the issue of GHG regulation will be addressed either by regulation under the CAA or by new federal legislation. As a result of the uncertainties surrounding these potential developments, the Company cannot estimate the effect of the decision on its operations.

On May 15, 2009, Rep. Waxman and Rep. Markey introduced H.R. 2454, the *American Clean Energy and Security Act*, in the Energy and Commerce Committee of the U.S. House of Representatives (the "Waxman-Markey Bill"). On May 21, the Energy and Commerce Committee approved the bill, as amended, by a vote of 33 to 25. The bill was reported out of Committee on June 5, 2009. The Waxman-Markey Bill would establish an economy wide cap and trade program; create incentives and standards for clean energy and energy efficiency; and establish GHG standards for vehicles, stationary sources, and fuels. The provisions of the bill remain subject to extensive debate and it is unclear whether it will be passed, and if so, what revisions will be made in advance of passage. Key issues include whether the target percentage of renewables is too high; whether in any cap and trade program emissions should be allocated by auction or some other means; if there is an auction of allowances how the proceeds should be applied; and incentives for development of nuclear power. Other members of the U.S. House of Representatives and the Senate have introduced and are expected to introduce proposed legislation addressing climate change and related issues.

Emissions reductions targets. All states in which the Company operates electric generating facilities, other than Indiana, have adopted targets for reducing GHG emissions. At the federal level, U.S. President Obama has proposed target reductions, and several pieces of proposed legislation contain reduction targets but none has yet been adopted. The adoption of targets can lead to adoption of mechanisms designed to help achieve the targets by limiting GHG emissions and by promoting use of renewable resources. These mechanisms include, but are not limited, to mandatory reporting, renewable portfolio standards, emissions performance standards, mitigation or other monetary payments based on GHG emissions, and cap and trade programs, all discussed below. In

addition, some observers believe that the U.S. must adopt targets in order to participate meaningfully in international negotiations relating to climate change.

Mandatory Reporting of GHG Emissions. In response to the *FY2008 Consolidated Appropriations Act*, the Environmental Protection Agency in April 2009 published a proposed rule that would require large sources in the U.S. to report GHG emissions. The purpose of the proposed rule would be to collect data to inform future policy decisions. In general, the Environmental Protection Agency proposes that facilities that emit 25,000 metric tons or more per year of GHG emissions be required to submit annual reports to the Environmental Protection Agency. The gases covered by the proposed rule are CO_2, methane, NO_x, hydrofluorocarbons, perfluorocarbons, sulfur hexafluoride, and other fluorinated gases including nitrogen trifluoride and hydrofluorinated ethers. The proposed rule was open for comment until June 9, 2009. Many states have adopted or are considering adoption of voluntary or mandatory GHG reporting programs. Reporting may serve a number of purposes, including without limitation: evaluation of how targets should be set and whether they have been met; determination of baseline emissions for purposes of any allocation system based on historic emissions; a determination of what if any mitigation is required; and a determination of whether any applicable performance standard or other permit-based emissions limit has been met. It is difficult to predict with any certainty how a reporting rule would affect the Company although such a rule would facilitate a cap and trade program or other restrictions on GHG emissions.

Cap and Trade Programs. U.S. President Obama has indicated that his administration will work to implement a cap and trade system to reduce U.S. GHG emissions with the goal of reducing GHG emissions 80% by the year 2050. To date, there is no consensus on a proposed framework or any regulation in place at the federal level so there is no reliable basis for estimating the potential financial implications to the Company. There presently are three regional GHG regulatory programs that are being or may be implemented in various states within the U.S., including the Regional Greenhouse Gas Initiative applicable to ten Eastern states, the Midwestern Regional Greenhouse Gas Reduction Accord applicable to Illinois and several other Midwestern states, and the WCI, in which Washington, California and several other Western states, as well as the Provinces of British Columbia, Ontario, Manitoba and Quebec are participants, while Colorado, Nova Scotia and Saskatchewan are among the observers. In the case of the Regional Greenhouse Gas Initiative, the regulations are implemented on a state-by-state basis and it appears unlikely that any of the existing or currently proposed EPLP plants will be affected by those regulations. EPLP has five plants in the U.S. that are located within states that will be affected by the Western Climate Initiative, if adopted — four plants in California (Naval Station Facility, Naval Training Centre Facility, North Island Facility and Oxnard Facility) and one plant, Frederickson, in Washington. At this time, there is insufficient information to estimate the potential financial impact of the Regional Greenhouse Gas Initiative, the Western Climate Initiative or the Midwestern Regional Greenhouse Gas Reduction Accord on EPLP.

Renewable Portfolio Standards. Many U.S. states have adopted some form of renewable portfolio standards ("RPS") and Congress this year is considering adoption of federal renewable portfolio standards. Presently, each U.S. state in which the Company operates other than Indiana has an RPS. In general, an RPS is intended to increase renewable energy generation by requiring electric utilities and retail electric providers to supply a preset minimum amount of electricity from renewable resources. The renewable standards are intended to stimulate market and technological development, creating renewable energy that is economically competitive with conventional forms of electric power. The definition of the resources that are qualifying renewable resources and the specific renewable portfolio requirements vary from state to state. Some states require that utilities and other retail power providers subject to the requirements procure a fixed number of MW of energy from qualifying renewable resources, and others require that such utilities and other retail providers procure a specific percentage (typically between 10% and 27%) of the power to serve their retail electric load from qualifying renewable sources. President Obama has stated a goal of having the U.S. obtain 10% of its electricity from renewable resources by 2012, and 25% by 2025.

Greenhouse Gas Performance Standards. Some states have adopted GHG performance standards to limit the amount of GHGs a power plant may emit. Again, these requirements vary from state to state. The requirements may also vary based on status of the plant as proposed or existing (in which case application of the standard may be triggered by, among other things, a change in ownership), location within or outside the state,

fuel source, baseload design, and potential for cogeneration. Among the states in which the Company operates, Washington and California presently have GHG performance standards. In Washington, the present standard is 1,100 pounds per MWh. In California, the Public Utilities Commission has adopted an interim emissions performance standard of 1,100 pounds of CO_2 per MWh for baseload resources of load-serving entities.

Carbon Capture and Storage. Carbon capture and storage may play a role in reducing emissions of greenhouse gases in the U.S. The U.S. Department of Energy has established and provided some funding to seven Regional Carbon Sequestration Partnerships. In May 2009, the Department of Energy announced that $2.4 billion from the *American Recovery and Reinvestment Act* will be used to expand and accelerate the commercial deployment of carbon capture and storage. The U.S. Environmental Protection Agency and several states have established or are considering regulatory frameworks for carbon sequestration. Research is ongoing into several methods of storage and sequestration. There is no certainty as to whether any method will be viable from a technical, regulatory or financial standpoint.

Regulation of Other Air Emissions — NO_x and SO_2. On May 12, 2005, the Environmental Protection Agency issued its "Clean Air Interstate Rule" or "CAIR", 70 Fed. Reg. at 25,165. CAIR's purpose is to reduce or eliminate the impact of upwind sources on the ability of downwind states to meet and maintain compliance with the national ambient air quality standards for fine particulate matter ("PM**[2.5]**") and eight-hour ozone. CAIR applies to certain electrical generating units ("EGUs") in 28 eastern states and the District of Columbia and regulates emissions of SO_2, a precursor to PM**[2.5]** formation, and NO_x, precursors to both PM**[2.5]** and ozone formation. EGUs covered by CAIR are primarily fossil-fuel-fired electrical generation stations with nameplate capacities greater than 25 MW.

Some states, including North Carolina, and certain regulated entities, brought legal challenges to CAIR in the D.C. Circuit Court of Appeals. These challenges were ultimately successful, and in an decision dated July 11, 2008, the D.C. Circuit held, in part, that there were several fatal flaws in CAIR. The court vacated the rule in its entirety and remanded it back to Environmental Protection Agency, instructing the agency to re-craft it to be consistent with the court's opinion.(1) On a petition for rehearing brought by the Environmental Protection Agency, however, the D.C. Circuit reversed its vacature of the rule in a opinion dated December 23, 2008, allowing CAIR to remain in effect until it is replaced by a new rule consistent with the court's original opinion.(2) While the court did not issue a deadline for the new rule, the Environmental Protection Agency stated to the court that development and finalization of a replacement rule could take about two years.

The Company has facilities located in the CAIR-covered states of Indiana, Illinois, North Carolina, New Jersey, and New York. Company facilities in those states that meet the coverage threshold under CAIR are required to comply with emission reductions mandated by CAIR regulations. For example, CAIR will require reductions in NO_x (beginning in 2009) and SO_2 (beginning in 2010) at EPLP's Southport and Roxboro facilities. EPLP had already elected to move forward with planned capital upgrades at these facilities to substantially reduce NO_x and SO_2 emissions and improve economic performance. EPLP will have to purchase additional NO_x and SO_2 credits until the retrofit of the Southport and Roxboro facilities is completed, which is anticipated to occur in the fourth quarter of 2009. Given the continuing uncertainty about the future of CAIR, the Company will continue to monitor and assess the situation.

Regulation of Other Air Emissions — Mercury. The decision of the D.C. Circuit Court of Appeals in *New Jersey v. EPA* (D.C. Cir. 2008) vacated the Clean Air Mercury Rule which had altered the manner by which mercury emissions were regulated under the CAA. In February 2009, the federal government withdrew its appeal to the Supreme Court and intends to develop new rules in accordance with the D.C. Circuit Court opinion. As a result, it is uncertain how potential changes to mercury regulations will impact the Company's facilities. Given this uncertainty, the Company will continue to monitor and assess the situation.

(1) *North Carolina v. Environmental Protection Agency,* 531 F.3d 896 (D.C. Cir. Jul. 11, 2008).

(2) *North Carolina v. Environmental Protection Agency,* 550 F.3d 1176 (D.C. Cir. Dec. 23, 2008).

Clean Water Act

The U.S. *Clean Water Act* establishes rules regulating the discharge of pollutants into waters of the U.S. The Company must obtain wastewater and storm water discharge permits for wastewater and runoff, respectively, from certain of its power plants. The Company must maintain a spill prevention control and countermeasure plan with respect to certain of its power plants. The Company believes that it is in material compliance with applicable discharge requirements of the U.S. *Clean Water Act*.

Resource Conservation and Recovery Act

The *Resource Conversation and Recovery Act* ("RCRA") regulates solid and hazardous waste management. Certain states have similar laws. The Company believes that its operations are in material compliance with RCRA and all such laws.

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 and 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, the Company is not subject to any material liability for any Superfund matters. However, the Company 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 the Company will not incur liability under CERCLA in the future.

Initiatives

As part of its strategy to reduce its GHG emission, 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 NRCan have each contributed $11 million to the study. The study is to be completed in early 2010. In addition to the front-end engineering design study, the Company has submitted two proposals in response to the Government of Alberta's Invitation for an Expression of Interest — Carbon Capture and Storage Projects. The first proposal is an amine project which focuses on technology that can be applied to existing coal-fired generation plants. The second proposal is the Genesee IGCC project with carbon capture technology. Both of the Company's projects have been invited to participate in the second stage of the process and submit full project proposals.

The Company is an active participant in the emerging carbon trading market in Canada and purchased 490,000 tonnes of carbon offsets in 2008.

The Company is conducting a long-term study of environmental impacts of coal-fired generation in the Genesee-Wabamum area of Alberta in partnership with TransAlta. This study is in compliance with conditions in the Alberta Environment approval for the Genesee 3 generating station. The results of the study are periodically reviewed by Alberta Environment and no major issues have arisen to date.

As evidence of the Company's environmental commitment, the Genesee generation facility maintains environmental management systems certified to the ISO 14001 standard. This certification is maintained after annual audits by a quality bureau accredited by the Standards Council of Canada, and the satisfactory completion of any required corrective actions. The purpose of an environmental management system is to minimize environmental incidents. It does this by identifying environmental risks within a particular operation, seeking to ensure that plans and processes are in place to minimize environmental risks and efficiently dealing with any incidents that do occur. It also includes an annual review process so that the plans and processes are updated with the latest best management practices.

RELATIONSHIP TO EPCOR

Reorganization

The following is a summary of the principal reorganization and acquisition transactions that will take place prior to and following completion of the Offering, in connection with the formation of Capital Power LP, the direct and indirect acquisition by Capital Power and Capital Power LP of the securities and assets described in this prospectus and the acquisition by each of Capital Power and EPCOR of their respective interests in Capital Power LP (collectively, the "Reorganization"). The transfer prices for these transactions will be determined by independent third party valuations. The transfer prices for these transactions set forth below are based on preliminary estimates of such valuations and are subject to change, and the amount of these transfer prices as finally determined may differ materially from the amounts disclosed below.

Sale of Interests in EPLP and EPLP General Partner to EPLP Holdco

1. EPCOR will incorporate EPLP Holdco and purchase 51 Class A Shares of EPLP Holdco for cash, EPGSI will transfer the shares of EPLP General Partner to EPLP Holdco for cash and EMCC Limited, a wholly-owned subsidiary of EPCOR, will transfer its 30.6% interest in the limited partnership units of EPLP to EPLP Holdco in return for 49 Class B Shares of EPLP Holdco and a promissory note in the principal amount of approximately $200 million.

Formation of Capital Power LP

2. Capital Power and a wholly-owned subsidiary of Capital Power ("Capital Power Subco") will form Capital Power LP. Capital Power will acquire one GP Unit and act as the initial general partner of Capital Power LP and Capital Power Subco will acquire one Common LP Unit and be the initial limited partner in Capital Power LP.

Sale of EMCC Limited to Capital Power

3. EPCOR will transfer 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 Capital Power LP

4. EMCC Limited will contribute substantially all of its assets (consisting primarily of certain securities of subsidiary entities and the Class B Shares and promissory note of EPLP Holdco acquired in Step 1 above) to Capital Power LP in return for GP Units. Capital Power will transfer its GP Unit in Capital Power LP to EMCC Limited and EMCC Limited will be the sole general partner of Capital Power LP.

Sale of Assets by EPDC to Capital Power LP

5. EPDC will transfer substantially all of its assets (consisting primarily of assets related to Genesee Units 1 and 2, the Genesee Coal Mine joint venture and interests in partnerships) to Capital Power LP in return for 56.625 million Exchangeable LP Units of Capital Power LP and approximately $896 million in cash (which cash amount will be financed by a loan from EPCOR under the credit agreement described under "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and capital resources").

6. Concurrently with Step 5, above, EPDC will subscribe for 56.625 million Special Voting Shares of Capital Power for a nominal amount.

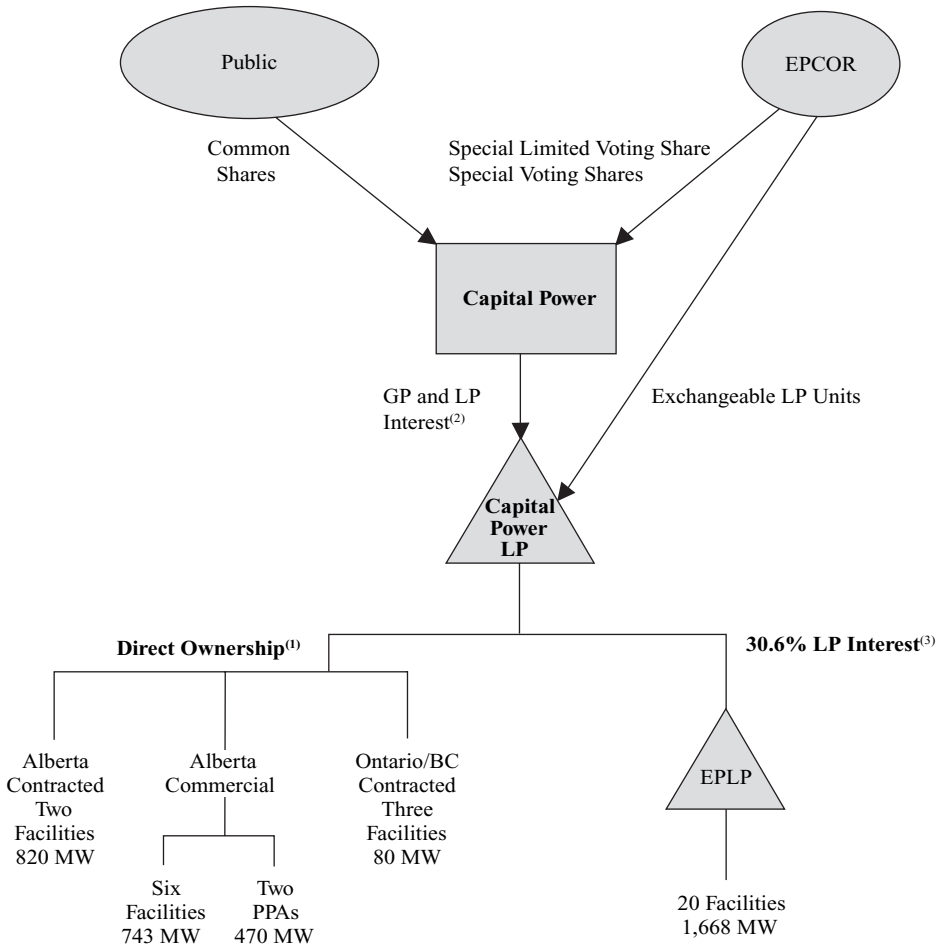
   Upon completion of the transactions described above:

   - Capital Power will, indirectly, hold an approximate 27.8% equity interest in Capital Power LP and EPCOR will, indirectly, hold an approximate 72.2% equity interest in Capital Power LP

- the Common Shares issuable to EPCOR upon the exchange of its Exchangeable LP Units will represent approximately 72.2% of the Common Shares outstanding assuming the exchange of all Exchangeable LP Units for Common Shares

The Special Voting Shares of Capital Power held by EPCOR will represent not more than 49% of the votes attached to all outstanding Common Shares and Special Voting Shares, taken together. EPCOR's right to exchange Exchangeable LP Units is restricted. See "— EPCOR's Ownership in Capital Power" and "Description of Share Capital and Exchangeable LP Units — Capital Power — Special Voting Shares". Capital Power LP will, in turn, directly or indirectly, own the assets used to carry on the business of Capital Power.

The structure of Capital Power and Capital Power LP on completion of the Offering and the Reorganization will be as follows:



(1) Stated capacity represents owned and/or operated capacity.

(2) Held through EMCC Limited, a subsidiary of Capital Power.

(3) Capital Power LP has a 49% voting interest and a 100% economic interest in EPLP Holdco, a holding company that owns a 30.6% interest in the limited partnership units of EPLP and 100% of the shares of EPLP General Partner, the general partner of EPLP. EPCOR owns the other 51% voting interest in EPLP Holdco. EPLP facilities are managed by indirect wholly-owned subsidiaries of Capital Power.

Limited Partnership Agreement of Capital Power LP

General

Capital Power LP is a limited partnership established under the laws of the Province of Ontario for the purpose of engaging in, and providing services and products to persons engaged in, the generation, production, transmission, distribution and consumption of electric energy and other energy commodities, including by acquiring, investing in, holding, transferring, disposing of or otherwise dealing with investments or assets relating thereto, and engaging in such other activities as the general partner of Capital Power LP may, in its discretion, determine. The following is a summary of the material attributes and characteristics of the partnership units of Capital Power LP and certain provisions of the Limited Partnership Agreement which is not intended to be complete. Reference is made to the full text of the Limited Partnership Agreement for a complete description thereof. See "Material Contracts and Other Information".

General Partner

Following completion of the Reorganization, the general partner of Capital Power LP will be EMCC Limited, which will be a subsidiary of Capital Power.

Partnership Units

Capital Power LP will be entitled to issue various classes of partnership interests, designated as GP Units, Common LP Units and Exchangeable LP Units, for such consideration and on such terms and conditions as may be determined by the general partner of Capital Power LP, subject to the provisions of the Limited Partnership Agreement. Immediately following the Reorganization, Capital Power LP will have issued and outstanding a nominal limited partner interest in the form of Common LP Units held by Capital Power Subco, 21,750,001 GP Units held indirectly through EMCC Limited by Capital Power, and 56,625,000 Exchangeable LP Units held indirectly through EPDC by EPCOR. At that time, the Exchangeable LP Units will represent an approximate 72.2% equity interest in Capital Power LP.

The GP Units, Common LP Units and Exchangeable LP Units will be entitled to participate in distributions of Capital Power LP on an equal per-unit basis. Certain fundamental matters must be approved by special resolution of the holders of Common LP Units and Exchangeable LP Units, voting together as a class, including (i) a consolidation, subdivision or reclassification of limited partnership units, and (ii) a waiver of a default by the general partner or release of the general partner from any claims in respect thereof. Other matters must be approved by special resolution of the holders of Common LP Units, including (i) removal of the general partner, (ii) dissolution, termination, wind up or other discontinuance of Capital Power LP, (iii) sale, exchange or other disposition of all or substantially all of the business or assets of Capital Power LP, (iv) amendments to the Limited Partnership Agreement, and (v) merger or consolidation involving Capital Power LP. However, amendments to the rights, privileges, restrictions and conditions of a class of limited partnership units must be approved by special resolution of the holders of that class of limited partnership units, voting separately as a class.

Exchangeable LP Units are exchangeable for Common Shares at the option of the holder on a one-for-one basis (subject to customary anti-dilution protections) at any time, subject to the limitation that the maximum number of Common Shares for which Exchangeable LP Units may be exchanged at any time is the largest whole number of Common Shares that, when added to the aggregate number of Common Shares outstanding at that time owned or whose voting rights are controlled by persons who own Exchangeable LP Units or persons who, for purposes of the *Income Tax Act* (Canada) (the "Tax Act") do not deal at arm's length with an owner of Exchangeable LP Units, does not exceed 49% of the aggregate number of Common Shares that would be outstanding immediately following such exchange. Following any such exchange, each Exchangeable LP Unit acquired by Capital Power will automatically be converted into a Common LP Unit. Each of the Exchangeable LP Units will be accompanied by a Special Voting Share which will entitle the holder of such Special Voting Share to receive notice of, to attend and to vote at meetings of shareholders of Capital Power. Under the Exchange Agreement, holders will agree not to transfer the Special Voting Shares separately from the

Exchangeable LP Units, except for certain permitted transfers among affiliates. See "Description of Share Capital and Exchangeable LP Units".

EPDC, Capital Power, EMCC Limited and Capital Power LP will enter into an Exchange Agreement to give effect to the foregoing terms of the Exchangeable LP Units. See "— Agreements Between Capital Power and EPCOR — Exchange Agreement".

If the Over-Allotment Option is exercised, Capital Power will invest the proceeds in additional Common LP Units and/or GP Units of Capital Power LP which will redeem and cancel a number of Exchangeable LP Units equal to the number of Common Shares issued by Capital Power upon such exercise. See "Use of Proceeds".

Distributions

It is anticipated that Capital Power LP will make cash distributions, as determined by Capital Power LP General Partner, to its partners on a quarterly basis, and in any event on or before the scheduled date for payment by Capital Power of dividends to holders of Common Shares. Distributions are not, however, guaranteed and will be at the discretion of Capital Power LP General Partner. Capital Power will be dependent, to a significant extent, on receiving distributions from Capital Power LP in order to pay dividends on the Common Shares. See "Dividend Policy" and "Risk Factors".

Allocation of Net Income and Losses

The income for tax purposes of Capital Power LP for a particular fiscal year will be allocated to each partner by multiplying the total income for tax purposes of Capital Power LP allocated to all partners by a fraction, the numerator of which is the aggregate of the distributions paid or payable or allocated to that partner with respect to that fiscal year and the denominator of which is the aggregate of the amount or value of the distributions paid or payable or allocated to all partners by Capital Power LP with respect to that fiscal year. The amount of income for tax purposes allocated to a partner may be more or less than the amount of cash distributed by Capital Power LP to that partner.

Income and loss of Capital Power LP for accounting purposes is allocated to each partner in the same proportion as income or loss is allocated for tax purposes.

If, with respect to a given fiscal year, no distribution is paid or payable or allocated to the partners, or Capital Power LP has a loss for tax purposes, one-twelfth of the income or loss, as the case may be, for tax purposes of Capital Power LP for that fiscal year will be allocated to the partners at the end of each month ending in that fiscal year in the proportion that the number of limited partnership units and/or GP Units held at each of those dates by that partner bears to the total number of limited partnership units and GP Units issued and outstanding at each of those dates.

The fiscal year end of Capital Power LP will initially be December 31.

Functions and Powers of Capital Power LP General Partner

In its capacity as general partner of Capital Power LP, Capital Power LP General Partner will be authorized and obliged to manage, control, administer and operate the business and affairs of Capital Power LP, to make all decisions regarding the business of Capital Power LP and to bind Capital Power LP in respect of any such decisions, subject to certain limitations contained in the Limited Partnership Agreement. Capital Power LP General Partner will be required to exercise its powers and discharge its duties honestly, in good faith with a view to the best interests of Capital Power LP and to exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances. It is contemplated that, following completion of the Offering, the board of directors of Capital Power LP General Partner will be the same as the Board of Directors. See "Management — Directors and Executive Officers".

The authority and power vested in the general partner to manage the business and affairs of Capital Power LP will include all authority to do any act, take any proceeding, make any decision and execute and deliver any instrument, deed, agreement or document necessary or incidental to carrying out the objects,

purposes and business of Capital Power LP, including, without limitation, the ability to engage agents to assist the general partner to carry out its management obligations and administrative functions in respect of Capital Power LP and its business.

Restrictions on the Authority of Capital Power LP General Partner

The authority of Capital Power LP General Partner, as general partner, will be limited in certain respects under the Limited Partnership Agreement. Capital Power LP General Partner will be precluded from, without the prior approval of the holders of Common LP Units and Exchangeable LP Units, voting together, given by special resolution: (i) issuing or accepting, recognizing or registering the transfer of any limited partnership units of Capital Power LP, unless such issuance or transfer has been effected in compliance with the Limited Partnership Agreement; and (ii) waiving any default on the part of a general partner or releasing a general partner from any claims in respect thereof. For these purposes, limited partnership units held by Capital Power, Capital Power LP General Partner or their subsidiaries will not be entitled to vote. See "— Partnership Units" for additional restrictions on the authority of Capital Power LP General Partner.

Limited Liability

Capital Power LP will operate in a manner so as to ensure, to the greatest extent possible, the limited liability of the limited partners. Limited partners may lose their limited liability in certain circumstances. If limited liability of the limited partners is lost due to the negligence of Capital Power LP General Partner, Capital Power LP General Partner will indemnify the limited partners against all costs and damages suffered or incurred by the limited partners to the extent that their liability is not limited as intended by the Limited Partnership Agreement.

Transfer of Partnership Units

No limited partner may transfer any of the limited partnership units owned by it except to persons and in the manner expressly permitted in the Limited Partnership Agreement. Limited partnership units may not be transferred to a person who is a "non-resident" of Canada or is not a "Canadian partnership" for purposes of the Tax Act and the regulations thereunder (the "Regulations"). No holder of Exchangeable LP Units will be permitted to transfer such Exchangeable LP Units other than as provided in the Limited Partnership Agreement and the Exchange Agreement or in exchange for Common Shares in accordance with the terms of the Exchange Agreement, unless either: (i) such transfer would not require that the transferee make an offer to holders of Common Shares to acquire Common Shares on the same terms and conditions under applicable securities laws, if such Exchangeable LP Units were converted into Common Shares at the then applicable exchange ratio; or (ii) if such transfer would require that the transferee make such an offer to holders of Common Shares to acquire Common Shares on the same terms and conditions under applicable securities laws, the transferee acquiring such Exchangeable LP Units makes a contemporaneous identical offer for Common Shares (in terms of price, timing, proportion of securities sought to be acquired and conditions and at the then applicable exchange ratio in effect under the Exchange Agreement) and does not acquire such Exchangeable LP Units unless the transferee also acquires a proportionate number of Common Shares actually tendered to such identical offer.

A limited partnership unit will not be transferable in part, and no transfer of a limited partnership unit will be accepted by the general partner unless a transfer form, duly completed and signed by the registered holder of the limited partnership unit, has been remitted to the registrar and transfer agent of Capital Power LP. A transferee of a limited partnership unit will become a limited partner and will be subject to the obligations and entitled to the rights of a limited partner under the Limited Partnership Agreement on the date on which the transfer is recorded.

EPCOR's Ownership in Capital Power

Immediately following the Reorganization, assuming no exercise of the Over-Allotment Option and no exchange of Exchangeable LP Units by EPCOR for Common Shares, EPCOR will own, indirectly, 100% of the outstanding Exchangeable LP Units of Capital Power LP, representing an approximate 72.2% partnership

interest in Capital Power LP. The Common Shares issuable upon exchange of such Exchangeable LP Units would represent approximately 72.2% of the Common Shares outstanding immediately after the completion of the Offering and the Reorganization, assuming the exchange of all Exchangeable LP Units for Common Shares, provided that, under the terms of the Exchange Agreement, an Exchangeable LP Unit may not be exchanged if, immediately following such exchange, EPCOR would own, directly or indirectly, more than 49% of the Common Shares.

If the underwriters exercise the Over-Allotment Option in full, and assuming no exchange of Exchangeable LP Units by EPCOR for Common Shares, immediately following the Offering, EPCOR will own, indirectly, 100% of the outstanding Exchangeable LP Units, representing an approximate 68.1% partnership interest in Capital Power LP. The Common Shares issuable upon exchange of such Exchangeable LP Units would represent approximately 68.1% of the Common Shares outstanding immediately after the completion of the Offering and the Reorganization, assuming the exchange of all Exchangeable LP Units for Common Shares, provided that, under the terms of the Exchange Agreement, an Exchangeable LP Unit may not be exchanged if, immediately following such exchange, EPCOR would own, directly or indirectly, more than 49% of the Common Shares.

Each Exchangeable LP Unit will be accompanied by a Special Voting Share, conferring on the holder certain voting rights at meetings of shareholders of Capital Power. Immediately following completion of the Reorganization, EPCOR will hold, indirectly, 100% of the outstanding Special Voting Shares. As described under "Description of Share Capital and Exchangeable LP Units", such voting rights will at all times represent not more than 49% of the votes attached to all outstanding Common Shares and Special Voting Shares, taken together. In addition, the holders of Special Voting Shares will, so long as they beneficially own not less than a certain percentage of the Common Shares on a diluted basis, be entitled to elect a certain number of directors of the Company voting as a separate class. Until such time as the holders of Special Voting Shares beneficially own less than 10% of the Common Shares and Common Shares issuable upon exchange of Exchangeable LP Units, they will not be entitled to vote together with holders of Common Shares for the remaining directors of the Company. See "Description of Share Capital and Exchangeable LP Units — Capital Power — Special Voting Shares".

Capital Power expects that, following completion of the Offering, EPCOR, through EPDC, will be the largest voting shareholder of Capital Power and, pursuant to its right to elect up to four directors of the Company under its Special Voting Shares, four of the twelve directors of the Company immediately after closing of the Offering will be directors or officers of EPCOR. See "Description of Share Capital and Exchangeable LP Units — Capital Power — Special Voting Shares". EPDC will otherwise have significant voting power pursuant to its Special Voting Shares.

EPCOR has advised the Company that it intends to act only as an investor in and not as a manager of Capital Power, and that EPCOR intends to direct or exercise the voting rights attached to the Special Voting Shares and Special Limited Voting Share, as such. EPCOR has further advised the Company that it may eventually sell all or a substantial number of the Common Shares underlying its Exchangeable LP Units, subject to market conditions, its requirements for capital and other circumstances that may arise in the future. EPCOR has indicated to the Company that it has no specific plans to exercise its right to exchange its Exchangeable LP Units or sell such resulting Common Shares at this time. See also "Risk Factors — Risks Relating to the Company's Relationship to EPCOR".

EPCOR holds the one issued and outstanding Special Limited Voting Share. The Special Limited Voting Share confers on the holder the right to vote separately as a class in connection with certain amendments to the articles of Capital Power, including an amendment to change or permit the change of the location of the head office of Capital Power from The City of Edmonton, Alberta. EPCOR will undertake to its sole shareholder, The City of Edmonton, that it will not dispose of or otherwise relinquish any rights it has under the Special Limited Voting Share without the consent of The City of Edmonton. For a discussion of the attributes of the Special Limited Voting Share, see "Description of Share Capital and Exchangeable LP Units — Capital Power — Special Limited Voting Share".

Agreements Between Capital Power and EPCOR

This section provides a summary description of the principal agreements between EPCOR and Capital Power and/or Capital Power LP relating to the Offering and Capital Power's relationship with EPCOR after the Offering. The description of the agreements discloses all attributes material to an investor in Common Shares but is not complete and, with respect to each such agreement that constitutes a material contract, is qualified by reference to the terms of the agreement, which will be filed with the Canadian securities regulatory authorities. Investors are encouraged to read the full text of such agreements. See "Material Contracts and Other Information".

Overview

The Master Separation Agreement provides for the separation of the business of Capital Power from EPCOR and contemplates the transfer of the business of EPCOR Power Group to Capital Power pursuant to a series of transfer agreements. The Master Separation Agreement also contemplates that Capital Power will enter into certain other separation agreements with EPCOR (the material separation agreements, collectively with the Master Separation Agreement, are herein referred to as the "Separation Agreements") that will govern certain aspects relating to the separation and various interim and ongoing relationships between EPCOR and Capital Power. These other Separation Agreements include:

- Share Purchase Agreement;
- Asset Purchase Agreement;
- Cooperation Agreement;
- EPCOR Services Agreement;
- EPCOR Transitional Services Agreement;
- Capital Power Transitional Services Agreement;
- Registration Rights Agreement;
- EPLP Holdco Shareholder Agreement;
- Secondment Agreement. See "Management — Executive Compensation — Benefit and Pension Plans — Defined Benefit ("DB") Pension Plan"; and
- Pension Transfer Agreement. See "Management — Executive Compensation — EPLP Component".

Master Separation Agreement

The Master Separation Agreement contains the key provisions related to the separation of the business of Capital Power from EPCOR and the transfer of the business of EPCOR Power Group to Capital Power pursuant to the transfer agreements in connection with the Offering and the Reorganization. All of Capital Power's and EPCOR's covenants and agreements in the Master Separation Agreement will survive indefinitely, subject to applicable laws. Certain of the principal provisions of the Master Separation Agreement are discussed below.

Ownership and Transfer of Assets

The Master Separation Agreement provides for the separation of Capital Power's assets and assumption of liabilities from EPCOR through transfer agreements that Capital Power and/or Capital Power LP will enter into with EPCOR in a transfer sequence established by the Master Separation Agreement, that will occur as part of the closing of the Reorganization.

After the completion of the Reorganization, if it is discovered that EPCOR has title to, or an interest in, any asset, other than an asset specifically excluded, that is used exclusively or held for use exclusively in Capital Power's business, as it existed at the completion of the Reorganization, EPCOR will cooperate with Capital Power and/or Capital Power LP and use commercially reasonable efforts to transfer such asset to Capital Power or Capital Power LP. Likewise, if it is discovered after the completion of the Reorganization, that Capital Power and/or Capital Power LP has title to, or an interest in, any asset other than those used exclusively or held for use

exclusively in Capital Power's business, as it existed at the completion of the Reorganization, Capital Power or Capital Power LP will cooperate with EPCOR and use commercially reasonable efforts to transfer such asset to EPCOR.

The assets constituting the business of Capital Power will be transferred to Capital Power and Capital Power LP on an "as is", "where is" basis without any representations or warranties, express or implied, as to its condition, quality, merchantability or fitness and Capital Power and/or Capital Power LP, as applicable, will bear the economic and legal risks if any conveyance proves to be insufficient to vest good and marketable title in such transferee.

Indemnification and Release

Capital Power has agreed to indemnify EPCOR, each of EPCOR's controlled subsidiaries (other than, for greater clarity, Capital Power and Capital Power's subsidiaries), and EPCOR's and each of EPCOR's controlled subsidiaries' respective directors, officers, employees, consultants, advisers and agents, from all losses they may suffer relating to, arising out of, or in respect of certain circumstances or events, whether such losses arise or accrue prior to, on or following the closing of the Reorganization, including:

- any failure by Capital Power or any of its subsidiaries or any other person to pay, perform or otherwise properly discharge any of their liabilities;
- Capital Power's business or future business or any liabilities arising out of or related to such business or Capital Power's assets;
- any demand for payment made under an agreement or arrangement in which EPCOR and/or a controlled subsidiary of EPCOR is the primary obligor or issued or made available guarantees, sureties, bonds, letters of credit or similar instruments, in any such case to support or facilitate Capital Power's business or future business;
- any breach by Capital Power or any of Capital Power's subsidiaries of any Separation Agreement; and
- with respect to all information contained in this prospectus and any other materials distributed in connection with the Offering or the transactions contemplated in the Separation Agreements, any untrue statement or alleged untrue statement of a material fact or omission or alleged omission to state a material fact required to be stated therein or necessary to make the statements therein not misleading, other than with respect to statements or omissions relating exclusively to (i) EPCOR and its subsidiaries (other than, for greater clarity, Capital Power and Capital Power's subsidiaries), and (ii) EPCOR's businesses (other than the business of Capital Power), which (i) and (ii) are collectively referred to as the "EPCOR Disclosure Portions".

EPCOR will indemnify Capital Power, each of Capital Power's controlled subsidiaries, and each of their respective directors, officers, employees, consultants, advisers and agents, from all losses Capital Power or they may suffer relating to, arising out of, or in respect of certain circumstances or events, whether such losses arise or accrue prior to, on or following the closing of the Reorganization, including:

- any failure by EPCOR or any of its subsidiaries (for greater clarity, other than Capital Power and Capital Power's subsidiaries) or any other person to pay, perform or otherwise properly discharge any of their liabilities (excluding any liability arising out of the business of Capital Power);
- EPCOR's business or future business or any liabilities arising out of or related to such business or EPCOR's assets (excluding any liability arising out of the business of Capital Power);
- any breach by EPCOR or any of EPCOR's subsidiaries of any Separation Agreement; and
- with respect to all information contained in the EPCOR Disclosure Portions, any untrue statement or alleged untrue statement of a material fact or omission or alleged omission to state a material fact required to be stated therein or necessary to make the statements therein not misleading.

Subject to the indemnities described above, Capital Power, Capital Power LP and EPCOR will also release each other and Capital Power's and EPCOR's respective subsidiaries, and Capital Power's and EPCOR's and such subsidiaries' respective directors, officers, employees, consultants, advisers and agents, from any and all

liabilities existing or arising from any acts or events occurring or failing to occur or alleged to have occurred or to have failed to occur or any conditions existing or alleged to have existed on or before the time immediately prior to the closing of the Reorganization, including any acts, events or conditions in connection with implementing the Offering or the transactions contemplated by the Separation Agreements. This release will not impair either Capital Power or EPCOR from enforcing the Master Separation Agreement, any other Separation Agreement or any other agreement between Capital Power and EPCOR in force and effect upon closing of the Reorganization.

Non-competition and Non-solicitation

The Master Separation Agreement provides that Capital Power (and/or Capital Power's subsidiaries) will not, for a period of three years from the date of that agreement, directly or indirectly, engage in any business competitive with EPCOR's business, as conducted upon closing of the Reorganization, and EPCOR (and/or EPCOR's subsidiaries) will not, for a period of three years from the date of that agreement, directly or indirectly, engage in any business competitive with Capital Power's business, as conducted at the time of closing of the Reorganization.

In addition, under the Master Separation Agreement, Capital Power and EPCOR have agreed, for a period of two years from the date of that agreement, not to hire, employ, retain or contract for service, or offer to hire, employ, retain or contract for service, as an officer, employee, partner, consultant, independent contractor or otherwise, any individual employed by the other party or any of its affiliates, or solicit for employment, solicit for hire, contract for the services of, or encourage any individual to terminate his or her employment with the other party or any of its affiliates, subject in each case to certain limited exceptions.

Confidentiality and Records Retention

The Master Separation Agreement provides Capital Power and EPCOR will maintain the confidentiality of all information respecting the other party and its subsidiaries that it holds, and will use such information only for the purposes designated in the Separation Agreements. Each party will agree to provide the other with access to such information for a period ending when EPCOR's diluted interest in Capital Power is 10% or less of the outstanding Common Shares after giving effect to the exchange of the Exchangeable LP Units held by EPCOR, and Capital Power agrees to adopt and comply with a record retention policy with respect to such information.

Business Guarantees

The Master Separation Agreement provides that Capital Power will use its commercially reasonably efforts to, as promptly as practicable, cause EPCOR and each applicable person EPCOR controls to be released from all of its obligations under all business guarantees in respect of the business of Capital Power. To the extent that Capital Power is unable to arrange for such a guarantee release prior to July 1, 2010, and/or such a release would be prejudicial to Capital Power to obtain, Capital Power has agreed to pay to EPCOR a guarantee fee on arm's length terms.

Expenses

Capital Power will be responsible for all costs incurred in connection with the Offering. Capital Power and EPCOR generally will be responsible for their own costs incurred in connection with the matters contemplated by the Separation Agreements.

Disputes

Disputes under all Separation Agreements will be subject to negotiation and arbitration procedures.

Assignment

EPCOR will have the right to assign its rights under the Master Separation Agreement with Capital Power's consent, such consent not to be unreasonably withheld. EPCOR will have the right to assign its rights under the Master Separation Agreement to an affiliate of EPCOR without Capital Power's consent. Capital Power will have the right to assign its rights under the Master Separation Agreement with EPCOR's consent, such consent

to be granted or withheld in EPCOR's sole discretion. Any permitted assignee shall agree to perform the obligations of the assignor of the Master Separation Agreement.

Share Purchase Agreement

Capital Power will enter into a Share Purchase Agreement with EPCOR providing for the purchase by Capital Power from EPCOR of all of the issued and outstanding shares of EMCC Limited. The purchase by Capital Power under the Share Purchase Agreement is conditional upon completion of the Offering and the transactions contemplated by the Master Separation Agreement, including the Asset Purchase Agreement.

The purchase price for the shares of EMCC Limited is approximately $468 million, payable in cash. The purchase price was determined by negotiation between Capital Power and EPCOR.

Asset Purchase Agreement

Capital Power and Capital Power LP will enter into an Asset Purchase Agreement with EPDC providing for the contribution by EPDC to Capital Power LP of substantially all of the assets of EPDC.

The contribution of property by EPDC to Capital Power LP under the Asset Purchase Agreement is conditional upon completion of the Offering and the transactions contemplated by the Master Separation Agreement, including the Share Purchase Agreement.

The purchase price for the assets contributed to Capital Power LP is approximately $2,864 million, and is payable by (i) the issuance of 56.625 million Exchangeable LP Units (together with the issuance by Capital Power of 56.625 million accompanying Special Voting Shares) and (ii) approximately $896 million in cash (which cash amount will be financed by a loan from EPCOR under the credit agreement described under "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and capital resources"). The purchase price will be determined by negotiation between Capital Power and EPDC.

Cooperation Agreement

The Cooperation Agreement will provide for, among other things, certain governance, tax and financial reporting matters by Capital Power to EPCOR. The Cooperation Agreement does not in any way limit the ability of EPCOR to exercise its rights attached to the Special Voting Shares, Special Limited Voting Share and Special Limited GP Voting Share.

Governance Matters

The Cooperation Agreement records the parties' agreement respecting certain governance matters including:

- setting the size of the Board of Directors at (i) a minimum of (x) nine directors so long as EPCOR has the right to nominate and elect four directors pursuant to the rights attached to the Special Voting Shares and (y) five directors so long as EPCOR has the right to nominate and elect two directors pursuant to the rights attached to the Special Voting Shares and (ii) a maximum of 12 directors;
- requiring committees of the Board of Directors, including an audit committee; corporate governance, compensation and nominating committee; and environmental, health and safety committee;
- establishing quorum for meetings of the Board of Directors: (i) as a majority of the number of directors, subject to the Canadian residency requirements of the *Canada Business Corporations Act*; (ii) so long as EPCOR's interest in the outstanding Common Shares is not less than 10% (after giving effect to the exchange of the Exchangeable LP Units held by EPCOR), that a majority of the directors in attendance shall be directors not elected by EPCOR; and (iii) so long as EPCOR's interest in the outstanding Common Shares is not less than 20% (after giving effect to the exchange of the Exchangeable LP Units held by EPCOR), at least one of the directors is elected by EPCOR; and
- providing that within 30 days of receipt of a written request by any two directors of the Board of Directors, a meeting of holders of Common Shares is to be called by the Company.

Financial Reporting

The Company has been advised by EPCOR that, immediately following the completion of the Reorganization, EPCOR expects to account for its investment in the Company using the equity method of accounting. Under the Cooperation Agreement, the Company has agreed that, for so long as EPCOR is required to (i) account for its investment in the Company under the equity method of accounting or (ii) consolidate the Company's results of operations and financial position, and for a further 12 months after the date on which neither (i) nor (ii) apply, the Company shall provide EPCOR, in a timely fashion, in accordance with the scheduled meetings of EPCOR's board of directors and committees thereof for the approval of financial statements, and in any event in sufficient time to allow EPCOR to meet its financial and legal obligations, with financial and other information and data with respect to the Company and its subsidiaries and their respective businesses, properties, financial positions, results of operations and prospects. In addition, during such period, the Company has agreed that it will, among other things:

- maintain effective disclosure controls and procedures and internal control over financial reporting and otherwise comply with applicable law regarding such controls and procedures;
- deliver certain periodic budgets and financial projections, and monthly, quarterly and annual financial reports to EPCOR;
- propose KPMG LLP for appointment as the auditing firm of the Company, subject to applicable law;
- not change its fiscal year to be different than EPCOR;
- cooperate, and use commercially reasonable efforts to cause the Company's auditors to cooperate, to the extent reasonably requested by EPCOR, in connection with the preparation of EPCOR's financial statements and other information provided to the public, securities regulatory authorities, or any securities exchange quotation system or marketplace by EPCOR;
- provide EPCOR with access to the Company's auditors, in accordance with auditor professional standards, and to certain financial information and records reasonably required by EPCOR; and
- to the extent appropriate and applicable, keep the Company's accounting policies and practices consistent with those of EPCOR.

Tax-Related Matters

The Cooperation Agreement will record the parties' agreement respecting certain tax-related matters including:

- prohibiting each party from (i) amending any tax return or (ii) making or changing any tax election with respect to any portion of a period prior to the completion of the Offering, in each case a manner that results in a material increase in a tax liability or a material reduction in a tax asset of the other party;
- requiring each party to promptly notify the other party and keep the other party apprised of any proposed adjustments that arise out of an audit or examination of a tax return that could reasonably be expected to affect in any material way the tax liability of the other party for any portion of a period prior to the completion of the Reorganization or which could reasonably result in treatment of items that is inconsistent in a material respect with the manner in which the other party filed its tax returns for such periods; and
- requiring the Company to provide any draft tax returns for any portion of a period prior to the completion of the Reorganization to EPCOR in advance of filing and requiring the Company to consider and reflect, as considered appropriate by the Company, acting reasonably, any comments from EPCOR in finalizing such tax returns for filing.

Acquisitions or Investments by Capital Power

Under the Cooperation Agreement, the Company has agreed to not, directly or indirectly, undertake any acquisition or investing activity that would be material to the Company, on a consolidated basis, except in or through Capital Power LP, EPLP Holdco or their respective subsidiaries.

Term

Unless terminated earlier by written agreement of the parties, the Cooperation Agreement will terminate when EPCOR owns less than 10% of the outstanding Common Shares, after giving effect to the exchange of the Exchangeable LP Units to be held by EPCOR.

Transitional Services Agreements

Certain services will be provided to Capital Power by EPCOR following closing of the Offering through the EPCOR Transitional Services Agreement and the EPCOR Services Agreement and certain services will be provided to EPCOR by Capital Power and/or Capital Power LP following Closing of the Offering through the Capital Power Transitional Services Agreement.

The EPCOR Transitional Services Agreement is designed to provide Capital Power with certain administrative and corporate level operational resources for a limited period of time following closing of the Offering, with duration determined by reference to the relevant service. Under the EPCOR Services Agreement, the relevant administrative or corporate level operational services will generally be provided on a longer term basis. Under the EPCOR Transitional Services Agreement and the EPCOR Services Agreement, EPCOR will provide services to Capital Power, Capital Power LP and/or to one or more of their respective subsidiaries, including certain:

- information technology and communications services;
- human resources services;
- data centre management;
- tax, accounting, treasury and finance support;
- facilities services; and
- other specified services.

EPCOR will, as a reasonable and prudent operator, perform these services in a manner consistent with the past practices of EPCOR with respect to the business to be owned by Capital Power. The use of such services generally will not be substantially greater than the level of use required prior to the completion of this Offering.

EPCOR may terminate the EPCOR Transitional Services Agreement or the EPCOR Services Agreement if Capital Power is in material breach of such agreement(s), is subject to certain insolvency processes or if continued performance would cause EPCOR to be in breach of any law or contract with a third party. These services will be provided for certain periods depending on the relevant services and these periods may vary from three to approximately 12 months in the case of services provided pursuant to the EPCOR Transitional Services Agreement and up to five years in the case of services provided pursuant to the EPCOR Services Agreement. Capital Power may terminate any individual service for convenience upon 45 to 60 days' written notice. The services will be provided on a cost plus basis by EPCOR to Capital Power.

EPCOR will be relieved of its obligations to provide the services in the event of force majeure, which may include any failure to hold rights, technology or information from third parties that are necessary to perform the relevant service.

Capital Power and/or Capital Power LP will provide certain limited services to EPCOR on terms substantially similar to those in the EPCOR Transitional Services Agreement pursuant to the Capital Power Transitional Services Agreement. These services shall include:

- tax support for open audit periods arising prior to closing of the Offering;
- support for the issue by EPCOR of its venture issuer basic certificate for financial reporting;
- certain financial settlement services; and
- other specified services,

and each service shall be provided for a specific term to be agreed by EPCOR and Capital Power and/or Capital Power LP, depending on the service. The services will be provided on a cost plus basis by Capital Power and/or Capital Power LP to EPCOR.

Registration Rights Agreement

Capital Power will enter into the Registration Rights Agreement with EPCOR, which will provide EPCOR with the right to require Capital Power to qualify Common Shares held by EPCOR, including Common Shares issuable upon the exchange of Exchangeable LP Units, for distribution (i) by prospectus filed with the applicable Canadian securities regulatory authorities and/or (ii) by registration statements filed with the United States Securities and Exchange Commission. In addition, the Registration Rights Agreement will provide EPCOR with the right to require Capital Power to include Common Shares held by EPCOR, including Common Shares issuable upon exchange of Exchangeable LP Units, in future offerings undertaken by Capital Power by way of prospectuses that it may file with applicable Canadian securities regulatory authorities or registration statements that Capital Power may file with the United States Securities and Exchange Commission. These rights are subject to various conditions and limitations, and Capital Power will be entitled to defer any such filings requested by EPCOR in certain circumstances for a limited period.

Pursuant to the Registration Rights Agreement, Capital Power is obliged to indemnify EPCOR for any misrepresentation in a prospectus under which EPCOR's Common Shares were sold (other than in respect of any information provided by EPCOR for inclusion in the prospectus). The Registration Rights Agreement (other than the indemnity provisions) will terminate upon the earlier of (i) the date that EPCOR owns less than 10% of the outstanding Common Shares, after giving effect to the exchange of the Exchangeable LP Units and (ii) July 1, 2024.

Exchange Agreement

Under the Exchange Agreement, Capital Power will grant the holders of Exchangeable LP Units the right to require Capital Power to exchange Exchangeable LP Units for Common Shares on a one-for-one basis at any time, subject to customary anti-dilution protections and adjustment provisions and to a limitation that the maximum number of Common Shares for which Exchangeable LP Units may be exchanged at any time is the largest whole number of Common Shares that, when added to the aggregate number of Common Shares outstanding at that time owned or whose voting rights are controlled by the holder or persons who, for purposes of the Tax Act, do not deal at arm's length with the holder, does not exceed 49% of the aggregate number of Common Shares that would be outstanding immediately following such exchange. A holder of Exchangeable LP Units will also be entitled to be paid by Capital Power LP the amount of any declared but unpaid distributions upon such exchange.

The exchange procedure may be initiated by the holder of an Exchangeable LP Unit by delivering to Capital Power and Capital Power LP General Partner an exchange notice together with a unit certificate in respect of the Exchangeable LP Units to be exchanged, duly endorsed in blank for transfer. Capital Power will then be required to deliver to the exchanging holder the number of Common Shares required to complete the exchange in consideration for the applicable Exchangeable LP Units. Immediately following such exchange, the Exchangeable LP Units will automatically be converted into Common LP Units. Capital Power LP will then cause the Exchangeable LP Units so tendered for exchange to be cancelled, and record the issuance of the applicable number of Common LP Units. The accompanying Special Voting Shares will be redeemed and cancelled by Capital Power in connection with any exchange of Exchangeable LP Units. The exchange rights under the Exchange Agreement may be assigned by the holders of Exchangeable LP Units, in whole or in part, in connection with a transfer of Exchangeable LP Units; provided, however, that each holder of Exchangeable LP Units will agree that it will not transfer Special Voting Shares separately from the Exchangeable LP Units to which they relate, except to an affiliate in accordance with the terms and conditions of the Exchange Agreement.

Capital Power will agree to not issue or distribute rights, options or warrants to the holders of all or substantially all of the then outstanding Common Shares entitling them to subscribe for or purchase Common Shares, evidences of indebtedness or assets of Capital Power, unless the equivalent of such Common Shares, rights, options, warrants, securities, evidences of indebtedness or other assets are simultaneously issued or distributed to holders of Exchangeable LP Units. Capital Power will agree to not issue any additional Special Voting Shares following completion of the offering and the Reorganization without the prior written consent of holders of at least 66⅔% of the outstanding Exchangeable LP Units.

EPLP Holdco Shareholder Agreement

Immediately following the completion of the Offering and the Reorganization, the Company and EPCOR will hold 49 Class B Shares and 51 Class A shares in the capital of EPLP Holdco, respectively. See "— Reorganization" and "Description of Share Capital and Exchangeable LP Units — EPLP Holdco". Capital Power LP and EPCOR will enter into the EPLP Holdco Shareholder Agreement in their contemplated capacities as shareholders of EPLP Holdco. Under this agreement, the Company and EPCOR will agree that: (i) the board of directors of EPLP Holdco will consist of three directors; (ii) EPCOR will nominate not more than one person for election to the board of directors of EPLP Holdco; and (iii) any disputes between the Company and EPCOR in their capacities as shareholders of EPLP Holdco will be resolved by way of binding arbitration.

Edmonton Social Objectives Agreement

Capital Power has entered into the Edmonton Social Objectives Agreement with EPCOR and The City of Edmonton pursuant to which Capital Power has agreed to maintain its "Head Office" (as defined in the agreement) in The City of Edmonton in the Province of Alberta. In addition, the Company must maintain at least 350 employees based in The City of Edmonton for a period of 25 years following completion of the Offering.

Pursuant to this agreement, the Company has agreed to maintain its Head Office in The City of Edmonton, and in connection with that agreement, to issue and to cause Capital Power LP General Partner to issue the Special Limited Voting Share and the Special Limited Voting GP Share, respectively, to EPCOR. See "Description of Share Capital and Exchangeable LP Units — Capital Power — Special Limited Voting Share" and "Description of Share Capital and Exchangeable LP Units — Capital Power LP General Partner — Special Limited GP Voting Share". Each of the Special Limited Voting Share and the Special Limited Voting GP Share is non-voting except with respect to its right to vote separately as a class in connection with certain specified fundamental matters affecting the Company or Capital Power LP General Partner, respectively, including any proposal to amend the articles of the Company or Capital Power LP General Partner to provide that the "Head Office" will be in a location other than Edmonton, and certain related matters. EPCOR has agreed to obtain the approval of The City of Edmonton to any exercise of the voting rights attaching to the Special Limited Voting Share or the Special Limited Voting GP Share.

MANAGEMENT

Directors and Executive Officers

The following table sets forth information regarding the Company's directors and executive officers whose appointment will be effective immediately following completion of the Offering.

Name	Municipality of Residence	Age	Position/Title	Share Ownership
Donald James Lowry	Edmonton, Alberta, Canada	57	Chair	2,000
Brian Tellef Vaasjo	Edmonton, Alberta, Canada	53	Director, President and Chief Executive Officer	20,000
Albrecht W.A. Bellstedt	Canmore, Alberta, Canada	60	Director	2,500
William Edward Bennett	Chicago, Illinois, U.S.	62	Director	0
Brian C. Bentz	Vancouver, British Columbia, Canada	66	Director	0
Hugh John Bolton, FCA	Edmonton, Alberta, Canada	71	Director	1,000
Richard H. Cruickshank Q.C.	Edmonton, Alberta, Canada	59	Director	1,000
Philip C. Lachambre	Edmonton, Alberta, Canada	58	Director	1,000
Robert Lawrence Phillips Q.C.	Vancouver, British Columbia, Canada	58	Director	2,000
Brian F. MacNeill FCA	Calgary, Alberta, Canada	69	Director	5,000
Allister John McPherson	Edmonton, Alberta, Canada	65	Director	5,000
Janice Rennie FCA	Edmonton, Alberta, Canada	52	Director	1,000
Graham Lloyd Brown	Chicago, Illinois, U.S.	56	Senior Vice President Operations	0
B. Kathryn Chisholm	Edmonton, Alberta, Canada	46	Senior Vice President General Counsel and Corporate Secretary	1,500
Dr. Kenneth Douglas Cory	Sherwood Park, Alberta, Canada	42	Senior Vice President Strategy and Risk	500
Stuart Anthony Lee	Sherwood Park, Alberta, Canada	45	Senior Vice President and Chief Financial Officer	4,000
James Nicholas Oosterbaan	Calgary, Alberta, Canada	49	Senior Vice President Commercial Services	10,500
John David Harrison Patterson	Edmonton, Alberta, Canada	63	Vice President and Treasurer	0

Each of Messrs. Vaasjo, Cory and Lee is a director and executive officer of the Company and Mrs. Chisholm and Mr. Patterson are executive officers of the Company as at the date of this prospectus. As none of the other above-mentioned individuals will be appointed as directors or executive officers of the Company prior to the filing of this prospectus, such other individuals will not have any liability for the contents of this prospectus in such capacities under Canadian provincial securities legislation.

As a group, the directors and executive officers of the Company beneficially own, or control or direct, directly or indirectly, 57,000 Common Shares, representing less than 1% of the issued and outstanding Common Shares immediately following the closing of the Offering (on a fully-diluted basis).

Directors

Donald James Lowry

Donald Lowry is the President and Chief Executive Officer at EPCOR and has led the transformation of EPCOR into a North American power and water company. Under his leadership, EPCOR has delivered on its plan to achieve sustained growth.

Over the 10-year period from 1996-2006, EPCOR's revenues and employee count have doubled, and shareholder book equity grew an average of 12.4% annually. In 2007, EPCOR increased its common dividend payment for the seventh consecutive year.

Prior to joining EPCOR, Mr. Lowry spent more than 20 years in the telecommunications industry, including six years as President and Chief Operating Officer of Telus Communications Inc.

Mr. Lowry graduated from the University of Manitoba with a Bachelor of Commerce (Honours), followed by a Master of Business Administration degree. He is a graduate of the Harvard Advanced Management Program and the Banff School of Management.

Mr. Lowry is chair of the EPLP General Partner board of directors. He is past chair of the Canadian Electricity Association, and serves on a several other Boards, including Canadian Oil Sands Trust, Alberta Economic Development Authority, and the Banff Centre.

Brian Tellef Vaasjo

Brian Vaasjo was appointed Chief Operating Officer of EPCOR in 2008. Mr. Vaasjo was chiefly responsible for regional power generation and water operations. A primary responsibility was advancing the company's competitive power and water businesses across North America including the clean coal initiatives. Mr. Vaasjo was also President of EPLP and a director of EPLP General Partner since its acquisition in 2005.

Mr. Vaasjo joined EPCOR in 1998 as Executive Vice President and Chief Financial Officer. Mr. Vaasjo led EPCOR's initial public offering of debentures and preferred shares. Since joining EPCOR, Mr. Vaasjo has been responsible for EPCOR's development and acquisition activity for most of his tenure with EPCOR, including the Genesee 3 project and the UE Waterheater Income Fund spin-off. Before joining EPCOR, Mr. Vaasjo spent 19 years with the Enbridge Group of Companies. At Enbridge, Mr. Vaasjo led or played a substantial role in the Consumers Gas acquisition, development of the Alliance and Vector Natural Gas Pipelines and the initial public offering of the Lakehead Pipeline Partners LP among other initiatives. Mr. Vaasjo holds a Master of Business Administration from the University of Alberta where he also received his undergraduate degree. Mr. Vaasjo is a Fellow of the Society of Management Accountants. Mr. Vaasjo also attended the University of Western Ontario Executive Program. In addition, he is a past Chairman of the Board of the United Way, Alberta Capital Region, a member of the Financial Executives Institute of Canada and a board member for the Alberta Shock Trauma Air Rescue Society.

Albrecht W.A. Bellstedt

Albrecht Bellstedt served as general counsel of TransCanada Corporation and a predecessor corporation from January, 1999 until retiring in January, 2007. Prior to that, he was a transactional lawyer in private practice for 27 years.

He currently serves on the boards of The Forzani Group Ltd. (lead director), Canadian Western Bank, and The Churchill Corporation (Chairman). Mr. Bellstedt has served on various other for profit boards (including TC PipeLines, L.P., Sun Times Media Group, Inc., Atlas Cold Storage Income Fund and LSI Logic Corporation of Canada, Inc.) and also not-for-profit boards (including the Alberta University Hospital Foundation, the Edmonton Symphony Orchestra and the Banff Centre).

William Edward Bennett

William Bennett has held numerous positions as a corporate director. Mr. Bennett currently sits as chair of the audit committee of the TD Bank Financial Group, and is a member of TDBFG's Risk Committee. In addition, Mr. Bennett chairs the audit committee of TD Banknorth, the U.S. banking operation of TD Bank Financial Group. Mr. Bennett is the former president and chief executive officer of Draper & Kramer, Inc., a Chicago-based financial services and real estate company. Previously, he served as executive vice president and chief credit officer of First Chicago Corp. and its principal subsidiary, the First National Bank of Chicago. Mr. Bennett has been a private investor since 1998. He holds an undergraduate degree in economics from Kenyon College and a Master of Business Administration from the University of Chicago. Mr. Bennett was a former director of Nuveen Investments Bond and Mutual Funds and currently serves on several non-profit boards in the U.S.

Brian C. Bentz

Brian Bentz provides advisory management services to AMEC plc and acts as an independent corporate director. Mr. Bentz retired in 2008 after a 38 year career in the engineering and project management industry, during which time he held several executive positions including: President, Oilsands and Mining, AMEC, plc; President, Project Investments Americas and Director of Business Development in the United Kingdom; member of the board of directors for AMEC Project Investments Limited (the AMEC company group responsible for developing and operating Private Finance Initiatives (Public Private Partnerships)); President, Special Projects Group, Agra Inc.; and President and Chief Executive Officer of Simons International Corporation. Mr. Bentz has served as a director of several corporations including Czar Oil and Gas Corporation and B.C. Telecom Inc. Mr. Bentz currently acts as a director of MacDonald, Dettwiller and Associates Ltd. (serving on both the Governance & Nomination Committee and the Human Resources & Management Compensation Committee), Seacliff Construction Corp, (serving both on the Governance Committee and the Audit Committee), WDC Exploration and Wells Holding Corporation, Canadian Council for Public-Private Partnerships and is a member of the B.C. Business Council Board of Governors. Mr. Bentz has been a Chartered Accountant since 1969, and holds a Bachelor of Science degree from University of British Columbia.

Hugh John Bolton, FCA

Hugh Bolton is the non-executive chair of the board of directors of EPCOR Utilities Inc. Prior to his appointment as chair of the EPCOR Utilities Inc. board of directors on January 1, 2000, and after his retirement as chairman & chief executive partner of Coopers & Lybrand Canada, Chartered Accountants on January 1, 1998, Mr. Bolton continued as a financial consultant with PricewaterhouseCoopers until December 2000. Mr. Bolton currently serves as: chair of the board of directors of Matrikon Inc., and a director of Canadian National Railway Company, Teck Resources Limited, WestJet Airlines Ltd., TD Bank Financial Group, and the Alberta Shock Trauma Air Rescue Society.

Mr. Bolton holds an undergraduate degree in economics from the University of Alberta. He is a chartered accountant and fellow of the Alberta Institute of Chartered Accountants. In 2006, he was honoured as a Fellow of the Institute of Corporate Directors.

Richard H. Cruickshank, Q.C.

Richard Cruickshank currently serves as a senior partner with the national law firm, Fraser Milner Casgrain LLP. Prior to the merger of Cruickshank Karvellas with Fraser Milner Casgrain LLP in 2000, Mr. Cruickshank had, for 20 years, served as a member of the executive committee and, periodically, as the managing partner of Cruickshank Karvellas.

Mr. Cruickshank has practiced primarily in the tax and corporate law areas for 33 years and has served as president of the Edmonton Bar Association, member of the Board of the Edmonton Chamber of Commerce, Secretary to the Board of the Edmonton Community Foundation and Chair and member of the Board of Trustees of the University Hospital Foundation.

Mr. Cruickshank attended Brown University of the University of Winnipeg from which he received a Bachelor of Arts (Economics) followed by his LL.B. from the University of Manitoba.

Philip C. Lachambre

Phillip Lachambre is currently President of PCML Consulting Inc. Mr. Lachambre has held many positions in the oil and gas, mining and construction sectors during his thirty-seven year career, thirty-one of which were at Syncrude Canada Ltd. where he was appointed to the position of Executive Vice President in 1997 and held the position of Chief Financial Officer from 1994 until his retirement in 2007. Mr. Lachambre's areas of responsibility have included corporate strategy and business planning, controllers, treasury and pension, legal and regulatory affairs, corporate environment, health and safety, mine closure and reclamation, business development, government and public affairs, investor and stakeholder relations, human resources, procurement and contracts, information services and technology, aboriginal affairs, corporate aviation and housing construction, property management and maintenance.

Mr. Lachambre holds a Bachelor of Commerce degree from the University of Alberta, is a Certified Professional Purchaser, and is a graduate of the Executive Management Program of the University of Western Ontario. Mr. Lachambre is also active in a number of local community organizations and boards, including Director of Flint Energy Services Ltd., Director of GLM Industries Inc. and Director of the University Hospital Foundation.

Robert Lawrence Phillips, Q.C.

Robert Phillips was most recently president and chief executive officer of the BCR Group of Companies from March 2001 to July 2004. Mr. Phillips practiced corporate law for 15 years and has served in senior executive positions with Husky Oil, Dreco Energy Services, PTI Group, and MacMillan Bloedel Limited.

Mr. Phillips received degrees in Chemical Engineering and Law from the University of Alberta. He serves on the boards of several Canadian corporations, including Axia NetMedia Corporation, TerraVest Income Fund, Canadian Western Bank, Precision Drilling Corporation, West Fraser Timber Co. Ltd., and MacDonald, Dettwiler & Associates Ltd.

Brian F. MacNeill, FCA

Brian MacNeill held the position of Chief Executive Officer of Enbridge Inc., from 1990 until his retirement on January 1, 2001. Mr. MacNeill currently holds board positions with Petro-Canada (Chairman of the Board), West Fraser Timber Co. Ltd., and Telus Corporation.

Mr. MacNeill is a member of the Alberta and Ontario Institutes of Chartered Accountants, and the Financial Executives Institute, and is also a fellow of the Canadian Institute of Chartered Accountants. In 2000, Mr. MacNeill was awarded the University of Calgary's Distinguished Business Leader Award and the Canadian Business Leader Award from the University of Alberta's School of Business in 2002. He was admitted to the Alberta Junior Achievement Business Hall of Fame in 2001 and the Canadian Petroleum Hall of Fame in 2002. In 2005, he was awarded the Lifetime Achievement Award from the Institute of Chartered Accountants of Alberta and honored as a Fellow of the Institute of Corporate Directors.

Allister John McPherson

Allister McPherson has served as Executive Vice President of Canadian Western Bank from September 2000 to November 2005 and was deputy provincial treasurer (Finance and Revenue) for the Province of Alberta from 1984 to 1996. He holds a Master of Science from the University of British Columbia.

Mr. McPherson is currently an external member of the University of Alberta's Investment Committee, chair of the Alberta Credit Union Deposit Guarantee Corporation, a director of The Churchill Corporation and a member of the Edmonton Regional Advisory Board of the Alberta Motor Association. He is a past director and vice chair of the Edmonton Regional Airports Authority and a past governor of Northern Alberta Institute of Technology and past chair of the Endowment Fund Policy Committee of Alberta Finance.

Janice Rennie, FCA

Janice Rennie is an independent director and business advisor. She has held senior management positions with a number of companies including, most recently as Senior Vice President of Human Resources and Organizational Effectiveness at EPCOR from 2004 to 2005. Ms. Rennie was also Principal of Rennie & Associates, which operated a number of business interests and she has served as President of Research Technology Management Inc. and Bellanca Developments Ltd. and Senior Vice President of Princeton Developments Ltd., all private companies. Ms. Rennie has served as Corporate Director for various for-profit and not-for-profit organizations since 2005 to present. Ms. Rennie currently serves on the boards of Greystone Capital Management Inc., Matrikon Inc., Methanex Corporation, West Fraser Timber Co. Ltd. and Teck Resources Limited. In addition, Ms. Rennie has served on the boards of the Alberta Stock Exchange, Bellanca Developments Ltd., Calgary Centre Holdings Ltd., Canadian Hotel Income Properties REIT, EPCOR, EPCOR Preferred Equity Inc., NOVA Chemicals Inc., Research Technology Management Inc. and Weldwood of Canada Limited.

Ms. Rennie attended the University of Alberta where she received her Bachelor of Commerce (with distinction), her Chartered Accountant designation and thereafter was made a fellow of the Alberta Institute of Chartered Accountants.

Executive Officers

***Graham Lloyd Brown**, Senior Vice President Operations*

Graham Brown joined EPCOR Regional Power Services LP as Director of Eastern Operations in 2005 where his chief role included maximizing plant revenues while improving efficiency, safety and environmental compliance. In November 2006, EPCOR purchased Ventures where his experience in managing hydro, solid fuel, natural gas turbine and renewable energy plants proved highly valuable as he assumed the role of Vice President of Operations for Ventures in January 2007.

Mr. Brown began his career at GEC Gas Turbines Ltd. in Leicester, England in 1975 where he spent seven years building, operating and maintaining natural gas turbine power plants and gas pumping stations in the United Kingdom, Europe and the U.S. In 1982, he immigrated to Canada to join Ontario Hydro (subsequently Ontario Power Generation) and was involved in power operations for the next 23 years. Mr. Brown is from Manchester, England, and is a graduate of Mechanical Engineering from Leicester Polytechnic, Leicester, England as well as a Certified Professional Engineer since 1988. Mr. Brown is a director of EPLP General Partner.

***B. Kathryn Chisholm**, Senior Vice President General Counsel and Corporate Secretary*

Kathryn Chisholm is Senior Vice President General Counsel and Corporate Secretary, with overall responsibility for the management of Capital Power's legal and regulatory affairs. Mrs. Chisholm joined EPCOR in 2004. Mrs. Chisholm served as EPCOR's Senior Vice President General Counsel and Corporate Secretary, directing all legal, regulatory and environmental affairs for EPCOR, EPLP, and their subsidiaries. At EPCOR, she also had responsibility for corporate compliance and ethics.

Mrs. Chisholm obtained her Bachelor of Arts from Mount Allison University, her LL.B. from the University of Alberta, and her Master of Business Administration from Queen's University. She was called to the Alberta Bar in 1989, and is a member of the Canadian Bar Association, the Law Society of Alberta, the Calgary Bar Association, the Canadian Corporate Counsel Association, the Association of Corporate Counsel (U.S.) and the Canadian Society of Corporate Secretaries. Mrs. Chisholm holds the ICD.D designation from the Institute of Corporate Directors and is a Certified Compliance and Ethics Professional in the U.S. and Canada. Mrs. Chisholm has authored various works about electric industry issues and corporate/commercial concerns.

Mrs. Chisholm has practiced law within the energy industry since 1989 and has specialized in the electric industry since 1994. She regularly deals with corporate, commercial, operational, environmental and regulatory issues, and has significant experience with transaction and project development work. Before joining EPCOR, Mrs. Chisholm represented clients before such tribunals as the Alberta Energy and Utilities Board, the British Columbia Utilities Commission, the Ontario Energy Board, the National Energy Board and the (U.S.) Federal Energy Regulatory Commission. Mrs. Chisholm provided counsel and expert witness testimony in numerous electric utility hearings, including those arising from the restructuring of the Alberta electricity industry.

In 2008, Mrs. Chisholm was awarded the Robert V.A. Jones Award for excellence in corporate counsel service.

***Dr. Kenneth Douglas Cory**, Senior Vice President Strategy and Risk*

Kenneth Cory was appointed Executive Vice President of Finance and Administration in 2007 and was responsible for the creation of EPCOR's long-term plan, its supporting financial strategy, and the oversight of the Information Technology function. He holds a Bachelor degree in Finance from the University of South Florida and a Doctor of Philosophy in Strategic Management from Texas A&M where he also served on the faculty.

Dr. Cory has over 12 years of industry experience in strategy/financial management that includes serving as the head of strategy for two Fortune 500 power companies (Calpine Corporation, from 2000 to 2006, and TXU Corporation, from 1999 to 2000) and as a strategy consultant with Deloitte Consulting. He came to EPCOR

after serving as Chief Executive Officer of V3 Technologies LLC, a start-up renewable-power generation company. Dr. Cory is a director of EPLP General Partner.

***Stuart Anthony Lee**, Senior Vice President and Chief Financial Officer*

Stuart Lee is the Chief Financial Officer of EPLP and has been in this position since Capital Power acquired its interest in EPLP in 2005. He has led several equity and debt offerings to finance EPLP acquisitions. He joined EPCOR in 2003 as Vice President and Corporate Controller.

Mr. Lee is a chartered accountant who articled with one of the large international accounting firms. Prior to joining EPCOR, Mr. Lee worked for five years for Celanese Canada Inc., a large petrochemical manufacturer, as Vice-President and Controller where he was responsible for the reporting, treasury, tax, IT and supply chain functions for the Canadian operations. Mr. Lee has more than 23 years of relevant financial and reporting experience.

***James Nicholas Oosterbaan**, Senior Vice President Commercial Services*

James Oosterbaan was Senior Vice President at EPCOR, responsible for the competitive power and water businesses in Alberta. Mr. Oosterbaan joined EPCOR in 2001. His areas of focus were business development, major project construction, commodity trading, water and power plant operations, and sales to end use customers. During his time at EPCOR, Mr. Oosterbaan was successful in guiding and further developing EPCOR's competitive water and power and commodity trading businesses through the deregulation of the Alberta electricity markets.

Prior to joining EPCOR, Mr. Oosterbaan was a consultant in the energy and information technology sectors, and employed with the Westcoast Energy Group of Companies. While at Westcoast, he had management responsibilities in the areas of marketing, business development, forecasting, natural gas supply portfolio management, and regulatory affairs. Mr. Oosterbaan is a graduate of Stanford University's Executive Management Program. He holds a Master of Business Administration from the Ivey School of Business and a Bachelor of Business Administration (Honours) from Wilfred Laurier University.

***John David Harrison Patterson**, Vice President and Treasurer*

John Patterson is a senior financial executive with over 30 years experience in developing treasury, corporate finance and strategic planning functions to meet the operational requirements of Canadian resource and telecommunications companies. At EPCOR, his responsibilities include developing and implementing financial structuring solutions for EPCOR, its subsidiaries and the projects that they undertake.

Since joining EPCOR as Assistant Treasurer in early 2000, Mr. Patterson has provided his financial expertise and advice to facilitate EPCOR's growth during the last 9½ years. He was the financial representative on EPCOR's project teams: (a) evaluating and acquiring Alberta PPAs for deregulation, (b) acquiring Union Energy and Ontario Hydro Energy Services and (c) establishing the new UE Waterheater Income Fund. During this same period, he has completed three Alberta rate rider securitizations, amended a fourth securitization of rental waterheater receivables and played a leading role in EPCOR's two preferred share issues and the creation of its Medium Term Note program. In addition, he has provided financial engineering for a number of EPCOR projects. In 2005, he was appointed Treasurer of EPCOR and in 2007 also became Treasurer of EPLP.

Previously, Mr. Patterson's career experience has included negotiating several corporate and project financings, performing numerous evaluations of resource projects and potential acquisition targets, preparing long term strategic plans and developing banking relationships and treasury functions for six Canadian companies in the resource, telecommunications and manufacturing sectors.

Pending completion of the Offering and the Reorganization, the following individuals, being officers of EPCOR, serve as the Company's directors and officers:

Name	Municipality of Residence	Age	Position/Title	Share Ownership
Brian Tellef Vaasjo	Edmonton, Alberta	53	Director, President and Chief Executive Officer	0
Stuart Anthony Lee	Sherwood Park, Alberta	45	Director, Senior Vice President and Chief Financial Officer	0
Dr. Kenneth Douglas Cory . . .	Sherwood Park, Alberta	42	Director, Senior Vice President Strategy and Risk	0
B. Kathryn Chisholm	Edmonton, Alberta	46	Senior Vice President General Counsel and Corporate Secretary	0
John David Harrison Patterson . .	Edmonton, Alberta	63	Vice President and Treasurer	0

Terms of Directors and Executive Officers

The Company's directors will hold office for a term expiring at the conclusion of the next annual meeting of shareholders of the Company or until their successors are elected or appointed and will be eligible for re-election. The Company's officers are appointed by, and serve at the discretion of, the Board.

Board of Directors

Currently, the Company's Board of Directors (the "Board") consists of three directors, Brian Vaasjo, Stuart Lee and Kenneth Cory, each of whom is an officer of EPCOR and an officer of the Company. Following the filing of the final prospectus, Stuart Lee and Kenneth Cory will be removed from the Board and Allister McPherson and Robert Phillips will be added to the Board. Each of Messrs. McPherson and Phillips is an EPCOR director, and is considered independent of EPCOR and the Company.

Immediately following the completion of the Offering and immediately prior to the Reorganization, nine additional directors will be appointed to the Board. Of these nine additional directors, Messrs. Lowry and Bolton will be additional nominees of EPCOR. Nine of the twelve directors will be independent directors of the Company.

Independent Directors

The members of the Company's audit committee (the "Audit Committee") and a majority of the members of the Company's Corporate Governance, Compensation and Nominating Committee (the "CGCN Committee") will be independent directors.

At the first annual meeting of the Company and thereafter, only holders of Common Shares will be entitled to vote for the election of any director other than the individuals nominated and elected to the Company's Board by EPCOR (or its assignees) pursuant to the rights attached to the Special Voting Shares, unless the holders of Special Voting Shares collectively beneficially own Exchangeable LP Units and Common Shares representing less than 10% of the Common Shares, assuming the exchange of all Exchangeable LP Units for Common Shares, in which case holders of Special Voting Shares will vote together with the holders of Common Shares as a single class for the election of directors. Each candidate for election as a director by the holders of the Common Shares proposed in any management proxy circular of the Company will have been recommended to the Board by the CGCN Committee and approved as a proposed director by the Board.

Selection of Independent Directors

EPCOR retained a third party consultant to assist it in the identification and selection of the proposed independent directors of the Company in addition to its nominees. The consultant reported to EPCOR's Chief Executive Officer and its Corporate Governance and Nominating ("CG&N") Committee. In turn, EPCOR's

CG&N Committee recommended a slate of independent directors for the Company to the board of directors of EPCOR for its consideration and further recommendation to the Board.

In addition, EPCOR retained another third party consultant to assist it in the determination of the appropriate compensation for directors of the Company. This consultant reported to EPCOR's CG&N Committee, which in turn recommended to the EPCOR board compensation for the directors of the Company it considered appropriate until such time as the Board undertakes a review of Board Policies director compensation.

The EPCOR board of directors has determined that it would be of assistance to provide the Board with recommendations for the Board's consideration, as to certain documents in respect of the corporate governance practices of the Company, including the Board's mandate and a mandate for each of its committees, position descriptions for each of the Board Chair, the lead director and the Chief Executive Officer ("CEO") of the Company and a Board policy addressing, among other things, areas such as conflicts of interest, insider trading and whistle-blowing. These recommendations are based in large part on existing practices of EPCOR.

EPCOR Nominees

Each of Messrs. Lowry, Bolton, McPherson and Phillips is an EPCOR nominee and is familiar with the business that EPCOR will transfer to the Company pursuant to the Offering and the Reorganization. The appointment of each as a nominee of EPCOR and of Mr. Vaasjo as President and CEO and a director of the Company has been recommended to the EPCOR board of directors by the EPCOR CG&N Committee and approved by the EPCOR board of directors. It is intended that Mr. McPherson, who is a member of the EPCOR audit committee, will initially serve in a similar capacity on the Audit Committee to provide continuity.

Audit Committee

Audit Committee Mandate

The Audit Committee will operate under the Audit Committee Terms of Reference set out under Appendix B hereto.

Composition of the Audit Committee

Effective immediately following the completion of the Offering, the Audit Committee will consist of Messrs. Bennett, Lachambre and McPherson and Ms. Rennie, each of whom is considered "independent" and "financially literate" within the meaning of National Instrument 52-110 — *Audit Committees* ("NI 52-110"). The Company is relying on the exemption in Section 3.2(2) of NI 52-110 for the period between the filing of the prospectus and the completion of the Offering and the Reorganization as a majority of the Audit Committee will be "independent" within the meaning of NI 52-110. For the education and experience of each member of the Audit Committee relevant to the performance of his or her duties as a member of the Audit Committee see "— Directors".

Polices and Procedures for the Engagement of Audit and Non-audit Services

Under its Terms of Reference, the Audit Committee is required to pre-approve all non-auditing services to be performed by the external auditors in relation to the Company and its subsidiaries. Annually, the external auditors will submit their work plan to the Audit Committee, including the nature and scope of any audit-related advisory services (as requested by management) planned for the upcoming year. That plan is reviewed and pre-approved by the Audit Committee. Once pre-approved, management has the authority to schedule such services. Any unplanned audit-related advisory services or other advisory services are presented for pre-approval at the regularly scheduled meetings of the Audit Committee. If, due to timing issues, the pre-approval of non-audit services must be expedited and it is not practical to wait until the next scheduled Audit Committee meeting, the Chair of the Audit Committee has the delegated authority, on behalf of the Audit Committee, to pre-approve the non-audit services when the individual engagement fees are projected to be less than $50,000, subject to an annual maximum approval limit of $200,000.

Auditor's Fees

KPMG LLP is the Company's auditor and has also served as EPCOR's auditor continuously for the past 14 years. Fees billed by KPMG LLP to the Company for the five months ended May 31, 2009 in respect of the Company and the Company's subsidiaries are estimated to be approximately $1.3 million as detailed below.

($ millions)	Five months ended May 31, 2009
Audit fees	$1.0
Audit-related fees	0.3
Tax fees	—
All other fees	—
Total	**$1.3**

Audit fees — Audit fees billed are for professional services rendered for the audit and review of the financial statements of the EPCOR Power Group or services provided in connection with the Offering.

Audit-related fees — Audit-related fees are for assurance and related services that are reasonably related to the performance of the audit or review of the financial statements and are not reported under audit fees listed above.

Tax fees — Tax fees are tax-related services for review of tax returns, assistance with questions on tax audits, and tax planning.

All other fees — All other fees are fees for services other than audit fees, audit-related fees and tax fees, including advisory services.

Other Committees

Apart from the Audit Committee and the CGCN Committee, the Board of Directors has established: (i) the Environmental, Health & Safety Committee to oversee matters relating to the impact of the Company's operations on the environment and on workplace health and safety; and (ii) the Keephills 3 Oversight Committee to oversee the construction of Keephills 3.

Executive Compensation

Corporate Governance, Compensation & Nominating Committee

Composition

The CGCN Committee will be a committee of the Board, composed of four members of the Board of Directors, all or a majority of which will be independent. The composition of the CGCN Committee will be established after all members to be appointed to the Board have been appointed.

In the absence of an existing CGCN Committee for Capital Power, the EPCOR Human Resources and Compensation Committee ("EPCOR HR&C Committee") has set the initial compensation for the Company's executives. None of the members of the EPCOR HR&C Committee are employed by EPCOR or the Company.

Mandate

With respect to executive compensation, the CGCN Committee will assist the Board in fulfilling its responsibilities relating to the compensation, evaluation and succession of directors and employees of the Company, as well as oversight of the Company's corporate governance and identifying conditions for Board nomination. The role of the CGCN Committee with respect to compensation will be to:

- oversee, review and recommend for approval by the Board, executive compensation policies including all forms of compensation for the directors, the CEO and each member of the Company's executive team;
- oversee the general compensation policies and plans for the Company; and
- review and approve the annual performance measures for incentive plans.

The CGCN Committee has written terms of reference that establish its purpose, responsibilities, and membership.

The CGCN Committee will seek to undertake an objective process for determining compensation by holding "in camera" sessions at the end of each committee meeting, without management present, and a record will be kept of any decisions made during such sessions.

In conjunction with the establishment of compensation for the Company's executives, the EPCOR HR&C Committee retained the services of an executive compensation consultant, Towers Perrin, to provide advice on levels of compensation in the competitive market in which the Company operates and on other compensation matters such as total compensation benchmarking, peer group selection and incentive design and calibration. In 2009, fees of approximately $165,000 have been paid to Towers Perrin for their advice to the EPCOR HR&C Committee regarding compensation for the Company's executives.

Towers Perrin also provides consulting advice and administrative support to the Company on pension and benefits matters.

Compensation Approval Process

In determining the base salary, short-term incentives and long-term incentives of the Company's executives, the EPCOR HR&C Committee considered a comprehensive market analysis including market data for similar positions within the comparator group, including the CEO, the Chief Financial Officer (the "CFO") and the next three most highly compensated executive officers of the Company (together with the CEO and CFO, the "Named Executive Officers", or "NEOs", unless indicated otherwise).

The EPCOR HR&C Committee reviewed the various compensation elements both individually and in total to seek alignment with the Company's compensation program objectives. The EPCOR HR&C Committee then made recommendations on all executive pay and long-term incentive options to the EPCOR Board of Directors for approval.

Compensation Philosophy

The compensation of the Company's executives is influenced by a number of factors, including business strategy, organizational performance and governance. The Company's compensation philosophy aims to achieve the following objectives:

- attract and retain high performing employees through market competitive compensation and a performance culture that rewards superior performance;
- link compensation with the Company's business strategy and objectives; and
- align total compensation with the interests of stakeholders.

These objectives have guided the development of a compensation model that includes base salary, short-term incentives and long-term incentives. The compensation programs are designed to be market competitive with organizations in the Canadian energy and utility industries that are of a similar size and scope of operations to those of the Company. For executives, the primary focus is on performance-related compensation (short- and long-term incentives). The relative weighting on salary, short- and long-term incentives for each executive takes into account the executive's role, his/her ability to affect the Company's results over the short- and longer-term and the compensation mix for similar positions in the competitive market. The Company's short-term incentive plan is designed to reward executives for achievement of corporate, business and individual goals that have a one-year time horizon. The Company's long-term incentive plan is designed to align longer-term executive and stakeholder interests by focusing executives on the Company's longer-term strategic objectives and sustained value creation. The compensation model will transition over time to where base salaries for executives will be targeted at below the median and short- and long-term incentive opportunities at above the median of this market when all performance objectives are met. The aggregate of salary, short-term and long-term incentives would produce above median compensation in the event of superior performance of the Company and/or individual, median compensation in the event of target performance and below-median compensation if performance falls short of expectations.

Comparator Group

Annually, the CGCN Committee will review salary, short- and long-term incentive compensation. As part of this review, the CGCN Committee will consider comparable market data from third party surveys to provide an initial reference point for determining future compensation levels. The CGCN Committee will consider Alberta based energy and utility companies with which the Company competes for talent. In some cases, the comparator group will be modified to reflect geographic location, a particular business line and/or a more comparable position.

The composition of the Company's comparator group is expected to be reviewed annually by third-party consultants and the CGCN Committee for continued relevance. In 2009, the executive compensation comparator group comprised the following companies:

ATCO Ltd.
Canadian Natural Resources Ltd.
Emera Inc.
Enbridge Inc.
Ensign Energy Services Inc.
Fortis Inc.
Husky Energy Inc.
Nexen Inc.
Spectra Energy Corp.
Suncor Energy Inc.
Talisman Energy Inc.
TransAlta Corp.
TransCanada Corp.

Overview of Compensation Mix for Executives in 2009

The table below outlines the mix of base salary and compensation-at-risk for each executive. The percentages shown for short- and long-term incentive compensation assume achievement of target performance levels. While variable compensation represents the greatest proportion of total compensation for each NEO, the actual mix varies according to the executive's role and level in the Company, his relative ability to influence short- and long-term business results and market practices for comparable positions.

Executive	Base Salary (%)	Short-term Incentive Compensation (%)	Long-term Incentive Compensation (%)
Brian Tellef Vaasjo	33	25	42
Stuart Anthony Lee	46	21	33
Kenneth Douglas Cory	45	23	32
James Nicolas Oosterbaan	48	24	28
Graham Lloyd Brown	48	24	28

Base Salary

Salaries are determined based on the responsibilities of each position, the executive's experience and knowledge when compared with market, his performance and internal comparability and will generally align at a point below the median of the comparator group for executive positions with similar responsibilities to those of the Company. Base salaries for non-executive positions will be targeted at the median of the comparator group for positions with similar responsibilities to those of the Company.

Short-Term Incentive Compensation

The Corporate Short-Term Incentive Plan

The corporate short-term incentive plan ("STIP") provides competitive bonuses that reflect corporate, business unit and individual performance. Corporate measures focus on corporate results and create joint accountability among the executives. Business unit measures create added alignment with outcomes, and individual performance allows for the differentiation of payouts based on individual contributions.

- The corporate component will have a 50% weighting and will focus on financial measures.
- The business non-financial component will have a 20% weighting and will focus on unit specific non-financial measurable priorities, for example, safety targets and project milestones.

- Individual performance will have a 30% weighting. Individual executive objectives will include a combination of quantitative and qualitative goals with no pre-determined weightings. These goals are intended to align with the annual corporate objectives and reflect goals which have a reasonable likelihood of being achieved within the relevant year and which, if met, would be considered target performance for purposes of the plan.

The target incentive for each position will be a percentage of base salary and will generally align at a point above the median of the comparator group for executive positions with similar responsibilities to those of the Company. The target incentive for non-executive positions will align at the median of the comparator group for positions with similar responsibilities. The target bonus represents the amount that would be paid if all objectives were achieved at target levels. The corporate STIP is funded using a "sum of targets" approach.

Base Salary (e.g. $300,000)	X	Annual Incentive Target Payout (e.g. 50% — $150,000)	X	Actual Results on Performance Measures: Corporate Performance + Unit Performance + Individual Performance	=	Annual STIP Award (e.g. $150,000)
				Corporate Performance: 50% weight (e.g. $75,000) / Unit Performance: 20% weight (e.g. $30,000) / Individual Performance: 30% weight (e.g. $45,000)		

Actual payouts may be above or below target depending on performance. The maximum payout under the plan will not exceed 2.3 time target.

The Merchant Short-Term Incentive Plan

The merchant STIP is designed to provide traders with an incentive opportunity that is reflective of the competitive market for these types of positions. The plan is funded through a modified version of the corporate STIP and retains the basic threshold, target, maximum framework (50%); combined with a fixed percentage sharing of the merchant groups' incremental profit (50%). The combined pool is allocated based on a discretionary assessment of individual performance. The Senior Vice President of Commercial Services and his direct reports do not participate in the plan. Earnings under the merchant STIP are not pensionable.

Transition from EPCOR's Short Term Incentive Plans

The Company will transition from EPCOR's STI plan by calculating a prorated incentive award for each transferring employee on the basis of eligible service between January 1, 2009 and June 30, 2009, employee STI target percentages immediately preceding the transaction date and the employee's 2008 performance rating. Payments will be held on reserve and paid out in 2010. The Company's approved STI model will be used to calculate incentive payments for eligible service after July 1, 2009.

CGCN Committee Oversight

After considering and evaluating the performance results for the year, the CGCN Committee will retain the discretion to adjust payouts under the corporate STIP and merchant STIP to take into account factors affecting performance that are beyond the participants' control.

Long-Term Incentive Compensation

The EPCOR board of directors has approved the 2009 Plan and has recommended as to the structure of the LTI Plan for the Company's 2010 fiscal year and onward, pursuant to which the Board may in its discretion grant from time to time stock options, performance share units ("PSUs"), restricted share units ("RSUs") and stock appreciation rights ("SARs") to employees and consultants, the "eligible participants", of the Company and its affiliated entities. See also "Options to Purchase Securities".

2009 Plan

The 2009 Plan is structured as a stock option plan providing for one-time only grants of options that will replace the value of outstanding 2006, 2007, 2008 and 2009 phantom option grants of EPCOR currently held by individuals who will become employees and executives of Capital Power. The options granted under the 2009 Plan have not yet been granted, but will be granted prior to closing of the Offering.

The purpose of the options granted under the 2009 Plan is to make whole, and not provide any immediate advantage to, employees and executives of Capital Power whose employment with EPCOR will cease and whose replaced phantom options will be cancelled. The terms of the stock options are based on the fair market value of the Common Shares, and give recipients the opportunity to benefit financially when the Company's value, as reflected by the market price of the Common Shares as determined in accordance with the terms of the 2009 Plan, appreciates between the date on which the options are granted and the date on which they are exercised.

The value of phantom options of EPCOR from 2006, 2007, and 2008 grants to be cancelled will be calculated on a theoretical value basis, based on the remaining term and current value. The value of phantom options of EPCOR from 2009 grants to be cancelled will be calculated on an expected value basis, as at the time of their grant. The exercise price for options granted under the 2009 Plan will not be less than the initial public offering price. The number of stock options to be granted under the 2009 Plan to replace the value of the cancelled phantom options will be determined using the binomial option pricing model, which will be dependent on the initial public offering price and other variables including:

Variable	Value
Expected Life	"Safe Harbour" method based on a seven-year term
Volatility	20% (estimated based on similar publicly-traded companies)
Dividend Yield	4.75% - 5.5%
Risk Free Interest Rate	Based on Government of Canada treasury bills and bonds at December 31, 2008

The valuation will be reviewed by the EPCOR HR&C Committee and approved by the Board as part of the approval of the 2009 Plan prior to awarding grants.

The Board has overall authority for interpreting, applying, amending and terminating the 2009 Plan.

Options granted under the 2009 Plan may be exercised during the period determined under the 2009 Plan, which is generally seven years, or the shorter option period established by the CGCN Committee for any individual grant. The 2009 Plan also provides that, unless otherwise determined by the Board, options will terminate within specified time periods set out in the 2009 Plan following the termination of employment of an eligible participant with the Company or affiliated entities. The options granted under the 2009 Plan will be unvested at grant, with one third vesting on January 1 of each of 2010, 2011, and 2012.

When used in this paragraph, the terms "insiders" and "security-based compensation arrangement" have the meanings ascribed thereto in the TSX rules for this purpose. The number of Common Shares that may be (a) reserved for issuance to insiders pursuant to the 2009 Plan and under any other security-based compensation arrangement of the Company and (b) issued within a one-year period to insiders pursuant to the 2009 Plan and under any other security-based compensation arrangement of the Company, is in each case limited to 10% of the total number of outstanding Common Shares after giving effect to the exchange of the Exchangeable LP Units. The number of Common Shares which may be reserved for issuance to any one participant pursuant to the 2009 Plan and under any other security-based compensation arrangement of the Company or options for services granted by the Company is limited to 5% of the total number of outstanding Common Shares after giving effect to the exchange of the Exchangeable LP Units.

If options granted under the 2009 Plan would otherwise expire during a trading black-out period or within 10 business days of the end of such period, the expiry date of the option will be extended to the tenth business day following the end of the black-out period.

The interests of any participant under the 2009 Plan or in any option are not transferable, subject to limited exceptions.

The 2009 Plan may be amended with the approval of the Board, in accordance with TSX requirements and, to the extent provided under the 2009 Plan, the approval of shareholders of the Company.

LTI Plan

Under the LTI Plan, the Board may in its discretion grant from time to time stock options, PSUs, RSUs and SARs to employees and consultants, the "eligible participants", of the Company and its affiliated entities.

Eligibility to receive grants of stock options, PSUs, RSUs and SARs and grant guidelines will be determined by the Board, provided that non-employee directors of the Company will not be eligible to participate in the LTI Plan. The CEO will recommend to the CGCN Committee the actual recipients of such grants from among the eligible participants, the composition of the grants (as among options, PSUs, RSUs and SARs) and the actual grant size, taking into consideration such factors as their levels of responsibility, performance and market information. In determining the size and composition of the grants that the CGCN Committee recommends to the Board, the CGCN Committee will consider their expected payout and the competitiveness of the Company's total compensation relative to the Company's comparator group in addition to the recommendation of the CEO. The CGCN Committee will determine the grant size and composition to be recommended to the Board in respect of the CEO. The Company intends to make new grants under the LTI Plan in subsequent years without taking prior grants into account when making such new grants.

An aggregate of five million Common Shares or approximately 6.4% of the number of Common Shares expected to be outstanding immediately following completion of the Offering, after giving effect to the exchange of the Exchangeable LP Units, will be reserved for issuance from treasury under the LTI Plan and the 2009 Plan. The Company may satisfy its obligations to deliver Common Shares under the LTI Plan by the issuance of Common Shares from treasury or by acquiring Common Shares in the market. No grants have been awarded under the LTI Plan to date.

When used in this paragraph, the terms "insiders" and "security-based compensation arrangement" have the meanings ascribed thereto in the TSX rules for this purpose. The number of Common Shares that may be (a) reserved for issuance to insiders pursuant to the LTI Plan and under any other security-based compensation arrangement of the Company and (b) issued within a one-year period to insiders pursuant to the LTI Plan and under any other security-based compensation arrangement of the Company, is in each case limited to 10% of the total number of outstanding Common Shares after giving effect to the exchange of the Exchangeable LP Units. The number of Common Shares which may be reserved for issuance to any one participant pursuant to the LTI Plan and under any other security-based compensation arrangement of the Company or options or rights granted for services granted by the Company is limited to 5% of the total number of outstanding Common Shares after giving effect to the exchange of the Exchangeable LP Units.

Options granted under the LTI Plan may be exercised during the period determined under the LTI Plan, which is generally seven years, or the shorter option period established by the CGCN Committee for any individual grant. The LTI Plan also provides that, unless otherwise determined by the Board, options will terminate within specified time periods following the termination of employment of an eligible participant with the Company or affiliated entities. The exercise price for options granted under the LTI Plan is the closing price for Common Shares on the day prior to the grant. The exercise of options may, in the discretion of the Board, be subject to vesting conditions, including specific time schedules for vesting and performance-based conditions such as share price and financial results.

Under the LTI Plan, the Board also has the discretion to attach a SAR to an option when granted to an eligible participant or at a later date. Such SARs provide the holder with a right to receive an amount in cash or Common Shares equal to the difference between the option exercise price at the time of the grant and the closing price for a Common Share on the last trading day prior to exercise. The exercise of any such SARs will be subject to the same terms and conditions as the options to which they are attached. When SARs attached to an option are exercised, the related options are cancelled and the Common Shares underlying such cancelled options will, to the extent not used to satisfy stock-settled SARs, no longer be available for issuance under the LTI Plan.

The LTI Plan also permits eligible participants to receive grants of SARs that are not attached to options ("Stand Alone SARs"). Each Stand Alone SAR gives holders the right to receive an amount in cash or Common Shares equal to the difference between the market price of a Common Share at the time of grant and the market price of Common Shares at the time of exercise of the Stand Alone SAR. The "market price" used for this purpose is the simple-average closing price of the Common Shares as traded on the stock exchange on which the highest aggregate volume of Common Shares have traded on each of the five trading days immediately preceding the grant or exercise date, as the case may be. Such amounts may also be payable at the election of the Company by the delivery of Common Shares. The exercise of Stand Alone SARs may also, at the discretion of the Board, be subject to conditions similar to those that may be imposed on the exercise of stock options.

Under the LTI Plan, eligible participants may be granted PSUs or RSUs, which represent the right to receive an equivalent number of Common Shares at a specified release date or an amount equal to the market price of such number of Common Shares on the release date (market price having the same meaning as in the case of Stand Alone SARs). The delivery of such Common Shares or payment of cash in respect of PSUs or RSUs may, at the discretion of the Board, be subject to vesting requirements similar to those described above with respect to the exercisability of options and SARs, including such time or performance-based conditions as may be established by the Board.

If incentives granted under the LTI Plan that are to be settled in newly issued Common Shares would otherwise expire during a trading black-out period or within 10 business days of the end of such period, the expiry date of the incentive will be extended to the tenth business day following the end of the black-out period.

The interests of any participant under the LTI Plan or in any option, PSUs, RSUs or SAR are not transferable, subject to limited exceptions.

The LTI Plan may be amended with the approval of the Board, in accordance with TSX requirements and, to the extent provided under the LTI Plan, the approval of shareholders of the Company.

The Board has overall authority for interpreting, applying, amending and terminating the LTI Plan.

Benefit and Pension Plans

The Company's benefit and pension plans support the well-being of employees and facilitate retirement savings. The plans will be reviewed periodically to determine whether they are competitive and whether they continue to meet the Company's business and human resources objectives.

Health and Welfare Benefits

The benefit plans are designed to protect the health of employees and their dependents, and cover them in the event of death or disability. The executive officers participate in the same benefits program as all other permanent employees of the Company. The Company provides Canadian based executives with an executive benefit allowance, paid on a bi-weekly basis, to offset employee costs under the plan.

Executive Business Allowance

Executive officers are provided with an annual taxable allowance that can be used to offset the cost of a variety of business related expenses including but not limited to memberships and other out-of-pocket costs associated with performing the duties of the position.

Financial Planning Allowance

Mr. Vaasjo is eligible to receive an annual financial planning allowance in an amount not exceeding $5,000. Other NEOs are eligible to receive an annual financial planning allowance in an amount not to exceed $3,500.

Employee Savings Plan

Under the voluntary Employee Savings Plan, all Canadian based non-bargaining unit employees may contribute up to 10% of their base salary towards a range of investment options, including EPLP units. The

Company matches employee contributions to a maximum of 3% of base salary. It is expected that employees will also be able to invest in Company Common Shares once these shares are publicly traded.

Defined Benefit ("DB") Pension Plan

The NEOs, with the exception of Messrs. Oosterbaan and Brown, as well as many of the current employees of EPCOR whose employment is to be transferred to the Company, participate in the Local Authorities Pension Plan (the "LAPP"), a contributory, defined benefit, best average earnings pension plan that is governed by the *Public Sector Pension Plans Act* (Alberta). The LAPP is a multi-employer pension plan covering approximately 130,000 active employees of Alberta municipalities, hospitals and other public entities as at December 31, 2008. Employee and employer contribution rates under the LAPP are set out in the plan rules and are adjusted from time to time by the LAPP Board of Trustees based on recommendations from the plan's actuary.

The Company is currently in discussions with the LAPP and the Alberta government to determine whether the Company may become a participating employer in the LAPP. If the Company is permitted to become a LAPP participating employer, then employees whose employment is to be transferred to the Company and who currently participate in the LAPP will continue to participate in the LAPP and accrue pension benefits thereunder for service with the Company.

Given that it has not yet been determined whether the Company may become a participating employer in the LAPP, the Company and EPCOR will enter into a secondment agreement (the "Secondment Agreement") pursuant to which they have agreed that the transfer of the employment of the employees of EPCOR who are to become employees of the Company will be deferred until the earlier of: (a) September 30, 2009; (b) the termination of the Secondment Agreement according to the terms of the Secondment Agreement; or (c) such other date as the Company or EPCOR may agree (the "Employment Transfer Date"). Pending such transfer of employment, the Secondment Agreement provides that such employees will provide on comparable terms the same services to the Company as are to be provided to the Company following the Employment Transfer Date. Pursuant to the Secondment Agreement, such services will be provided at the expense of the Company. If the Company is permitted to become a LAPP participating employer, it has agreed with EPCOR to do so. If the Company is not permitted to become a LAPP participating employer, then effective as of the Employment Transfer Date, pursuant to the Pension Transfer Agreement, such of those employees who currently participate in the LAPP will become participants in a DB component to be established by the Company under its registered pension plan (such DB component referred to herein as the "Company DB Plan") having pension benefit provisions comparable to the current pension benefit provisions under the LAPP applicable to such employees. Service and pensionable earnings of such employees will be "frozen" under the LAPP as at the Employment Transfer Date. A DB pension supplement will be provided under the Company DB Plan to enable employees to preserve or keep whole their defined benefit pension with respect to their LAPP service. A more detailed description of the Company's registered pension plan, including the DB pension supplement, may be found under "— Pension Program" below.

Defined Contribution ("DC") Pension Plan

Mr. Oosterbaan participated in the DC component of the EPCOR Utilities Inc. Pension Plan (the "EPCOR Pension Plan") under which contributions are made based on pensionable earnings subject to the annual limits under the Tax Act. The registered pension plan which will be established by the Company will include a DC component (such DC component referred to herein as the "Company DC Plan") and Mr. Oosterbaan's existing DC account balance under the EPCOR Pension Plan will be transferred to the Company DC Plan. Mr. Oosterbaan will participate in the Company DC Plan.

401(k) Plan

Mr. Brown presently participates in the EPCOR 401(k) plan, under which he is permitted to make pre-tax elective contributions of up to 100% (less applicable tax withholdings) of eligible compensation (maximum of U.S. $20,500 in 2008, including up to $5,000 in catch-up contributions for employees at least age 50). Prior to that, as a Canadian based employee, he participated in the DC component of the EPCOR Pension Plan. Mr Brown's existing DC account balance under the EPCOR Pension Plan will be transferred into the Company

DC Plan. Effective on January 1, 2010, Mr. Brown will cease participation in the EPCOR 401(k) plan and commence participation in the Company DC Plan.

Supplemental Pension Plan

The Company will adopt a supplemental pension plan ("SPP") for current management employees which will provide benefits which cannot be provided under the Company's registered pension plan, and, if applicable, the LAPP, due to the Tax Act maximum pension and annual contribution limits. All of the NEOs will participate in the SPP.

Summary Compensation Table

The following table provides a pro forma summary of compensation for each of the NEOs as at the date of closing of the Offering.

					Non-Equity Incentive Plan Compensation				
Name and Principal Position	**Year**	**Salary[1] ($)**	**Share-Based Awards ($)**	**Option-Based Awards[2] ($)**	**Annual Incentive Plans[3] ($)**	**Long-Term Incentive Plans ($)**	**Pension Value[7] ($)**	**All Other Compen-sation ($)**	**Total Compensation ($)**
Brian Tellef Vaasjo . . . . . President and Chief Executive Officer	2009	$650,000	—	$610,370	$487,500	$0	$184,058[8][9]	$45,000[4]	$1,976,928
Stuart Anthony Lee . . . . . Senior Vice President and Chief Financial Officer	2009	$320,000	—	$152,100	$144,000	$0	$ 63,711[8][9]	$33,500[5]	$ 713,311
Kenneth Douglas Cory . . . . . Senior Vice President Strategy and Risk	2009	$350,000	—	$302,530	$175,000	$0	$ 69,914[8]	$44,500[6]	$ 941,944
James Nicholas Oosterbaan . . Senior Vice President Commercial Services	2009	$325,000	—	$303,270	$162,500	$0	$ 65,069[10]	$33,500[5]	$ 889,339
Graham Lloyd Brown . . . . . Senior Vice President Operations	2009	$250,000	—	$141,910	$125,000	$0	$ 17,150[11]	$33,500[5]	$ 567,560

(1) Annualized base salary immediately after the date of closing of the Offering.

(2) Expected value of the stock option grant for 2009 as well as the replacement for the outstanding 2006, 2007 and 2008 grants.

(3) Value of STIP payment at target. Actual awards will vary based on the applicable criteria for such awards. See "— Short-Term Incentive Compensation — The Corporate Short-Term Incentive Plan".

(4) Includes an executive business allowance of $25,000 and an executive benefits allowance of $14,000.

(5) Includes an executive business allowance of $15,000 and an executive benefits allowance of $14,000.

(6) Includes an executive business allowance of $15,000, an executive benefits allowance of $14,000 and estimated mortgage assistance of $12,000.

(7) Value (i) assumes that the Company is permitted to become a participating employer in the LAPP and (ii) excludes one-time transitional effects such as any increase to accrued benefit obligations due to changes in pensionable earnings. If the Company cannot participate in the LAPP and establishes the Company DB Plan, the values will be the same or lower. See "— Benefit and Pension Plans — Defined Benefit ("DB") Pension Plan".

(8) Reflects service cost in respect of the SPP and the annual 2009 employer contribution (current service cost and unfunded liability) of $14,389 to the LAPP.

(9) Reflects increase in pensionable earnings after date of closing of the Offering.

(10) Reflects (i) service cost in respect of the SPP and the annual 2009 DC employer contribution of $12,435 and (ii) change in earnings threshold due to increase in DC employer contribution rates.

(11) Reflects annual 2009 employer contributions to the EPCOR 401(k) plan.

Long-Term Incentive Plan

Treatment of Outstanding LTIP Grants

Employees transferring to the Company will have the value of phantom options granted to them in 2006, 2007 and 2008 under the EPCOR long term incentive plan ("EPCOR LTIP") converted to Company stock options under the 2009 Plan. Vested and unvested phantom options will be converted using a binomial option pricing model with the calculated value of both the vested and unvested EPCOR phantom options determining the replacement grant of Company options. The replacement options will vest one-third each year for the next three years with the first third vesting on January 1, 2010.

The following table sets forth the information regarding the conversion of phantom options held by the NEOs under the EPCOR LTIP:

Name	Phantom Options Held under EPCOR LTIP (#)	Replaced Value ($)	Options granted under Capital Power 2009 Plan (#)
Brian Tellef Vaasjo	133,700	247,420	96,330
Stuart Anthony Lee	31,300	56,500	22,000
Kenneth Douglas Cory	32,500	57,530	22,400
James Nicholas Oosterbaan	60,100	108,270	42,200
Graham Lloyd Brown	14,100	26,910	14,100

Options granted in 2009 under the EPCOR LTIP will be cancelled and a new grant of Capital Power stock options that is equivalent in value to the cancelled EPCOR options will be awarded under the 2009 Plan.

2009 LTIP Grant

The EPCOR LTIP grant for each Company executive is a percentage of salary ranging from 40% to 85%. The grant under the EPCOR LTIP for 2009 will be replaced with a grant of stock options under the 2009 Plan. The initial exercise price of an option is determined based on the value of the Common Shares as at the date on which the options are granted, as further described in the section "— Long-Term Incentive Compensation", above. Options granted in 2009 will vest in equal amounts in each of 2010, 2011 and 2012, with the first third vesting on January 1, 2010, and will have a seven-year term.

The following table sets forth the information regarding the options that will be granted to the NEOs under the 2009 Plan during the 2009 fiscal year in place of phantom options under the EPCOR LTIP:

Name	Expected value of 2009 grant[1]	Number of securities underlying unexercised options (#)	Option exercise price ($)	Option expiration date[2]	Value of unexercised in-the-money options ($)
Brian Tellef Vaasjo	$362,950	141,300	23.00	July 1, 2016	0
Stuart Anthony Lee	$ 95,600	37,200	23.00	July 1, 2016	0
Kenneth Douglas Cory	$245,007	95,400	23.00	July 1, 2016	0
James Nicholas Oosterbaan	$195,000	75,900	23.00	July 1, 2016	0
Graham Lloyd Brown	$115,000	54,900	23.00	July 1, 2016	0

(1) The 2009 grant is based on EPCOR base salaries and LTIP targets and has the equivalent value to the cancelled EPCOR options awarded under the EPCOR LTIP.

(2) Assumes a July 1, 2009 grant date.

Pension Program

Canadian based EPCOR employees currently participate in one of two registered pension plans: the LAPP for employees in the Edmonton region; and the EPCOR Pension Plan which includes a DB component for employees who work in EPLP plants (the "EPLP Component") and a DC component for all remaining employees (the "DC Component"). In addition, EPCOR provides a supplemental pension benefit to management employees whose benefits under the EPCOR Pension Plan and the LAPP are limited due to the Tax Act maximum pension and contribution limits.

The Company intends to establish a single registered pension plan with two components: the Company DC Plan; and a DB component with pension benefit provisions comparable to the current pension benefit provisions under the EPLP Component (the "Company EPLP Plan") for transferring employees currently participating in the EPLP Component.

LAPP Plan

If the Company is permitted to become a LAPP participating employer, then employees of the Company who participate in the LAPP immediately prior to the closing of the Offering will continue to participate in the LAPP and accrue pension benefits thereunder for service with the Company. Employee and employer contribution rates under the LAPP are set out in the plan rules and are adjusted from time to time by the LAPP Board of Trustees based on recommendations from the plan's actuary.

Company DB Plan

If the Company is not permitted to become a LAPP participating employer, the Company intends to establish the Company DB Plan as a third component to its registered pension plan for transferring employees who participated in the LAPP effective as of the Employment Transfer Date. The Company DB Plan will contain pension benefit provisions comparable to the current pension benefit provisions under the LAPP applicable to EPCOR employees currently participating in the LAPP. Under this scenario, the Company will not assume any portion of the LAPP obligations or assets for employees transferring to the Company DB Plan.

The Company DB Plan will include a DB pension supplement intended to keep participants whole by reflecting their earnings and service with the Company in the calculation of their benefit under the LAPP. Specifically, when a participant ultimately retires, terminates or dies, the DB pension supplement will be determined by updating the calculation of the participant's benefit under the LAPP to reflect his or her earnings and service history with the Company and then offsetting this amount by the participant's actual LAPP deferred pension entitlement and entitlement under the Company DB Plan. Participants in the Company DB Plan who elect a deferred pension under the LAPP and who provide sufficient supporting documentation will be eligible for the DB pension supplement. An order of magnitude estimate of the DB pension supplement liability is approximately $15 million, which will be cost-shared between the Company and Company DB Plan participants.

EPLP Component

Transferring employees who participated in the EPLP Component will cease to participate thereunder, effective as of the Employment Transfer Date, and will commence participation in the Company EPLP Plan. Pursuant to an agreement between EPCOR and the Company (the "Pension Transfer Agreement") and in accordance with applicable law, assets and liabilities will be transferred from the EPLP Component to the Company EPLP Plan effective on the date of the closing of the Offering. Following the completion of such transfer of assets and liabilities, the Company EPLP Plan will provide benefits to participants in respect of their service with EPCOR and the Company. A transfer of assets and liabilities into the EPLP Component from a registered pension plan sponsored by TransCanada PipeLines Limited as a result of a prior transaction remains outstanding pending regulatory approval.

Company DC Plan

Contributions to the Company DC Plan are made based on pensionable earnings subject to the annual limits imposed under the Tax Act. All transferring employees who currently participate in the DC component of the EPCOR Pension Plan will commence participation in the Company DC Plan effective as of the Employment Transfer Date. The account balances of such employees under the DC component of the EPCOR Pension Plan will be transferred to the Company DC Plan.

Supplemental Pension Plan

The SPP will provide benefits which cannot be provided under the Company registered pension plan or, if applicable, the LAPP due to the Tax Act maximum pension and annual contribution limits. The Company will assume all obligations of EPCOR relating to the entitlements of the transferring employees under the EPCOR supplemental pension plan. The SPP is unfunded. The pension obligation which the Company will assume from EPCOR under the SPP is estimated to be between $4 million and $5 million.

Capital Power 401(k) Plan

The 401(k) plan maintained by EPCOR will be assumed by the Company effective as of the Employment Transfer Date and the Company's U.S. employees will continue to participate in this plan.

Members are permitted to make pre-tax elective contributions of up to 100% (less applicable tax withholdings) of eligible compensation (maximum of U.S. $20,500 in 2008, including up to $5,000 in catch-up contributions for employees at least age 50). After tax contributions are not permitted. Eligible compensation includes total salary and wages during the plan year as reported on the W-2, including pre-tax contributions to the Plan. Annual compensation in excess of U.S.$230,000, as adjusted for cost of living increases, is not included.

The Company will match employee contributions equal to 100% of the member's pre-tax contributions up to 5% of compensation plus the Company will have the option to make additional matching contribution equal to 2% of the first 2% the member defers. Each year the Company has the option to make an additional matching contribution and/or additional employer contribution on behalf of each eligible participant in amounts determined by the Company.

Interest credited on 401(k) accounts reflects the rate of return on investment options selected by the participant.

Employment Contracts

The Company anticipates that it will enter into employment agreements with all of the named NEOs prior to the completion of the Offering.

If Mr. Vaasjo were to cease employment with Capital Power, his compensation and benefits would be treated as follows:

Event	Action
Resignation	• All salary and benefit programs cease. • Annual short-term incentive payment is forfeited. • All unvested options under the LTI Plan and 2009 Plan are forfeited. • Vested pension paid as a commuted value or deferred benefit. Vested options to expire on the earlier of the original expiry date and the date 90 days after termination of employment.
Retirement	• All salary and benefit programs cease. • Annual short-term incentive payment is paid at target on a pro rata basis. • All unvested options under the LTI Plan and 2009 Plan are forfeited. Vested options to expire on the earlier of the original expiry date and the date 12 months after termination of employment. • Vested pension paid as a monthly benefit.
Death	• All salary, compensation and benefit programs cease. • All unvested options under the LTI Plan and 2009 Plan are forfeited. Vested options to expire on the earlier of the original expiry date and the date 12 months after termination of employment. • Vested pension paid as a commuted value or deferred benefit.
Termination for cause	• All salary, compensation and benefit programs cease. • All unvested options under the LTI Plan and 2009 Plan are forfeited. Vested options to expire on the earlier of the original expiry date and the date 90 days after termination of employment. • Pension paid as a commuted value or deferred benefit.
Termination without cause	• All salary, compensation and benefit programs cease. • Annual short-term incentive is paid at target on a pro rata basis. • All unvested options under the LTI Plan and 2009 Plan vest. Options to expire on the earlier of the original expiry date and the date 90 days after termination of employment. • Vested pension paid as a commuted value or deferred benefit • Severance is provided representing an aggregate of 24 months' of each of, salary, short-term incentive at target, and benefit costs, pension contributions and business allowance.
Double trigger change of control — change of control and termination without cause/resignation based on adverse changes to terms of employment	• All salary, compensation and benefit programs cease. • All unvested options under the LTI Plan and 2009 Plan vest. Options to expire on the earlier of the original expiry date and the date 90 days after termination of employment. • Vested pension paid as a commuted value or deferred benefit • Severance is provided representing an aggregate of 24 months' of each of salary, short-term incentive at target, and benefit costs, pension contributions and business allowance.

If Dr. Cory were to cease employment with Capital Power, his compensation and benefits would be treated as follows:

Event	Action
Resignation	• All salary and benefit programs cease • Annual short-term incentive payment is forfeited • All unvested options under the LTI Plan and 2009 Plan are forfeited. Vested options to expire on the earlier of the original expiry date and the date 90 days after termination of employment. • Vested pension paid as a commuted value or deferred benefit
Retirement	• All salary and benefit programs cease • Annual short-term incentive payment is paid at target on a pro rata basis • All unvested options under the LTI Plan and 2009 Plan are forfeited. Vested options to expire on the earlier of the original expiry date and the date 12 months after termination of employment. • Vested pension paid as a monthly benefit
Death	• All salary and benefit programs cease • Annual short-term incentive payment is paid on a pro rata basis • All unvested options under the LTI Plan and 2009 Plan are forfeited. Vested options to expire on the earlier of the original expiry date and the date 12 months after termination of employment. • Vested pension paid as a commuted value or deferred benefit
Termination for cause	• All salary and benefit programs cease • Annual short-term incentive payment is not paid • All unvested options under the LTI Plan and 2009 Plan are forfeited. Vested options to expire on the earlier of the original expiry date and the date 90 days after termination of employment. • Vested pension paid as a commuted value or deferred benefit
Termination without cause	• All salary and benefit programs cease • Annual short-term incentive is paid at target on a pro rata basis. • All unvested options under the LTI Plan and 2009 Plan vest. Vested options to expire on the earlier of the original expiry date and the date 90 days after termination of employment. • Vested pension paid as a commuted value or deferred benefit • Severance is provided representing an aggregate of 18 months plus two months for each year of service with EPCOR, plus two months for each year worked with Capital Power to a maximum of 24 months', of each of, salary, short-term incentive at target, and benefit costs, pension contributions and allowances
Double trigger change of control — change of control and termination without cause/resignation based on adverse changes to terms of employment	• All salary and benefit programs cease • All unvested options under the LTI Plan and 2009 Plan vest. Options to expire on the earlier of the original expiry date and the date 90 days after termination of employment • Vested pension paid as a commuted value or deferred benefit • Severance is provided representing an aggregate of 18 months plus 2 months for each year of service with EPCOR, plus two months for each year worked with Capital Power to a maximum of 24 months', of each of, salary, short-term incentive at target, and benefit costs, pension contributions and allowances

All other NEOs would receive the following in the event of separation:

Event	Action
Resignation	• All salary and benefit programs cease. • Annual short-term incentive payment is forfeited. • All unvested options under the LTI Plan and 2009 Plan are forfeited. Vested options to expire on the earlier of the original expiry date and the date 90 days after termination of employment. • Vested pension paid as a commuted value or deferred benefit.
Retirement	• All salary and benefit programs cease. • Annual short-term incentive payment is paid at target on a pro rata basis. • All unvested options under the LTI Plan and 2009 Plan are forfeited. Vested options to expire on the earlier of the original expiry date and the date 12 months after termination of employment. • Vested pension paid as a monthly benefit.
Death	• All salary and benefit programs cease. • Annual short-term incentive payment is paid on a pro rata basis. • All unvested options under the LTI Plan and 2009 Plan are forfeited. Vested options to expire on the earlier of the original expiry date and the date 12 months after termination of employment. • Vested pension paid as a commuted value or deferred benefit.
Termination for cause	• All salary and benefit programs cease. • Annual short-term incentive payment is not paid. • All unvested options under the LTI Plan and 2009 Plan are forfeited. Vested options to expire on the earlier of the original expiry date and the date 90 days after termination of employment. • Vested pension paid as a commuted value or deferred benefit.
Termination without cause	• All salary and benefit programs cease. • All unvested options under the LTI Plan and 2009 Plan vest. Vested options to expire on the earlier of the original expiry date and the date 90 days after termination of employment. • Vested pension paid as a commuted value or deferred benefit. • Severance is provided representing an aggregate of 12 month plus ½ a month for each year of service with EPCOR, plus one month for each year worked with Capital Power to a maximum of 24 months', of each of, salary, short-term incentive at target, and annual benefits allowance and annual business allowance.
Double trigger change of control — change of control and termination without cause/resigntion based on adverse changes to terms of employment	• All salary and benefit programs cease. • All unvested options under the LTI Plan and 2009 Plan vest. Vested options to expire on the earlier of the original expiry date and the date 90 days after termination of employment. • Vested pension paid as a commuted value or deferred benefit. • Severance is provided representing an aggregate of 12 months plus ½ month of each year of service with EPCOR, plus one month for each year worked with Capital Power to a maximum of 24 months', of each of, salary, short-term incentive at target, and annual benefits allowance and annual business allowance.

The following table provides an estimate of amounts payable to each NEO in the event of termination without cause or double trigger change of control:

Name	Service for the purpose of calculating severance payment[1]	Estimated severance payment	Estimated value of vested stock options
Brian Tellef Vaasjo	24 months	$2,600,000	$—
Stuart Anthony Lee	15 months	$ 600,000	$—
Kenneth Douglas Cory	20 months	$ 950,000	$—
James Nicholas Oosterbaan	17 months	$ 700,000	$—
Graham Lloyd Brown	14 months	$ 450,000	$—

(1) Assumes a July 1, 2009 date of termination.

Board of Directors Compensation

Retainers and Attendance Fees

The directors' compensation program is designed to attract and retain the most qualified individuals to serve on the Board. In consideration for serving on the Board for 2009, each non-employee director will be compensated as indicated below:

Type of Fee	Amount ($)
Board Chair Annual Retainer	$ 150,000/year
Board Chair Annual Equity Retainer	$ 135,000/year
Lead Director Annual Retainer	$ 45,000/year
Lead Director Annual Equity Retainer	$ 100,000/year
Director Annual Retainer	$ 35,000/year
Director Annual Equity Retainer	$ 80,000/year
Audit Committee Chair Annual Retainer	$ 10,000/year
Corporate Governance, Compensation & Nominating Committee Chair Annual Retainer	$ 7,500/year
Other Committee Chair Annual Retainer	$ 5,000/year
Board Meeting Attendance Fee	$1,500/meeting
Committee Attendance Fee	$1,500/meeting

Directors' DSU Plan

The Company has approved a deferred stock unit plan ("DSU Plan") pursuant to which it is contemplated that non-employee directors of the Company will receive their annual equity retainer in the form of deferred stock units ("DSUs"). Directors will also be entitled to elect to receive DSUs in full or partial satisfaction of their annual retainer, committee retainer, and/or committee chair retainer. The number of DSUs to be granted will be determined by dividing the amount of the retainer payable by the simple-average closing price of the Common Shares as traded on the stock exchange on which the highest aggregate volume of Common Shares have traded on each of the five trading days immediately preceding the date of grant (the "value of a DSU"). Each director will be required to hold DSUs received until the director resigns or is not re-elected, or in the event of the death of a director, following which the DSU will be redeemed for cash during a prescribed period at the value of a DSU prevailing at the date of redemption. No Common Shares will be issuable pursuant to the DSU Plan and a director who receives DSUs will receive additional DSUs in respect of dividends payable on Common Shares, based on the value of a DSU at that time. The Corporation may amend the DSU Plan as it deems necessary or appropriate, but no such amendment may adversely affect the rights of an eligible director in DSUs granted prior to the date of amendment or adversely affect the rights of an eligible director with respect to any amount of eligible retainer in respect of which the director has elected to receive DSUs, without the consent of the eligible director unless required by applicable law. In the view of the CGCN Committee and the Board, the DSU Plan will further align the interests of directors with those of the Company's shareholders.

Corporate Governance

Board of Directors

Immediately after completion of the Offering, nine of the twelve members of the Board will be independent, for the purpose of National Instrument 58-101 — *Disclosure of Corporate Governance Practices* ("NI 58-101"). Under NI 58-101, a director is independent if he or she would be independent within the meaning of independence under NI 52-110. Essentially, a director is independent if he or she has no direct or indirect material relationship with the Company. A "material relationship" is a relationship which could, in the view of the Board, be reasonably expected to interfere with the exercise of a director's independent judgment.

The Board will determine annually whether each of its members is independent based on whether he or she worked for the Company, had any immediate family member engaged in the employment of the Company, benefitted from a business relationship with the Company that could reasonably be perceived to materially interfere with his/her independent judgment or received remuneration from the Company other than remuneration for acting as a member of the Board and Board established committees of the Company.

The Company has taken steps to ensure that adequate structures and processes are in place to permit the Board to function independently of management of the Company. It is contemplated that, following completion of the Offering, the directors will hold in camera sessions of the independent directors without management present at each meeting of the Board. In addition, as it is contemplated that following completion of the Offering, the Chair will not be an independent director, it is contemplated that one of the independent directors who is not a nominee of EPCOR will be appointed as Lead Director in order to ensure appropriate leadership for the independent directors. It is contemplated that the primary responsibilities of the Lead Director will be to (i) seek to ensure that appropriate structures and procedures are in place so that the Board may function independently of management of the Company and, where appropriate, the EPCOR nominees to the Board; and (ii) lead the process by which the independent directors seek to ensure that the Board represents and protects the interests of all shareholders.

Outside Directorships

A number of the individuals who will become directors of the Company upon completion of the Offering are presently a director or trustee of one or more other issuers that are reporting issuers (or the equivalent) in a jurisdiction or a foreign jurisdiction. In addition to EPCOR and EPLP General Partner, there are seven such issuers of which two or more directors of the Company are directors or trustees. The Board has determined that these interlocking directorships/trusteeships do not impact the ability of these directors to act in the best interests of the Company.

Board Meetings

The Board holds regularly scheduled meetings as well as *ad hoc* meetings from time to time. The Board regularly meets without management and the independent directors meet for a portion of such meetings.

Board Mandate

The Board operates under the Board of Directors Terms of Reference set out at Appendix A hereto.

Position Descriptions

The Board acts in a plenary role, and sets out clear expectations for management. The Board has adopted terms of reference for each of the Board Chair, individual directors and CEO. In addition, the Company's by-laws further delineate the role of senior management positions and the Board annually determines the CEO's objectives and conducts an evaluation of the CEO's performance against the established objectives.

Orientation and Continuing Education

The Company has procedures and policies in place for the orientation of new directors. The CGCN Committee's terms of reference require that the CGCN Committee review, monitor and make

recommendations to the Board regarding new director orientation and ongoing development of existing Board members. The Board identifies discussion topics for its annual planning retreat.

In addition, all directors are provided with a Board governance package which contains detailed information about the Company's business, Board and committee mandates, individual director mandates, authority matrices, corporate structure and governance and other related matters of interest for the directors.

Ethical Business Conduct and Compliance

The Company has adopted a written Compliance and Ethics Policy (the "Ethics Policy"), applicable to all permanent and temporary employees of the Company and its directors. The Board of Directors has oversight and control over the policy including governance over all material changes to and deviations from the Ethics Policy. A copy of the Ethics Policy may be obtained from the Company's Corporate Secretary upon request or from the Company's website at www.capitalpowercorp.com.

The Board of Directors will be responsible for oversight of the Company's compliance with applicable laws. The Board of Directors receives regular reports from the Company's compliance and ethics department that includes a report of any breach, management follow-up activities and mitigation strategies. A disclosure committee consisting of members of senior management will be responsible for reviewing and reporting to the Audit Committee with respect to proposed disclosure required to be made in accordance with applicable securities laws.

Nomination of Directors

Other than the directors nominated by EPCOR, the CGCN Committee is responsible for identifying new candidates for Board nomination and for recommending to the Board qualifications for directors including, among other things, the competencies, skills, business and financial experience, leadership roles and level of commitment required to fulfill Board responsibilities. The CGCN Committee recognizes that each director will contribute differently to the Board and will each bring particular strengths in different areas of qualification. After considering the qualifications that existing directors possess and that each potential new nominee would be expected to bring to the Board, and after considering the appropriate level of representation on the Board by directors who are independent, the CGCN Committee identifies candidates qualified for Board membership, and recommends to the Board nominees to be placed before the shareholders at the next annual general meeting.

The EPCOR CG&N Committee will be responsible for identifying EPCOR-elect candidates for nomination to the Board. The EPCOR-elect candidates will be recommended to EPCOR's board of directors for further recommendation to the Company.

Compensation

The CGCN Committee is also responsible for recommending to the Board for approval the compensation arrangements for the directors, including compensation for the Board Chair, for the chairpersons of each Board committee and for member attendance at Board and committee meetings. The CGCN Committee also approves compensation policies and guidelines applicable to employees; it recommends for approval by the Board such incentive compensation plans, equity compensation plans, registered pension plans, supplemental pension plans and other compensation plans for employees as it deems appropriate; and it oversees the management of the Company's incentive compensation plans and equity compensation plans. See "— Executive Compensation — Corporate Governance, Compensation & Nominating Committee".

Towers Perrin has been engaged to provide the CGCN Committee with independent advice in respect of directors' compensation and to advise the CGCN Committee on levels of compensation in the competitive market in which the Company operates and on other compensation matters. In addition, Towers Perrin provides consulting advice and administrative support to the Company on pension and benefits matters.

Further particulars of the process by which compensation for the Company's directors and officers is determined can be found under "— Executive Compensation".

All or a majority of the members of the CGCN Committee are independent for the purpose of NI 58-101.

Assessments

The CGCN Committee will monitor the relationship between management and the Board. Directors will be regularly surveyed with respect to the effectiveness of the Board, its committees and individual Board members and annual Board/director assessments will be conducted with the results reviewed by the Board Chair.

Equity Ownership Guidelines

Directors are subject to share ownership guidelines that require ownership of Common Shares and/or DSUs with an acquisition or market value equivalent to not less than three times the aggregate value of their annual cash and equity retainer. Directors will have five years to accumulate the required number of Common Shares and/or DSUs.

The NEOs are subject to share ownership guidelines that require ownership of Common Shares with an acquisition or market value equivalent to not less than three times base salary in the case of the CEO, and in the case of the other NEOs (inclusive of the CFO), two times base salary. NEOs will have five years from date of appointment to accumulate the required number of Common Shares.

Additional Information Regarding Directors and Officers

Conflicts of interest

Certain conflicts of interest could arise as a result of the Company's relationship with EPCOR. Certain executive officers and directors of EPCOR serve as directors of the Company and its subsidiaries. The Board Chair is an executive officer of EPCOR. See "Risk Factors — Risks Related to the Company's Relationship to EPCOR — Significant Ownership by EPCOR".

Indebtedness of directors and officers

None of the directors or senior or executive officers of the Company, or any of their respective associates or affiliates, is or has since the date of incorporation of the Company, been indebted to the Company, except for routine indebtedness.

Indemnification and insurance

The Company will implement a $100 million director and officer insurance program to be effective on closing. In addition, following the completion of the Offering and the Reorganization, the Company will enter into indemnification agreements with each of its directors and officers. The indemnification agreements will generally require that the Company indemnify and hold the indemnitees harmless to the greatest extent permitted by law for liabilities arising out of the indemnitees' service to the Company as directors and officers, provided that the indemnitees acted honestly and in good faith and in a manner the indemnitees reasonably believed to be in or not opposed to the Company's best interests and, with respect to criminal and administrative actions or proceedings that are enforced by monetary penalty, the indemnitees had no reasonable grounds to believe that his or her conduct was unlawful. The indemnification agreements also provide for the advancement of defence expenses to the indemnitees by the Company.

DESCRIPTION OF SHARE CAPITAL AND EXCHANGEABLE LP UNITS

A description of the share capital of each of the Company, EPLP Holdco and Capital Power LP General Partner, and of the Exchangeable LP Units of Capital Power LP is set forth below. This description discloses all attributes material to an investor in Common Shares but is a summary only, and is qualified in its entirety by reference to the articles of each such corporation and to the Limited Partnership Agreement, as applicable, which will be filed with the Canadian Securities regulatory authorities. Investors are encouraged to read the full text of such articles and the Limited Partnership Agreement. See "Material Contracts and Other Information".

Capital Power

Capital Power's authorized share capital consists of an unlimited number of Common Shares, an unlimited number of preference shares issuable in series, an unlimited number of Special Voting Shares and one Special

Limited Voting Share. Immediately following the closing of the Offering and the Reorganization, 21,750,000 Common Shares (25,012,500 Common Shares, if the Over-Allotment Option is exercised in full), no preference shares, 56,625,000 Special Voting Shares and one Special Limited Voting Share will be issued and outstanding.

Common Shares

Holders of Common Shares will be entitled to one vote for each Common Share held on a ballot vote at all meetings of shareholders of the Company except meetings at which or in respect of matters on which only holders of another class of shares are entitled to vote separately as a class. Except as otherwise provided by the articles of the Company or required by law, the holders of Common Shares will vote together with the holders of Special Voting Shares as a single class.

The holders of Common Shares will be entitled to receive, subject to the rights of the holders of another class of shares, any dividend declared by the Company and the remaining property of the Company on the liquidation, dissolution or winding-up of the Company, whether voluntary or involuntary.

None of the Common Shares will be subdivided, consolidated, reclassified or otherwise changed unless contemporaneously therewith the Special Voting Shares are subdivided, consolidated, reclassified or otherwise changed in the same proportion or same manner. In addition, the Company shall not issue or distribute to all or to substantially all of the holders of the Common Shares either (i) Common Shares or (ii) rights or securities of the Company exchangeable for or convertible into or exercisable to acquire any Common Shares, unless contemporaneously therewith the Company issues or distributes Special Voting Shares or rights or securities of the Company exchangeable for or convertible into or exercisable to acquire Special Voting Shares on the same terms *mutatis mutandis* and in the same proportion.

For a description of Capital Power's dividend policy, see "Dividend Policy".

Preference Shares

The preferences shares may at any time be issued in one or more series. Subject to the Canada Business Corporations Act, the directors may fix, before the issue thereof, the number of preference shares of each series, the designation, rights, privileges, restrictions and conditions attaching to the preference shares of each series, including, without limitation, any voting rights, any right to receive dividends (which may be cumulative or non cumulative and variable or fixed) or the means of determining such dividends, the dates of payment thereof, any terms and conditions of redemption or purchase, any conversion rights, any rights on the liquidation, dissolution or winding up of Capital Power, and any sinking fund or other provisions, the whole to be subject to the issue of a certificate of amendment setting forth the designation, rights, privileges, restrictions and conditions attaching to the preference shares of the series. The preference shares of each series shall, with respect to the payment of dividends and the distribution of assets in the event of the liquidation, dissolution or winding up of Capital Power, whether voluntary or involuntary, rank on a parity with the preference shares of every other series and be entitled to preference over the Common Shares and any other shares ranking junior to the preference shares with respect to priority in payment of dividends and the distribution of assets in the event of the liquidation, dissolution or winding-up of Capital Power. If any amount of cumulative dividends (whether or not declared) or declared non cumulative dividends or any amount payable on any such distribution of assets constituting a return of capital in respect of the preference shares of any series is not paid in full, the preference shares of such series shall participate rateably with the preference shares of every other series in respect of all such dividends and amounts in accordance with the amounts that would be payable with respect to such preference shares if all such dividends were declared and paid in full and all amounts payable on such a return of capital were paid in full. There are currently no outstanding preference shares, and Capital Power has no present intention to issue any preference shares.

Special Voting Shares

Special Voting Shares will initially be issued in connection with or in relation to Exchangeable LP Units for the purpose of providing voting rights with respect to Capital Power to the holders of Exchangeable LP Units. Under the Exchange Agreement, holders will agree not to transfer Special Voting Shares separately from the related Exchangeable LP Units except for certain permitted transfers among affiliates.

Holders of Special Voting Shares will have the right, voting separately as a class, at any meeting of shareholders of the Company at which directors are to be elected, provided that, as at the record date established for the purpose of determining shareholders entitled to vote at the meeting, the holders of Special Voting Shares collectively beneficially own the requisite number of Exchangeable LP Units and Common Shares issuable upon exchange of outstanding Exchangeable LP Units, to nominate and elect the number of directors to the Board set forth below:

Proportion of outstanding Common Shares and Common Shares issuable upon exchange of outstanding Exchangeable LP Units represented by aggregate number of Exchangeable LP Units and Common Shares collectively beneficially owned by the holders of Special Voting Shares	Number of Directors
Not less than 20%	four
Less than 20% but not less than 10%	two

Holders of Special Voting Shares will be entitled at any time, subject to applicable law, voting separately as a class, to remove any one or more of the directors elected by the holders of Special Voting Shares and to nominate and elect successor director(s) to replace the individual(s) previously elected. If there exists or occurs a vacancy on the Board with respect to a director elected or entitled to be elected by the holders of Special Voting Shares, the vacancy will be filled by an individual who is nominated and elected by the holders of Special Voting Shares, voting separately as a class.

If the holders of Special Voting Shares collectively beneficially own an aggregate number of Exchangeable LP Units and Common Shares that represents less than 10% of the aggregate number of outstanding Common Shares and Common Shares issuable upon exchange of Exchangeable LP Units as at the record date established for the purpose of determining shareholders entitled to vote at a meeting, then each Special Voting Share will entitle the holder thereof to that number of votes on a ballot vote at the meeting that is equal to the Vote Per Share, and the holders of Special Voting Shares will vote together with the holders of Common Shares as a single class for the election of directors.

Except as provided above, the holders of the Special Voting Shares will not, in that capacity, have the right to vote for the election of directors.

"Vote Per Share" means, at any time, the amount that is equal to the quotient, rounded down to the nearest 0.0001, obtained when:

(x) the "Maximum Exchange Number" at that time is divided by

(y) the number of Special Voting Shares outstanding at that time.

"Maximum Exchange Number" means, at a time, the number that is equal to the lesser of:

(x) the number of Common Shares for which the Exchangeable LP Units outstanding at that time are then exchangeable; and

(y) the largest whole number that, when added to the aggregate number of votes attached to all of the Common Shares outstanding at that time owned or whose voting rights are controlled by persons that own Exchangeable LP Units or persons who, for purposes of the Tax Act do not deal at arm's length with an owner of Exchangeable LP Units, does not exceed 49% of the aggregate number of votes attached to all of the Common Shares and the Special Voting Shares outstanding at that time.

With respect to all other matters, except matters on which only holders of another class of shares are entitled to vote separately as a class, each Special Voting Share will entitle the holder thereof to that number of votes on a ballot vote at any meeting of shareholders of the Company that is equal to the Vote Per Share, and the holders of Special Voting Shares will vote together with the holders of Common Shares as a single class.

The Special Voting Shares are subject to anti-dilution provisions provided that adjustments will be made to the Special Voting Shares in the event of a change to the Common Shares, or distribution of either Common Shares or rights or securities exercisable to acquire Common Shares to holders of the Common Shares.

If a holder of Exchangeable LP Units exchanges some or all of its Exchangeable LP Units pursuant to the Limited Partnership Agreement and the Exchange Agreement, the Company will redeem the related number of Special Voting Shares held by such holder. The number of Special Voting Shares that the Company will redeem will be equal to the number of Common Shares issuable upon the exchange of such Exchangeable LP Units owned by such holder. The Special Voting Shares will be redeemed at a price per share equal to $0.000001. See "Relationship to EPCOR — Limited Partnership Agreement of Capital Power LP — Partnership Units".

Special Limited Voting Share

The authorized number of Special Limited Voting Shares will be limited to one. The holder of the Special Limited Voting Share will be entitled to receive notice of, to receive materials relating to, and to attend, any meeting of Capital Power's shareholders; however, the holder of the Special Limited Voting Share will not, in such capacity, be entitled to vote at any shareholder meeting except as provided by law or as described below.

The articles of Capital Power provide that any amendment to the articles of Capital Power to change the place in which the "Head Office" (as defined in the articles) is located to a place other than The City of Edmonton in the Province of Alberta or to change in any way the definition of "Head Office" and the related definitions set out in the articles, or any merger, amalgamation, arrangement, reorganization, liquidation or sale of all or substantially all of the property of Capital Power or similar transaction pursuant to which the resulting corporation or other successor to the Company or its business is not required to (i) have its Head Office located in The City of Edmonton; (ii) have a definition of "Head Office" as set out in the articles; or (iii) have a Special Limited Voting Share in the capital of the resulting corporation or other successor to the Company having the same rights and restrictions as those relating to the Special Limited Voting Shares issued to the holder of the Special Limited Voting Share, must be approved by the holder of the Special Limited Voting Share, voting separately as a class, in addition to approval of the holders of the Common Shares and Special Voting Shares voting together as a class or as otherwise required by law. In addition, the jurisdiction of incorporation of Capital Power may not be changed, by continuance or otherwise; no amendment to the articles to increase the maximum number of authorized Special Limited Voting Shares may be made; the rights, privileges, restrictions and conditions of the Special Limited Voting Share may not be amended; no exchange or creation of a right of exchange or right to acquire Special Limited Voting Shares may be effected; and no transaction, including any amendment to the articles, to effect an exchange, reclassification or cancellation of the Special Limited Voting Share may be undertaken, without the approval by the holder of the Special Limited Voting Share, voting separately as a class.

The articles of the Company define "Head Office" to mean the office or offices at which (i) the majority of the Company's senior "Executive Officers", which consist of the persons carrying out as a substantial part of their duties any of the functions of the chief executive officer, chief operating officer, chief financial officer, president, any executive vice-president, senior vice-president or general counsel of Capital Power, which majority shall include the chief executive officer, are located and from which they carry out the majority of their functions, and (ii) the majority of the "Executive Officers" are located and from which they carry out the majority of their functions (such majority including the Chief Executive Officer and the senior Executive Officers referred to in clause (i) above). The term "Executive Officers" is defined in the articles to include the senior Executive Officers referred to above; and (to the extent different from such senior Executive Officers) the persons, whether employed by the Company or any of its subsidiary entities, carrying out as a substantial part of their duties any of the functions of the chief executive officer, chief operating officer, chief financial officer, president, any executive vice-president or senior vice-president or general counsel, with respect to a substantial portion of the businesses carried on by the Company and its subsidiary entities, taken as a whole.

The articles further require that the registered office of the Company be located in The City of Edmonton.

The Special Limited Voting Share carries no right for the holder to receive dividends. The holder of the Special Limited Voting Share has the right to receive, subject to any payment or distribution to holders of preference shares, in preference to the holders of Common Shares and on a pari passu basis with the holders of Special Voting Shares, the amount of $1.00 from the remaining property and assets of Capital Power upon the voluntary or involuntary liquidation, dissolution or winding-up of Capital Power.

EPLP Holdco

The authorized capital of EPLP Holdco will consist of an unlimited number of Class A Shares and an unlimited number of Class B Shares.

Class A Shares

Class A Shares carry no right for the holder to receive dividends or to receive any remaining property and assets of EPLP Holdco upon the voluntary or involuntary liquidation, dissolution or winding-up of EPLP Holdco other than $1.00 per Class A Share in preference to the holders of Class B Shares. Holders of Class A Shares will, except where otherwise provided by law, vote together with holders of Class B Shares as one class at all meetings of shareholders of EPLP Holdco. Each Class A Share will entitle the holder to one vote per Class A Share.

Class B Shares

Holders of Class B Shares of EPLP Holdco are entitled to receive dividends as and when declared by EPLP Holdco's board of directors and, upon the voluntary or involuntary liquidation, dissolution or winding-up of EPLP Holdco, the holders of Class B Shares are entitled to share rateably in the remaining property and assets of EPLP Holdco available for distribution, after payment of liabilities and any payment or distribution to holders of Class A Shares. Holders of Class B Shares will, except where otherwise provided by law, vote together with holders of Class A Shares as one class at all meetings of shareholders of EPLP Holdco, and will be entitled to one vote per Class B Share.

Capital Power LP

Exchangeable LP Units

In connection with closing of the Offering, Capital Power LP will issue Exchangeable LP Units to EPDC. These Exchangeable LP Units will be exchangeable for Common Shares at the option of the holder on a one-for-one basis (subject to customary anti-dilution protections) at any time, subject to certain restrictions described below. Each of the Exchangeable LP Units will be accompanied by a Special Voting Share, as described above, which will entitle the holder of such Special Voting Share to receive notice of, to attend and to vote at meetings of shareholders of Capital Power.

The maximum number of Common Shares for which Exchangeable LP Units may be exchanged at any time is the largest whole number of Common Shares that, when added to the aggregate number of Common Shares outstanding at that time owned or whose voting rights are controlled by persons that own Exchangeable LP Units or persons who, for purposes of the Tax Act do not deal at arm's length with an owner of Exchangeable LP Units, does not exceed 49% of the aggregate number of Common Shares that would be outstanding immediately following such exchange.

For a further description of the attributes of the Exchangeable LP Units and the Limited Partnership Agreement, see "Relationship to EPCOR — Limited Partnership Agreement of Capital Power LP".

Capital Power LP General Partner

The authorized capital of Capital Power LP General Partner will consist of an unlimited number of common shares and one Special Limited Voting GP Share.

The rights, privileges, restrictions and conditions of the Special Limited Voting GP Share contained in the articles of Capital Power LP General Partner are substantially similar to those of the Special Limited Voting Share *mutatis mutandis*. See "— Capital Power — Special Limited Voting Share".

The holder of the Special Limited Voting GP Share is entitled to receive notice of, and to attend any meeting of, Capital Power LP General Partner's shareholders; however, the holder of the Special Limited Voting GP Share is not, in such capacity, entitled to vote at any shareholder meeting except as provided by law or as described below.

The articles of Capital Power LP General Partner will require that the registered office of Capital Power LP General Partner be located in The City of Edmonton.

The Special Limited Voting GP Share carries no right for the holder to receive dividends. The holder of the Special Limited Voting GP Share has the right to receive, subject to any payment or distribution to holders of prior ranking shares, in preference to the holders of common shares of Special Limited Voting GP Share, the amount of $1.00 from the remaining property and assets of Capital Power LP General Partner upon the voluntary or involuntary liquidation, dissolution or winding-up of Capital Power LP General Partner.

CERTAIN CANADIAN FEDERAL INCOME TAX CONSIDERATIONS

In the opinion of Blake, Cassels & Graydon LLP, counsel to the Company, and Osler, Hoskin & Harcourt LLP, counsel to the Underwriters, the following is a general summary, as of the date hereof, of the principal Canadian federal income tax considerations under the Tax Act generally applicable to a holder who acquires Common Shares pursuant to this Offering and who, for the purposes of the Tax Act and at all relevant times, beneficially owns a Common Share as capital property, is not affiliated with the Company, and deals with the Company at arm's length (a "Holder"). A Common Share will generally be capital property to a Holder unless it is held in the course of carrying on a business of trading in or dealing in securities, or it has been acquired in a transaction or transactions considered to be an adventure in the nature of trade. Holders who are resident in Canada for purposes of the Tax Act ("Resident Holders"), and whose Common Shares do not otherwise qualify as capital property may in certain circumstances make an irrevocable election in accordance with subsection 39(4) of the Tax Act to have their Common Shares and every "Canadian security" (as defined in the Tax Act) owned by such Resident Holder in the taxation year of the election and in all subsequent taxation years be deemed to be capital property. In the case of a Holder who is not a resident of Canada, the comments in this summary under the headings "Non-Resident Holders" below are further restricted to a Holder who is not, has not been and is not deemed to be resident in Canada for purposes of the Tax Act or any applicable income tax convention to which Canada is a signatory, who does not hold or use and is not deemed to hold or use Common Shares in connection with the carrying on of a business in Canada and is not otherwise required by or for the purposes of the laws of Canada to include an amount in respect of Common Shares in computing income from carrying on a business in Canada and who is not a non-resident insurer for purposes of the Tax Act ("Non-Resident Holder").

This summary is not applicable to: (a) a Holder that is a "financial institution", as defined in the Tax Act for purposes of the mark-to-market rules; (b) a Holder, an interest in which would be a "tax shelter investment" as defined in the Tax Act; (c) a Holder that is a "specified financial institution" as defined in the Tax Act or (d) a Holder that has made an election under the Tax Act to determine its Canadian tax results in a foreign currency. Any such Holder to which this summary does not apply should consult its own tax advisor with respect to the tax consequences of the Offering.

This summary is based on the current provisions of the Tax Act and the Regulations, all specific proposals to amend the Tax Act and the Regulations publicly announced by or on behalf of the Minister of Finance (Canada) ("Tax Proposals") before the date of this Prospectus, and the current published administrative practices of the Canada Revenue Agency. No assurance can be made that the Tax Proposals will be enacted in the form proposed or at all. This summary is not exhaustive of all possible Canadian federal income tax considerations and, except as mentioned above, does not take into account or anticipate any changes in law, whether by legislative, regulatory, administrative or judicial decision or action, nor does it take into account provincial, territorial or foreign income tax legislation or considerations, which may differ significantly from the Canadian federal income tax considerations discussed herein.

This summary is of a general nature only and is not intended to be, nor should it be construed to be, legal or tax advice to any particular holder of a Common Share. Accordingly, a holder of a Common Share should consult its own tax advisors about the specific tax consequences to such holder of acquiring, holding and disposing of a Common Share.

Dividends on Common Shares

Resident Holders

Dividends on a Common Share received by a Resident Holder who is an individual (other than certain trusts) will be included in income and will be subject to the gross-up and dividend tax credit rules normally applicable under the Tax Act to taxable dividends received from taxable Canadian corporations. The Company may designate all or a portion of such dividends as "eligible dividends" that are entitled to the enhanced dividend tax credit. The Company will notify its shareholders of any such designations at the appropriate times. The gross-up and dividend tax credit rules do not apply to taxable dividends received by a trust in a year to the extent that such dividends are included in computing the income of a non-resident beneficiary under such trust. The amount of the dividend received by an individual or a trust (other than certain specified trusts), but not the amount of the gross-up, may be subject to the alternative minimum tax. Dividends received on a Common Share by a Resident Holder that is a corporation will be included in its income but normally will also be deductible in computing its taxable income. A Resident Holder that is a "private corporation" or a "subject corporation", each as defined in the Tax Act, will generally be liable to pay a refundable tax under Part IV of the Tax Act at a rate of 33⅓% on dividends received on a Common Share, unless such Resident Holder is "connected" with the Company for purposes of the Tax Act. A Resident Holder will be "connected" with the Company if such Resident Holder either a) controls the Company for purposes of Part IV of the Tax Act; or b) owns, at that time, i) more than 10% of the issued share capital of the Company having full voting rights under all circumstances, and ii) shares of the Company having a fair market value of more than 10% of the fair market value of all the issued shares of the Company. Based on published CRA administrative practice, Common Shares will likely not be considered to be shares having full voting rights in all circumstances at a particular time if, at that time, the Special Voting Shares, voting as a class, have the right to elect one or more directors of the Company.

Non-Resident Holders

Canadian withholding tax at a rate of 25% (subject to reduction under the provisions of any applicable income tax convention) will be payable on dividends on a Common Share paid or credited, or deemed to be paid or credited, to a Non-Resident Holder. The rate of withholding tax applicable to dividends paid on a Common Share to a Non-Resident Holder who is a resident of the U.S. for purposes of the Canada-U.S. Income Tax Convention (the "Convention"), beneficially owns the dividend and qualifies for the benefits of the Convention will generally be reduced to 15% or, if the Non-Resident Holder is a corporation that owns at least 10% of the voting stock of the Company, to 5%. Not all persons who are residents of the U.S. for purposes of the Convention will qualify for the benefits of the Convention. A Non-Resident Holder who is a resident of the U.S. is advised to consult its tax advisor in this regard. The rate of withholding tax on dividends is also reduced under certain other bilateral income tax conventions to which Canada is a signatory.

Dispositions of Common Shares

Resident Holders

Upon a disposition or deemed disposition of a Common Share, a capital gain (or loss) will generally be realized by a Resident Holder to the extent that the proceeds of disposition are greater (or less) than the aggregate of the adjusted cost base of the Common Share to the Resident Holder immediately before the disposition and any reasonable costs of disposition. Any such capital gain (or loss) will be subject to the treatment described below under "— Taxation of Capital Gains and Capital Losses".

A Resident Holder's adjusted cost base of a Common Share acquired pursuant to this Offering will be determined in accordance with certain rules in the Tax Act by averaging the cost to the Resident Holder of such Common Share with the adjusted cost base of all other Common Shares held by the Resident Holder as capital property at that time. The Resident Holder's cost for purposes of the Tax Act of a Common Share will include all amounts paid or payable by the Resident Holder to acquire the Common Share.

A Resident Holder that is throughout the year a "Canadian-controlled private corporation" (as defined in the Tax Act) may be liable for tax, a portion of which may be refundable, on certain investment income including amounts in respect of taxable capital gains.

Non-Resident Holders

Upon a disposition or deemed disposition of a Common Share, a capital gain (or loss) will generally be realized by a Non-Resident Holder to the extent that the proceeds of disposition are greater (or less) than the aggregate of the adjusted cost base of the Common Share to the Non-Resident Holder thereof immediately before the disposition and any reasonable costs of disposition.

A Non-Resident Holder's adjusted cost base of a Common Share acquired pursuant to this Offering will be determined in accordance with certain rules in the Tax Act by averaging the cost to the Non-Resident Holder of such Common Share with the adjusted cost base of all other Common Shares held by the Non-Resident Holder as capital property at that time. The Non-Resident Holder's cost for purposes of the Tax Act of the Common Share will include all amounts paid or payable by the Non-Resident Holder for the Common Share.

A Non-Resident Holder will not be subject to tax under the Tax Act in respect of any capital gain realized on a disposition of a Common Share unless the property disposed of constitutes "taxable Canadian property" of the Non-Resident Holder and the Non-Resident Holder is not entitled to relief under an applicable income tax convention. A Common Share will not be taxable Canadian property to a Non-Resident Holder unless the Non-Resident Holder, persons with whom the Non-Resident Holder did not deal at arm's length, or the Non-Resident Holder together with all such persons at any time within the five year period before the disposition, owned 25% or more of the issued shares of any class or series of shares of the Company, which includes Common Shares. Interests in corporations, partnerships or trusts that are Non-Resident Holders of Common Shares may constitute taxable Canadian property if more than 50% of the fair market value of all of the Non-Resident Holder's property is, or was in the five-year period preceding a disposition of such interests, taxable Canadian property. However, a disposition of a share of the capital stock of a U.S. domestic corporation that is taxable Canadian property by a resident of the U.S. may be exempt from Canadian taxation under the Convention. Non-Resident Holders are urged to consult with their tax advisors with respect to the application of these rules.

Taxation of Capital Gains and Capital Losses

Generally, one-half of a capital gain (a taxable capital gain) must be included in a Holder's income. Subject to and in accordance with the provisions of the Tax Act, a Holder is required to deduct one-half of a capital loss as an allowable capital loss against taxable capital gains realized in that year, and allowable capital losses in excess of taxable capital gains may be carried back and deducted in any of the three preceding taxation years, or in any subsequent year, against net taxable capital gains realized in such years (but not against other income) to the extent and under the circumstances described in the Tax Act. If the Holder is a corporation, any such capital loss realized on the sale of a Common Share may in certain circumstances be reduced by the amount of any dividends which have been received on the Common Share. Similar rules may apply where a Common Share is owned by a partnership or certain trusts of which a corporation, trust or partnership is a member or beneficiary. Taxable capital gains realized by a Holder who is an individual may give rise to alternative minimum tax depending on the Holder's circumstances.

Eligibility for Investment

In the opinion of Blake, Cassels & Graydon LLP, counsel to the Company, and Osler, Hoskin & Harcourt LLP, counsel to the Underwriters, the Common Shares offered hereby will, when listed on a designated stock exchange, as defined in the Tax Act, (which includes the Toronto Stock Exchange), be qualified investments under the Tax Act and the Regulations for trusts governed by a registered retirements savings plan, registered retirement income fund, registered disability savings plan, deferred profit sharing plan, tax-free savings account ("TFSA") or registered education savings plan, all within the meaning of the Tax Act. The Common Shares will not be a prohibited investment for a registered pension plan under the Tax Act and the Regulations. The Common Shares will not be a prohibited investment for a trust governed by a TFSA provided the holder of the TFSA deals at arm's length with the Company for purposes of the Tax Act and does not have a significant interest (within the meaning of the Tax Act) in the Company, or in a corporation, partnership or trust with which the Company does not deal at arm's length for purposes of the Tax Act.

PRIOR SALES

During the 12-month period prior to the date of this prospectus, the only issuances of shares by Capital Power were (i) the issuance of one Common Share to Mr. J. Rob Collins, Partner, Blake, Cassels & Graydon LLP, for a price of $10.00 on May 1, 2009 in connection with the organization of Capital Power, and (ii) the issuance of one Special Limited Voting Share to EPCOR for a price of $1 on June 18, 2009.

DIVIDEND POLICY

Capital Power has not declared or paid any dividends since its incorporation and will not declare or pay any dividends prior to completion of the Offering and the Reorganization. The Board is expected to establish a dividend policy pursuant to which Capital Power will, following the completion of the Offering and the Reorganization, initially authorize the declaration and payment of a dividend of $1.26 per Common Share, to be paid to holders of Common Shares on a quarterly basis. The payment of dividends is not guaranteed, however, and the amount and timing of any dividends payable by Capital Power will be at the discretion of the Board and will be established on the basis of Capital Power's earnings, distributions received from Capital Power LP, financial requirements for Capital Power's operations, the satisfaction of solvency tests imposed by the corporate law for the declaration and payment of dividends and other relevant factors. See "Risk Factors".

OPTIONS TO PURCHASE SECURITIES

Options Outstanding

Employees transferring to the Company will have the value of phantom options granted to them in 2006, 2007, 2008 and 2009 under the EPCOR LTIP replaced with Company stock options. See "Management — Executive Compensation — Long-Term Incentive Plan" for a description of such options, which are included in the following table.

Class of Optionee (number of individuals in receipt of Company options)	Number of Common Shares under Company options
All executive officers (8)	790,600
All directors who are not also executive officers (0)	0
All subsidiaries' executive officers (0)	0
All subsidiaries' directors who are not also executive officers (0)	0
All other employees (82)	1,354,000
All subsidiaries' other employees (0)	0
All consultants (0)	0
All other persons (0)	0
	2,144,600

CAPITALIZATION

The following table sets forth the pro forma consolidated capitalization of the Company as at December 31, 2008 and as at March 31, 2009 and the pro forma consolidated capitalization of the Company as at March 31, 2009 after giving effect to the Offering and the Reorganization. This table should be read in conjunction with the audited comparative combined and consolidated financial statements of EPCOR Power Group as at and for the year ended December 31, 2008 and the unaudited interim comparative combined and consolidated financial

statements of EPCOR Power Group as at and for the three months ended March 31, 2009, each contained elsewhere in this prospectus.

	As at December 31, 2008	As at March 31, 2009	As at March 31, 2009 after giving effect to the Offering and the Reorganization
Short-term debt	—	—	—
Long-term debt	3,027	3,064	1,781
Non-controlling interests	540	507	1,863
Common shareholders' equity	381	436	468
Special Limited Voting Shareholder's equity	—	—	—
Special Voting Shareholders' equity	—	—	—
Total shareholders' equity	381	436	468
Total capitalization	3,948	4,007	4,112

PRINCIPAL SECURITYHOLDERS

The following table sets forth information regarding the beneficial ownership of, of control or direction over shares of Capital Power as of the date of this prospectus and as anticipated immediately after the Offering by:

- each person or entity known to the Company to beneficially own, or have control or direction over, 10% or more of the outstanding Common Shares, Special Voting Shares or Special Limited Voting Share, as applicable; and
- the Company's directors and executive officers.

Other than as set forth below, no other person or entity beneficially owned, or had control or direction over, 10% or more of the outstanding shares of any class of the Company as of the date of this prospectus or is anticipated to beneficially own, or have control or direction over, 10% or more of the outstanding shares of any class of the Company immediately after the Offering and the Reorganization.

	Shares Beneficially Owned Prior to the Offering		Shares Beneficially Owned Immediately After the Offering[1]	
	Number	%	Number	%
EPCOR (directly, indirectly and beneficially)				
Common Shares[2]	—	—	—	—
Special Voting Shares	—	—	56,625,000	100
Special Limited Voting Share	1	100	1	100
Directors and Executive Officers				
Common Shares	0	0	57,000	less than 1
J. Rob Collins (directly and beneficially)				
Common Shares[3]	1	100	0	0

(1) Assumes no exercise of the Underwriters' Over-Allotment Option.

(2) EPCOR will own indirectly 56.625 million Exchangeable LP Units, exchangeable on a one-for-one basis for Common Shares, subject to certain limitations. EPCOR's percentage ownership of the outstanding Common Shares assumes the exchange of all Exchangeable LP Units for Common Shares.

(3) See "Prior Sales".

USE OF PROCEEDS

The net proceeds to be received from the sale of the Common Shares in the Offering are estimated to be approximately $468 million (or $539 million if the Over-Allotment Option is exercised in full), after deducting underwriting fees and estimated offering expenses payable by Capital Power. Capital Power intends to use the net proceeds from the Offering as partial consideration for the acquisition of the assets and operations of the business of Capital Power from EPCOR (in the case of the Over-Allotment Option, through redemption of Exchangeable LP Units held indirectly by EPCOR) pursuant to the Master Separation Agreement described in "Relationship to EPCOR — Agreements Between Capital Power and EPCOR". See "Business" for a description of the assets and operations of the business.

PLAN OF DISTRIBUTION

The Company is offering the Common Shares described in this prospectus through the Underwriters, for whom TD Securities Inc. and Goldman Sachs Canada Inc. are acting as representatives and joint book-running managers. The Company has entered into an underwriting agreement dated June 25, 2009 with the Underwriters. Subject to the terms and conditions of the underwriting agreement, each of the Underwriters has severally agreed to purchase the Common Shares offered hereby on or about July 9, 2009 or such later date as the Company and the Underwriters may agree, but in any event not later than August 9, 2009, at a price of $23.00 per Common Share payable in cash to the Company against delivery.

The obligations of the Underwriters are several and neither joint nor joint and several and may be terminated at their discretion on the basis of their assessment of the state of the financial markets and may also be terminated upon the occurrence of certain stated events. The underwriting agreement provides that the Underwriters must buy all of the shares if they buy any of them. However, the Underwriters are not required to take or pay for the shares covered by the Underwriters' Over-Allotment Option described below.

The Common Shares are offered subject to a number of conditions, including:

- receipt and acceptance of the Company's Common Shares by the Underwriters, and
- the Underwriters' right to reject orders in whole or in part.

In connection with the Offering, certain of the Underwriters or securities dealers may distribute prospectuses electronically.

The Offering is being made in each of the provinces and territories of Canada. The Common Shares will be offered in each of the provinces and territories of Canada through those Underwriters or their affiliates who are registered to offer the Common Shares for sale in such provinces and territories and such other registered dealers as may be designated by the Underwriters. Subject to applicable law, the Underwriters may offer the Common Shares outside of Canada.

The TSX has conditionally approved the listing of the Common Shares. Listing is subject to the Company fulfilling all of the original listing requirements of the TSX on or before August 31, 2009, including distribution of these Common Shares to a minimum number of public securityholders.

The Common Shares offered hereby have not been and will not be registered under the U.S. Securities Act, or any state securities laws, and may not be offered or sold within the U.S. or to, or for the account of, U.S. persons (as defined in Regulation S under the U.S. Securities Act) absent registration or pursuant to an applicable exemption from the registration requirements of the U.S. Securities Act, and applicable state securities laws. Accordingly, except to the extent permitted by the underwriting agreement and except for offers and sales made by the Company pursuant to an available exemption from registration requirements of the U.S. Securities Act, the Common Shares may not be offered or sold within the U.S. or to, or for the account or benefit of, U.S. persons. Each Underwriter has agreed that it will not offer or sell Common Shares within the U.S. or to, or for the account or benefit of, U.S. persons except in transactions exempt from the registration requirements of the U.S. Securities Act, and applicable state securities laws. The underwriting agreement provides that the underwriters may re-offer and re-sell the Common Shares that they have acquired pursuant to the underwriting agreement to qualified institutional buyers in the U.S. in accordance with Rule 144A under the U.S. Securities Act. The underwriting agreement also provides that the Underwriters will offer and

sell the Common Shares outside the U.S. in accordance with Regulation S. In addition, until 40 days after the commencement of the Offering, an offer or sale of the Common Shares within the U.S. by any dealer (whether or not participating in the Offering) may violate the registration requirements of the U.S. Securities Act, unless such offer is made pursuant to an exemption under the U.S. Securities Act.

Prior to the Offering, there has been no public market for the Common Shares. The sale of a substantial amount of the Common Shares in the public market after the Offering, or the perception that such sales may occur, could adversely affect the prevailing market price of the Common Shares. Furthermore, because some of the shares will not be available for sale after the Offering due to the contractual and legal restrictions on resale described at "— Lock-Up", the sale of a substantial amount of Common Shares in the public market after these restrictions lapse could adversely affect the prevailing market price of the Common Shares and the Company's ability to raise equity capital in the future.

Over-Allotment Option

The Company has granted to the Underwriters the Over-Allotment Option, exercisable at the Underwriters' sole discretion, in whole or in part, at any time for a period of 30 days from the date of the closing of the Offering, to purchase up to an additional 3,262,500 Common Shares from the Company on the same terms as set forth above, for the purpose of covering over-allotments, if any. This prospectus also qualifies the grant of the Over-Allotment Option and the Common Shares issuable upon the exercise of the Over-Allotment Option. The Company has agreed to pay the Underwriters a fee equal to $1.15 per Common Share for each Common Share purchased on exercise of the Over-Allotment Option.

A purchaser who acquires Common Shares from part of the Underwriters' over-allocation position acquires such Common Shares under this prospectus, regardless of whether the over-allocation position is ultimately filled through the exercise of the Over-Allotment Option or secondary market purchases.

Price Stabilization, Short Positions and Passive Market Making

In connection with the Offering, the Underwriters may over-allocate or effect transactions which stabilize or maintain the market price of the Common Shares at levels other than those which otherwise might prevail on the open market, including:

- stabilizing transactions;
- short sales;
- purchases to cover positions created by short sales;
- imposition of penalty bids; and
- syndicate covering transactions.

Stabilizing transactions consist of bids or purchases made for the purpose of preventing or retarding a decline in the market price of the Common Shares while the Offering is in progress. These transactions may also include making short sales of the Common Shares, which involve the sale by the Underwriters of a greater number of Common Shares than they are required to purchase in the Offering. Short sales may be "covered short sales", which are short positions in an amount not greater than the Over-Allotment Option, or may be "naked short sales", which are short positions in excess of that amount.

The Underwriters may close out any covered short position either by exercising the Over-Allotment Option, in whole or in part, or by purchasing Common Shares in the open market. In making this determination, the Underwriters will consider, among other things, the price of Common Shares available for purchase in the open market compared with the price at which they may purchase Common Shares through the Over-Allotment Option. The Underwriters must close out any naked short position by purchasing Common Shares in the open market. A naked short position is more likely to be created if the Underwriters are concerned that there may be downward pressure on the price of the Common Shares in the open market that could adversely affect investors who purchase in the Offering.

In addition, in accordance with rules and policy statements of certain Canadian securities regulators, the Underwriters may not, at any time during the period of distribution, bid for or purchase Common Shares. The foregoing restriction is, however, subject to exceptions where the bid or purchase is not made for the purpose of creating actual or apparent active trading in, or raising the price of, the Common Shares. These exceptions include a bid or purchase permitted under the by-laws and rules of applicable regulatory authorities and the TSX, including the Universal Market Integrity Rules for Canadian Marketplaces, relating to market stabilization and passive market making activities and a bid or purchase made for and on behalf of a customer where the order was not solicited during the period of distribution.

As a result of these activities, the price of the Common Shares may be higher than the price that otherwise might exist in the open market. If these activities are commenced, they may be discontinued by the Underwriters at any time. The Underwriters may carry out these transactions on any stock exchange on which the Common Shares are listed, in the over-the-counter market, or otherwise.

Pricing of the Offering

Prior to the Offering, there was no public market for the Common Shares. The initial public offering price will be determined by negotiations between the Company, EPCOR and the Underwriters. Among the factors considered in determining the initial public offering price will be the Company's future prospects and future prospects of the Company's industry in general, the Company's sales, earnings and other financial and operating information in recent periods, the Company's dividend policy and the price-earnings ratios, market prices of securities and financial and operating information of companies engaged in activities similar to those of the Company's.

The Underwriters propose to offer the Common Shares initially at the offering price specified on the cover page of this prospectus. After the Underwriters have made a reasonable effort to sell all of the Common Shares at the price specified on the cover page, the offering price may be decreased and may be further changed from time to time to an amount not greater than that set out on the cover page, and the compensation realized by the Underwriters will be decreased by the amount that the aggregate price paid by purchasers for the Common Shares is less than the gross price paid by the Underwriters to the Company.

Commissions

The public offering price for the Common Shares is payable in Canadian dollars.

The following table shows the per share and total underwriting commissions the Company will pay to the Underwriters, assuming both no exercise and full exercise of the Over-Allotment Option:

	Over-Allotment not Exercised	Over-Allotment Fully Exercised
Per share	$ 1.15	$ 1.15
Total	$25,012,500	$28,764,375

Expenses Related to the Offering

It is estimated that the total expenses of the Offering payable by the Company, not including the underwriting commissions, will be approximately $7 million.

Allocation of Common Shares to Edmontonians

The Company has requested that the Underwriters make arrangements to facilitate participation in the Offering by residents of The City of Edmonton, including by endeavouring to reserve some portion of the Common Shares offered under this prospectus for sale to such residents. All Common Shares offered to such residents will be offered at the initial public offering price set forth on the cover page of this prospectus.

Lock-Up

Each of the Company and EPCOR has agreed that it will not, without the prior consent of TD Securities Inc. and Goldman Sachs Canada Inc., issue, in the case of the Company, and sell in the case of EPCOR, or offer, grant any option to purchase or agree to issue or sell, as applicable, any equity securities or other securities convertible into, or exchangeable or exercisable for, equity securities (other than the Common Shares offered hereby, Common Shares issuable upon the exercise of the Over-Allotment Option, Common Shares issuable pursuant to the exercise of the options granted under the Company's 2009 Plan and Common Shares issuable in connection with the acquisition of property), for a period of 180 days from the closing date of the Offering.

Relationship between the Company and Certain of the Underwriters

Each of TD Securities Inc., RBC Dominion Securities Inc., CIBC World Markets Inc., BMO Nesbitt Burns Inc., Scotia Capital Inc., National Bank Financial Inc. and HSBC Securities (Canada) Inc. is a subsidiary or an affiliate of a bank that is a lender to each of the Company and EPCOR. In addition, two directors of EPCOR are directors of a bank that is a lender to the Company or EPCOR. Capital Power intends to use the net proceeds from the Offering as partial consideration for the acquisition of the assets and operations of the business of Capital Power from EPCOR, and is advised by EPCOR that it may in turn use such funds to repay certain of its indebtedness payable in the current year under credit facilities to lenders that include certain of those banks. Consequently, the Company may be considered to be a "connected issuer" of such Underwriters under applicable securities legislation. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and capital resources".

None of the bank affiliates of TD Securities Inc., RBC Dominion Securities Inc., CIBC World Markets Inc., BMO Nesbitt Burns Inc., Scotia Capital Inc., National Bank Financial Inc. and HSBC Securities (Canada) Inc. have been or will be involved in the decision to offer the Common Shares and none have been and will be involved in the determination of the terms of any distribution of Common Shares, including pricing of the Common Shares, but will be advised of the issuance and the terms of the Offering. As a consequence of the Offering, such Underwriters will receive their share of the underwriting fee payable to the Underwriters.

RISK FACTORS

An investment in the Common Shares involves significant risks. Investors should carefully consider the risks described below and the other information elsewhere in this prospectus, including EPCOR Power Group's combined and consolidated financial statements, before making a decision to buy the Common Shares. If any of the following or other risks occur, the Company's business, prospects, financial condition, results of operations and cash flows could be materially adversely impacted. In that case, the trading price of the Common Shares could decline and investors could lose all or part of their investment in the Common Shares. There is no assurance that risk management steps taken will avoid future loss due to the occurrence of the below described or other unforeseen risks.

Risks Relating to the Company's Business

Operational Risks

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) fluctuating costs, including fuel costs; (vii) compliance with all 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 the Company, 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 the Company'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 the Company. If a power plant delivers less than the required quantities of electricity in a given month, or is available for production less than required under the PPAs in a given month, revenue may be insufficient to cover contractual or financial obligations.

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, the Company's cost of generating electricity will be increased and/or the Company's revenues may be negatively affected. As an adopter of new technology, the Company can be exposed to design flaws or other issues, the impacts of which may not be covered by warranties or insurance. The decision regarding expenditures and maintenance would depend on, among other things, the remaining term of the PPA. The failure of the Company's facilities to operate at required capacity levels may result in the facilities having their contracted capacity reduced and, in certain cases, the Company having to make payments on account of reduced capacity to power purchasers. In the case of EPLP's Ontario plants, a combination of increasing operation and maintenance costs, fuel costs, and decreasing availability of waste heat as a fuel source, may cause EPLP to restrict their operation to on-peak hours to maximize revenue under their respective PPAs.

In addition, counterparties to PPAs have remedies available to them if the Company fails to operate facilities in accordance with contract requirements, including the recovery of damages and termination of contractual arrangements.

In the fourth quarter of 2008, there was an unplanned outage at the Company's Genesee 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. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Results of operations — non-GAAP financial measures". Although the Company continues to investigate the turbine blade failure at Genesee 3, it has not ascertained the 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 3 facility or the Keephills 3 facility at which the same turbine equipment is to be installed. To the extent that the Company experiences a further turbine blade failure at Genesee 3 prior to the commissioning of the Keephills 3 facility, one potential means of remediating the failure may be to access components from the Keephills 3 turbine. To the extent that any components from the Keephills 3 turbine were used for such purpose, such use could result in delay to the schedule date for commissioning of the Keephills 3 facility.

PPA Contract Risks

Many of the Company's generation plants operate under PPAs. Such contracts contain performance benchmarks that must be achieved and other obligations that must be complied with by the Company. The Company may incur charges in the event of unplanned outages or variations from the contract performance benchmarks. In addition, there is no assurance that counterparties to PPAs will perform their obligations or make required payments to the Company or EPLP, as applicable.

Electricity sales associated with the Company's Genesee 1 and 2 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. Most of the Company's other plants, including Brown Lake, Miller Creek, and Kingsbridge I, operate under long-term commercial contracts with counterparties. Joffre, in which the Company holds a 40% interest, operates under a long-term commercial contract with NOVA which is currently rated CCC+ by S&P. Electricity sales or steam sales associated with Joffre are subject to market price variability as there are provisions in the NOVA contract that require the facility to run to provide steam to the host facility, irrespective of market prices.

In order to stabilize future cash flows, EPLP seeks to re-contract existing generation plants under new or extended contracts and acquire new plants that meet its investment criteria. However, there is no guarantee that existing PPAs will be extended or renewed on more favourable terms. Electricity prices under the PPAs for the

Naval Facilities and Oxnard are based on the purchasing utilities' SRAC. The SRAC formula is determined by the California Public Utility Commission and is subject to adjustment. In the future, the California Public Utility Commission may make adjustments to the SRAC formula to change the basis on which future electricity prices will be determined for these facilities. Such adjustments may adversely affect the value of the affected PPAs to the Company.

Electricity Price and Volume Risk

The Company's revenues are tied, directly and indirectly, to the market price for electricity in the jurisdictions in which the Company operates. The Company buys and sells some of its electricity in the wholesale markets of Alberta, Ontario, and the U.S. Such transactions are settled at the spot market prices of the respective markets. Market electricity prices are dependent upon a number of factors, including: the projected supply and demand of electricity; the price of raw materials that are used to generate sources of 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 the Company.

In order to manage its exposure to spot price variability within specified risk limits, the Company enters into purchase and sale arrangements, including CfDs and firm price physical contracts, for varying periods of duration. However, due to limited market liquidity and the variance in electricity consumption between peak usage hours and off-peak usage hours, it is not possible to hedge all positions every hour.

When aggregate customer electricity consumption (load shape) changes unexpectedly, the Company is exposed to price risk. Load shape refers to the different pattern of consumption between peak hours and off-peak hours. Consumption is higher during peak hours when people and organizations are most active; conversely, consumption is lower during off-peak hours. The Company purchases blocks of electricity in advance of consumption so as to minimize exposure to extreme price fluctuations, especially during higher priced peak hour periods. In order to do this, the Company 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, the Company 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.

PPA Contract Expiration Risks

Power generated from the Company'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 the Company. Failure by the Company 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 the Company's operations and financial condition, and may even require the Company to temporarily or permanently cease operations at the affected facility.

Fuel Costs, Supply and Transportation

The Company requires fuel supplies, such as natural gas, coal, wood waste, waste heat, 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 the Company could have a material adverse impact on the Company'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 the Company's facilities. Changes in any of these factors could increase the Company's cost of generating electricity or decrease the Company's revenues due to production cutbacks, either of which could have a material adverse effect on the Company's business, financial condition and results of operation.

The Company's fuel expense for the Genesee plants is predominantly comprised of coal supply. 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.

The Roxboro and Southport facilities purchase coal and coal-based fuel from local suppliers in the Southeast U.S. The coal and coal-based fuel is transported to the power plants by rail service. Any disruption in rail service due to unforeseen circumstances could impair the operations of these coal-fired power plants if alternative transportation cannot be arranged in a timely manner. Existing coal supply contracts will meet the 2009 requirements and approximately half of the 2010 requirements for Roxboro and Southport. There can be no assurance of if, when or upon what terms, including pricing, the existing supply agreements will be renewed or replaced.

Some of the Company'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 the Naval Station, Naval Training Centre, North Island, Oxnard and Kenilworth power plants are made under variable price structures with fuel cost flow-through provisions that partially mitigate risks relating to natural gas price changes. However, each of these power plants has PPAs extending for terms in excess of existing contractual supply arrangements. The Company is exposed to commodity price risk on its natural gas purchases for EPLP's Tunis Plant beginning in 2010 when its natural gas supply agreements end prior to expiry of the OEFC PPA in 2014. In addition, EPLP's Greeley facility is exposed to fuel price risk when existing natural gas contracts expire in 2011, prior to the PPA expiry in 2013. 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. The Company also maintains a quantity of natural gas in storage for trading and management of natural gas needs. At December 31, 2008, the estimated fair value of the inventory was $12 million (2007 — $nil). The inventory is subject to resale in current or forward markets and realized or unrealized gains or losses on such natural gas are subject to the volatility of the market price for natural gas.

Wood waste is required to fuel EPLP's two Canadian biomass wood waste plants, Williams Lake and Calstock. In addition, the enhancements that are in process 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 EPLP is at risk for the wood waste price escalation for the remaining 20% of the fuel supply. At Calstock, the PPA price does not permit EPLP to directly flow through the fuel supply cost to the OEFC, and EPLP is at risk for wood waste price escalation. Market forces, including levels of activity in the regional forestry sector, competition from other users of wood waste and limits to the distance over which wood waste can economically be transported, expose EPLP to price and supply risk for wood waste. Weakness in the North American economy has placed economic hardships on forestry mills, which has caused mills to shutdown or scale back production in British Columbia and Ontario, or to renegotiate aspects of their wood waste supply agreements with EPLP. In addition, one supply agreement with a local mill has expired, although EPLP is currently able to continue to purchase wood waste from the mill on a spot basis. Failure to obtain wood waste supply, failure to contract suppliers to supply wood waste or failure of wood waste suppliers to perform under their contracts due to deteriorating economic circumstances in the forestry industry could negatively affect EPLP's operations at Williams Lake and Calstock.

EPLP's five Ontario plants (namely, Nipigon, Kapuskasing, North Bay, Calstock and Tunis) also generate electricity in part from the use of waste heat gases of 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 TransCanada pipeline system, and the host's 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. In 2008, waste heat contributed to approximately 16% of power revenue at EPLP's Ontario plants. Declining waste heat availability that began in 2007 continued in 2008 due to lower throughput on the TransCanada pipeline system. This decrease was due to lower natural gas demand in Northern Ontario in part due to lower forestry industry activity, lower natural gas volumes leaving Alberta due to lower levels of natural gas supply from the Western Canadian Sedimentary Basin because of lower drilling activity combined with increasing demand in Alberta, structural changes in the underlying long-haul transportation agreements with

shippers, the conversion of an upstream high pressure natural gas line to oil and the addition of looping in and around the North Bay shortcut.

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, in Alberta. A continued tightening of such regulations could have a material adverse effect on the Company's business, financial condition and results of operation.

The Company's wind power facilities, like those of the Kingsbridge I project, 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.

Reliance Upon Transmission Systems

The Company 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, the Company's ability to sell and deliver wholesale power may be adversely impacted. If a region's power transmission infrastructure is inadequate, the Company'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. The Company also cannot predict whether transmission facilities will be expanded in specific markets to accommodate competitive access to those markets.

The Company's ability to develop new projects is also impacted by the availability of various transmission and distribution systems.

Environmental Regulatory Risk

Many of the Company'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.

On April 29, 2009, the Canadian Environment Minister announced in a media interview that the Canadian Federal Government is planning new climate change regulations aimed at coal-fired power in Canada's electricity sector. The regulations would purportedly require all newly constructed coal generation plants to use technology to capture GHG and inject it underground for permanent storage. Compliance with this and other known and unknown environmental regulations may require material capital and operating expenditures and failure to comply with such regulations could result in fines, penalties or the forced curtailment of operations. Further, there can be no assurances that compliance with and/or changes to environmental regulations will not materially adversely impact the Company's business, prospects, financial conditions, operations or cash flow.

The Company's business is a significant emitter of CO_2, NO_x, 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.

EPLP's wood waste plants may also be subject to SO_2 and mercury reduction requirements within the next five to seven years. In addition, the decreased availability in waste heat used by EPLP's Ontario plants may lead to increased emissions and decreased allowances being allocated with respect to these facilities. There are a

number of uncertainties associated with the estimated cost of compliance with these existing and emerging requirements. It is not yet clear as to the form in which the new carbon and GHG regulations will be implemented or whether such regulations, when implemented, will reflect the proposed regulatory aims. In addition, the Company is not able to determine the extent to which future compliance costs will be recoverable from customers or whether such costs may be shared among emitters, customers and stakeholders. Other unknown factors include the future composition of the Company's generation assets, the future production of electricity from the Company's generation assets, the extent and timing of the development of carbon offset markets, whether economically feasible emission-reducing technology will emerge, the market price for carbon offset credits and other measures that the Company might undertake to reduce its emissions.

Compliance with new regulatory requirements may require EPLP to incur significant capital expenditures and/or additional operating expenses. See "Environmental Regulation and Initiatives".

Health, Safety and Environmental Matters

The ownership and operation of the Company's generation assets carry an inherent risk of liability related to public health and worker health and safety and the environment, including the risk of government imposed orders to remedy unsafe conditions and/or to remediate or otherwise address environmental contamination, potential penalties for contravention of health, safety and environmental laws and potential civil liability. The Company may become subject to government orders, investigations, inquiries or other proceedings (including civil claims) relating to health, safety and environmental 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. The Company has filed a significant lawsuit in the Court of Queen's Bench against the former owner of a neighbouring property related to groundwater contamination under the Clover Bar site. The source of contamination has not been remediated. Although this litigation is presently not proceeding pending the filing of an amended decommissioning plan for the site and additional investigation and analysis of the nature of the contaminants by the Company, a risk remains that the Company could become liable for the cost of remediating the groundwater contamination at the Clover Bar site.

The Company'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 the Company's condition.

Political, Legislative and Regulatory Risk

The Company 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 the Company 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 the Company 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 the Company 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 the Company. Also, if any of the Company's operations that are not currently regulated were to become subject to regulation at a future date, compliance with such regulation could result in significant cost to the Company.

The Company is also required to maintain numerous licenses, permits and governmental approvals for operation of its projects. Some of the licenses, permits and governmental approvals that have been issued in connection with the Company's projects contain conditions and restrictions and/or have limited effective periods. If the Company 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, the Company 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 the Company's projects

may be limited or suspended. The Company'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.

In addition, regulatory authorities may from time to time investigate or inspect the Company's activities, including as a result of transferring the licences, permits and approvals referred to above as part of the Reorganization, and such investigations or inspections could result in fines, penalties or sanctions, or other adverse regulatory actions, any of which could have a material adverse impact on the Company.

Credit Risk

Credit risk is the possible financial loss associated with the potential inability of counterparties to satisfy their contractual obligations to the Company, 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 the Company relative to their current markets. The Company 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, the Company 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 the Company's plants and could adversely impact the Company's financial results. Furthermore, a prolonged deterioration in economic conditions, such as the current economic recession, could increase the foregoing risks and could have a material adverse affect on the Company.

Risks Associated with Financial Liquidity, the Current Financial Market Environment and the Ability to Access Future Financings

The Company's internally generated funds from operations may not provide sufficient capital for the Company, whether to undertake or complete ongoing or future development, enhancement opportunities or acquisition plans or otherwise, and, accordingly, the Company may require additional financing from time to time. The ability of the Company to arrange such financing in the future will depend in part upon prevailing market conditions as well as the business performance of the Company. Current global financial conditions and recent market events have been characterized by increased volatility and the resulting tightening of the credit and capital markets has reduced the amount of available liquidity and overall economic activity. 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 the Company's initiatives, objectives or requirements or, if financing is available to the Company, that it will be on terms acceptable to the Company. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and capital resources". The inability of the Company to access sufficient amounts of capital on terms acceptable to the Company for its operations could have a material adverse effect on the Company's business, prospects and financial condition.

Project Development and Construction

The Company 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, the Company 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 the Company 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 the Company 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 the Company

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 and other matters beyond the direct control of the Company. Any one of these factors could cause actual results to vary materially from the projections of power production, future revenue and earnings.

There is a risk that projects currently under construction, developmental projects and future projects will not be completed on time or on budget or at all. Projects may be delayed, or experience interruption of operations or increased costs, due to many factors, including: permitting delays, conditions or even cancellation imposed by regulatory authorities, appeals by various interest groups which may delay or halt the project, changes in engineering and design requirements, errors or omissions in preparing detailed project economic analysis, non-performance or errors by third-party contractors, inability to attract sufficient numbers of qualified workers, labour disputes, disruptions or decreases in productivity, increases in materials or labour costs, disruption in fuel supply, *force majeure*, breakdown or failure of equipment or processes and construction performance falling below expected levels of output or efficiency. Furthermore, rapid cost escalation has occurred in a number of regions in which the Company operates. These risks can translate into performance issues, delays and cost overruns. Project delays may delay expected revenues and project cost overruns could render projects unprofitable for the Company.

Even when completed, a facility may not operate as planned and power generation equipment may experience mechanical breakdown or design or manufacturing flaws, any of which may result in additional costs or decreased revenue and may not be covered by warranty or insurance or be otherwise recoverable.

In the event that a project is not completed or does not operate at anticipated performance levels, the Company may not be able to recover its investment, materially and adversely affecting the Company's financial position, operating results and business.

Supply Risk of Alberta PPAs

The Company holds interests in PPAs in Alberta which entitle the Company to its proportionate interest in the electricity produced from certain generating units up to their committed capacity. In most cases where plant capability falls below committed capacity, the Company is entitled to receive availability payments from the plant owner based on 30-day rolling average power pool prices and target availability. The occurrence of an event which disrupts the ability of the power plants to produce or sell power or thermal energy for an extended period under such PPAs, including events which preclude the subsequent purchasers of the rights and obligations under the acquired PPAs from fulfilling their obligations under such PPAs, could have a material negative impact on the ability of the Company to generate revenue. In such circumstances, the Company 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 PPA, thus increasing the cost of energy purchases to the Company.

Labour Risks

The Company's ability to continuously operate its facilities and grow the business is dependent upon retaining and developing sufficient labour and management resources. The Company 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, is extremely competitive, posing a risk to the timing and cost of projects in those provinces. Failure to secure sufficient qualified labour may negatively impact the Company's operations or materially increase expenses.

The Company's current collective bargaining agreements expire periodically and the Company 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 the Company's employees in response to any future efforts by management to reduce labour costs, restrain wage increases or modify work practices, could adversely affect the Company's business by disrupting operations or constraining the Company's ability to carry out such efforts. In the event of a labour disruption such as a strike or lock-out, the ability of the Company's

generation assets to generate electricity may be impaired, which could have a material and adverse effect on the Company's results from operations and cash provided by operating activities.

Weather Risks

Weather can have a significant impact on the Company's operations. Temperature levels, seasonality and precipitation, both within the Company's markets and adjacent geographies, can affect the level of demand for electricity and natural gas, thus resulting in electricity and natural gas price volatility. In addition, the performance of the hydroelectric facilities is partly dependent upon the availability of water and variances in water flows are caused by non-controllable weather-related factors affecting precipitation and could result in volatility of hydroelectric plant revenues. Although the Company's wind power facilities have no fuel costs, they rely on the availability and constancy of wind resources, which could vary due to abnormal weather conditions.

Competition and Changes in Power Generation Technology

The power generation industry is characterized by intense competition, and the Company's facilities encounter competition from utilities, industrial companies and other IPPs. In recent years, there has been increasing competition among electricity generators in an effort to obtain power sales agreements, and this competition has contributed to a reduction in electricity prices in certain markets in which the Company operates. In addition, many jurisdictions are implementing or considering regulatory initiatives designed to increase competition in the power industry. Power generation contracts are obtained through participation in competitive request for proposal processes and, as a result, the Company may compete with other companies for the acquisition of such contracts. There can be no assurance that the Company will be able to effectively compete with its competitors in the long-term.

Improvements to current electricity generation technologies could render certain existing technologies obsolete. In addition, alternative sources of power, including fuel cells, micro turbines, wind turbines and photovoltaic (solar) cells, currently produce electricity at a higher average price than the Company's generation facilities. 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 the Company's competitors may be more efficient than the Company's plants, which may put some of these plants at a competitive disadvantage to the extent the Company's competitors are able to consume the same, less, or lower cost fuel as the Company's plants consume. Over time, the Company's plants may be displaced from their markets, or may be unable to compete with these more efficient plants. If this were to happen, the Company's assets, liabilities, business, financial condition and results of operations could be materially and adversely affected as a result.

In the Company's power marketing and commercial operations, it competes on the basis of its relative skills, financial position and access to capital with other providers of electric energy in the procurement of fuel and transportation services, and the sale of capacity, energy and related products. In order to compete successfully, the Company seeks to aggregate fuel supplies at competitive prices from different sources and locations and to efficiently utilize transportation services from third-party pipelines, railways and other fuel transporters and transmission services from electric utilities.

Other companies with which the Company competes with may have greater liquidity, greater access to credit and other financial resources, lower cost structures, more effective risk management policies and procedures, greater ability to incur losses, longer-standing relationships with customers, greater potential for profitability from ancillary services or greater flexibility in the timing of their sale of generation capacity and ancillary services than the Company does.

The Company's competitors may be able to respond more quickly than the Company to new laws or regulations or emerging technologies, or to devote greater resources to the construction, expansion or refurbishment of their power generation facilities. In addition, current and potential competitors may make strategic acquisitions or establish cooperative relationships among themselves or with third parties. Accordingly, it is possible that new competitors or alliances among current and new competitors may emerge and rapidly gain significant market share. There can be no assurance that the Company will be able to compete successfully

against current and future competitors, and any failure to do so would have a material adverse effect on the Company's business, financial condition, results of operations and cash flow.

Stakeholder Consultation

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 stakeholder intervention.

A key feature of the current Ontario, British Columbia, Alberta and Federal environmental assessment processes for electricity projects that may be developed by the Company in the future, and a requirement of the ecoEnergy Renewable Power Program, is the requirement to consult with First Nations. Depending on the location of a future project, there may be Aboriginal land title or other claims in respect of the property on which such projects are situated. If there are claims in respect of a project and an agreement has not been reached with First Nations, there is a risk of project delays, business interruption or even cancellation of the project. If First Nation consultation is not conducted or is poorly concluded, by either the Company or the Crown, there is a risk that the Company could face project delays, business interruption or cancellation.

Control Over the Operation of Certain Projects

In some cases, the Company's facilities are not wholly-owned by the Company, and the Company has limited control over the operation of these facilities. Third-party operators manage the operations of some of these facilities. As such, the Company must rely on the technical and management expertise of these third-party operators. To the extent that such third party operators do not fulfill their obligations to manage the operations of the Company's facilities or are not effective in doing so, the Company's financial performance may be adversely affected.

Foreign Exchange Risk

Fluctuations in the exchange rate between the U.S. dollar and the Canadian dollar affect the Company's capital and operating costs, revenues and cash flows and could have an adverse impact on the Company's financial performance and condition. The U.S. plant operations of EPLP and the foreign-sourced equipment required for capital projects such as Keephills 3 and Clover Bar are transacted in U.S. dollars. In addition, certain of EPLP's indebtedness is denominated in U.S. dollars.

Qualifying Facility Status Risk

Certain of EPLP's U.S. facilities are dependent on their QF status. See "Regulatory Overview — United States — Public Utility Regulatory Policies Act of 1978". The Company endeavours to monitor regulatory compliance by EPLP's QF facilities in a manner that is designed to minimize the risk of losing these facilities' QF status. However, some factors necessary to maintain QF status are subject to risks of events outside the Company's control. The loss of QF status could have adverse consequences to EPLP and the applicable facility could become subject to rate regulation by FERC under the FPA, regulation by FERC under the *Public Utility Holding Company Act of 2005* and additional state regulation. Loss of QF status could also trigger defaults under covenants to maintain QF status in the facilities' PPAs, Steam Purchase Contracts and financing agreements and result in termination, penalties or acceleration of indebtedness under such agreements. If a steam host facility were to become insolvent, it could result in the loss of QF status if operations cease. If a power purchaser were to cease taking and paying for electricity or were to seek to obtain refunds of past amounts paid because of the loss of QF status, the Company would not be able to provide assurance that the costs incurred in connection with the facility could be recovered through sales to other purchasers. Upon the occurrence of such an event, the Company would seek to replace the thermal energy customer or find another use for the thermal energy that meets the requirements of PURPA. If the obligation to purchase from some or all of EPLP's QFs is terminated, the Company would need to find alternative purchasers for the output of such

QFs or enter into negotiated rate contracts with existing counterparties once their current contracts expire. Such sales would be at prevailing market rates, which may not be as favourable as the terms of the PURPA sales arrangements under existing contracts and may thus diminish the value of EPLP's QFs.

CFIUS Approval Risk

As described under "Business — EPLP — CFIUS Approval", as certain of EPLP's facilities are located in the United States, the Company has made a voluntary notification of the Offering and the Reorganization to CFIUS. If after such notice CFIUS determines to take no further action, the Offering and the Reorganization will not be subject to future challenge under the Defense Act except in very limited circumstances involving any material misrepresentations made to CFIUS. CFIUS is expected to complete its review of the notice on or about July 8, 2009. No assurance can be given that CFIUS will determine to take no further action and/or will not require a modification of terms of the Offering and the Reorganization, which could have an adverse effect on the Company.

Technological and Systems Risks

The Company 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.

Failure to Meet Quarterly Financial Expectations

The Company's quarterly revenue and results of operations are difficult to predict and fluctuate from quarter to quarter. The Company's quarterly results of operations are influenced by a number of factors, including the risks described in this prospectus, many of which are outside of the Company's control, which may cause such results to fall below market expectations.

Although the Company bases its planned operating expenses in part on the Company's expectations of future revenue, a significant portion of the Company's expenses are relatively fixed in the short-term. If revenue for a particular quarter is lower than expected, the Company likely will be unable to proportionately reduce its operating expenses for that quarter, which will adversely affect the Company's results of operations for that quarter. If the Company fails to meet or exceed analyst or investor expectations, the price of the Common Shares may significantly decline.

In addition, the Company engages in commodity-related marketing and price-risk management activities in order to financially hedge its exposure to market risk with respect to electricity sales from its generation assets, fuel utilized by those assets and emission allowances. The Company generally attempts to balance its fixed-price physical and financial purchases and sales commitments in terms of contract volumes and the timing of performance and delivery obligations through the use of financial and physical derivative contracts. As a result, the Company's quarterly and annual results are subject to significant fluctuations caused by changes in market prices.

Internal Controls

Effective internal controls are necessary for the Company to provide reliable financial reports and to help prevent fraud. Although the Company undertakes a number of procedures in order to help ensure the reliability of its financial reports, including those imposed on it under Canadian securities law, the Company cannot be certain that such measures will ensure that the Company will maintain adequate control over financial processes and reporting. Failure to implement required new or improved controls, or difficulties encountered in their implementation, could harm the Company's results of operations or cause it to fail to meet its reporting obligations. If the Company or its independent auditors discover a material weakness, the disclosure of that fact, even if quickly remedied, could reduce the market's confidence in the Company's consolidated financial statements and harm the trading price of Common Shares.

Insurance Risks

The Company'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 the Company.

Dependence on Subsidiaries and EPLP

The Company's principal assets are the equity interests it owns in its operating subsidiaries and EPLP. As a result, the Company is dependent upon cash dividends, distributions or other transfers from its subsidiaries and EPLP in order to repay any debt the Company may incur, make dividend payments to its shareholders and meet its other obligations. The ability of the Company's subsidiaries and EPLP to pay dividends or distributions and make payments to the Company will depend on their respective results of operations and may be restricted by, among other things, applicable corporate, tax and other laws and regulations and agreements of those entities. Under EPLP's revolving credit facilities, EPLP 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. The Company's subsidiaries and EPLP are separate and distinct legal entities. Any right that the Company has to receive any assets of or distributions from any subsidiary or EPLP upon its bankruptcy, dissolution, liquidation or reorganization, or to realize proceeds from the sale of the assets of any subsidiary or EPLP, will be junior to the claims of that entity's creditors, including trade creditors. In addition, the Company may enter into joint ventures with third parties as a means to execute its business strategy. The Company's ability to access its assets, including cash, in these joint ventures, may be restricted by the governing documents of any such joint ventures.

Derivatives Risks

The Company 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 the Company to other risks. When the Company 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 the Company to post significant amounts of cash collateral or other credit support to its counterparties. In addition, the Company purchases and sells commodity-based contracts in the natural gas and electricity markets for trading purposes. In the future, the Company 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. In the absence of actively quoted market prices and pricing information from external sources, the valuation of these contracts involves judgement and use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of these contracts. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Overview and Summary of Combined and Consolidated Financial Information — Risk Management and Hedge Accounting" for more information about the Company's use of derivative instruments.

The Company may engage in trading activities, including the trading of power, fuel and emissions allowances that are not directly related to the operation of the Company's generation facilities or the management of related risks. These trading activities take place in volatile markets and some of these trades could be characterized as speculative. The Company would expect to settle these trades financially rather than through the production of power or the delivery of fuel. This trading activity may expose the Company to the risk of significant financial losses which could have a material adverse effect on its business and financial condition.

Catastrophic Event Risk

The Company'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. The Company's generation assets could be exposed to effects of severe weather conditions

(see "— Weather Risks"), natural disasters and potentially catastrophic events such as a major accident or incident at the Company's generation assets. A pandemic (see "— Health, Safety and Environmental Matters") or an assault or an action of malicious destruction, sabotage or terrorism committed on the Company's generation assets could also disrupt its ability to generate or sell power. In certain cases, there is the potential that some events may not excuse the Company from performing its obligations pursuant to agreements with third parties. The Company may be liable for damages or suffer further losses as a result. The occurrence of a significant event that disrupts the ability of the Company's generation assets to produce or sell power for an extended period, including events which preclude existing customers from purchasing electricity, could have a material adverse effect on the Company's assets, liabilities, business, financial condition and results of operations.

Litigation Risks

In the normal course of the Company'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 the Company and as a result, could have a material adverse effect on the Company's assets, liabilities, business, financial condition and results of operations. Even if the Company prevails in any such legal proceeding, the proceedings could be costly and time-consuming and would divert the attention of management and key personnel from the Company's business operations, which could adversely affect its financial condition.

Energy Trading Inherent Risks

The Company 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.

The Company undertakes these marketing activities through agreements with various counterparties. Many of the Company's agreements with counterparties include provisions that require the Company to provide guarantees, offset of netting arrangements, letters of credit, and/or cash collateral to protect the counterparties against the risk of the Company's default or insolvency. The amount of such credit support that must be provided typically is based on the difference between the price of the commodity in a given contract and the market price of the commodity. Significant movements in market prices can result in the Company being required to provide cash collateral and letters of credit in very large amounts. The effectiveness of the Company's strategy may be dependent on the amount of collateral available to enter into or maintain these contracts, and liquidity requirements may be greater than the Company anticipates or will be able to meet. Without a sufficient amount of working capital to post as collateral in support of performance guarantees or as a cash margin, the Company may not be able to manage price volatility effectively or to implement its strategy. An increase in the amount of letters of credit or cash collateral required to be provided to the Company's counterparties may negatively affect the Company's liquidity and financial condition.

Further, if any of the Company's facilities experience unplanned outages, the Company may be required to procure replacement power at spot market prices in order to fulfill contractual commitments. Without adequate liquidity to meet margin and collateral requirements, the Company may be exposed to significant losses, may miss significant opportunities, and may have increased exposure to the volatility of spot markets.

General Economic Conditions, Business Environment and Other Risks

The business of the Company is subject to the general economic conditions of the jurisdictions in which the Company operates. Adverse changes in general economic and market conditions could negatively impact demand for electricity, revenue, operating costs, results of financing efforts, timing and extent of capital expenditures or credit risk and counterparty risk. Volatility in natural gas prices, coal prices, other fuel prices,

future electricity prices, and fluctuations in interest rates, product supply and demand, market competition, labour market supplies, risks associated with technology, risks of a widespread influenza or other pandemic, the Company's ability to generate sufficient cash flow from operations to meet its current and future obligations, the Company's ability to access external sources of debt and equity capital, general economic and business conditions, the Company's ability to make capital investments and the amounts of capital investments, risks associated with existing and potential future lawsuits and other regulations, assessments and audits (including income tax) against the Company and its subsidiaries, political and economic conditions in the geographic regions in which the Company and its subsidiaries operate, difficulty in obtaining necessary regulatory approvals, a significant decline in the Company's reputation and such other risks and uncertainties described from time to time in the Company's reports and filings with the Canadian securities authorities could materially adversely impact the Company's business, prospects, financial condition, results of operation or cash flows.

Challenging market conditions and the health of the economy as a whole may have a material adverse effect on the Company's business, financial condition, liquidity and results of operations.

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

Future acquisition activities may have adverse effects

The Company may seek to acquire additional companies or assets in the Company'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, the Company's acquisitions may not be successfully integrated. 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.

Management estimates and assumptions

In preparing combined and consolidated financial statements in conformity with GAAP and management's discussion and analysis of financial conditions and results of operations, several estimates and assumptions are used by management, including those used in determining the reported amounts of assets and liabilities, revenues and expenses recognized during the periods presented and disclosures of contingent assets and liabilities known to exist as of the date of the financial statements. These estimates and assumptions must be made because certain information that is used in the preparation of such financial statements is dependent on future events, cannot be calculated with a high degree of precision from data available or is not capable of being readily calculated based on generally accepted methodologies. In some cases, these estimates are particularly difficult to determine and the Company must exercise significant judgment. Estimates may be used in management's assessment of items such as the impact of Genesee plant outages, fair values, useful lives of assets, income taxes and PPA availability incentives. Actual results for all estimates could differ materially from the estimates and assumptions used by the Company, which could have a material adverse effect on the financial condition, results of operations and cash flows of the Company.

Historical and pro forma financial information

The historical financial information in this prospectus does not reflect the added costs the Company expects to incur as a stand-alone public entity or the resulting changes that will occur in the Company's capital structure and operations. In preparing the pro forma financial information in this prospectus, the Company has given effect to, among other items, the Offering and the Reorganization. The estimates used in the pro forma financial information may not be similar to the Company's actual experience as a stand-alone public entity. For more information on historical financial information and pro forma financial information, see "Unaudited Pro Forma Consolidated and Other Financial Information", "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the historical financial statements of EPCOR Power Group included elsewhere in this prospectus.

Risks Related to the Company's Relationship to EPCOR

Historical Financial Information as a Business Segment of EPCOR

The historical financial information relating to the Company included in this prospectus has been derived from the EPCOR Power Group's historical accounting records. The Company believes that the assumptions underlying the combined and consolidated financial statements are reasonable. However, the combined and consolidated financial statements may not reflect what the Company's financial position, results of operations or cash flows would have been had the Company been a stand-alone entity during the historical periods presented or what the Company's financial position, results of operations or cash flows will be in the future.

In particular, the historical costs and expenses reflected in the EPCOR Power Group's and consolidated financial statements include an allocation for certain corporate functions historically provided by EPCOR. These expense allocations were based on what EPCOR considered to be reasonable allocations of the utilization of services provided or the benefit received by the Company. The Company estimates that general annual corporate expenses may increase when it becomes a stand-alone company. The Company has not made adjustments to its historical financial information to reflect changes that may occur in its cost structure, financing and operations as a result of its separation from EPCOR, including certain tax changes resulting from the reorganization to be undertaken by EPCOR related to the Offering. These changes potentially include increased costs associated with reduced economies of scale and compliance costs from being a publicly-traded, stand-alone company.

As a public company, the Company will incur a significantly higher level of legal, accounting and other related expenses than it did as a business segment of EPCOR. The Company expects current and future applicable Canadian securities laws and TSX requirements to increase the Company's legal and financial compliance costs and to make some activities more time-consuming and costly.

Dependence on EPCOR for Key Services

Historically, EPCOR has performed various administrative and corporate level administrative functions on behalf of the business to be owned by Capital Power, including accounting, treasury and finance services, tax services, employee benefits management, legal, regulatory and environmental management services, human resources management, real estate management, risk and claims management, information management and technology services, and office administration services. Prior to the closing of the Offering, Capital Power will enter into agreements with EPCOR related to the separation of Capital Power's business operations from EPCOR, including an EPCOR Transitional Services Agreement and an EPCOR Services Agreement. Under the terms of the EPCOR Transitional Services Agreement and EPCOR Services Agreement, EPCOR will provide Capital Power with many key services, and EPCOR will have no obligation to provide any services on Capital Power's behalf other than as provided in such agreements. These services include certain:

- information technology and communications services;
- human resources services;
- data centre management;
- tax, accounting, treasury and finance support;
- facilities services; and
- other specified services.

Capital Power expects some of these services may be provided for longer or shorter periods than set out initially in the agreements. Capital Power believes it is necessary for EPCOR to provide these services for Capital Power to facilitate the efficient operation of its business as it transitions into a public company. Capital Power will, as a result, be dependent on EPCOR for certain services following the closing of the Offering. See "Relationship to EPCOR — Agreements Between Capital Power and EPCOR — Transitional Services Agreements".

Once the service periods specified in the EPCOR Transitional Services Agreement and EPCOR Services Agreement have expired and are not renewed, or if EPCOR does not or is unable to perform its obligations under such agreements, Capital Power will be required to provide these services itself or to make alternative arrangements with third parties. Capital Power may be unable to provide these services because of financial or other constraints or may be unable to implement alternative arrangements on a timely basis on terms that are favourable to it or at all. As a result, Capital Power may not be able to effectively operate its business, it may experience unexpected material costs and its profitability may be adversely affected.

Significant Ownership by EPCOR

After the completion of the Offering and the Reorganization, EPCOR will beneficially own, indirectly, a 49% voting interest in the Company. In addition, as the indirect holder of Special Voting Shares, EPCOR will be able to elect a certain number of directors of the Company. See "Description of Share Capital and Exchangeable LP Units — Capital Power — Special Voting Shares" and "Principal Securityholders". For so long as EPCOR maintains a significant indirect equity and voting interest in the Company, EPCOR will have the ability to significantly affect the outcome of shareholder votes, including the ability to prevent certain fundamental transactions. As a result, EPCOR will have the ability to influence many matters affecting the Company, including:

- the composition of the board of directors and, through the board of directors, any determination with respect to the business plans and policies, including the appointment and removal of its officers;
- determinations with respect to acquisitions of businesses, mergers or other business combinations;
- the Company's acquisition or disposition of assets;
- the Company's capital structure, including financing activities;
- compensation, option programs and other human resource policy decisions;
- changes to the transitional agreements with EPCOR, subject to applicable laws;
- changes to other agreements that may adversely affect the Company; and
- the Company's payment or non-payment of dividends.

EPCOR's significant equity ownership may discourage transactions involving a change of control of the Company, including transactions in which an investor as a holder of the Common Shares might otherwise receive a premium for its Common Shares over the then-current market price. As well, the Company's Cooperation Agreement with EPCOR provides for, among other things, financial reporting to EPCOR by the Company and certain other governance matters. See "Relationship to EPCOR — Agreements Between Capital Power and EPCOR — Cooperation Agreement" for a description of the Cooperation Agreement.

EPCOR's ownership of the Special Limited Voting Share and the Special Limited Voting GP Share, together with the Company's obligations under the Edmonton Social Objectives Agreement, requires that the "Head Office" of the Company and the Capital Power Limited Partner GP (as defined in each corporation's respective articles) be located in The City of Edmonton. This obligation could potentially discourage transactions involving a change of control of the Company or limit the Company's ability to attract individuals for the positions of "Executive Officers" (as defined in each corporation's respective articles). See "Description of Share Capital and Exchangeable LP Units — Capital Power — Special Limited Voting Shares and — Capital Power Limited Partner General Partner" and "Relationship to EPCOR — Agreements Between Capital Power and EPCOR — Edmonton Social Objectives Agreement" for a description of the Edmonton Social Objectives Agreement.

EPCOR may not act in a way that promotes the interest of the Company's other shareholders. For example, EPCOR generally has the right at any time to sell Common Shares that it owns or that are issuable to it upon exchange of Exchangeable LP Units to a third party after the expiration of 180 days from the closing date of the Offering, without shareholder approval and without providing for a purchase of the Common Shares of any other of the Company's shareholders, subject to applicable securities laws. See "Plan of Distribution — Lock-up". Accordingly, the Common Shares may be less liquid and worth less than they would if EPCOR did

not have the ability to influence or determine matters affecting the Company. If EPCOR determines to sell Common Shares that it owns (including those issuable to it upon exchange of Exchangeable LP Units) and reduces its ownership interest to less than 50% of the outstanding Common Shares (on a fully diluted basis), EPCOR may be expected, through the voting rights attaching to the Common Shares and/or Special Voting Shares it then owns, to continue to have significant influence over matters affecting the Company, and may, in connection with any matter requiring approval by two-thirds of the votes attaching to Common Shares and Special Voting Shares and represented by holders in attendance at a meeting of the Company's shareholders in person or by proxy, have sufficient votes to preclude any such matter from proceeding.

Ability of the Company and EPCOR to Sell Common Shares

After the completion of the Offering and the Reorganization, EPCOR will own Exchangeable LP Units exchangeable for Common Shares representing, in aggregate, 56.625 million or approximately 72.2% of the outstanding Common Shares assuming the exchange of all Exchangeable LP Units for Common Shares. EPCOR has no contractual obligation to retain any Exchangeable LP Units or Common Shares, except that, as described under "Plan of Distribution — Lock-up", it has agreed not to sell any Exchangeable LP Units or Common Shares without the Underwriters' consent until expiration of the period of 180 days from the closing date of the Offering. Subject to applicable securities laws, after the expiration of this 180-day lock-up period (or before with consent of the representatives of the Underwriters), EPCOR may sell any and all of the Exchangeable LP Units or Common Shares that it beneficially owns (including Common Shares issuable upon exchange of Exchangeable LP Units). EPCOR has advised the Company 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. The Registration Rights Agreement grants EPCOR the right to require the Company to register with the U.S. Securities and Exchange Commission the Common Shares it holds (including Common Shares issuable upon exchange of Exchangeable LP Units) in specified circumstances. See "Relationship to EPCOR — Agreements Between Capital Power and EPCOR — Registration Rights Agreement". In addition, the Company has agreed not to sell any Exchangeable LP Units or Common Shares without the Underwriters' consent until expiration of the period of 180 days from the closing date of the Offering, subject to certain exceptions, as described under "Plan of Distribution — Lock-up". Any sale of substantial amounts of Common Shares in the public market by EPCOR or the Company after the expiration of the lock-up arrangement, or the perception that such sales could occur, could adversely affect prevailing market prices for the Common Shares and impede the Company's ability to raise capital through the issuance of additional equity securities.

Business Conflicts of Interest

Conflicts of interest and disputes may arise between EPCOR and the Company relating to a potential misalignment between the companies' corporate objectives and business interests or the companies past and ongoing relationships, including:

- labour, tax, employee benefits, indemnification and other matters arising under the Separation Agreements;
- intellectual property matters;
- employee recruiting and retention;
- investment in business opportunities;
- funding of the Company;
- dividend policy;
- sales or distributions by EPCOR of all or any portion of its ownership interest in the Company; and
- business combinations involving the Company.

The Company may not be able to resolve any potential conflicts, and, even if it does, the resolution may be less favourable to the Company than if it were dealing with a party that was not a significant holder of equity of

the Company. The agreements that the Company entered into with EPCOR may be amended upon agreement between the parties, subject to applicable laws. Because EPCOR may have significant equity holdings in the Company, the Company may not have the leverage to negotiate any required amendments to these agreements on terms as favourable to the Company as those the Company would negotiate with a party that was not a significant holder of equity of the Company.

Although EPCOR, in connection with the Offering, is transferring to the Company its interest in the assets that are used exclusively in the Company's business conducted by EPCOR and its subsidiaries, this transfer is subject to certain excluded assets. EPCOR's continuing businesses may lead to conflicts of interest between EPCOR and the Company which may not be resolved in the Company's favour or at all.

Assumption of Past, Present and Future Liabilities

Pursuant to the Separation Agreements, the Company will assume all liabilities arising out of or related to the Company's past, present or future business, operations or assets, and will agree to indemnify EPCOR for, among other matters, such liabilities. Pursuant to the Separation Agreements, the Company may assume unknown liabilities that could be significant. The assets constituting business of the Company will be transferred to the Company on an "as is", "where is" basis without any representations or warranties, express or implied, as to its condition, quality, merchantability or fitness thereof. The allocation of assets and liabilities between EPCOR and the Company may not reflect the allocation that would have been reached between the Company and a party that was not in a position to exercise significant influence. See "Relationship to EPCOR — Agreements Between Capital Power and EPCOR — Master Separation Agreement" for a description of these obligations.

Risks Attributable to the Businesses of EPCOR

Although EPCOR will, pursuant to the Separation Agreements, indemnify the Company from losses suffered by the Company arising out of certain circumstances or events, such indemnification may not be sufficient to protect the Company from all risks attributable to the businesses of EPCOR. Following the Offering, any claims made against the Company that are properly attributable to EPCOR in accordance with these arrangements would require the Company to exercise the Company's rights under the Separation Agreements to obtain payment from EPCOR. If the amounts of such claims are significant, individually or in the aggregate, and the Company is ultimately held liable for them, the Company cannot be certain that it will be able to recover the full amount of such claims from EPCOR.

Risks Related to the Company's Relationship with EPLP

Conflict of Interest Risk

Capital Power LP has a 49% voting interest and a 100% economic interest in EPLP Holdco, a holding company (EPCOR owns the other 51% voting interest) that owns a 30.6% interest in the limited partnership units of EPLP and 100% of the shares of EPLP General Partner, and through its wholly-owned subsidiaries in both Canada and the U.S., the Company is manager of the assets and operations of EPLP. Certain of the officers of the Company are officers and directors of EPLP General Partner and EPLP's subsidiaries. As a result of the Company's relationship with EPLP, certain conflicts of interest could arise and the Company may become subject to differing interests as between the Company and EPLP that potentially require the Company to not only consider its own interest but also those of EPLP. For instance, EPLP may from time-to-time choose to bid for or acquire opportunities on which the Company plans to bid (see "Business — Right of First Offer").

EPLP's terms of reference for the board of directors of EPLP 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 Company 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 the EPLP General Partner and EPLP. Any non-arms' length agreements are evaluated solely by a committee of independent directors of EPLP. There are four senior officers of the Company who are members of EPLP General Partner's board of directors and are not considered independent. The Chairman,

who is an executive officer of the Company, has a casting vote or second vote in case of a tie vote at any meeting of such board of directors.

In addition, other conflicts of interest could arise as a result of EPLP's relationship with PERC. EPLP, through its subsidiaries, holds 17.0% of the common share interest and 14.2% of the preferred share interest in PERH; PERC holds the remaining 84.6% interest in PERH. PERC, through PERH and its subsidiaries, engages in activities similar to those of EPLP and some of its subsidiaries. The Company, pursuant to a sub-contracting arrangement with a wholly-owned subsidiary of EPLP, provides management and administrative services to PERH and PERH's subsidiaries.

Risk of Investment in EPLP

The market price for limited partnership units of EPLP, and accordingly the value of the Company's investment in EPLP, may be volatile and subject to wide fluctuations in response to numerous factors, many of which are beyond the Company's and EPLP's control, including the following:

- actual or anticipated fluctuations in EPLP's quarterly results of operations;
- actual or anticipated changes in the distributions declared or paid by EPLP;
- actual or anticipated changes in energy prices;
- recommendations by securities research analysts;
- changes in the economic performance or market valuations of other companies that investors deem comparable to EPLP;
- addition or departure of EPLP's executive officers and other key personnel;
- sales or perceived sales of additional limited partnership units of EPLP;
- significant acquisitions or business combinations, strategic partnerships, joint ventures or capital commitments by or involving EPLP or its competitors; and
- news reports relating to trends, concerns, technological or competitive developments, regulatory changes and other related issues in EPLP's industry or target markets.

Financial markets have recently experienced significant price and volume fluctuations that have particularly affected the market prices of equity securities of issuers and that have, in many cases, been unrelated to the operating performance, underlying asset values or prospects of such companies. Accordingly, the market price of the limited partnership units of EPLP may decline even if EPLP's operating results, underlying asset values or prospects have not changed. Additionally, these factors, as well as other related factors, may cause decreases in asset values that are deemed to be other than temporary, which may result in impairment losses. There can be no assurance that continuing fluctuations in price and volume will not occur. If such increased levels of volatility and market turmoil continue, the trading price of the limited partnership units of EPLP and the value of the Company's investment in EPLP could be adversely impacted.

EPLP Access to Capital Risk

As a publicly traded partnership, EPLP is subject to reduced access to capital as result of changes in tax laws in the form of the so-called "SIFT rules" and, as a result, the trading price of the limited partnership units of EPLP and the value Company's investment in EPLP could be adversely impacted.

Risks Related to the Offering

No Prior Public Market for Common Shares

The TSX has conditionally approved the listing of the Common Shares. Listing is subject to the Company fulfilling all of the original listing requirements of the TSX on or before August 31, 2009, including distribution of these Common Shares to a minimum number of public securityholders. Prior to the Offering, no public market existed for the Common Shares. An active and liquid market for the Common Shares may not develop

following the completion of the Offering or, if developed, may not be maintained. If an active public market does not develop or is not maintained, investors may have difficulty selling their Common Shares.

The initial public offering price of Common Shares was determined by negotiation among Capital Power, EPCOR and the Underwriters and may not be indicative of the price at which the Common Shares will trade following the completion of the Offering. The Company cannot assure investors that the market price of Common Shares will not materially decline below the initial public offering price.

Volatile Market Price for Common Shares

The market price for Common Shares may be volatile and subject to wide fluctuations in response to numerous factors, many of which are beyond the Company's control, including the following:

- actual or anticipated fluctuations in the Company's quarterly results of operations;
- actual or anticipated changes in energy prices;
- recommendations by securities research analysts;
- changes in the economic performance or market valuations of other companies that investors deem comparable to the Company;
- addition or departure of the Company's executive officers and other key personnel;
- release or expiration of lock-up or other transfer restrictions on outstanding Common Shares;
- sales or perceived sales of additional Common Shares;
- significant acquisitions or business combinations, strategic partnerships, joint ventures or capital commitments by or involving the Company or its competitors; and
- news reports relating to trends, concerns, technological or competitive developments, regulatory changes and other related issues in the Company's industry or target markets.

Financial markets have recently experienced significant price and volume fluctuations that have particularly affected the market prices of equity securities of companies and that have, in many cases, been unrelated to the operating performance, underlying asset values or prospects of such companies. Accordingly, the market price of the Common Shares may decline even if the Company's operating results, underlying asset values or prospects have not changed. Additionally, these factors, as well as other related factors, may cause decreases in asset values that are deemed to be other than temporary, which may result in impairment losses. As well, certain institutional investors may base their investment decisions on consideration of the Company's environmental, governance and social practices and performance against such institutions' respective investment guidelines and criteria, and failure to meet such criteria may result in a limited or no investment in the Common Shares by those institutions, which could adversely affect the trading price of the Common Shares. There can be no assurance that continuing fluctuations in price and volume will not occur. If such increased levels of volatility and market turmoil continue, the Company's operations could be adversely impacted and the trading price of the Common Shares may be adversely affected.

Issuance of Additional Securities

The Company's Board of Directors may issue an unlimited number of Preference Shares, issuable in one or more series, and an unlimited number of Common Shares, without any vote or action by the Company's shareholders, subject to the rules of the Toronto Stock Exchange. If the Company were to issue any Preference Shares or any additional Common Shares, the percentage ownership of existing shareholders may be reduced and diluted. In addition, the Company's Board of Directors may determine the price, rights, preferences, privileges and restrictions, including voting, dividend and conversion rights, of each series of the Company's Preference Shares and determine to whom they shall be issued. Immediately after the completion of the Offering, there will be no Preference Shares outstanding and the Company has no present plans to issue any Preference Shares. However, the rights of the holders of any series of Preference Shares that may be issued in the future may be senior to the rights of holders of the Common Shares, which could preclude holders of the

Common Shares from receiving dividends, proceeds of a liquidation or other benefits. The issuance of Preference Shares, while providing desirable flexibility in connection with possible acquisitions and other corporate purposes, could make it more difficult for a third party to acquire control of the Company, for example, by discouraging an unsolicited acquisition proposal or a proxy contest, the effect of which may be to deprive the Company's shareholders of a control premium that might otherwise be realized in connection with an acquisition of the Company.

Dividend Policy

The Board of Directors of Capital Power has established a dividend policy pursuant to which Capital Power will, following the completion of the Offering and the Reorganization, initially authorize the declaration and payment of a dividend of $1.26 per Common Share, to be paid to holders of Common Shares on a quarterly basis. The payment of dividends is not guaranteed, however, and the amount and timing of any future dividends will be at the discretion of the Company's Board of Directors after taking into account such factors as the Company's financial condition, results of operations, distributions from Capital Power LP, current and anticipated cash needs, the requirements of any future financing agreements and other factors that the Company's Board of Directors may deem relevant. See "Dividend Policy".

Litigation

On June 11, 2009, an action was commenced in the Court of Queen's Bench of Alberta, Judicial District of Edmonton by William Pidruchney, making claims related to the Reorganization and Offering. The claim alleges, among other things, that The City of Edmonton acted beyond its power and contrary to the *Municipal Government Act* (Alberta) and did not observe an appropriate public process, consultation and approval in its consideration of those transactions. If the claim is decided in favour of the applicant, the Court could subject the Company to equitable remedies, including an injunction restraining the Reorganization and the Offering from proceeding, and to damages, which could adversely affect the Company's financial condition. In addition, the litigation could require significant attention of the Company's management.

LEGAL MATTERS

Management of Capital Power is not aware of any existing or contemplated legal proceedings material to the Company to which it is a party or to which its property is the subject except as described below.

On June 11, 2009, an action was commenced in the Court of Queen's Bench of Alberta, Judicial District of Edmonton by William Pidruchney, making claims related to the Reorganization and Offering. The claim names The City of Edmonton, the Mayor and Councillors of The City of Edmonton, EPCOR, EPLP General Partner, EPLP and Capital Power as defendants and alleges, among other things, that The City of Edmonton acted beyond its power and contrary to the *Municipal Government Act* (Alberta) and did not observe an appropriate public process, consultation and approval in its consideration of those transactions. Based on its review of the available information, the Company believes that the claim is without merit and intends to vigorously defend itself. See "Risk Factors — Risks Related to the Offering — Litigation".

Certain Canadian legal matters related to the Offering, including the validity of the issuance of the Common Shares, will be passed upon for the Company and EPCOR by Blake, Cassels & Graydon LLP. Certain Canadian and U.S. legal matters relating to the Offering will be passed upon for the Underwriters by Osler, Hoskin & Harcourt LLP. Certain U.S. legal matters relating to the Offering will be passed upon for the Company and EPCOR by K&L Gates LLP. J. Rob Collins, a partner of Blake, Cassels & Graydon LLP beneficially owns, directly, the sole issued and outstanding Common Share, and the partners and associates of Blake, Cassels & Graydon LLP, collectively, beneficially own, directly and indirectly, no outstanding common shares of EPCOR. The partners and associates of Osler, Hoskin & Harcourt LLP, collectively, beneficially own, directly and indirectly, (i) no outstanding Common Shares; and (ii) no outstanding common shares of EPCOR. The partners and associates of K&L Gates LLP, collectively, beneficially own, directly and indirectly, (i) no outstanding Common Shares; and (ii) no outstanding common shares of EPCOR.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

No director, executive officer or principal holder of securities (as described under "Principal Securityholders") or any associate or affiliate of the foregoing has, or has had, any material interest in any transaction prior to the date hereof or any proposed transaction that has materially affected or will materially affect the Company or any of its affiliates, except as disclosed elsewhere in this prospectus.

EXPERTS

EPCOR Power Group's combined and consolidated financial statements as of December 31, 2008, 2007 and 2006 and for each of the three years then ended, included in this prospectus have been audited by KPMG LLP, and have been so included in reliance upon the report of such firm given upon their authority as experts in accounting and auditing. KPMG has advised that it is independent of the Company in accordance with the rules of professional conduct applicable to auditors in Alberta.

AUDITORS, TRANSFER AGENT AND REGISTRAR

The Company's independent auditors are KPMG LLP, located at Edmonton, Alberta.

The transfer agent and registrar for the Common Shares is Computershare Trust Company of Canada at its principal offices in Calgary, Alberta and Toronto, Ontario.

MATERIAL CONTRACTS AND OTHER INFORMATION

The following are the only material contracts, other than those contracts entered into in the ordinary course of business, which the Company has entered into during the two years before the date of this prospectus or to which the Company is or will become a party on or prior to the closing of the Offering and the Reorganization.

1. the Underwriting Agreement, dated as of the date of this prospectus, among Capital Power, EPCOR and the Underwriters, referred to under "Plan of Distribution";
2. the following agreements referred to under "Relationship to EPCOR — Limited Partnership Agreement of Capital Power LP" and "— Agreements Between Capital Power and EPCOR":
   - Master Separation Agreement;
   - Cooperation Agreement;
   - Registration Rights Agreement;
   - Limited Partnership Agreement;
   - Share Purchase Agreement;
   - Asset Purchase Agreement;
   - Exchange Agreement;
   - EPLP Holdco Shareholder Agreement; and
   - Edmonton Social Objectives Agreement; and
3. the credit agreement between Capital Power LP and EPCOR, referred to under "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and capital resources".
4. the Memorandum of Agreement, dated June 7, 2009, among Capital Power, EPCOR and EPLP, referred to under "Business — Memorandum of Agreement";

Copies of the above material agreements, once executed, and the articles of the Company, EPLP Holdco and Capital Power L.P. General Partner may be inspected during ordinary office business hours at the Company's principal executive offices located at TD Tower, 10188-102 Avenue, Edmonton, Alberta T5J 2Z1 during the period of distribution of the Common Shares or may be viewed at the website maintained by the Canadian Securities Administrators at http://www.sedar.com.

PROMOTER

EPCOR may be considered a promoter of the Company within the meaning of Canadian provincial securities legislation by virtue of its initiative in founding the business of the Company. A description of the nature of the relationship between Capital Power and EPCOR is described under "Relationship to EPCOR" and "Principal Securityholders".

PURCHASERS' STATUTORY RIGHTS

Securities legislation in certain of the provinces and territories of Canada provide purchasers with the right to withdraw from an agreement to purchase securities. This right may be exercised within two business days after receipt or deemed receipt of a prospectus and any amendment. In several of the provinces and territories, the securities legislation further provides a purchaser with remedies for rescission or, in some jurisdictions, revisions of the price or damages if the prospectus and any amendment contains a misrepresentation or is not delivered to the purchaser, provided that the remedies for rescission, revisions of the price or damages are exercised by the purchaser within the time limit prescribed by the securities legislation of the purchaser's province or territory. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province or territory for the particulars of these rights or consult with a legal adviser.

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AUDITORS' CONSENT

The Board of Directors of EPCOR Utilities Inc.:

We have read the supplemented PREP prospectus dated June 25, 2009 of Capital Power Corporation (the "Company") relating to the sale and issue of common shares of the Company (the "Prospectus"). We have complied with Canadian generally accepted standards for an auditor's involvement with offering documents.

We consent to the use in the above-mentioned Prospectus of our report to the Board of Directors of EPCOR Utilities Inc. on the combined and consolidated balance sheets of EPCOR Power Group as at December 31, 2008 and 2007 and the combined and consolidated statements of income, comprehensive income, changes in shareholders' equity and cash flows of EPCOR Power Group for each of the years in the three-year period ended December 31, 2008. Our report is dated May 8, 2009, except for note 2(h), 28(g) and 31 for which the date is June 25, 2009.

"*KPMG LLP*"

Chartered Accountants
Edmonton, Canada
June 25, 2009

INDEX TO COMBINED AND CONSOLIDATED FINANCIAL STATEMENTS

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AUDITORS' REPORT TO THE BOARD OF DIRECTORS OF EPCOR UTILITIES INC.

We have audited the combined and consolidated balance sheets of EPCOR Power Group (the Group) as at December 31, 2008 and 2007 and the combined and consolidated statements of income, comprehensive income, changes in shareholders' equity and cash flows for the years ended December 31, 2008, 2007 and 2006. These financial statements are the responsibility of the Group's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits 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 combined and consolidated financial statements present fairly, in all material respects, the financial position of the Group as at December 31, 2008 and 2007 and the results of its operations and its cash flows for the years ended December 31, 2008, 2007 and 2006 in accordance with Canadian generally accepted accounting principles.

"*KPMG LLP*"

Chartered Accountants

Edmonton, Canada
May 8, 2009, except as to notes 2(h), 28(g) and 31
which are as of June 25, 2009

EPCOR POWER GROUP

COMBINED AND CONSOLIDATED STATEMENTS OF INCOME

(In millions of dollars)
Years ended December 31, 2008, 2007 and 2006

	2008	2007	2006
Revenues	$2,649	$2,953	$2,246
Energy purchases and fuel	1,914	2,079	1,462
	735	874	784
Operations, maintenance and administration	370	287	248
Depreciation, amortization and asset retirement accretion (note 7)	181	175	154
Foreign exchange losses (gains)	18	(56)	54
Gain on sale of power purchase arrangement and related transactions (note 4)	(34)	(34)	(378)
Impairments (notes 9, 10 and 11)	52	13	5
Net financing expenses (note 19)	219	219	227
	806	604	310
Income (loss) before income taxes and non-controlling interests	(71)	270	474
Income taxes (reductions) (note 20)	(24)	113	(3)
Income (loss) before non-controlling interests	(47)	157	477
Non-controlling interests (note 15)	(51)	23	44
Net income	$ 4	$ 134	$ 433

See accompanying notes to combined and consolidated financial statements.

EPCOR POWER GROUP

COMBINED AND CONSOLIDATED BALANCE SHEETS

(In millions of dollars)
December 31, 2008 and 2007

	2008	2007
Assets		
Current assets:		
Cash and cash equivalents (note 26)	$ 69	$ 51
Notes receivable (note 5)	—	115
Accounts receivable	320	412
Income taxes recoverable	5	3
Inventories (note 6)	62	39
Prepaid expenses	8	8
Derivative instruments assets (note 22)	126	104
Future income tax assets (note 20)	—	2
	590	734
Property, plant and equipment (note 7)	3,185	2,810
Power purchase arrangements (note 8)	593	679
Contract and customer rights and other intangible assets (note 9)	183	161
Derivative instruments assets (note 22)	75	116
Future income tax assets (note 20)	97	93
Goodwill (note 10)	159	183
Other assets (note 11)	120	146
	$5,002	$4,922
Liabilities and Shareholders' Equity		
Current liabilities:		
Notes payable (note 5)	$ 155	$ —
Accounts payable and accrued liabilities	430	472
Income taxes payable	4	44
Derivative instruments liabilities (note 22)	130	128
Future income tax liabilities (note 20)	34	39
Current portion of long-term debt (note 12)	20	25
	773	708
Long-term debt (note 12)	3,007	2,460
Derivative instruments liabilities (note 22)	110	76
Other non-current liabilities (note 13)	91	82
Future income tax liabilities (note 20)	100	127
	4,081	3,453
Non-controlling interests (note 15)	540	740
Shareholders' equity:		
Share capital (note 16)	673	673
Retained earnings (deficit)	(228)	136
Accumulated other comprehensive loss (note 17)	(64)	(80)
	381	729
Contingencies and commitments (note 28)		
Subsequent event (note 31)		
	$5,002	$4,922

See accompanying notes to combined and consolidated financial statements.

EPCOR POWER GROUP

COMBINED AND CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

(In millions of dollars)

Years ended December 31, 2008, 2007 and 2006

	2008	2007	2006
Share capital:			
Balance, beginning of year	$ 673	$ 673	$ 274
Common shares issued (note 3)	—	—	399
Balance, end of year (note 16)	673	673	673
Contributed surplus:			
Balance, beginning of year	—	—	200
Deemed equity distribution (note 3)	—	—	(200)
Balance, end of year	—	—	—
Retained earnings (deficit):			
Balance, beginning of year	136	89	411
Adjustment for changes in accounting policies (note 2b)	—	11	—
Net income	4	134	433
Deemed equity distribution (note 3)	—	—	(699)
Common share dividends paid	(370)	(122)	(19)
Refundable taxes	2	24	(37)
Balance, end of year	(228)	136	89
Accumulated other comprehensive loss:			
Balance, beginning of year	(80)	(19)	(59)
Adjustment for changes in accounting policies (note 2b)	—	(40)	—
Other comprehensive income (loss)	16	(21)	40
Balance, end of year (note 17)	(64)	(80)	(19)
Total shareholders' equity, end of year	$ 381	$ 729	$ 743

See accompanying notes to combined and consolidated financial statements.

EPCOR POWER GROUP

COMBINED AND CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(In millions of dollars)
Years ended December 31, 2008, 2007 and 2006

	2008	2007	2006
Net income	$ 4	$134	$433
Other comprehensive income (loss), net of income taxes:			
Unrealized gains (losses) on derivative instruments designated as cash flow hedges[1]	26	(73)	—
Reclassification of losses on derivative instruments designated as cash flow hedges to net income[2]	7	46	—
Unrealized gains on financial instruments designated as available for sale[3]	7	3	—
Reclassification of gains on financial instruments designated as available for sale to net income[4]	(10)	—	—
Unrealized loss in self-sustaining foreign operations[5]	(62)	—	(4)
Reclassification of foreign exchange losses on self-sustaining foreign operations to net income (note 4)[5]	—	—	44
Non-controlling interests[5] (note 15)	48	3	—
	16	(21)	40
Comprehensive income	$ 20	$113	$473

(1) For the year ended December 31, 2008, net of income tax expense of $13 (2007 — net of income tax recovery of $29; 2006 — not applicable).

(2) For the year ended December 31, 2008, net of reclassification of income tax recovery of $3 (2007 — $20; 2006 — not applicable).

(3) For the year ended December 31, 2008, net of income tax expense of $2 (2007 — $1; 2006 — not applicable).

(4) For the years ended December 31, 2008, net of reclassification of income tax expense of $3 (2007 — nil; 2006 — not applicable).

(5) For the years ended December 31, 2008, 2007 and 2006, net of income tax expense of nil.

See accompanying notes to combined and consolidated financial statements.

EPCOR POWER GROUP

COMBINED AND CONSOLIDATED STATEMENTS OF CASH FLOWS

(In millions of dollars)
Years ended December 31, 2008, 2007 and 2006

	2008	2007	2006
Operating activities:			
Net income	$ 4	$ 134	$ 433
Adjustments to reconcile net income to cash flows from operating activities:			
Depreciation, amortization and asset retirement accretion (note 7)	181	175	154
Impairments (notes 9, 10 and 11)	52	13	5
Gain on sale of power purchase arrangement and related transactions (note 4)	(34)	(34)	(378)
Reduction of Clover Bar asset retirement obligations	—	(5)	(13)
Non-controlling interests in Power LP (note 15)	(58)	19	44
Fair value changes on derivative instruments	111	(30)	(1)
Unrealized foreign exchange losses (gains)	18	(73)	55
Future income taxes	(14)	78	(11)
Other	5	2	(7)
	265	279	281
Change in non-cash operating working capital (note 18)	(100)	(149)	(142)
	165	130	139
Investing activities:			
Property, plant and equipment and other assets	(439)	(235)	(49)
Business acquisitions, net of acquired cash (note 4)	(89)	—	(354)
Net proceeds on PSA interests (note 4)	53	59	301
Proceeds on sale of portfolio investments	16	—	—
Other	4	(8)	7
Change in non-cash investing working capital (note 18)	306	175	(416)
	(149)	(9)	(511)
Financing activities:			
Net proceeds from issue of short-term debt	—	—	209
Repayment of short-term debt	—	(200)	—
Proceeds from issue of long-term debt	85	240	406
Repayment of long-term debt	(48)	(329)	(272)
Issue of subsidiary preferred shares (note 15)	—	121	—
Distributions to non-controlling interests	(94)	(91)	(85)
Issue of limited partnership units of Power LP to non-controlling interests (note 15)	—	69	55
Common share dividends	(370)	(122)	(19)
Other	—	—	(5)
Change in non-cash financing working capital (note 18)	417	190	82
	(10)	(122)	371
Foreign exchange gain (loss) on cash held in a foreign currency	12	(7)	1
Increase (decrease) in cash and cash equivalents	18	(8)	—
Cash and cash equivalents, beginning of year	51	59	59
Cash and cash equivalents, end of year	$ 69	$ 51	$ 59
Supplementary cash flow information:			
Interest paid net of interest received	$ 187	$ 201	$ 184
Income taxes paid net of income taxes recovered	69	18	(3)

See accompanying notes to combined and consolidated financial statements.

1. DESCRIPTION OF BUSINESS

EPCOR Power Group (the Group) builds, owns and operates power plants and manages its related electricity and natural gas portfolios by undertaking trading and marketing activities. The Group 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 companies combining to form the Group are owned by EPCOR Utilities Inc. (EUI).

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) Basis of presentation:

These combined and consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles (GAAP). Management believes the assumptions underlying these combined and consolidated financial statements are reasonable.

These combined and consolidated financial statements of the Group have been derived from the consolidated financial statements and accounting records of EUI, on a basis which maintains the historical operations and the historical measurement of assets and liabilities, and principally include the accounts of EPCOR Power Development Corporation, EPCOR Power Generation Services Inc., EMCC Limited and EPCOR PPA Management Inc., their subsidiaries, and their proportionate share of assets, liabilities, revenues and expenses of joint ventures. The assets, liabilities and operations of the Rossdale generation plant are excluded from the accounts of EPCOR Power Development Corporation as included in these combined and consolidated financial statements. The accounts of the Group's approximate 30.6% interest in EPCOR Power L.P. (Power LP), a publicly traded entity, are also included in these combined and consolidated financial statements. Under GAAP, the Group controls Power LP which therefore is a subsidiary of the Group. The comparative figures include, on a continuity of interests basis, the financial position, results of operations and cash flows of certain other entities within the EUI corporate group that, as a result of various transactions within the EUI corporate group, form all or part of the historical results of the companies combined to form the group as at December 31, 2008. These combined and consolidated financial statements may not necessarily reflect the Group's financial position, results of operations and cash flows in the future, nor what its financial position, results of operations and cash flows would have been had the Group been a stand-alone entity during the periods presented.

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

(b) Changes in significant accounting policies:

2007 changes

Commencing January 1, 2007, the Group adopted new accounting standards as issued by the Canadian Institute of Chartered Accountants (CICA) for Comprehensive Income, Equity, Financial Instruments and Hedges. In accordance with the new standards, the comparative financial statements for the year ended December 31, 2006 have not been restated as a result of implementing the new accounting standards except to reclassify unrealized foreign currency translation gains and losses on net investments in self-sustaining foreign operations from the cumulative translation adjustment account to accumulated other comprehensive income, both within shareholders' equity.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Comprehensive income and equity

These new standards establish requirements for the reporting and presentation of comprehensive income which is composed of net income and other comprehensive income and for the presentation of equity and changes in equity due to the comprehensive income requirements. Other comprehensive income includes unrealized gains or losses arising from the translation of net investments in self-sustaining foreign operations, the changes in the fair value of the effective portion of derivative instruments used in cash flow hedges and unrealized gains and losses on available-for-sale financial instruments. Each component of the statement of comprehensive income is recorded net of income taxes. Accumulated other comprehensive income is a new component of shareholder's equity.

Financial instruments

The new standards require that financial assets be 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 must be 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 Group 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 Group has designated its cash and cash equivalents as held for trading. All other non-derivative financial assets not meeting the Group's criteria for designating as held for trading are classified as available for sale, loans and receivables or held to maturity.

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.

All derivative instruments, including embedded derivatives, are recorded at fair value on the balance sheet as derivative instruments assets and derivative instruments liabilities unless exempted from derivative treatment as an expected purchase, sale or usage. All changes in their fair value 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 Group chose a

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

transition date of January 1, 2003 for embedded derivatives and therefore is only required to account separately for those embedded derivatives in any hybrid instruments issued, acquired or substantively modified after that date. The Group 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.

Hedges

Hedge accounting standards specify the criteria that must be met in order for hedge accounting to be applied. Hedge accounting enables the recording of gains, losses, revenues and expenses from derivative instruments in the same period as those related to the hedged item. Hedge accounting may be applied for fair value hedges, cash flow hedges and hedges of foreign currency exposures of net investments in self-sustaining foreign operations if the criteria are met.

The Group 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 net income. 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. For the detailed accounting policy on hedge accounting, refer to note 2(f) below.

Financial statement impact upon adoption

Certain physical fuel purchase contracts are not designated as contracts used in accordance with the Group's expected purchase requirements and, therefore, are measured at fair value. An opening adjustment to retained earnings to reflect the fair value of these contracts at January 1, 2007 was recorded. Subsequent changes in the fair value of these contracts are reported in net income.

Qualifying cash flow hedges of electricity sales and purchases have been established and the changes in the fair value of the effective portion of the associated derivative instruments have been reflected as an opening adjustment to accumulated other comprehensive income. Subsequent fair value changes in the effective portion of the associated derivative instruments are also included in other comprehensive income. The changes in the fair value of the ineffective portion of these derivatives are included in net income.

Prior to the adoption of these new standards, the unrealized losses on certain derivative instruments which did not satisfy all the requirements for hedge accounting, were recorded as derivative instruments assets on the balance sheet. As required by the new standards, these unrealized losses were reclassified to opening retained earnings.

Also prior to the adoption of these new standards, the unrealized gains associated with hedges which were voluntarily discontinued by the Group in prior periods were included in derivative instruments liabilities on the balance sheet. These gains are recognized in net income in the same period or periods when the variability in the cash flows of the related hedged item affects net income. Consistent with the requirements of the new standards, these unrealized gains were reclassified to accumulated other comprehensive income as a cumulative opening adjustment.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

On January 1, 2007, the Group made the following adjustments to the balance sheet to adopt the new standards:

Description	Balance sheet item	Increase (decrease)
Physical power and natural gas purchase and sales contracts measured at fair value	Derivative instruments assets — current	$ 47
	Derivative instruments assets — non-current	94
	Derivative instruments liabilities — current	18
	Derivative instruments liabilities — non-current	27
	Future income tax liabilities — current and non-current	10
	Non-controlling interests	67
	Opening retained earnings	19
Deferred unrealized losses relating to financial instruments not qualifying as hedges	Derivative instruments assets — non-current	(12)
	Future income tax assets — non-current	4
	Opening retained earnings	(8)
Cash flow hedges measured at fair value	Derivative instruments assets — current	59
	Derivative instruments assets — non-current	32
	Future income tax assets — non-current	18
	Derivative instruments liabilities — current	71
	Derivative instruments liabilities — non-current	80
	Opening accumulated other comprehensive loss	(42)
Deferred unrealized gains relating to certain previously discontinued hedges reclassified to accumulated other comprehensive income	Derivative instruments liabilities — non-current	(7)
	Future income tax liabilities — current and non-current	1
	Non-controlling interests	4
	Opening accumulated other comprehensive loss	2
Deferred financing costs reclassified from other assets to long-term debt	Other assets	(7)
	Long-term debt	(7)

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

During the year ended December 31, 2007, these new standards impacted the financial statements as follows:

Financial statement line item	Increase (decrease)
Derivative instruments assets — current and non-current	$(89)
Future income tax assets	8
Other assets	(7)
Derivative instruments liabilities — current and non-current	(27)
Future income tax liabilities	(1)
Non-controlling interests (balance sheet)	(22)
Revenues	2
Fuel expense	32
Net financing expenses	11
Income tax expense	(2)
Non-controlling interests (statement of income)	(22)
Other comprehensive loss	(21)

2008 changes

Commencing January 1, 2008, the Group adopted new accounting standards as issued by the Canadian Institute of Chartered Accountants (CICA) for Financial Instruments — Disclosures and Presentation, Capital Disclosures, and Inventories. The new accounting standards have been applied retrospectively and the comparative financial statements have not been restated.

Financial instruments — disclosures and presentation

The new standards establish requirements for the reporting and presentation of quantitative and qualitative information that is intended to provide users of the financial statements with additional insight into the Group's risks associated with financial instruments and how these risks are managed. These risks include credit, liquidity and market risks. The disclosures required under these new standards have been incorporated into these combined and consolidated financial statements and discussed in note 21 — Fair value and classification of non-derivative financial assets and liabilities, note 22 — Derivative instruments and hedge accounting and note 23 — Risk management.

Capital disclosures

The new standard requires qualitative information about the Group's objectives, policies and processes for managing capital and quantitative data related to the Group's capital, as discussed in note 24 — Capital management.

Inventories

The new standard requires the Group's inventories to be measured at the lower of cost and net realizable value except for natural gas inventories held in storage for trading purposes which are measured at fair value less costs to sell. The Group's adoption of the standard did not have a material impact on these combined and consolidated financial statements. The additional disclosures required under the new standard are provided in note 6 — Inventories.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Future accounting changes

Goodwill and intangible assets

In February 2008, the CICA issued Handbook Section 3064 — Goodwill and Intangible Assets and consequential amendments to Section 1000 — Financial Statement Concepts. The new section establishes standards for the recognition, measurement and disclosure of goodwill and intangible assets. The provisions relating to the definition and initial recognition of intangible assets, including internally generated intangible assets, are equivalent to the corresponding provisions in International Financial Reporting Standards (IFRS). These amendments are effective January 1, 2009, and have been adopted by the Group as of that date. The Group has reviewed its capitalization policies and practices for compliance with the new standard and has reclassified approximately $11 million (2007 — $8 million) of assets from property, plant and equipment to contract and customer rights and other intangible assets. The retrospective impact of this change in accounting policy has been reflected in these financial statements as required by CICA Handbook Section 1506 — Accounting Changes. The Group does not expect the other impacts of this standard to be material.

Credit risk in determining fair value of financial assets and liabilities

On January 20, 2009 the Emerging Issues Committee of the CICA issued EIC-173, Credit Risk and the Fair Value of Financial Assets and Financial Liabilities, which clarifies that an entity's own credit risk and the credit risks of the counterparties should be taken into account in determining the fair value of financial assets and liabilities, including derivative instruments. EIC-173 is to be applied retrospectively without restatement of prior periods in interim and annual financial statements for periods ending on or after the date of issuance of EIC-173. Effective January 1, 2009, the Group adopted the recommendations of EIC-173 and made adjustments to its balance sheet to decrease non-current derivative instruments liabilities by $6 million and increase non-controlling interests by $3 million with the offsetting difference of $3 million impacting opening retained earnings, non-current future income tax liabilities and non-current derivative assets by $1 million each.

The CICA has announced that Canadian reporting issuers will need to begin reporting under IFRS, including comparative figures, by the first quarter of 2011. The Group is currently assessing the impact of the differences in accounting standards on the Group's future financial reporting requirements and working towards the conversion to IFRS in 2011.

(c) Measurement uncertainty:

The preparation of the Group'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 degree to which revenues are recognized or deferred under the Power Purchase Arrangements (PPAs) described in note 2(k) depends upon long-term outlooks of generation unit performance. Such outlooks of performance are estimated based on the generation units' historical performance, planned maintenance, reliability and generation availability, and revisions in the estimated long-term price embedded in the PPA.

For certain accounting measures such as determining asset impairments, purchase price allocations for business combinations, recording financial assets and liabilities, recording certain non-financial

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

derivatives and for certain disclosures, the Group 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.

Measurement of the Group'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.

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.

Income taxes are determined based on estimates of the Group'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.

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.

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

(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 year-end.

The Group recognizes revenue from its Alberta generation units operating under PPAs as described in note 2(k). PPAs are a form of long-term sales arrangements between the owner of a generation unit and the buyer of the PPA.

Revenues from the Group's power generation plants located outside of Alberta are recognized on delivery of output or on availability for delivery as prescribed by contractual arrangements. These contractual arrangements are also commonly referred to as PPAs. 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.

(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

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

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 Group 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 Group has designated its cash and cash equivalents as held for trading. All other non-derivative financial assets not meeting the Group's criteria for designating as held for trading are classified as available for sale, loans and receivables or held to maturity.

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 Group 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 Group'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. On the adoption of the current accounting standards for derivatives in 2007, the Group chose a transition date of January 1, 2003 for embedded derivatives and therefore is only required to account separately for those embedded derivatives in any hybrid instruments issued, acquired or substantively modified after that date. The Group does not

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

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 Group uses financial contracts-for-differences (or fixed-for-floating swaps) to hedge the Group's exposure to fluctuations in electricity prices. Under these instruments, the Group 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 Group uses non-financial forward delivery derivatives to manage the Group'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 Group 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 Group 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 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.

The Group may use forward interest rate or swap agreements and option agreements to manage the impact of fluctuating interest rates on existing debt.

The Group 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 Group 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 retroactive and prospective basis. The Group 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 net income. 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 Group has not designated any fair value hedges at the balance sheet dates.

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 Group 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 Group'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,

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

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 financial instruments reflects changes in the commodity market prices, interest rates and foreign exchange rates. Fair value is determined based on exchange or over-the-counter price quotations by reference to bid or asking price as appropriate, in active markets. In illiquid or inactive markets, the Group 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.

(g) Income taxes:

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

From January 1, 2001, the Group was required to pay amounts in lieu of income taxes (PILOT) to the Alberta Balancing Pool on certain of its Alberta operations. Following the January 3, 2006 reorganization, the Group no longer has any entities subject to PILOT as they have become subject to the ITA and the Alberta Corporate Tax Act.

The Group 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, short-term investments with an investment-grade credit rating and they are recorded at fair market value. For a short-term investment, an investment-grade credit rating means a credit rating of R-3 or higher from DBRS, A-3 or higher from S&P or P-3 or higher from Moody's.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

(i) Inventories:

Small parts and other consumables and coal, the majority of which are consumed by the Group 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, overhead costs, asset retirement costs, 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 Group capitalizes interest during construction to provide for the costs of borrowing on construction activities. Interest is applied during construction using the average cost of debt associated with the specific project.

(k) Power purchase arrangements:

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

Alberta PPAs, which are comprised of the Sundance PPA and a portion of the Battle River PPA, reflect the cost to acquire the rights to the committed generating capacity of five regulated Alberta generation units auctioned by the Government of Alberta in the year 2000 as part of provincial electricity deregulation. The cost of the Alberta PPAs also reflects the sale over a four-year period, ending in 2010, of the Group's interest in the Battle River PPA and related transactions, including the current and prior period sales of the Battle River Power Syndicate Agreement (Battle River PSA) described in note 4. Under the terms of the Alberta PPAs, the Group 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, 2008, the remaining term of the 20-year Sundance PPA is 12 years. The Group is 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 Group's remaining interest in the Battle River PSA is completed in 2010.

The Group purchased the Alberta PPAs with an equity syndicate under syndication agreements. 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.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

The Group'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 Power LP PPAs reflect the cost to acquire long-term sales contracts under which revenue is earned by Power LP's generation units. The Power LP PPAs are amortized over their remaining terms, which range from one to 20 years.

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

Contract rights include acquired management and operations agreements. Costs assigned to contract rights are amortized on a straight-line basis, from the dates of acquisition, over the contract terms which range from one to 70 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.

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.

Other rights include the cost to acquire land lease agreements for use in wind power projects in Ontario and coal supply access rights relating to the Keephills 3 Project (note 28(b)). 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.

(m) Goodwill:

Goodwill is the cost of an acquisition less the fair value of the net assets of an acquired business. Goodwill is not amortized, but rather is tested for impairment at least 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 to the carrying amount, including goodwill, of the reporting unit. If the carrying amount 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. The Group determines the fair value of a reporting unit using discounted cash flow techniques and estimated future cash flows.

(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 2009 and 2025.

Investments in which the Group 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.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

(o) Impairment of long-lived assets:

The Group 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) Deferred availability incentives:

Under the terms of the Genesee PPA, the target levels of generation availability set out in the PPA recognize that the respective generation units will experience planned and forced outages over the term of the PPA. The Group records the electricity revenue from these generation units at the price embedded in the PPA, including expected incentives and penalties for operating above or below specified availability targets set out in the PPA. Under this approach, incentives for the current period are deferred since they are not expected to be sustained over the full term of the PPA. As penalties are incurred, any balance of deferred incentive will be drawn down. If cumulative penalties exceed cumulative incentives, the excess will be charged to income and no deferred charge will be created. Deferred incentive amounts are included in other non-current liabilities on the balance sheet.

The degree to which incentives are recognized or deferred will change due to revisions to the long-term outlook of plant performance, which is based on historical performance, planned maintenance, reliability and generation availability, and due to revisions in the estimated long-term price embedded in the PPA.

(q) Asset retirement obligations:

The Group 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 Group 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.

(r) Leases or arrangements containing a lease:

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)

(s) Foreign currency translation:

The Group'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 Group's net investment in the foreign operations.

Foreign currency transactions and financial statements of integrated foreign operations are translated to Canadian dollars using the temporal method. Transactions denominated in foreign currencies are translated at exchange rates in effect at the transaction date. Monetary assets and liabilities denominated in foreign currencies are translated at the exchange rate in effect on the balance sheet date. The resulting foreign exchange gains and losses are included in the combined and consolidated statements of income.

During the fourth quarter of 2008, changes in economic circumstances caused the Group to re-evaluate the functional currency of Power LP's indirectly-owned U.S. subsidiaries. As a result, the functional currency of these U.S. subsidiaries was determined to be the U.S. dollar. Accordingly, these operations are being translated prospectively using the current rate method.

(t) Employee future benefits:

The Group utilizes the services of EUI employees. EUI employees are 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. EUI 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, EUI and the Group do not recognize their share of any plan surplus or deficit.

EUI maintains additional defined contribution and defined benefit pension plans to provide pension benefits to those employees (comprising less than 20% of total employees of EUI) who are not otherwise served by LAPP.

EUI accrues its obligations for its defined benefit pension plans net of plan assets. The Group's allocated share of the accrual is reflected 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.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

EUI 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, recover and termination experience, and inflation rates. The Group's allocated portion of this accrual 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.

(u) Offsetting of financial assets and financial liabilities:

Financial assets and financial liabilities are presented on a net basis when the Group 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.

(v) 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. REORGANIZATION

In 2006, the Group acquired 100% of EPCOR Generation Inc. (EGI) from EUI for consideration consisting of $500 million of long-term debt and $399 million of common shares issued to EUI. Since, at the time of the transaction, EGI, the Group and EUI were subject to common control, the acquisition was already accounted for using the continuity-of-interests method and the net assets acquired were recorded at their carrying amounts at the time of the transaction. Accordingly, this transaction did not result in any further addition to the Group's net assets and therefore the consideration given by the Group was recorded as a distribution of equity to EUI, with $200 million charged against the existing contributed surplus balance that arose from previous related party transactions and the remaining $699 million charged against retained earnings.

4. ACQUISITIONS AND DISPOSALS

Acquisition of Morris Cogeneration LLC:

On October 31, 2008, the Group, through its Power LP subsidiary, acquired 100% of the equity interest in Morris Cogeneration LLC (Morris), a combined heat and power facility in Illinois. The total purchase price was $89 million (US$74 million) in cash.

The financial results of Morris are included in the Group's combined and consolidated statement of income from the date of acquisition.

4. ACQUISITIONS AND DISPOSALS (Continued)

The purchase price for the acquisition of Morris was allocated to the assets acquired and liabilities assumed based on their estimated fair values as follows:

Current assets excluding cash and cash equivalents and derivative instruments assets	$10
Derivative instruments assets — current	1
Derivative instruments assets — non-current	3
Property, plant and equipment	83
Power purchase agreements	4
Other assets	2
Current liabilities	(7)
Other non-current liabilities	(7)
Fair value of net assets acquired	$89

Acquisition of Primary Energy Ventures LLC:

On November 1, 2006, the Group, through its Power LP subsidiary, acquired 100% of the outstanding shares representing membership interests in Primary Energy Ventures LLC (Ventures). Ventures owns eight combined heat and power facilities located in the U.S. and 17.0% of the common interests and 14.2% of the preferred interests in Primary Energy Recycling Holdings LLC (PERH). PERH owns four waste heat recovery power facilities and a 50% interest in a coal pulverization facility in the U.S. In addition, Ventures provides management and administrative services to PERH and Primary Energy Recycling Corporation (PERC). PERC owns the balance of PERH not owned by Ventures.

The total consideration paid was $366 million (US$326 million) in cash plus acquisition costs of approximately $5 million for a total purchase price of $371 million. The purchase price was allocated to the assets acquired and liabilities assumed based on their estimated fair values. The purchase price was allocated as follows:

Current assets excluding cash and cash equivalents	$ 26
Property, plant and equipment	140
Power purchase arrangements (included in Power LP PPAs)	138
Contract rights and other intangible assets	14
Future income tax assets, non-current	8
Goodwill	34
Other assets, including long-term investments of $59	99
Current liabilities	(15)
Capital lease obligations	(79)
Other non-current liabilities	(11)
	354
Cash and cash equivalents	17
Fair value of net assets acquired	$371

The results of operations of Ventures are included in the Group's combined and consolidated statements of income from the date of acquisition. The goodwill is deductible for income tax purposes.

4. ACQUISITIONS AND DISPOSALS (Continued)

Sale of power purchase arrangement and related transactions:

The Group acquired the Battle River Power Purchase Arrangement (Battle River PPA) in August 2000 through an auction conducted by the Government of Alberta as part of provincial electricity deregulation. The Battle River PPA includes Alberta Power (2000) Ltd.'s Battle River generation units 3, 4 and 5 with a total committed capacity of 662.8 megawatts. Following acquisition of the Battle River PPA, the rights under the PPA were assigned under the Battle River Power Syndicate Agreement (Battle River PSA) to the syndicate members, including a Group subsidiary. As a result, the syndicate members held the beneficial ownership of the committed capacity and ancillary services produced by the Battle River generation units.

In June 2006, the Group agreed to sell its Battle River PPA and its related interest in the Battle River PSA to ENMAX Corporation (ENMAX). The Battle River PSA was to be sold over a four year period, with an initial sale of 55%. Additional sales of 10% occurred in the first quarter of each of 2007 and 2008. The transactions in the current and comparative periods are summarized as follows:

	2008	2007	2006
Net cash proceeds	$53	$59	$301
Notes receivable from non-Group syndicate members	—	—	40
Total proceeds	53	59	341
Less net book value and costs of disposal	19	25	(37)
Gain on sale before income taxes	34	34	378
Less future income taxes	4	4	51
Gain on sale after income taxes	$30	$30	$327

A related transaction to the sale of the Battle River PPA was the sale of an interest in the Group's Sundance Power Syndicate Agreement (Sundance PSA) for cash consideration of $17 million and notes receivable from non-Group syndicate members of $40 million. Since the carrying amount of the interest in the Sundance PSA was $8 million, the Group recognized a pre-tax gain of $49 million on this transaction which has been included in the 2006 amounts above.

Refundable taxes of $6 million (2007 — $7 million; 2006 — $42 million), which arose from the taxable capital gains on the sale of the Battle River PSA, have been charged to retained earnings.

The timing of the remaining future sales include the sale of a 10% interest closing on January 15, 2009, followed by the sale of the final 15% interest on January 15, 2010.

Sale of Frederickson power plant and related entities:

On August 1, 2006, the Group finalized the sale of certain of its subsidiaries associated with its interest in its Frederickson power plant to Power LP. No gain or loss was recognized on the intercompany sale. As a result of the sale, the Group recognized a reduction in the net investment in the Frederickson operations to the extent of the non-controlling interest in Power LP of approximately 69.4%. The related and previously deferred foreign exchange losses of $44 million included in accumulated other comprehensive income were recorded in foreign exchange gains and losses in the combined and consolidated statement of income for the year ended December 31, 2006.

5. NOTES RECEIVABLE AND NOTES PAYABLE

Notes receivable and notes payable consist of unsecured notes receivable from and notes payable to EUI are due on demand and bear interest at rates ranging from one-month Bankers' Acceptance plus a credit spread to Canadian prime plus a credit spread.

6. INVENTORIES

	2008	2007
Small parts and other consumables	$ 36	$ 29
Coal	14	10
Natural gas held in storage for trading purposes	12	—
	$ 62	$ 39

Inventories expensed upon usage during the year ended December 31, 2008 of $48 million (2007 — $40 million; 2006 — $10 million) were charged to energy purchases and fuel, and operations, maintenance and administration. No write-downs of inventories or reversals of previous write-downs were recognized in the year ended December 31, 2008 or in the years ended December 31, 2007 and 2006. At December 31, 2008 and 2007, no inventories were pledged as security for liabilities.

7. PROPERTY, PLANT AND EQUIPMENT

	2008			
	Composite Depreciation Rate	Cost	Accumulated Depreciation	Net Book Value
Land	None	$ 68	$ —	$ 68
Plant and equipment	3.9%	3,425	872	2,553
Contributions	19.3%	(22)	(4)	(18)
Construction work in progress	None	582	—	582
		$4,053	$868	$3,185

	2007			
	Composite Depreciation Rate	Cost	Accumulated Depreciation	Net Book Value
Land	None	$ 69	$ —	$ 69
Plant and equipment	3.4%	3,264	769	2,495
Contributions	20.9%	(10)	(2)	(8)
Construction work in progress	None	254	—	254
		$3,577	$767	$2,810

7. PROPERTY, PLANT AND EQUIPMENT (Continued)

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

	2008	2007	2006
Depreciation on assets in service	$127	$116	$116
Accretion on asset retirement obligations (note 14)	5	4	4
Gain on disposal of assets	(5)	(7)	(20)
Amortization of contributions	(2)	(1)	(1)
Amortization of PPAs	53	58	50
Amortization of contract and customer rights and other intangible assets	3	5	5
	$181	$175	$154

Interest capitalized to property, plant and equipment for 2008 is $19 million (2007 — $6 million; 2006 — $1 million).

8. POWER PURCHASE ARRANGEMENTS

	2008		
	Cost	Accumulated amortization	Net book value
Alberta PPAs	$197	$ 85	$112
Power LP PPAs	613	132	481
	$810	$217	$593

	2007		
	Cost	Accumulated amortization	Net book value
Alberta PPAs	$219	$ 78	$141
Power LP PPAs	633	95	538
	$852	$173	$679

9. CONTRACT AND CUSTOMER RIGHTS AND OTHER INTANGIBLE ASSETS

	2008		
	Cost	Accumulated amortization	Net book value
Contract rights	$122	$13	$109
Other rights	37	—	37
Water rights	15	—	15
Software intangibles	26	15	11
Customer rights	8	2	6
Emission credits	9	4	5
	$217	$34	$183

9. CONTRACT AND CUSTOMER RIGHTS AND OTHER INTANGIBLE ASSETS (Continued)

	2007		
	Cost	Accumulated amortization	Net book value
Contract rights	$120	$ 9	$111
Other rights	18	—	18
Water rights	15	—	15
Software intangibles	21	13	8
Customer rights	8	2	6
Emission credits	5	2	3
	$187	$26	$161

In 2007, management revised the outlook for incentives expected to be earned under the management agreement between a subsidiary of the Group and PERH, Primary Energy Operations LLC and PERC. Based on expected future cash distributions from PERH, it was determined that the full book value of this management agreement was unlikely to be recovered from future cash flows. As a result, during the year ended December 31, 2007, the Group wrote down this contract right to its estimated fair value of nil and recorded a $13 million pre-tax charge to impairments.

10. GOODWILL

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

	2008	2007	2006
Balance, beginning of year	$183	$181	$148
Impairment	(28)	—	—
Goodwill acquired on Ventures acquisition (note 4)	—	—	33
Foreign exchange translation adjustment	4	—	—
Adjustments to purchase price allocations	—	2	—
Balance, end of year	$159	$183	$181

The Group completed its annual goodwill impairment testing in the fourth quarter of 2008. The future cash flows of the underlying business are reasonably stable since they relate largely to contracted power generation operations. However, interest rate spreads have risen significantly in the fourth quarter of 2008 which increased the underlying rate used to discount the future cash flows. This higher discount rate resulted in the estimated fair value of goodwill related to Power LP being lower than its carrying amount. The resulting impairment of $28 million is recorded in net income.

11. OTHER ASSETS

	2008	2007
Carrying amount		
Loans and other long-term receivables	$ 52	$ 46
Net investments in lease	33	29
Investment in PERH	19	50
Portfolio investments	6	13
Other	10	9
	120	147
Accumulated amortization		
Other	—	1
	$120	$146

Net investment in lease

The PPA under which the Group'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 (2007 — $1 million) is included in accounts receivable. Financing income for the year ended December 31, 2008 of $3 million (for the year ended December 31, 2007 — $3 million; for the two-month period ended December 31, 2006 — $1 million) is included in revenues.

Investment in PERH

The Group, through its Power LP subsidiary, holds 17.0% of the common share interests and 14.2% of the preferred interests in PERH. The Class B Common interest is accounted for using the equity method. The Class B Preferred interest is recorded on the cost basis. For the year ended December 31, 2008, equity losses of $6 million (for the year ended December 31, 2007 — $4 million; for the two-month period ended December 31, 2006 — $1 million) included in operations, maintenance and administration expense, and $3 million (for the year ended December 31, 2007 — $3 million; for the two-month period ended December 31, 2006 — $1 million) in dividends have been recorded against the common share investment in PERH. Upon acquisition in 2006, the excess of the Group's share of the book value of PERH net assets over the carrying amount of the Class B Common interest was $19 million.

The Group, through its Power LP subsidiary, monitors its investment in PERH for impairment by considering current economic factors and records an impairment charge when it believes the investment has experienced a decline that is other than temporary. The Group estimates the fair value of its investment in PERH by considering factors such as the quoted market price of the securities issued by PERC, which owns the remaining interests in PERH not held by Power LP, and the market yield of comparable preferred shares. As a result, the Group recorded a $24 million pre-tax and pre-non-controlling interest impairment charge during the year ended December 31, 2008 to write down the investment based on its fair value.

12. LONG-TERM DEBT

	Effective Interest Rate	2008	2007	2006
Obligation to The City of Edmonton, net of sinking fund (note 25)				
Due in 1-5 years at 10.12%[1] (2007 — 10.28%)	10.24%	$ 93	$ 94	$ 96
Due in 6-10 years at 8.50%[1] (2007 — 9.00%)	10.17%	61	38	82
Due in 11-15 years (2007 — 8.50%)		—	67	70
		154	199	248
Long-term notes payable to EUI				
Due in 2012 at 9.382%		—	—	200
Due in 2015 at 7.75%	7.75%	325	325	325
Due in 2015 at 12.00%	12.00%	30	30	30
Due in 2016 at 5.01%	5.01%	20	160	160
Due in 2021 at 5.55%	5.55%	250	250	250
Due in 2026 at 6.75%	6.75%	500	500	500
Due in 2027 at 7.27%	7.27%	350	350	—
Due in 2028 at 8.68%	8.68%	125	—	—
Due in 2028 at 6.69%	6.69%	200	—	—
Due in 2028 at 8.27%	8.27%	225	—	—
Power LP unsecured senior notes (US$190), at 5.90%, due in 2014	6.16%	233	191	225
Power LP unsecured senior medium-term notes, at 5.95%, due in 2036	6.12%	210	210	210
Power LP unsecured senior medium-term notes (US$150), at 5.87%, due in 2017	6.01%	183	149	—
Power LP unsecured senior medium-term notes (US$75), at 5.97%, due in 2019	6.11%	91	74	—
Power LP secured term loan, at 11.25%, due in 2010	11.57%	2	4	5
Non-recourse financing:				
Brown Lake Project, at 8.7%, due in 2016	8.69%	7	7	8
Joffre Cogeneration Project, at fixed and floating rates, due in 2020	8.82%	41	41	60
Power LP revolving extendible credit facilities, at floating rates, due in 2009	1.09%	87	—	149
Power LP bridge acquisition credit facility (US$44), at floating rates, due in 2009		—	—	51
Obligations under capital leases		—	2	82
		3,033	2,492	2,503
Less: Current portion		20	25	46
Deferred debt issue costs		6	7	—
		$3,007	$2,460	$2,457

(1) Weighted average coupon rate on gross principal balance outstanding.

12. LONG-TERM DEBT (Continued)

Obligation to The City of Edmonton

Debentures were issued, on behalf of the Group, pursuant to The City of Edmonton (COE) Bylaw authorization. The outstanding debentures are a direct, unconditional obligation of the COE. The Group's obligation to the COE matches the COE's obligation pursuant to the debentures. The portion of the 8.50% debentures, maturing in the year 2018 and totaling $61 million, rank as subordinated debt. In the event of default on other interest obligations, the coupon and sinking fund payments on the subordinated debt may be deferred for a period of up to five years, not exceeding the maturity date. If still in default at the end of five years, all unpaid payments plus accrued interest thereon may be repaid by issuing common shares to the COE. Except for the subordinated debt, the obligation to the COE will rank at least equal to all future debt that may be issued by the Group.

The Group makes annual contributions into the Sinking Fund of the COE pertaining to certain debenture issues. These payments constitute effective settlement of the respective debt as the sinking fund accumulates to satisfy the underlying debenture maturity. For any specific COE debenture with sinking fund requirements, the payment obligation ceases on maturity of the debenture.

Long-term notes payable to EUI

The long-term notes payable to EUI are unsecured and, subject to statutory preferred exemptions, rank equally with all other unsecured and unsubordinated indebtedness of the Group. These notes include a provision which may cause the entire unpaid principal and all accrued interest to become due immediately upon a change in ownership of the borrower. The notes due in 2015 can be prepaid, in whole or in part, at the option of the borrower. Interest is payable semi-annually.

Power LP unsecured senior notes

The unsecured senior notes of $233 million mature in 2014 and are fully and unconditionally guaranteed by Power LP 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 $210 million issued during 2006 are due in 2036 with interest payable semi-annually.

The unsecured senior medium-term notes aggregating to $274 million (US$225 million) were issued in two tranches. The $183 million (US$150 million) and $91 million (US$75 million) issued during 2007 are due in 2017 and 2019 respectively with interest payable semi-annually.

Power LP secured term loan

The term loan is secured by a first fixed and specific mortgage over the Queen Charlotte plant which has a carrying amount of $14 million (2007 — $15 million) and matures in 2010.

Non-recourse financing

Joffre Cogeneration Project financing represents the Group'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% (2007 — 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 $114 million (2007 — $110 million). Brown Lake Project financing is

12. LONG-TERM DEBT (Continued)

secured by a charge against project assets which have a carrying amount of $12 million (2007 — $12 million).

Power LP revolving extendible credit facilities

Unsecured three-year credit facilities of $100 million each for a total of $300 million, committed to 2010 and 2011, and uncommitted amounts of $20 million, are available to the Group's subsidiary, Power LP. At December 31, 2008, the Group had $23 million in bankers' acceptances and $64 million (US$52 million) in U.S. LIBOR loans outstanding under this facility (2007 — $nil).

Under the terms of the extendible facilities, the Group 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 of 0.75%. 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 of 0.75%. Amounts drawn by way of U.S. LIBOR loans bear interest at the prevailing LIBOR rate plus a spread ranging from 0.4% to 0.5% varying by facility. Amounts drawn by way of bankers' acceptances bear interest at the prevailing bankers' acceptance rate plus a spread ranging from 0.4% to 0.5% varying by facility.

Capital lease obligations

On August 24, 2007, the Group paid off its capital lease obligations for the Naval Station, North Island and Naval Training Center for $72 million (US$68 million).

13. OTHER NON-CURRENT LIABILITIES

	2008	2007
Asset retirement obligations (note 14)	$ 82	$ 71
Employee future benefit liabilities	4	4
Other	5	7
	$ 91	$ 82

14. ASSET RETIREMENT OBLIGATIONS

	2008	2007	2006
Balance, beginning of year	$ 79	$ 79	$ 89
Liabilities incurred	15	8	10
Liabilities settled	(9)	(12)	(24)
Asset retirement accretion expense	5	4	4
	90	79	79
Less: current portion in accounts payable and accrued liabilities	8	8	12
	$ 82	$ 71	$ 67

14. ASSET RETIREMENT OBLIGATIONS (Continued)

The Group estimates the undiscounted amount of cash flow required to settle its asset retirement obligations is approximately $390 million, calculated using inflation rates ranging from 2% to 3%. The expected timing for settlement of the obligations is between 2009 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 2009 and 2013 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.

15. NON-CONTROLLING INTERESTS

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

	2008	2007	2006
Non-controlling interests in Power LP	$(58)	$ 19	$ 44
Preferred share dividends paid by subsidiary companies	7	4	—
	$(51)	$ 23	$ 44

Non-controlling interests reflected on the combined and consolidated balance sheets are comprised of:

	2008	2007	2006
Non-controlling interests in Power LP, beginning of year	$618	$554	$542
Partnership units issued to non-controlling interests	—	69	55
Earnings attributed to non-controlling interests	(58)	19	43
Other comprehensive loss attributable to non-controlling interests	(48)	(3)	—
Opening accumulated other comprehensive income adjustments attributable to non-controlling interests	—	4	—
Opening retained earnings adjustments attributable to non-controlling interests	—	67	—
Distributions to non-controlling interests	(94)	(92)	(86)
Non-controlling interests in Power LP, end of year	418	618	554
Preferred shares issued by subsidiary companies, beginning of year	122	—	—
Issue of preferred shares	—	122	—
Preferred shares issued by subsidiary companies, end of year	122	122	—
	$540	$740	$554

The non-controlling interests in Power LP represents the approximately 69.4% interest in Power LP not owned by the Group.

Preferred shares issued by subsidiary companies

During 2007, EPCOR Power Equity Ltd. (EPEL), a subsidiary of Power LP issued 5 million of 4.85% cumulative, redeemable First Preference 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. Proceeds of $121 million, net of issue costs of $4 million, were used to repay amounts outstanding under the Power LP bridge acquisition credit facility.

15. NON-CONTROLLING INTERESTS (Continued)

Future income tax assets of $1 million related to the share issue costs are recorded in the preferred share balance. On or after June 30, 2012, the shares are redeemable by EPEL 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. The Group will not make any distributions on the Power LP 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 Power LP unsecured senior notes are in default.

16. SHARE CAPITAL

Authorized	Number of shares authorized
EPCOR Power Development Corporation	Unlimited
Common voting shares, without nominal or par value	Unlimited
Preferred shares, Class A, cumulative, redeemable(2)(3)	Unlimited
Preferred shares, Class B, cumulative, redeemable(2)(3)	Unlimited
Preferred shares, Class C, non-cumulative, redeemable(2)(4)(7)	Unlimited
Preferred shares, Class D, non-cumulative, redeemable(2)(4)(7)	Unlimited
EPCOR Power Generation Services Inc.	
Common voting shares, without nominal or par value	Unlimited
Preferred shares, Class A, 8% non-cumulative, redeemable(2)(5)(7)	Unlimited
Preferred shares. Class B, 10% non-cumulative, redeemable(2)(7)	Unlimited
Preferred shares, Class C, non-cumulative, redeemable(2)(4)(7)	Unlimited
Preferred shares, Class D, non-cumulative, redeemable(2)(4)(7)	Unlimited
EMCC Limited	
Common voting shares, without nominal or par value	Unlimited
Preferred shares, Class E, non-cumulative, redeemable, retractable(2)(6)	Unlimited
Preferred shares, Class F, non-cumulative, redeemable, retractable(2)(6)	Unlimited
Preferred shares, Class G, non-cumulative, redeemable, retractable(2)(6)	Unlimited
Preferred shares, Class H, non-cumulative, redeemable, retractable(1)(6)	Unlimited
Preferred shares, Class I, non-cumulative, redeemable, retractable(1)(6)	Unlimited
EPCOR PPA Management Inc.	
Common voting shares, without nominal or par value	Unlimited

(1) The redemption amount is $100 per share.

(2) The redemption amount is to be set by Directors at time of issuance.

(3) The dividend rate is to be determined by Board of Directors upon issuance.

(4) The dividend rate is at discretion of the Board of Directors not to exceed 20% of redemption amount per annum.

(5) The dividend rate is 8% or other rate as approved by the Board of Directors not to exceed 15% of redemption amount per annum.

(6) The dividend rate is at discretion of the Board of Directors not to exceed 10% of redemption amount per annum.

(7) Articles of Incorporation include a retraction privilege which may be granted by the Board of Directors at the date of issuance.

16. SHARE CAPITAL (Continued)

Issuer (note 1)	Issued and outstanding	2008	2007
EPCOR Power Development Corporation	1,159 common shares	$499	$499
	1 preferred share, Class D	—	—
EPCOR Power Generation Services Inc.	102 common shares	1	1
	100 preferred shares, Class B	—	—
EMCC Limited	128 common shares	173	173
	1 preferred share, Class I	—	—
EPCOR PPA Management Inc.	100 common shares	—	—
		$673	$673

All common shares are issued to EUI. The preferred shares are issued to officers of certain entities within the Group.

In 2007, EPCOR Power Holdings Corporation, an entity within the Group, was amalgamated with EPCOR Power Development Corporation. As part of the amalgamation transaction, the 2 common shares of EPCOR Power Holdings Corporation (carrying amount of $12 million) previously issued to EUI were cancelled and 1 common share of EPCOR Power Development Corporation (carrying amount of $12 million) was issued to EUI. Since the carrying amounts of the shares were the same, there was no adjustment to the Group's financial statements as a result of this transaction.

In addition to the shares issued and outstanding above, EPCOR Power Development Corporation issued 14 million Class A preferred shares in 2007 and 6 million Class B preferred shares in 2008 to EMCC Limited; these shares have been eliminated upon consolidation.

17. ACCUMULATED OTHER COMPREHENSIVE LOSS

The components of accumulated other comprehensive loss at December 31, 2008, 2007 and 2006 are summarized as follows:

	2008	2007	2006
Unrealized losses on derivative instruments designated as cash flow hedges[1]	$(29)	$(62)	$ —
Unrealized gains on financial instruments designated as available for sale[2]	—	2	—
Unrealized loss in self-sustaining foreign operations[3]	(82)	(19)	(19)
Non-controlling interests[3]	47	(1)	—
	$(64)	$(80)	$(19)

(1) Net of income tax expense of $11 million (2007 — recovery of $27 million; 2006 — not applicable).

(2) Net of income tax expense of nil (2007 — $1 million; 2006 — not applicable).

(3) Net of income tax expense of nil (2007 — nil; 2006 — nil).

18. CHANGE IN NON-CASH WORKING CAPITAL

	2008	2007	2006
Notes receivable and notes payable	$ 681	$ 148	$(525)
Accounts receivable	88	80	(17)
Income taxes recoverable	(2)	(2)	11
Inventories	(18)	(5)	(2)
Prepaid expenses	—	2	1
Accounts payable and accrued liabilities	(52)	(20)	52
Income taxes	(74)	13	4
	$ 623	$ 216	$(476)
Relating to:			
Operating activities	$(100)	$(149)	$(142)
Investing activities	306	175	(416)
Financing activities	417	190	82
	$ 623	$ 216	$(476)

19. NET FINANCING EXPENSES

	2008	2007	2006
Interest on long-term debt	$200	$189	$209
Interest on short-term debt and other financing costs	42	33	22
Capitalized interest	(19)	(6)	(1)
Interest and dividend income	(4)	(5)	(3)
Other	—	8	—
	$219	$219	$227

20. INCOME TAXES

	2008	2007	2006
Current income taxes	$ 32	$ 83	$ 4
Future income taxes	(56)	30	(7)
	$(24)	$113	$ (3)

20. INCOME TAXES (Continued)

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

	2008	2007	2006
(Loss) income before income taxes and non-controlling interests	$ (71)	$ 270	$474
Statutory income tax rates	29.50%	32.12%	32.5%
Income taxes at statutory rate	(21)	87	154
Increase (decrease) resulting from:			
Unrecognized future income tax assets	45	(1)	(5)
Non-taxable portion of capital gains	(42)	(12)	(89)
Non-taxable (non-deductible) amounts	3	(28)	9
Change due to enactment of SIFT legislation	(6)	48	—
Income exempt from income taxes at statutory rates	(7)	11	13
Adjustment for enacted changes in income tax laws and rates and other tax rate differences	3	10	31
Net future income tax assets recognized on reorganization	—	—	(117)
Other	1	(2)	1
	$ (24)	$ 113	$ (3)

20. INCOME TAXES (Continued)

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

	2008	2007
Future income tax assets:		
Losses carried forward	$ 100	$ 71
Cumulative eligible capital	70	65
Property, plant and equipment — differences in net book value and undepreciated capital cost	42	35
Asset retirement obligations	18	8
Investment in partnership	20	23
Contract and customer rights and other intangible assets	9	—
Other	5	11
	264	213
Future income tax liabilities:		
Investment in partnership	191	173
Deferred income from partnership	51	56
Property, plant and equipment — differences in net book value and undepreciated capital cost	27	19
Asset retirement obligation assets	16	7
Power purchase arrangements	8	13
Long-term debt	—	8
Contract and customer rights and other intangible assets	2	—
Other	6	8
	301	284
Net future tax (liabilities) assets	$ (37)	$ (71)
Presented on the balance sheet as follows:		
Current assets	$ —	$ 2
Non-current assets	97	93
Current liabilities	(34)	(39)
Non-current liabilities	(100)	(127)
	$ (37)	$ (71)

At December 31, 2008, the Group has non-capital losses carried forward of approximately $346 million (2007 — $237 million; 2006 — $188 million), of which $119 million (2007 — $49 million; 2006 — $33 million) relate to certain U.S. subsidiaries. These losses expire between 2014 and 2028. The Group also has capital losses for income tax purposes of approximately $156 million (2007 — $16 million; 2006 — $20 million) and restricted limited partnership losses of approximately $22 million (2007 — $8 million; 2006 — nil) which carry forward indefinitely. There are non-capital losses available to be carried forward of $46 million (2007 — $35 million), capital losses available to be carried forward of $156 million (2007 — $4 million) and other deductible temporary differences of $220 million (2007 — $134 million) for which no tax benefit has been recognized.

20. INCOME TAXES (Continued)

Refundable taxes of $11 million (2007 — $13 million) recorded in retained earnings include $6 million (2007 — $7 million; 2006 — $42 million) arising from the sale of the Battle River PPA and related transactions as described in note 4. The December 31, 2006 balance of refundable taxes includes a reduction of $5 million as a result of the Group's sale of its interest in the Frederickson power plant and related entities as described in note 4.

Tax on flow-through entities

Currently, the taxable income of Power LP is to be taxed in the hands of its unit holders. Canadian tax legislation related to specified investment flow-through entities (SIFT Legislation) included in Bill C-52 was enacted in 2007 and will result in changes to how certain publicly traded trusts and partnerships, including Power LP, are taxed. The SIFT Legislation applies a tax at the specified investment flow-through entity level on certain income and at tax rates comparable to the combined federal and provincial corporate tax rates, and then re-characterizes that income net of tax payable as taxable dividends in the hands of unit holders. The SIFT Legislation will apply to Power LP starting the earlier of January 1, 2011 or January 1 of the year following the date at which the Power LP exceeds the normal growth guidelines issued by the Department of Finance (Canada) on December 15, 2006. The Group does not expect Power LP to be subject to the new rules prior to the January 1, 2011 date.

Enactment of the SIFT Legislation resulted in the recognition of future income taxes expense and net future tax liabilities of $48 million in 2007, based on estimated net taxable temporary differences which are expected to reverse after 2010 and for which no tax has previously been recorded at the partnership level. The Group previously recognized its 30.6% share of these future income taxes, commencing upon acquisition of Power LP, and the resulting additional future income taxes expense relates entirely to the non-controlling interests in Power LP.

Reorganization

On January 3, 2006, the Group reorganized certain subsidiaries to better align its legal structure (note 3) with its operating structure and thereby realize efficiencies.

Since January 1, 2001 and until the completion of certain transactions under this reorganization, EGI, a wholly-owned subsidiary of EPCOR Power Development Corporation (note 3), was subject to and made payments under PILOT. As a result of the reorganization, EGI no longer met the criteria for exemption from tax under section 149 of the ITA and therefore became taxable under the ITA effective January 3, 2006.

Under the ITA, when becoming taxable, EGI was deemed to have disposed of and reacquired all of its property at fair market value for income tax purposes. Since the fair market value of its property is greater than its underlying net book values, EGI will have additional deductions available for income tax purposes. The resulting net tax effect was recognized in the first quarter of 2006 as an increase in non-current future income tax assets in the Group's combined and consolidated balance sheet, with a corresponding income statement reduction of income taxes of $117 million. The resulting future income tax assets will be reduced over time, as the underlying income tax deductions are utilized to reduce taxable income.

21. FAIR VALUE AND CLASSIFICATION OF NON-DERIVATIVE FINANCIAL ASSETS AND LIABILITIES

The Group classifies its cash and cash equivalents as held for trading and measures them at fair value. Accounts receivable and notes receivable are classified as loans and receivables; accounts payable and accrued liabilities and notes payable 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 Group's beneficial interest in the Sinking Fund related to the COE debentures is classified as available for sale.

The classification, carrying amount and fair value of the Group's other financial instruments at December 31, 2008 and 2007 are summarized as follows:

		2008		2007	
Financial asset or liability	Classification	Carrying amount	Fair value	Carrying amount	Fair value
Other assets					
Investment in preferred shares of PERH	Available for sale	$ 16	$ 16	$ 15	$ 15
Loans and other long-term receivables	Loans and receivables	52	46	46	44
Net investments in leases	Loans and receivables	33	33	29	28
Portfolio investments	Available for sale	6	6	13	16
Long-term debt (including current portion)	Other financial liabilities	3,027	2,841	2,485	2,693

Net investments in leases

The fair values of the Group's net investments in leases are 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, 2008, and 2007.

Long-term debt and Sinking Fund

The fair value of the Group's long-term debt is based on determining a current yield for the Group's debt as at December 31, 2008, and 2007. This yield is based on an estimated credit spread for the Group over the yields of long-term Government of Canada and U.S. Government bonds that have similar maturities to the Group's debt. The estimated credit spread is based on the Group's indicative spread as published by independent financial institutions. Long-term debt (including the current portion) includes COE debentures which are offset by payments made by the Group into the Sinking Fund. The Group's beneficial interest in the Sinking Fund is a related party transaction and is therefore recorded at the exchange amount. It is not quoted in an active market.

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 the preferred share interest held in PERH and certain common share interests in certain capital venture investments cannot be measured reliably as the shares are not quoted in an active market.

21. FAIR VALUE AND CLASSIFICATION OF NON-DERIVATIVE FINANCIAL ASSETS AND LIABILITIES (Continued)

Investments in common shares held at their carrying amount have not been offered for sale and in the event the Group elected to dispose of the shares, they would most likely be sold in a private transaction.

22. 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 23 consist of the following:

	2008			
	Energy		Foreign exchange	
	Cash flow hedges	Non-hedges	Non-hedges	Total
Derivative instruments assets:				
Current	$ 10	$108	$ 8	$ 126
Non-current	9	62	4	75
Derivative instruments liabilities:				
Current	(31)	(88)	(11)	(130)
Non-current	(29)	(43)	(38)	(110)
Net fair value	$(41)	$ 39	$ (37)	$ (39)
Net notional buys (sells):				
Megawatt hours of electricity (millions)	(2)	(2)		
Gigajoules of natural gas (millions)		65		
Foreign currency (U.S. dollars)			$(457)	
Range of contract terms in years	0.1 to 8.0	0.1 to 8.0	0.1 to 6.0	

22. DERIVATIVE INSTRUMENTS AND HEDGE ACCOUNTING (Continued)

	2007			
	Energy		Foreign exchange	
	Cash flow hedges	Non-hedges	Non-hedges	Total
Derivative instruments assets:				
Current	$ 30	$ 60	$ 14	$ 104
Non-current	12	82	22	116
Derivative instruments liabilities:				
Current	(95)	(33)	—	(128)
Non-current	(40)	(33)	(3)	(76)
Net fair value	$(93)	$ 76	$ 33	$ 16
Net notional buys (sells):				
Megawatt hours of electricity (millions)		(2)		
Gigajoules of natural gas (millions)		75		
Foreign currency (U.S. dollars)			$(281)	
Range of contract terms in years	0.1 to 9.0	0.1 to 9.0	0.2 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 active markets. When there are limited observable prices due to illiquid or inactive markets, the Group uses appropriate valuation and price modeling techniques commonly used by market participants to estimate fair value. The Group 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 using 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, and volatility when 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.

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. With respect to natural gas, the Group has determined the market is active within five years. As the natural gas supply contracts extend beyond the active period of the market, fair value is determined by reference in part to published price quotations where there is observable market data and in part by relying on price forecasts prepared by an independent third party where there are limited observable natural gas prices. While external market forecasts outside the active period of the market reasonably reflect all factors that market participants would consider in setting a price, these expectations are not currently supportable by active forward market quotes. The fair values of these contracts could change significantly if the assumptions were changed to reasonably possible alternatives. The natural gas price forecasts for the period, where limited observable natural gas prices are available, range from $6.67 to $8.01 per gigajoule. The Group has determined that a reasonably possible increase or decrease of $1.00 per gigajoule in the natural gas price forecast would have a $65 million impact on the fair value estimate of these contracts. Included in this sensitivity is a $17 million impact for contract periods beyond the next five years where prices are not based

22. DERIVATIVE INSTRUMENTS AND HEDGE ACCOUNTING (Continued)

on observable natural gas prices. This valuation technique resulted in unrealized pre-tax fair value losses of $5 million recognized in energy purchases and fuel for the year ended December 31, 2008 (2007 — $19 million of unrealized pre-tax fair value gains).

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

	2008		2007	
	Unrealized gains (losses)	Realized gains (losses)	Unrealized gains (losses)	Realized gains (losses)
Energy cash flow hedges	$ 52	$(10)	$(33)	$(66)
Energy non-hedges	(41)	1	2	(6)
Foreign exchange non-hedges	(69)	10	29	(8)
Interest rate non-hedges	—	—	(1)	(3)

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 Group has elected to apply hedge accounting on certain derivatives it uses to manage commodity price risk relating to electricity prices. For 2008, the change in the fair value of the ineffective portion of hedging derivatives required to be recognized in the income statement was nil (2007 — nil; 2006 — not applicable). Of the $29 million (2007 — $62 million; 2006 — not applicable) of net losses related to derivative instruments designated as cash-flow hedges included in accumulated other comprehensive loss at December 31, 2008, net losses of $15 million (2007 — $45 million; 2006 — not applicable), net of income taxes of $7 million (2007 — $20 million; 2006 — not applicable) are expected to settle and be reclassified to net income over the next twelve months. The Group's cash flow hedges extend up to 2016.

23. RISK MANAGEMENT

Risk management overview

The Group 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 Group's overall risk management process is managed by its parent company, EUI, on a centralized basis and is designed to identify, manage and mitigate business risk which includes, among other risks, financial risk. Risk management is overseen by EUI's Risk Oversight Council (ROC) according to objectives, targets, and policies approved by the EUI Board of Directors. The ROC is comprised of a senior management group including the Vice President, Risk Management.

23. RISK MANAGEMENT (Continued)

EUI's Vice President, Risk Management, reports regularly to the Board of Directors on ROC activities. Risk management strategies, policies, and limits are designed to help ensure the risk exposures are managed within the Group's business objectives and risk tolerance. The Group'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 ROC 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 in accordance with applicable policies. EUI's Audit Committee of the Board of Directors, in its oversight role, performs regular and ad-hoc reviews of risk management controls and procedures to help ensure compliance.

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 Group 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 Group'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 Group 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 Group's actual exposure to market risks is constantly changing as the Group'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 Group.

Commodity price risk

The Group 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 Group'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 Group 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 Group actively

23. RISK MANAGEMENT (Continued)

manages commodity price risk by optimizing its asset and contract portfolios utilizing the following methods variously:

- The Group 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 Group enters into fixed-price energy sales contracts and power purchase arrangements which limit the exposure to electricity prices. The Group 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 Group 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 Group enters into back-to-back electricity and natural gas physical and financial contracts in order to lock in a margin.

The Group also engages in taking market risk positions within authorized limits approved by EUI's ROC 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 Group's energy related derivatives at December 31, 2008 that are required to be measured at fair value with the respective changes in fair value recognized in net income are disclosed in note 22.

On behalf of the Group, EUI 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. EUI'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.

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 Corporation 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.

23. RISK MANAGEMENT (Continued)

These limitations and the nature of the VaR measurements mean that the Group and its parent 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, EUI 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 Group has controlling interest, and reflects the Group's aggregate commodity positions from its trading and asset portfolios. EUI's Board of Directors has established an aggregate TE limit, under their risk management policy, which is monitored and reported to the ROC and other senior management 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, 2008, there is a higher than 95% probability that unfavorable daily market variations would not reduce the 12 month portfolio by more than $22 million.

Foreign exchange risk

The Group 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 Group operates internationally and therefore, is exposed to foreign exchange risk arising from transactions denominated in foreign currencies. The Group'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 Group's foreign exchange management policy is to attempt to minimize economic and material transactional exposures arising from movements in the Canadian dollar relative to the U.S. dollar or other foreign currencies. The Group'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 Group co-ordinates and manages foreign exchange risk centrally, by identifying opportunities for naturally-occurring opposite movements and then dealing with any material residual foreign exchange risks; these are hereinafter referred to as being economically hedged.

The Group 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 Group 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, 2008, US$457 million or approximately 96% of expected future net cash flows from Power LP's U.S. plants had been economically hedged for 2009 to 2014 at a weighted average exchange rate of $1.12 per U.S. dollar. At December 31, 2008, the Group has transactional exposure for approximately US$59 million of expected future net cash flows for capital expenditure commitments.

As at December 31, 2008, 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 $7 million after tax. There would be no impact to other comprehensive income.

23. RISK MANAGEMENT (Continued)

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 Group 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 Group 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, 2008, the proportion of fixed rate debt was approximately 97% (December 31, 2007 — 100%) of total long-term debt outstanding. The Group may also use derivative instruments to manage interest rate risk. At December 31, 2008 and December 31, 2007, the Group 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, 2008, a 100 basis point change to interest rates would decrease or increase full year net income by $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 Group at fixed interest rates.

Credit risk

Credit risk is the possible financial loss associated with the inability of counterparties to satisfy their contractual obligations to the Group. The counterparty credit risk management policy is established on behalf of the Group by EUI's ROC and approved by EUI's Board of Directors and the associated procedures and practices are designed to manage the credit risks associated with the various business activities throughout the Group. Credit and counterparty 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 are subsequently monitored and are regularly reported to ROC. Creditworthiness continues to be evaluated after transactions have been initiated, at minimum, on an annual basis. To manage and mitigate credit risk, the Group employs various credit mitigation practices such as master netting agreements, margining to reduce energy trading risks, pre-payment arrangements from retail customers, credit derivatives and other forms of credit enhancements including cash deposits, parent company guarantees, and bank letters of credit.

23. RISK MANAGEMENT (Continued)

Maximum credit risk exposure

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

	2008	2007
Cash and cash equivalents	$ 69	$ 51
Notes receivable	—	115
Accounts receivable[1]	320	412
Derivative instruments assets[1]	201	220
Loans and other long-term receivables	52	46
Net investments in leases	33	29
Loan commitments to third parties	6	6
	$681	$879

(1) The Group's maximum exposures related to accounts receivable and derivative instruments assets by major credit concentration are comprised of maximum exposures of $189 million for generation and $332 million for wholesale.

This table does not take into account collateral held. At December 31, 2008, the Group held cash deposits of $4 million (2007 — nil) as security for certain counterparty accounts receivable and derivative contracts. The Group is not permitted to sell or re-pledge this collateral in the absence of default of the counterparties providing the collateral. At December 31, 2008, the Group also held other forms of credit enhancement in the form of letters of credit of $18 million (2007 — $1 million) and parental guarantees of $737 million (2007 — $668 million).

Credit quality and concentrations

The Group 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, wholesale and retail customers. The Group 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.

23. RISK MANAGEMENT (Continued)

The credit quality of the Group's accounts receivable, by major credit concentrations, and other financial assets are the following:

	2008		
	Investment grade[1] or secured	Non-investment grade[1]	Unrated
Accounts receivable and financial derivative instruments[2]			
Generation	100%	—	—
Wholesale[3]	90%	10%	—
Cash and cash equivalents	100%	—	—
Loans and other long-term receivables[4]	100%	—	—

(1) Credit ratings are based on the Group's internal analyses which take into account the investment-grade credit ratings of external agencies.

(2) Percentages are based on potential 60 day accounts receivables.

(3) Includes industrial end-use customers, trading and position management counterparties.

(4) Loans and other long-term receivables are considered to have low credit risk as the financial assets are either secured by the underlying assets or the counterparties are local or provincial governments.

Generation credit risk

Credit risk exposure from power purchase arrangements, agreements with independent system operators, power and steam sales contracts, and certain energy supply agreements is predominantly restricted to accounts receivables and contract default. In certain cases, the Group 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 Group's financial results. Financial loss resulting from events of default by counterparties in certain power purchase arrangements and steam purchase agreements may not be recovered since the contracts may not be replaceable on similar terms under current market conditions. Consequently, the Group'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, netting amounts by legally enforceable set-off rights, and, when appropriate, taking back security from the counterparty. Credit risk with government-owned or sponsored entities and regulated public utility distributors is generally considered low.

Wholesale and merchant credit risk

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

23. RISK MANAGEMENT (Continued)

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. The Group also has credit exposures to large suppliers of electricity and natural gas. The Group mitigates these exposures by dealing with creditworthy counterparties and, when appropriate, taking back appropriate security from the supplier.

The aging of accounts receivable was:

	2008		
	Gross accounts receivable	Allowance for doubtful accounts	Net accounts receivable
Current[1]	$318	$ —	$318
Outstanding 30 to 60 days	1	—	1
Outstanding 61 to 90 days	1	—	1
Outstanding more than 90 days	4	4	—
Total	$324	$ 4	$320

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

Bad debt expense, exclusive of recoveries, of $1 million recognized in the year ended December 31, 2008 relates to customer amounts that the Group determined would not be fully collectable. Allowances for doubtful accounts are determined by each business unit considering the unique factors of the business unit's accounts receivable. Allowances and write-offs are determined by each business unit, either by applying specific risk factors to customer groups' aged balances in accounts receivable or by reviewing material accounts on a case-by-case basis. Accounts receivable and the related allowance for doubtful accounts amount are both written off or decreased when the Group has determined that recovery is not possible.

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

	2008	2007	2006
Balance, beginning of year	$ 3	$ 3	$ 3
Allowance of receivables	3	1	1
Receivables written off	(2)	(2)	(1)
Recovery of receivables	—	1	—
Balance, end of year	$ 4	$ 3	$ 3

At December 31, 2008, the Group held $4 million of customer deposits for the purpose of mitigating the credit risk associated with accounts receivable from residential and business customers.

23. RISK MANAGEMENT (Continued)

At December 31, 2008, 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.

Liquidity risk

Liquidity risk is the risk that the Group will not be able to meet its financial obligations as they become due. Liquidity is managed centrally on behalf of the Group by EUI's Treasury function. The Group 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 Power LP.

Power LP has a long-term debt rating of BBB+ and BBB(high), assigned by Standard & Poor's (S&P) and DBRS Limited (DBRS) respectively.

As at December 31, 2008, Power LP had undrawn and committed bank credit facilities of $213 million with remaining terms ranging from two to three years as discussed in note 12 — Long-term debt. In addition, Power LP 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.

The following are the undiscounted cash flow requirements and contractual maturities of the Group's financial liabilities, including interest payments, as at December 31, 2008:

	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:							
Notes payable	$155	$ —	$ —	$ —	$ —	$ —	$ 155
Long-term debt	20	103	13	50	7	2,840	3,033
Interest payments on long-term debt	248	241	228	218	202	1,978	3,115
Accounts payable and accrued liabilities[1]	362	—	—	—	—	—	362
Other current liabilities	4	—	—	—	—	—	4
Loan commitments	6	—	—	—	—	—	6
Derivative financial liabilities:							
Net forward foreign exchange contracts	12	9	8	10	6	7	52
Net commodity contracts-for-differences	94	50	10	2	1	1	158
Total	$901	$403	$259	$280	$216	$4,826	$6,885

(1) Excluding accrued interest on long-term debt of $64 million.

24. CAPITAL MANAGEMENT

The Group's primary objectives when managing capital are to safeguard the Group's ability to continue as a going concern and to facilitate the acquisition or development of projects in Canada and the U.S. consistent with the growth strategy of the Group. On a consolidated basis, EUI's objective of maintaining a suitable credit rating inherently matches the Group's objective although no separate, independent credit rating exists for the Group. The Group manages its capital structure in a manner consistent with the risk characteristics of the underlying assets. This overall objective and policy for managing capital remained unchanged in the current year from the prior comparative period.

The Group 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 Group matches the maturity profiles of financial assets and liabilities to identify financing requirements to help ensure an adequate amount of liquidity.

The Group considers its capital structure to consist of short-term debt, notes payable and long-term debt net of cash and cash equivalents and notes receivable, non-controlling interests (including preferred shares issued by subsidiary companies) and shareholder's equity. The following table represents the total capital of the Group:

	2008	2007
Notes payable	$ 155	$ —
Long-term debt (including current portion) (note 12)	3,027	2,485
Cash and cash equivalents	(69)	(51)
Notes receivable	—	(115)
Net debt	3,113	2,319
Non-controlling interests (note 15)	540	740
Shareholder's equity	381	729
Total equity	921	1,469
Total capital	$4,034	$3,788

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

Power LP 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 Power LP is assigned a rating of less than BBB+ by S&P and BBB(high) by DBRS, the Power LP 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.

For the year ended December 31, 2008, Power LP complied with all externally imposed capital restrictions.

To manage or adjust its capital structure, the Group can issue new debt, issue common or preferred shares, issue new Power LP units, repay existing debt or adjust dividends paid to its shareholders.

25. RELATED PARTY BALANCES AND TRANSACTIONS

The following summarizes the Group's related party balances and transactions with the Group's parent company, EUI and its subsidiaries, and with EUI's common shareholder, the COE. All transactions are in the normal course of operations (except as described in note 3), and are recorded at the exchange amount, which is the consideration established and agreed to by the parties.

	Related party		2008	2007	2006
Balance sheet:					
Notes receivable	EUI		$ —	$ 115	
Accounts receivable	COE	(a)	2	28	
	EUI	(b)	95	77	
Other assets	EUI		5	8	
Notes payable	EUI		155	—	
Accounts payable	EUI		7	10	
Accounts payable — accrued interest on debt	COE		15	22	
	EUI		36	33	
Long-term debt (note 12)	COE		154	199	
	EUI		2,025	1,615	
Other non-current liabilities	EUI		4	5	
Income statement:					
Revenues — energy sales	COE		24	23	17
	EUI		661	596	525
Revenues — other	EUI		2	—	—
	COE		—	—	6
Energy purchases and fuel	EUI		28	28	32
Operations, maintenance and administration	EUI	(c)	192	166	114
Net financing expenses	COE	(d)	40	50	51
	EUI	(e)	139	118	143
Common share dividends	EUI		370	122	19

(a) Accounts receivable from the COE includes nil (2007 — $27 million) in respect of the negotiated sharing of the earnings of the COE Sinking Fund. During the year, the Group received $28 million (2007 — nil) of these balances.

(b) Accounts receivable from EUI includes $3 million (2007 — $7 million) for accrued interest receivable on notes receivable.

(c) Operations, maintenance and administration expense includes amounts paid to EUI for executive, legal, finance, treasury, audit, human resources, procurement, information technology, and pension services of $52 million (2007 — $44 million; 2006 — $38 million) and amounts paid on behalf of the Group for wages and benefits of $136 million (2007 — $119 million; 2006 — $72 million). In addition, the Group capitalized $5 million (2007 — $3 million; 2006 — $2 million) of wages and benefits paid by EUI on behalf of the Group.

(d) Interest expense on the obligation to the COE.

(e) Net financing expenses on notes receivable and payable and long-term notes payable and guarantee fees to EUI.

25. RELATED PARTY BALANCES AND TRANSACTIONS (Continued)

Included in the Group's revenues is $4 million (2007 — $3 million; 2006 — $1 million) for the provision of management services by Power LP to PERC under a long-term management agreement. At December 31, 2008, accounts receivable includes nil due from PERC (2007 — $1 million).

26. JOINT VENTURES

The Group 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 Group's Genesee generation plant.

The Group 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 Group, through its Power LP subsidiary, also holds a 50.15% interest in the Frederickson power plant.

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

	2008	2007	2006
Current assets	$ 44	$ 38	$ 66
Long-term assets	986	728	584
Current liabilities	68	56	60
Long-term liabilities	42	42	57
Revenues[1]	74	67	75
Expenses[2]	100	78	80
Net loss	(26)	(11)	(5)
Cash flows from operating activities	13	17	1
Cash flows used in investing activities	(267)	(140)	(12)
Cash flows from financing activities	245	106	12

(1) Excludes all revenues from Genesee 3, which are recorded as revenues by the Group 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 Group.

Included in the Group's cash and cash equivalents is its proportionate share of cash and cash equivalents which are restricted to use within joint ventures of $24 million (2007 — $14 million).

Under the terms of the Group's interests in the Frederickson power plant, the Genesee 3 Project and the Keephills 3 Project, the Group 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.

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 Castleton, ManChief, Mamquam, Queen Charlotte, Southport, Roxboro, Kenilworth, Greeley and Williams Lake, are accounted for as assets under operating leases. As at December 31, 2008, the carrying amount of such property, plant and equipment was $477 million (2007 — $470 million), less accumulated depreciation of $63 million (2007 — $52 million). The Group's revenue pursuant to the arrangements for the year ended December 31, 2008 was $193 million (2007 — $200 million; 2006 — $116 million).

28. CONTINGENCIES AND COMMITMENTS

(a) The Group has committed to purchase new high efficiency gas-fired electric generating units at an estimated total cost of $284 million (2007 — $284 million), of which $186 million has been incurred as at December 31, 2008 (2007 $67 million).

(b) On February 26, 2007, the Group and TransAlta Corporation (TransAlta) announced their decision to build 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. The Group's 50% estimated committed share of the total capital cost is $903 million (2007 — $820 million). As part of contractual arrangements, EUI, on behalf of the Group, 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.

(c) Power LP has committed up to $119 million (US$98 million) for the enhancement of the Southport, Roxboro and North Island facilities, to be spent through 2009, of which $18 million (US$15 million) has been incurred as at December 31, 2008.

(d) Under the terms of the acquired Alberta PPAs, the Group is obligated to make monthly payments for fixed and variable costs. The estimated annual total of these payments for 2009 is $135 million. The actual amounts for 2009 and future years may vary from estimates depending on generation volume and scheduled outages. It is expected that the annual payments over the terms of the Alberta PPAs, as described in note 2(k), will range from $93 million to $159 million, adjusted for inflation, other than in the event of a forced outage.

(e) The Group 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 combined and 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
2009	$156	$ 27	$ 3
2010	122	28	3
2011	93	29	3
2012	77	30	1
2013	58	32	1
Thereafter	198	141	4
Total	$704	$287	$15

(f) The Group has committed to issue non-interest bearing notes receivable to the non-Group syndicate members involved in the Sundance Swap transaction entered into in 2006. The commitment relates to funding potential income tax liabilities incurred by the non-Group syndicate members in relation to the transaction. The total estimated loan commitment is $19 million, with annual payments of principal

28. CONTINGENCIES AND COMMITMENTS (Continued)

commencing from the date the commitment is called by the non-Group syndicate members through to December 2012. At December 31, 2008, the Group has extended $13 million (2007 — $13 million) under such notes and their carrying amount of $9 million (2007 — $9 million), after fair value adjustments, is included in other assets.

(g) On December 4, 2008, the Power LP signed a definitive agreement to sell its Castleton facility, located in the state of New York, to Castleton Energy Center, LLC for approximately US$10 million, subject to closing adjustments. The sale closed on May 26, 2009. The related assets and liabilities of the Castleton power plant, before giving effect to the non-controlling interest in such assets and liabilities, are:

	2008	2007
Current assets		
Accounts receivable	$ 1	$ 4
Inventories and prepaid expenses	1	2
	$ 2	$ 6
Non-current assets		
Property, plant and equipment	$ 11	$ 12
Future income tax assets	1	—
	$ 12	$ 12
Current liabilities		
Accounts payable and accrued liabilities	$ 1	$ 4
Non-current liabilities		
Asset retirement obligations	$ 2	$ 2
Future income tax liabilities	2	1
	$ 4	$ 3

Net loss, before giving effect to the non-controlling interest, from the Castleton power plant for the year ended December 31, 2008 was $1 million (2007 — nil; 2006 — nil).

(h) The Group and its subsidiaries are subject to various legal claims that arise in the normal course of business. Management believes that the aggregate contingent liability of the Group arising from these claims is immaterial and therefore no provision has been made.

29. GUARANTEES

On behalf of the Group's subsidiaries, EUI has issued letters of credit for $206 million (2007 — $313 million) to meet the credit requirements of energy market participants, to meet conditions of certain service agreements, and to satisfy legislated reclamation requirements.

30. GEOGRAPHIC INFORMATION

	2008			
	Canada	U.S.	Inter-area eliminations	Total
Revenues — external	$2,165	$484	$ —	$2,649
Inter-area revenues	54	10	(64)	—
Total revenues	$2,219	$494	$(64)	$2,649
Property, plant and equipment	$2,665	$520	$ —	$3,185
Goodwill	$ 121	$ 38	$ —	$ 159

	2007			
	Canada	U.S.	Inter-area eliminations	Total
Revenues — external	$2,505	$448	$ —	$2,953
Inter-area revenues	33	22	(55)	—
Total revenues	$2,538	$470	$(55)	$2,953
Property, plant and equipment	$2,364	$446	$ —	$2,810
Goodwill	$ 149	$ 34	$ —	$ 183

	2006			
	Canada	U.S.	Inter-area eliminations	Total
Revenues — external	$2,034	$212	$ —	$2,246
Inter-area revenues	25	10	(35)	—
Total revenues	$2,059	$222	$(35)	$2,246

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.

31. SUBSEQUENT EVENT

On May 8, 2009, EUI announced its plans to create Capital Power Corporation, a power generation company that will be permanently headquartered in Edmonton.

Capital Power Corporation and its subsidiaries (Capital Power) have agreed to acquire in July 2009 all the power generation assets and related operations of EUI and as included in these financial statements of the Group including the Group's 30.6% interest in Power LP. Capital Power will be responsible for operating the generating plants owned at March 31, 2009 by the Group and Power LP. Employees are anticipated to move to Capital Power in July 2009, with transition agreements in place between EUI and Capital Power in order to ensure continuity of operations and services.

At March 31, 2009, the carrying amount of the assets to be acquired by Capital Power was $5 billion (unaudited) (December 31, 2008 — $5 billion) and revenues for the three months then ended were $709 million (unaudited) (2008 — $633 million).

EPCOR POWER GROUP

COMBINED AND CONSOLIDATED STATEMENTS OF INCOME

(Unaudited, in millions of dollars)

	Three months ended March 31,	
	2009	**2008**
Revenues	$709	$633
Energy purchases and fuel	510	397
	199	236
Operations, maintenance and administration	82	83
Depreciation, amortization and asset retirement accretion	46	45
Foreign exchange losses	—	13
Gain on sale of power purchase arrangement and related transactions (note 11)	(30)	(34)
Net financing expenses	64	51
	162	158
Income before income taxes and non-controlling interests	37	78
Income taxes	5	5
Income before non-controlling interests	32	73
Non-controlling interests (note 6)	(22)	38
Net income	$ 54	$ 35

See accompanying notes to combined and consolidated financial statements.

EPCOR POWER GROUP

COMBINED AND CONSOLIDATED BALANCE SHEETS

(Unaudited, in millions of dollars)

	March 31, 2009	December 31, 2008
Assets		
Current assets:		
Cash and cash equivalents	$ 80	$ 69
Accounts receivable	257	320
Income taxes recoverable	9	5
Inventories	55	62
Prepaid expenses	5	8
Derivative instruments assets (note 9)	139	126
	545	590
Property, plant and equipment	3,274	3,185
Power purchase arrangements	549	550
Contract and customer rights and other intangible assets	188	183
Derivative instruments assets (note 9)	88	75
Future income tax assets	96	97
Goodwill	161	159
Other assets	122	120
Assets held for sale (note 11)	25	43
	$5,048	$5,002
Liabilities and Shareholders' Equity		
Current liabilities:		
Notes payable	$ 179	$ 155
Accounts payable and accrued liabilities	363	430
Income taxes payable	8	4
Derivative instruments liabilities (note 9)	155	130
Future income tax liabilities	50	34
Current portion of long-term debt	20	20
	775	773
Long-term debt	3,044	3,007
Derivative instruments liabilities (note 9)	102	110
Other non-current liabilities	91	91
Future income tax liabilities	93	100
	4,105	4,081
Non-controlling interests (note 6)	507	540
Shareholders' equity	436	381
Subsequent event (note 15)		
	$5,048	$5,002

See accompanying notes to combined and consolidated financial statements.

EPCOR POWER GROUP

COMBINED AND CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

(Unaudited, in millions of dollars)

	Three Months Ended March 31,	
	2009	2008
Share capital:		
Balance, beginning and end of period	$ 673	$673
Retained earnings (deficit):		
Balance, beginning of period	(228)	136
Adjustment for change in accounting policy (note 4)	1	—
Net income	54	35
Common share dividends	(17)	(5)
Refundable taxes (note 11)	(5)	(7)
Balance, end of period	(195)	159
Accumulated other comprehensive loss:		
Balance, beginning of period	(64)	(80)
Other comprehensive income	22	24
Balance, end of period	(42)	(56)
Total shareholders' equity, end of period	$ 436	$776

See accompanying notes to combined and consolidated financial statements.

EPCOR POWER GROUP

COMBINED AND CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Unaudited, in millions of dollars)

	Three months ended March 31,	
	2009	2008
Net income	$ 54	$ 35
Other comprehensive income (loss), net of income taxes:		
Unrealized gains on derivative instruments designated as cash flow hedges[1]	9	7
Reclassification of losses on derivative instruments designated as cash flow hedges to net income[2]	8	15
Unrealized loss in self-sustaining foreign operations[3]	17	1
Non-controlling interests[3] (note 6)	(12)	1
	22	24
Comprehensive income	$ 76	$ 59

(1) For the periods ended March 31, 2009 and 2008, net of income tax expenses of $4 million and $3 million respectively.

(2) For the periods ended March 31, 2009 and 2008, net of reclassification of income tax recoveries of $3 million and $7 million respectively.

(3) For the periods ended March 31, 2009 and 2008, net of income tax expense of nil.

See accompanying notes to combined and consolidated financial statements.

EPCOR POWER GROUP

COMBINED AND CONSOLIDATED STATEMENT OF CASH FLOWS

(Unaudited, in millions of dollars)

	Three months ended March 31,	
	2009	2008
Operating activities:		
Net income	$ 54	$ 35
Adjustments to reconcile net income to cash flows from operating activities:		
Depreciation, amortization and asset retirement accretion	46	45
Gain on sale of power purchase arrangement and related transactions (note 11)	(30)	(34)
Non-controlling interests in Power LP (note 6)	(24)	36
Fair value changes on derivative instruments	18	(29)
Unrealized foreign exchange (gains) losses	(2)	12
Future income taxes	17	7
Other	2	(2)
	81	70
Change in non-cash operating working capital (note 7)	(54)	(3)
	27	67
Investing activities:		
Property, plant and equipment and other assets	(108)	(76)
Net proceeds on PSA interests (note 11)	47	53
Other	2	3
Change in non-cash investing working capital (note 7)	36	9
	(23)	(11)
Financing activities:		
Repayment of long-term debt	(12)	(16)
Proceeds from issue of long-term debt	29	—
Distributions to non-controlling interests	(24)	(24)
Common share dividends	(17)	(5)
Other	—	1
Change in non-cash financing working capital (note 7)	29	20
	5	(24)
Foreign exchange gain on cash held in a foreign currency	2	1
Increase in cash and cash equivalents	11	33
Cash and cash equivalents, beginning of year	69	51
Cash and cash equivalents, end of year	$ 80	$ 84
Supplementary cash flow information:		
Interest paid net of interest received	$ 53	$ 51
Income taxes paid net of income taxes recovered	6	51

See accompanying notes to combined and consolidated financial statements.

1. BASIS OF PRESENTATION

These unaudited interim combined and consolidated financial statements of EPCOR Power Group (the Group) have been prepared in accordance with Canadian generally accepted accounting principles (GAAP) for interim financial statements and do not include all of the disclosures normally found in the Group's annual combined and consolidated financial statements.

These combined and consolidated interim financial statements of the Group have been derived from the consolidated financial statements and accounting records of EPCOR Utilities Inc. (EUI), on a basis which maintains the historical operations and the historical measurement of assets and liabilities, and principally include the accounts of EPCOR Power Development Corporation, EPCOR Power Generation Services Inc., EMCC Limited and EPCOR PPA Management Inc, their subsidiaries, and their proportionate share of assets, liabilities, revenues and expenses of joint ventures. The assets, liabilities and operations of the Rossdale generation plant are excluded from the accounts of EPCOR Power Development Corporation as included in these combined and consolidated financial statements. The accounts of the Group's approximate 30.6% interest in EPCOR Power L.P. (Power LP), a publicly traded entity, are also included in these combined and consolidated interim financial statements. Under GAAP, the Group controls Power LP which therefore is a subsidiary of the Group. The comparative figures include, on a continuity of interests basis, the financial position, results of operations and cash flows of certain other entities within the EUI corporate group that, as a result of various transactions within the EUI corporate group, form all or part of the historical results of the companies combined to form the group as at March 31, 2009. These unaudited interim combined and consolidated financial statements may not necessarily reflect the Group's financial position, results of operations and cash flows in the future, nor what its financial position, results of operations and cash flows would have been had the Group been a stand-alone entity during the periods presented.

Management believes the assumptions underlying these unaudited interim combined and consolidated financial statements are reasonable. These unaudited interim combined and consolidated financial statements should be read in conjunction with the Group's audited combined and consolidated financial statements for the year ended December 31, 2008.

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

These financial statements have been prepared following the same accounting policies and methods as those used in preparing the most recent annual combined and consolidated financial statements except for the changes in accounting policies as described in note 4.

2. NATURE OF OPERATIONS

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

3. MEASUREMENT UNCERTAINTY

In accordance with Canadian GAAP, the Group uses estimates in preparing its combined and consolidated financial statements. Interim combined and consolidated financial statements necessarily employ a greater use of estimates than the annual combined and consolidated financial statements.

4. CHANGES IN SIGNIFICANT ACCOUNTING POLICIES

Goodwill and intangible assets

In February 2008, the CICA issued Handbook Section 3064 — Goodwill and Intangible Assets and consequential amendments to Section 1000 — Financial Statement Concepts. The new section establishes standards for the recognition, measurement and disclosure of goodwill and intangible assets. The provisions relating to the definition and initial recognition of intangible assets, including internally generated intangible assets, are equivalent to the corresponding provisions in International Financial Reporting Standards (IFRS). These amendments have been adopted by the Group commencing January 1, 2009 and have been applied retrospectively resulting in $11 million of net assets being reclassified from property, plant and equipment to contract and customer rights and other intangible assets in the comparative December 31, 2008 balance sheet. The Group's adoption of these amendments had no other material impacts on these interim combined and consolidated financial statements.

Credit risk in determining fair value of financial assets and liabilities

On January 20, 2009 the Emerging Issues Committee of the CICA issued EIC-173, Credit Risk and the Fair Value of Financial Assets and Financial Liabilities, which clarifies that an entity's own credit risk and the credit risks of the counterparties should be taken into account in determining the fair value of financial assets and liabilities, including derivative instruments. Effective January 1, 2009, the Group adopted the recommendations of EIC-173 and applied the recommendations retrospectively without restatement of prior periods. On January 1, 2009, the Group made the following adjustments to the balance sheet in adopting the recommendations of EIC-173:

Balance sheet item	Increase (decrease)
Derivative instruments assets — non-current	$ (1)
Derivative instruments liabilities — non-current	(6)
Future income tax liabilities — non-current	1
Non-controlling interests — balance sheet	3
Opening retained earnings	1

Future accounting changes

The CICA has announced that Canadian reporting issuers will need to begin reporting under IFRS, including comparative figures, by the first quarter of 2011. The Group is currently assessing the impact of the differences in accounting standards on the Group'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 combined and 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 will be assessed as part of the Group's IFRS conversion project.

4. CHANGES IN SIGNIFICANT ACCOUNTING POLICIES (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 will be assessed as part of the Group's IFRS conversion project.

5. LONG-TERM DEBT

Unsecured three-year credit facilities of $100 million each for a total of $300 million, committed to June 2010, September 2010, and October 2011, respectively, are available to the Group through it's Power LP subsidiary. At March 31, 2009, the Group had $39 million in bankers' acceptances and $80 million (US$63 million) in U.S. LIBOR loans outstanding under this facility (December 31, 2008 — $23 million in bankers' acceptances and $64 million (US$52 million) in U.S. LIBOR loans) at an effective interest rate of 1.54% (December 31, 2008 — 1.09%).

6. NON-CONTROLLING INTERESTS

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

	Three months ended March 31,	
	2009	2008
Non-controlling interests in Power LP	$ (24)	$ 36
Preferred share dividends paid by subsidiary companies	2	2
	$ (22)	$ 38

Non-controlling interests reflected in the combined and consolidated balance sheets for the three months ended March 31, 2009 and the year ended December 31, 2008 consisted of:

	March 31, 2009	December 31, 2008
Non-controlling interests in Power LP, beginning of year	$418	$618
Net loss attributable to non-controlling interests	(24)	(58)
Other comprehensive loss attributable to non-controlling interests	12	(48)
Opening retained earnings adjustments attributable to non-controlling interests	3	—
Distributions to non-controlling interests	(24)	(94)
Non-controlling interests in Power LP, end of year	385	418
Preferred shares issued by subsidiary companies, beginning and end of year	122	122
	$507	$540

7. CHANGE IN NON-CASH WORKING CAPITAL

	Three months ended March 31	
	2009	2008
Accounts receivable	$ 62	$ 125
Income taxes recoverable	(5)	(1)
Inventories	7	2
Prepaid expenses	2	1
Notes payable	24	69
Accounts payable and accrued liabilities	(64)	(120)
Income taxes payable	(15)	(50)
	$ 11	$ 26
Relating to:		
Operating activities	$(54)	$ (3)
Investing activities	36	9
Financing activities	29	20
	$ 11	$ 26

8. FAIR VALUE AND CLASSIFICATION OF NON-DERIVATIVE FINANCIAL ASSETS AND LIABILITIES

		March 31, 2009		December 31, 2008	
Financial asset or liability	Classification	Carrying amount	Fair value	Carrying amount	Fair value
Other assets					
Investment in preferred shares of Primary Energy Recycling Holdings LLC (PERH)	Available for sale	$ 17	$ 17	$ 16	$ 16
Loans and other long-term receivables	Loans and receivables	52	48	52	46
Net investment in lease	Loans and receivables	34	34	33	33
Portfolio investments	Available for sale	6	7	6	6
Long-term debt (including current portion)	Other financial liabilities	3,064	2,969	3,027	2,850

9. 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.

9. DERIVATIVE INSTRUMENTS AND HEDGE ACCOUNTING (Continued)

The derivative instruments assets and liabilities used for risk management purposes consist of the following:

	March 31, 2009			
	Energy		Foreign exchange	
	Cash flow hedges	Non-hedges	Non-hedges	Total
Derivative instruments assets:				
Current	$ 12	$ 121	$ 6	$ 139
Non-current	9	78	1	88
Derivative instruments liabilities:				
Current	(25)	(116)	(14)	(155)
Non-current	(14)	(45)	(43)	(102)
Net fair value	$(18)	$ 38	$ (50)	$ (30)
Net notional buys (sells):				
Megawatt hours of electricity (millions)	(1)	(3)		
Gigajoules of natural gas (millions)	—	65		
Foreign currency (U.S. dollars)			$(488)	
Range of contract terms in years	0.1 to 7.8	0.1 to 7.7	0.1 to 6.7	

	December 31, 2008			
	Energy		Foreign exchange	
	Cash flow hedges	Non-hedges	Non-hedges	Total
Derivative instruments assets:				
Current	$ 10	$ 108	$ 8	$ 126
Non-current	9	62	4	75
Derivative instruments liabilities:				
Current	(31)	(88)	(11)	(130)
Non-current	(29)	(43)	(38)	(110)
Net fair value	$(41)	$ 39	$ (37)	$ (39)
Net notional buys (sells):				
Megawatt hours of electricity (millions)	(2)	(2)		
Gigajoules of natural gas (millions)		65		
Foreign currency (U.S. dollars)			$(457)	
Range of contract terms in years	0.1 to 8.0	0.1 to 8.0	0.1 to 6.0	

9. 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:

	Three months ended March 31			
	2009		2008	
	Unrealized gains (losses)	Realized gains (losses)	Unrealized gains (losses)	Realized gains (losses)
Energy cash flow hedges	$ 23	$ (11)	$ 33	$ (23)
Energy non-hedges	(1)	(20)	44	13
Foreign exchange non-hedges	(17)	(4)	(10)	4

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

The Group has elected to apply hedge accounting on certain derivatives it uses to manage commodity price risk relating to electricity prices. For the quarter ended March 31, 2009, the ineffective portion of hedging derivatives required to be recognized in the income statement was nil (2008 — nil). Of the $13 million (December 31, 2008 — $29 million) of net losses related to derivative instruments designated as cash-flow hedges included in accumulated other comprehensive loss at March 31, 2009, net losses of $9 million (December 31, 2008 — $15 million), net of income tax recoveries of $4 million (December 31, 2008 — $7 million) are expected to settle and be reclassified to net income over the next twelve months. The Group's cash flow hedges extend up to 2016.

10. RISK MANAGEMENT

Liquidity risk

As at March 31, 2009, Power LP had undrawn and committed bank credit facilities, including operating lines of credit, of $201 million (December 31, 2008 — $213 million), with remaining terms ranging from two to three years.

Power LP has in place a Canadian universal shelf prospectus, which expires in August 2010, under which Power LP may raise up to $1 billion in partnership units or debt, of which a maximum of $600 million can be debt. At March 31, 2009, Power LP has not drawn on the shelf prospectus (December 31, 2008 — nil).

10. RISK MANAGEMENT (Continued)

The following are the undiscounted cash flow requirements and contractual maturities of the Group's financial liabilities, including interest payments, as at March 31, 2009:

	Due within 1 year	Due between 1 and 2 years	2 and 3 years	3 and 4 years	4 and 5 years	Due after more than 5 years	Total contractual cash flows
Non-derivative financial liabilities:							
Long-term debt	$ 20	$134	$ 52	$ 7	$244	$2,611	$3,068
Interest payments on long-term debt	338	324	303	279	269	2,836	4,349
Accounts payable and accrued liabilities[1]	303	—	—	—	—	—	303
Loan commitments	6	—	—	—	—	—	6
Derivative financial liabilities:							
Net forward foreign exchange contracts	14	12	12	12	9	8	67
Net commodity contracts-for-differences	93	29	13	2	—	—	137
Total	$774	$499	$380	$300	$522	$5,455	$7,930

(1) Excluding accrued interest on long-term debt of $60 million.

11. SALE OF POWER SYNDICATE AGREEMENT

In June 2006, the Group finalized an agreement to sell its Battle River Power Purchase Arrangement and its related interest in the Battle River Power Syndicate Agreement (Battle River PSA). The agreement resulted in the sale of 75% of the Battle River PSA through the year-ended December 31, 2008.

During the current quarter, 10% of the Battle River PSA was sold. The transactions in the current and comparative periods are summarized as follows:

	Three months ended March 31, 2009	2008
Cash proceeds from sale	$ 47	$ 53
Less net book value and costs of disposal	17	19
Gain on sale before income taxes	30	34
Less future income taxes	4	4
Gain on sale after income taxes	$ 26	$ 30

Refundable taxes of $5 million (2008 — $6 million), which arose from the taxable capital gains on the sale of the Battle River PSA, have been charged to retained earnings.

The Group's remaining interest in the Battle River PSA will be disposed of on January 15, 2010. Since the final disposal will occur within one year of the balance sheet date, the remaining Battle River PSA assets on the combined and consolidated balance sheets have been retrospectively reclassified from power purchase arrangements to assets held for sale.

12. GUARANTEES

At March 31, 2009, on behalf of the Group's subsidiaries, EUI has issued letters of credit for $187 million (December 31, 2008 — $206 million) to meet the credit requirements of energy market participants, to meet conditions of certain service agreements, and to satisfy legislated reclamation requirements.

13. GEOGRAPHIC INFORMATION

	Three months ended March 31, 2009			
	Canada	U.S.	Inter-area eliminations	Total
Revenues — external	$593	$116	$ —	$709
Inter-area revenues	12	1	(13)	—
Total revenues	$605	$117	$(13)	$709

	Three months ended March 31, 2008			
	Canada	U.S.	Inter-area eliminations	Total
Revenues — external	$522	$111	$ —	$633
Inter-area revenues	10	4	(14)	—
Total revenues	$532	$115	$(14)	$633

14. SUBSEQUENT EVENT

On May 8, 2009, EUI announced its plans to create Capital Power Corporation, a power generation company that will be permanently headquartered in Edmonton.

Capital Power Corporation and its subsidiaries (Capital Power) have agreed to acquire in July 2009 all the power generation assets and related operations of EUI and as included in these financial statements of the Group including the Group's 30.6% interest in Power LP. Capital Power will be responsible for operating the generating plants owned at March 31, 2009 by the Group and Power LP. Employees are anticipated to move to Capital Power in July 2009, with transition agreements in place between EUI and Capital Power in order to ensure continuity of operations and services.

At March 31, 2009, the carrying amount of the assets to be acquired by Capital Power was $5 billion (unaudited) (December 31, 2008 — $5 billion) and revenues for the three months then ended were $709 million (unaudited) (2008 — $633 million).

APPENDIX A — BOARD OF DIRECTORS TERMS OF REFERENCE

I. INTRODUCTION

A. The Board of Directors (herein the "Board") have the power to manage, or supervise the management of the business and affairs of Capital Power Corporation (herein the "Corporation") except as limited or restricted by the *Canada Business Corporations Act* (herein the "Act"), the Corporation's Articles and By-laws.

B. The Corporation hereby adopts these terms of reference for the Board, which sets out the specific responsibilities to be discharged by the Board. The purpose of these terms of reference is to assist the Board in annually assessing its performance.

C. The CEO and management, formulate strategies and plans and present them to the Board for approval. The Board approves the goals of the business, the objectives and policies within which it is managed, and then assumes a stewardship role and evaluates management performance. Reciprocally, the CEO keeps the Board fully informed of the Corporation's progress towards the achievement of its goals and of all material deviations from the goals or objectives and policies established by the Board in a timely and candid manner.

II. RESPONSIBILITIES

All of the following responsibilities are undertaken within the parameters and restrictions established by the Act, the Articles, and the By-laws.

A. Managing the Affairs of the Board

The Board supervises the management of the affairs of the Board by establishing committees to provide more detailed review of important areas of responsibility, delegating certain of its authorities to management, reserving certain powers to itself and making certain recommendations to the shareholders. This process includes:

i) appointing committees and/or advisory bodies, which at a minimum shall comprise: Audit Committee, Corporate Governance, Compensation & Nominating Committee and the Environmental, Health & Safety Committee, and establishing and periodically reviewing their terms of reference;

ii) implementing processes to evaluate the performance of the Board, Committees and Directors in fulfilling their responsibilities;

iii) on the recommendation of the Corporate Governance, Compensation & Nominating Committee ("CGCN Committee") implementing processes for new Director orientation and ongoing Director development.

iv) appointing the Secretary;

v) establishing and enforcing a Board confidentiality policy;

vi) on the recommendation of the CGCN Committee, implementing effective governance processes to fulfill its responsibility for oversight and control;

vii) making recommendations to the shareholders in the following areas;

a) on the recommendation of the CGCN Committee, director nominees other than the EPCOR-elect nominees;

b) appointment of the external auditors; and

c) any special business items to be addressed by the shareholders that may be brought forward by the Board or the Corporation from time to time.

viii) delineating the authority to be retained by the Board and that to be delegated to the Chief Executive Officer; and

ix) publishing a corporate governance statement annually, describing how each of the principles of good governance in CSA National Policy 58-201 is put into practice.

B. Strategy and Plans

The Board has the responsibility to:

i) participate with management in the Corporation's strategic planning process including;

a) providing input to management on emerging trends and issues;

b) reviewing and approving management's strategic plans (long term business plan); and

c) reviewing and approving the Corporation's financial objectives, plans and actions, including significant capital allocations and expenditures.

ii) approve annual capital and operating budgets which support the Corporation's ability to meet the objectives established in the strategic plan; and

iii) monitor the Corporation's progress towards its goals, and to revise and alter its direction through management in light of changing circumstances.

C. Management and Human Resources

With the assistance of the CGCN Committee, the Board has the responsibility for:

i) the appointment, termination and succession of the CEO;

ii) approving CEO compensation;

iii) approving terms of reference for the CEO;

iv) monitoring CEO performance and reviewing CEO performance at least annually, against agreed upon written objectives;

v) providing advice and counsel to the CEO in the execution of the CEO's duties;

vi) approving decisions relating to senior management, including the:

a) appointment and discharge of officers;

b) compensation and benefits for officers;

c) acceptance of outside directorships on public companies by officers;

vii) ensuring succession planning programs are in place, including programs to train and develop management;

viii) approving certain matters relating to all employees, including:

a) the annual compensation policy/program for employees;

b) new benefit programs or material changes to existing programs;

c) material benefits granted to retiring employees outside of benefits received under approved pension and other benefit programs; and

ix) approving the parameters for negotiated union collective agreements with employees of the Corporation; and

x) ensure there are adequate procedures for the Board to be apprised on a timely basis of concerns relating to unethical behavior, fraudulent activities or violation of the Corporation's policies.

D. Business and Risk Management

The Board has the responsibility to:

i) with the assistance of the Audit Committee, monitor corporate performance against the strategic, operating and capital plans, including assessing operating results to evaluate whether the business is being properly managed and meeting its objectives;

ii) ensure management identifies the principal risks of the Corporation's business and implements appropriate systems to manage these risks;

iii) receive, at least annually, reports from Management and, where applicable, from the Board's committees, on matters relating to, among others, ethical conduct, environmental management, employee health and safety, human rights, and related party transactions;

iv) with the assistance of the Audit Committee, assess and monitor management control systems:

a) evaluate and assess information provided by management and others (e.g., internal and external auditors) about the effectiveness of management control systems; and

b) understand principal risks and determine whether the Corporation achieves a proper balance between risk and returns, and that management ensures that systems are in place to address the risks identified.

E. Financial and Corporate Issues

The Board has the responsibility to:

i) with the assistance of the Audit Committee, at least annually provide oversight of a review to ensure the implementation and integrity of the Corporation's internal control and management information systems;

ii) meet at least annually with and receive reports from the Auditor;

iii) with the assistance of the Audit Committee, monitor operational and financial results;

iv) on the recommendation of the Audit Committee, approve annual and quarterly financial statements, and approve release thereof by management;

v) declare dividends from time to time;

vi) approve debt financing, banking resolutions and significant changes in banking relationships;

vii) review coverage, deductibles and key issues regarding corporate insurance policies;

viii) approve commitments that may have a material impact on the Corporation; and

ix) approve the commencement or settlement of litigation that may have a material impact on the Corporation.

x) recommend, as required, for the shareholders' approval;

a) the appointment of the external auditors;

b) on the recommendation of the CGCN Committee, director nominees other than the EPCOR-elect nominees; and

c) any special business items to be addressed by the shareholders that may be brought forward by the Board or the Corporation from time to time.

F. Shareholder and Corporate Communications

The Board has the responsibility to take all reasonable steps to:

i) ensure the Corporation has in place effective communication processes with shareholders and major stakeholders;

ii) with the assistance of the Audit Committee, ensure that the financial performance of the Corporation is adequately reported to the shareholders, other security holders and regulators on a timely and regular basis;

iii) on the recommendation of the Audit Committee, ensure the financial results are reported fairly and in accordance with generally accepted accounting principles; and

iv) ensure the timely reporting of any other developments that have a significant and material impact on the value of the Corporation.

G. Policies and Procedures

The Board has the responsibility to take all reasonable steps to:

i) with the assistance of the CGCN Committee (where applicable), approve and monitor compliance with all significant policies and procedures by which the Corporation is operated;

ii) with the assistance of the CGCN Committee, direct management to ensure the Corporation operates at all times within applicable laws and regulations and to the highest ethical and moral standards;

iii) on the recommendation of the CGCN Committee, review significant new corporate policies or material amendments to existing policies (including, for example, policies regarding business conduct, conflict of interest and the environment);

iv) review governance guidelines annually; and

v) establish and monitor procedures for identification of and dealing with conflicts of interest.

III. GENERAL LEGAL OBLIGATIONS OF THE BOARD OF DIRECTORS

A. The Board is responsible for directing management to ensure legal requirements have been met, and documents and records have been properly prepared, approved and maintained.

B. The Act includes the following as legal requirements for Directors:

i) to act honestly and in good faith with a view to the best interests of the Corporation;

ii) to exercise the care, diligence and skill that reasonably prudent people would exercise in comparable situation; and

iii) to act in accordance with the obligations contained in the Act, and any other relevant legislation, regulations and policies, and the Corporation's Articles and By-laws.

APPENDIX B — AUDIT COMMITTEE TERMS OF REFERENCE

A. OVERVIEW AND PURPOSE

1. The Audit Committee (herein the "Committee"), except to the extent otherwise provided by law, is responsible to the Board of Directors (herein the "Board") of Capital Power Corporation (herein the "Corporation"). The Committee provides assistance to the Board in fulfilling its oversight responsibility to the shareholders, the investment community and others, relating to the integrity of the Corporation's financial statements, financial reporting process, systems of internal accounting and financial controls, the risk identification assessment conducted by Management and the programs established by Management and the Board in response to such assessment, the internal audit function and the external auditors' qualifications, independence, performance and reports to the Corporation. In addition, the Committee monitors, evaluates, advises or makes recommendations, in accordance with these Terms of Reference and any other directions of the Board, on matters affecting the financial and operational control policies and practices relating to the Corporation, including the external, internal or special audits thereof.

2. Management is responsible for preparing the interim and annual financial statements of the Corporation and for maintaining a system of risk assessment and internal controls to provide reasonable assurance that assets are safeguarded and that transactions are authorized, recorded and reported properly. The Committee is responsible for reviewing management's actions and has the authority to investigate any activity of the Corporation. The primary responsibilities of the Committee include:

   - assessing the processes related to identification of the Corporation's risks and effectiveness of its control environment;
   - overseeing financial reporting;
   - evaluating the Corporation's internal control systems for financial reporting; and
   - evaluating the internal and external, and any special, audit processes.

3. The Committee shall have unrestricted access to company personnel and documents, including internal auditors, and will be provided with the resources necessary to carry out its responsibilities. The Committee has the authority to retain, at the expense of the Corporation, outside advisors and consultants as it sees fit.

4. The Committee shall be the direct report for the external auditors, shall evaluate their performance and shall recommend their compensation to the Board.

B. STRUCTURE

1. The Committee shall be composed of such number of directors as may be specified by the Board from time to time, which number shall be not less than three.

2. At the first meeting of the Board following the Corporation's annual general meeting, Committee Members and the Committee Chair are appointed by the Board on the recommendation of the Corporate Governance, Compensation & Nominating Committee ("CGCN Committee").

3. Except to the extent that National Instrument 52-110 issued by the Canadian Securities Administrators or its successor instrument ("NI 52-110") contemplates that a member of the Committee need not be independent or unrelated, all Committee Members shall be determined by the Board to be independent and unrelated, as set forth in applicable securities laws, rules or guidelines of any stock exchange on which the securities of the Corporation are listed for trading, (which shall include, without limitation, NI 52-110), and have no relationship to the Corporation that may materially interfere with the member's ability to act with a view to the best interests of the Corporation.

4. All Committee Members shall possess sufficient financial literacy (as that term is defined in NI 52-110) to effectively discharge their responsibilities. At least one member of the Committee shall have a professional accounting designation or equivalent financial expertise as determined by the Board.

5. The Committee shall meet at least four times per year and may call other meetings as required.

6. The minutes of the Committee meetings shall accurately record the decisions reached and shall be distributed to Committee Members, and, as directed by the Committee, to other Board members, the Senior Vice President and Chief Financial Officer (herein the "CFO") and others.

C. DUTIES AND RESPONSIBILITIES

The Committee shall:

1. Review the annual audited financial statements including the notes thereto, management discussion and analysis, earnings press release and annual information form before such documents are submitted to the Board for approval, including any report or opinion to be rendered in connection therewith, and make recommendations as to their approval by the Board.

2. Review, and make recommendations for subsequent approval by the Board, to the quarterly financial statements including the notes thereto, management discussion and analysis and earnings press release of the Corporation.

3. Review with management, the external auditors and, if necessary, internal and external legal counsel, any material litigation, claim, compliance, regulatory or other contingency that could have a material effect upon the financial position or operating results of the Corporation and the manner in which these will be, or have been disclosed in the financial statements.

4. Review on a quarterly basis with the Senior Vice President and General Counsel, and if necessary, external legal counsel, the status of all material litigation, claim, compliance programs, regulatory or other contingency faced by the Corporation.

5. Review, or establish procedures for the review of, all public disclosure documents containing audited, unaudited or forward-looking financial information before release by the Corporation, including any prospectus, management information circulars, offering memorandums, annual reports, management certifications, management's discussion and analysis and annual information forms.

6. As required, review management's plans and strategies around investment practices, banking performance and treasury risk management.

7. Assess management's procedures to ensure compliance by the Corporation with its loan and indenture covenants and restrictions, if any.

8. Monitor the appropriateness of accounting policies and financial reporting used by the Corporation, review any actual and prospective significant changes in financial reporting and accounting policies and practices to be adopted by the Corporation and review and assess any new or proposed developments in accounting and reporting standards that may affect or have an impact on the Corporation.

9. Review and recommend the nomination of the external auditors to the Board for appointment by the shareholders at the Corporation's annual general meeting. In connection therewith, the Committee shall review the experience and qualifications of the external auditors' senior personnel who are providing audit services to the Corporation and the quality control procedures of the external auditors.

10. Review and discuss with the external auditors all relationships that the external auditors and their affiliates have with the Corporation and its affiliates in order to determine the independence of the external auditors, including, without limitation: (i) requesting, receiving and reviewing, at least annually, a formal written statement from the external auditors delineating all relationships that may reasonably be thought to bear on the independence of the external auditors with respect to the Corporation; (ii) discussing with the external auditors any disclosed relationships or services that the external auditors believe may affect the objectivity and independence of the external auditors;

(iii) recommending that the Board take appropriate action in response to the external auditors' report to satisfy itself of the external auditors' independence; and (iv) in discussions with the Board only, whether due to the passage of time or for other reasons it would be appropriate to change the external auditors or the audit engagement partner or retain such auditors for each future fiscal year, after consultation with appropriate management.

11. Review and:

    - recommend to the Board for approval, the compensation paid to the external auditors on an annual basis; and
    - pre-approve all non-auditing services performed by the external auditors in relation to the Corporation and its subsidiaries.

12. Oversee the work of the external auditor including review and approval of the planning of the annual audit and review the results thereof with the external auditors including:

    - approve the auditors' engagement letters;
    - approve the scope of the audit, including materiality, audit reports required, area of audit risk, timetable and deadlines;
    - review with the external auditors the quality, not just the acceptability, of the accounting principles applied in the Corporation's financial reporting and the degree of aggressiveness or conservatism of the Corporation's accounting principles and underlying estimates;
    - review the post-audit management letter together with management's responses;
    - review any other matters the external auditors bring to the attention of the Committee;
    - resolve disagreements with management regarding financial reporting;
    - review the use of any special purpose vehicles and/or off-balance sheet transactions;
    - review of accruals, reserves and estimates which have significant effect on financial results;
    - review the use of any "pro forma" or "adjusted" information not in accordance with GAAP; and
    - review interim review engagement reports.

    The Corporation's external auditors are ultimately accountable to the Board and the Committee as representatives of the shareholders, and shall report directly to the Committee.

13. Review the rationale for any proposed change in auditors which is not initiated by the Committee or the Board.

14. Review reports from external auditors respecting their internal quality control procedures, peer reviews and investigations by governmental or professional authorities.

15. Obtain and review annually, prior to the completion of the external audit, a report from the external auditors describing all critical accounting policies used by the Corporation in the preparation of its annual and interim financial statements; all alternative treatments of financial information within generally accepted accounting principles that have been discussed with management; ramifications of the use of such alternative disclosures and treatments; and the treatment preferred by the external auditors; and all other material written communications.

16. Obtain reasonable assurance from discussions with and/or reports from management and reports from external and internal auditors that the Corporation's accounting systems are reliable and that the prescribed internal controls are operating effectively.

17. Assess whether management has implemented policies ensuring that the Corporation's financial risks are identified and that controls are adequate, in place and functioning properly. In connection therewith, as part of the financial risk assessment, management will prepare tax compliance and planning strategies annually for review by the Committee, including a review of any tax reserves.

18. Monitor compliance with the Corporation's Compliance and Ethics Policy and to ensure Management Compliance Certificates are received from management quarterly.
19. Meet with the external auditors, at least annually and when requested by the auditors, without Management representatives present.
20. Meet with the internal auditors, at least annually or as requested by the auditors, without Management representatives present.
21. Review and ensure that appropriate liaison, cooperation exists where necessary between the external auditors and the internal auditors, and to provide a direct line of communication between the auditors and the Committee.
22. Review responses of Management to information requests from government or regulatory authorities in respect of filing documents required under securities legislation, which may affect the financial reporting of the Corporation.
23. Review and approve the annual internal audit plan, including the mandate, staffing, scope and objectives of the internal audit department, and receive and review all financial internal audit reports issued in relation thereto.
24. Receive and review all follow-up action or status reports relating to the non-financial recommendations of the external auditor, and the internal auditor.
25. Obtain such information and explanations regarding the accounts of the Corporation as the Committee may consider necessary and appropriate to carry out its duties and responsibilities.
26. Annually review the performance, budget and independence of the internal audit function and direct the CFO to make any changes necessary.
27. Establish procedures for receiving, retaining and responding to complaints relating to accounting or auditing matters, on a basis that protects the confidentially of the complainer.
28. Review and approve the hiring policies regarding employees and former employees of the present and former external auditors.
29. Periodically assess procedures for the review of disclosure of financial information, extracted or derived from the financial statements, other than the disclosure referred to in C.1 and 2 above,
30. Review disclosure made to the Committee by the President and CEO, CFO and/or Senior Vice President and General Counsel of a violation of applicable securities laws, a breach of a fiduciary duty under applicable laws or a similar violation by the Corporation or by any officer, director, employee or agent of the Corporation, which has been reported to the Committee, determine whether an investigation is necessary regarding any such report and report to the Board.
31. Receive, review and consider the annual and interim certificates provided by the President and CEO and CFO of the Corporation pursuant to NI 52-109 issued by the Canadian Securities Administrators or its successor instrument along with reports from the Corporation's Disclosure Committee regarding the design and effectiveness of the Corporation's disclosure controls and internal controls over financial reporting.
32. Conduct all other matters required by law or stock exchange rules to be dealt with by an audit committee.
33. Review annually the terms of reference for the Committee and to recommend any required material changes to the Board of Directors.
34. Conduct a regular, periodic self-assessment relating to Committee effectiveness and performance.
35. Report to the Board of Directors as required.

D. RISK MANAGEMENT

The Committee shall:

1. Review annually and discuss with Management the Corporation's policies and procedures for identifying and managing the principal risks of its business in order to ensure that Management:
   a. has identified appropriate business strategies taking into account the principal risks identified; and
   b. is maintaining systems and procedures to manage or mitigate those risks, including programs of loss prevention, insurance and risk reduction and disaster response and recovery programs;
2. Review and report to the Board, Management's quarterly risk assessment report including an update on residual risks, emergent risks and next steps;
3. Review annually the Corporation's enterprise risk management framework and reporting methodology;
4. Review annually the Corporations' Financial Exposure Management Policy ("FEMP") and associated commodity exposure management policies and approve all materials changes to such policies; review and authorize strategic hedging program guidelines and risk tolerance; review and monitor quarterly results of financial and commodity exposure management activities, including foreign currency and interest rate risk strategies, counterparty credit exposure and the use of derivative instruments;
5. Review the Corporation's annual insurance program, including the risk retention philosophy and resulting uninsured exposure and corporate liability protection programs for directors and officers including directors' and officers' insurance coverage;
6. Periodically consider the respective roles and responsibilities of the external auditor, the internal audit department, internal and external legal counsel concerning risk management of the Corporation and review their performance in relation to such roles and responsibilities; and
7. Annually, together with Management, report to the Board on:
   a. the Corporation's strategies in light of the overall risk profile of the Corporation;
   b. the nature and magnitude of all significant risks;
   c. the processes, policies, procedures and controls in place to manage or mitigate the significant risks; and
   d. the overall effectiveness of risk management processes including highlighting risk management problems and the actions that have been or will be taken to address them.

E. MEETINGS

1. Committee meetings may be called by the Committee Chair or by a majority of the Committee Members. In addition, the Committee Chair, shall call a meeting upon request of the external auditors. The Committee Chair shall be a voting member and questions will be decided by a majority of votes.
2. Meetings may be called with 24 hours' notice, which may be waived, before or after the meeting, by members. Attendance at a meeting shall be deemed to be waiver of notice of the meeting except where the Committee Member attends the meeting for the express purpose of objecting to the transaction of business on the grounds that the meeting has not been duly called. All Committee Members are entitled to receive notice of every meeting.
3. Meetings are chaired by the Committee Chair or in the Committee Chair's absence, by a member chosen by the Committee amongst themselves.
4. Agendas will be set by the Committee Chair with such assistance as the Committee Chair may request from the President and CEO, Senior Vice President and Corporate Secretary, CFO and auditors, and will be circulated with the materials for consideration at the meeting by the Committee Chair or the Corporate Secretary to all members and, if directed by the Committee Chair, to the Chair of the

Board, the President and CEO, the Senior Vice President and Corporate Secretary and the CFO, no later than the day prior to the date of the meeting. However, it should be standard practice to deliver the agenda and draft materials for consideration at the meeting at least five business days prior to the proposed meeting except in unusual circumstances.

5. Except as provided in these Terms of Reference, the Chair of the meeting may establish rules of procedure to be followed at meetings.

6. Meetings may be conducted with the participation of a member by telephone which permits all persons participating in the meeting to hear or communicate with each other. A member participating in a meeting by that means is deemed to be present at the meeting.

7. The powers of the Committee may be exercised at a meeting at which a majority of the Committee Members are present or by resolution in writing signed by all Committee Members who would have been entitled to vote on the resolution at a meeting of the Committee. In case of an equality of votes, the person acting as Chair of the Committee meeting shall not be entitled to a second or casting vote.

8. A resolution in writing may be signed and executed in separate counterparts by Committee Members and the signing or execution of a counterpart shall have the same effect as the signing or execution of the original. An executed copy of a resolution in writing or counterpart thereof transmitted by any means of recorded electronic transmission shall be valid and sufficient.

9. Attendance at all or a portion of Committee meetings by staff, other directors, the auditors and others, will be determined by the Committee.

10. The Corporate Secretary, or such other person as may be designated by the Committee, shall keep minutes of the proceedings of all meetings of the Committee, which following Committee approval, are, subject to determination by the Committee otherwise, available to any member of the Board. All minutes will be circulated to the Chair of the Board. With the exception of "in camera" items, minutes will be circulated to those receiving the agenda. Minutes will be retained by the Executive Assistant to the Board.

11. The Committee may delegate its power and authority to individual members of the Committee, where the Committee determines it is appropriate to do so in order for necessary decisions to be made between meetings of the Committee and where such delegation is permitted by law. Any such decisions shall be reported to the Committee at its next meeting.

CERTIFICATE OF CAPITAL POWER CORPORATION AND THE PROMOTER

Dated: June 25, 2009

The prospectus constitutes full, true and plain disclosure of all material facts relating to the securities offered by this prospectus as required under the securities legislation of each of the provinces and territories of Canada.

(Signed) BRIAN TELLEF VAASJO
President and Chief Executive Officer

(Signed) STUART ANTHONY LEE
Senior Vice President and Chief Financial Officer

On behalf of the Board of Directors

(Signed) BRIAN TELLEF VAASJO
Director

(Signed) STUART ANTHONY LEE
Director

(Signed) KENNETH DOUGLAS CORY
Director

PROMOTER

EPCOR Utilities Inc.

By: (Signed) MARK D. WILTZEN
Senior Vice President and Chief Financial Officer

CERTIFICATE OF THE UNDERWRITERS

Dated: June 25, 2009

To the best of our knowledge, information and belief, this prospectus constitutes full, true and plain disclosure of all material facts relating to the securities offered by this prospectus as required under the securities legislation of each of the provinces and territories of Canada.

TD SECURITIES INC.

By: (Signed) HAROLD R. HOLLOWAY

GOLDMAN SACHS CANADA INC.

By: (Signed) MICHAEL L. FREEBORN

RBC DOMINION SECURITIES INC.

By: (Signed) DAVID DAL BELLO

CIBC WORLD MARKETS INC.

By: (Signed) PAUL LANGLEY

BMO NESBITT BURNS INC.

By: (Signed) AARON M. ENGEN

SCOTIA CAPITAL INC.

By: (Signed) THOMAS I. KURFURST

NATIONAL BANK FINANCIAL INC.

By: (Signed) IAIN WATSON

HSBC SECURITIES (CANADA) INC.

By: (Signed) ROD MCISAAC

CAPITAL POWER

			Electric Capacity	Economic Interest of Capital Power LP	Location	Type	Major Equipment	Commercial Operations	Power Purchase Arrangements	PPA Counter-Party	PPA Counter Party Credit Rating	Fuel Purchase Agreements	Fuel Supply
CAPITAL POWER LP	Alberta	Contracted	Genesee 1	410 MW	100%	Warburg Genesee	Coal-fired steam turbine	Pulverized coal-fired pressure boiler, steam turbine	1994	PPA (expiry 2020)	Balancing Pool of Alberta	AAA	GCM[2]	GCM
			Genesee 2	410 MW	100%	Warburg Genesee	Coal-fired steam turbine	Pulverized coal-fired pressure boiler, steam turbine	1989	PPA (expiry 2020)	Balancing Pool of Alberta	AAA	GCM[2]	GCM
		Commercial	Genesee 3	495 MW	50% — operator (50% TransAlta Corp)	Warburg Genesee	Supercritical coal	Supercritical sliding pressure boiler, steam turbine	2005	Merchant	Merchant	n/a	GCM[2]	GCM
			Joffre	480 MW	40% (40% ATCO — operator, 20% NOVA)	Near Red Deer	Cogeneration natural gas-fired (combined cycle)	Two CTs, Two 173 MW HRSGs, 133 MW steam turbine, VHP boiler	2000	EPA for 100 MW and 50 MW of Merchant	NOVA and Merchant	CCC+	Open Market Acquisitions	Open Market Acquisitions
			Clover Bar Energy Centre Unit 1	43 MW	100%	Edmonton	Natural gas-fired (simple cycle)	Natural gas-fired turbine generator	2008	Merchant — Tolling Agreement with EMC	Merchant	n/a	Open Market Acquisitions	Open Market Acquisitions
			Taylor Coulee Chute	13 MW	50% (50% Canadian Hydro Developers)	Near Lethbridge	Hydroelectric	Horizontal Kaplan turbine	2000	Merchant	Merchant	n/a	n/a	Alberta Government
			Clover Bar Landfill Gas Plant	5 MW	100%	Edmonton	Landfill gas-fired	Three 1.6 MW reciprocating landfill natural gas-fired engines	2005	Merchant	Merchant	n/a	n/a	COE
			Weather Dancer	1 MW	99%[3]	Near Brockett	Wind	900 kW wind turbine	2001	Merchant	Merchant	n/a	Conditional License (no expiry)	n/a
	Ontario		Kingsbridge I	40 MW	100%	Goderich	Wind	Twenty two 1.8 MW wind turbines One 0.7 MW wind turbine	2006	PPA 1.8 MW turbines expiry 2026 0.7 MW turbine expiry 2027	OPA	AA (low)	n/a	n/a
	British Columbia		Miller Creek	33 MW	100%	Pemberton	Run-of-river hydroelectric	30 MW turbine, 3 MW turbine	2003	EPA (expiry 2023, extendable to 2033 at BCH's option)	BCH	AA (high)	Conditional License (no expiry)	BC Government
			Brown Lake	7 MW	100%	Near Prince Rupert	Run-of-river hydroelectric	Horizontal turbine generator, 600m water tunnel, substation	1996	EPA (expiry 2016)	BCH	AA (high)	n/a	BC Government
	Projects under Construction		Keephills 3	495 MW	50% (50% TransAlta — operator)	Keephills, Alberta	Supercritical coal	Supercritical sliding pressure boiler, steam turbine	2011	Merchant	Merchant	n/a	n/a	n/a
			Clover Bar Energy Centre Expansion	200 MW	100%	Edmonton, Alberta	Natural gas-fired (simple cycle)	Two 100 MW natural gas turbine generators	2009 2010	Merchant	Merchant	n/a	Open Market Acquisitions	Open Market Acquisitions
EPLP[1]	Ontario		Tunis	69 MW	30.6%	Iroquois Falls	Enhanced combined cycle natural gas-fired generation	31 MW gas turbine, 17 MW steam turbine, four HRSGs	1995	20-year term expiring in 2014	OEFC	AA	Natural gas supply agreements for 15-year terms expiring in 2010 and 2011, respectively	Devon NAL
			Nipigon	44 MW	30.6%	Nipigon	Enhanced combined cycle natural gas-fired generation	22 MW natural gas turbine, 18 MW steam turbine, three HRSGs	1992	20-year term expiring in 2012	OEFC	AA	Natural gas supply agreements for 21-year terms expiring in 2012	NAL Petrobank
			Kapuskasing	62 MW	30.6%	Kapuskasing	Enhanced combined cycle natural gas-fired generation	25 MW natural gas turbine, 20 MW steam turbine, three HRSGs	1997	20-year term expiring in 2017	OEFC	AA	Natural gas supply agreement for 20-year term expiring in 2017	TCPM
			North Bay	64 MW	30.6%	North Bay	Enhanced combined cycle natural gas fired generation	25 MW natural gas turbine, 20 MW steam turbine, two HRSGs	1997	20 year term expiring in 2017	OEFC	AA	Natural gas supply agreement for 20-year term expiring in 2017	TCPM
			Calstock	40 MW	30.6%	Hearst	Enhanced biomass wood waste generation	Wood waste boiler, 41 MW steam turbine, two HRSGs	2000	20-year term expiring in 2020	OEFC	AA	Wood waste agreements with five local mills for 20-year terms expiring in 2019	Tembec, Lecours, Columbia, Haavaldsrud, White River, Longlac[4]
	British Columbia		Williams Lake	68 MW	30.6%	Williams Lake	Biomass wood waste generation	Wood waste boiler, 66 MW steam turbine	1993	25-year term expiring in 2018 with an option for BCH for two extensions of five years each	BCH	AA (high)	Five wood waste agreements for 25 years expiring in 2018, two agreements expiring in December 2008 and several other periodic suppliers	Tolko, West Fraser, others
			Mamquam	52 MW	30.6%	Squamish	Hydroelectric run-of-river	Two hydroelectric turbines	1996	30-year term expiring in 2027[5]	BCH	AA (high)	Conditional water licenses (no expiry and expiry in 2048)	BC Government
			Queen Charlotte	6 MW	30.6%	Moresby Island	Hydroelectric reservoir-based station	Three hydroelectric turbines	1990	22-year term expiring in 2022	BCH	AA (high)	Conditional water licenses (no expiry)	BC Government
	Northwest U.S.		Manchief	301 MW	30.6%	Brush, Colorado	Simple-cycle natural gas-fired generation	Two gas turbines	2000	Original 11-year term with 10-year renewal expiring in 2022[6]	PSCo	BBB+	PSCo is responsible for the fuel supply	n/a
			Frederickson	249 MW + 20 MW duct firing	15.3% (50.15% EPLP, 49.85% Puget Sound Energy)	Pierce County, Washington	Combined cycle natural gas-fired generation	166 MW combustion turbine, 88 MW steam turbine	2002	20-year term expiring in 2022	Three PUDs[7]	A	PUDs are responsible for fuel supply	n/a
			Greeley	101 MW / (170 mlbs/hr)[11]	30.6%	Greeley, Colorado	Natural gas-fired CHP facility	Two 35 MW natural gas turbines, 12 MW steam turbine, two HRSGs	1988	2013	PSCo	BBB+	Natural gas is purchased on a daily or monthly basis	SENA
	California		Oxnard	49 MW / (120 mlbs/hr)[11]	30.6%	Oxnard	Natural gas-fired CHP facility	49 MW gas turbine, one HRSG, one AAARP	1990	2020	SCE	BBB+	Month-to-month natural gas supply	SETC
			Naval Station	54 MW / (479 mlbs/hr)[11]	30.6%	San Diego	Dual-fuel (natural gas or No. 2 distillate fuel oil) CHP facility	37 MW gas turbine, 10 MW steam turbine, one HRSG	1989	2019	SDG&E	A+	Month-to-month natural gas supply	SETC
			North Island	51 MW / (390 mlbs/hr)[11]	30.6%	San Diego	Natural gas-fired CHP facility	36 MW gas turbine, 4 MW steam turbine, one HRSG	1989	2019	SDG&E	A+	Month-to-month natural gas supply	SETC
			Naval Training Center	28 MW / (220 mlbs/hr)[11]	30.6%	San Diego	Dual-fuel (natural gas or No. 2 distillate fuel oil) CHP facility	22 MW gas turbine, 2.5 MW steam turbine, one HRSG	1989	2019	SDG&E	A+	Month-to-month natural gas supply	SETC
	Northeast U.S.		Morris	177 MW	30.6%	Morris, Illinois	Natural gas-fired cogeneration	Three turbine generators, three steam generators	1998	30-year term expiring in 2023 (77 MW of electricity and 100% of steam generation)/100 MW under PPA until 2011	Equistar (77 MW) Exelon (100 MW)	D	Energy Services Agreement until 2016	TPS
			Kenilworth	30 MW (78 mlbs/hr)[11]	30.6%	Kenilworth, New Jersey	Natural gas-fired CHP facility	23 MW natural gas turbine, 7 MW steam turbine, one HRSG	1989	2012	Schering	A−	Month-to-month natural gas supply	SETC[8]
			Curtis Palmer	60 MW	30.6%	Hudson River near Corinth, New York	Hydroelectric impoundment and run-of-river	Seven turbines	1986[9]	42-year term expiring in 2027 or delivery of 10,000 GWh	Niagara	A−	n/a	n/a
	North Carolina		Roxboro	54 MW / (540 mlbs/hr)[11]	30.6%	Roxboro	Coal, tire-derived fuel and wood waste CHP facility	Three stoker boilers, 57.4 MW steam turbine	1987	2009	CP&L	BBB+	Annual[10]	Various
			Southport	109 MW / (1,080 mlbs/hr)[11]	30.6%	Southport	Coal, tire-derived fuel and wood waste CHP facility	Six stoker boilers, two 57.4 MW steam turbines	1987	2009	CP&L	BBB+	Annual[10]	Various

The legal names of the respective counterparties are:

ATCO — ATCO Power Canada Ltd.
BCH — British Columbia Hydro and Power Authority
COE — City of Edmonton
CP&L — Carolina Power & Light Company
Devon — Devon Canada Corporation
EMC — EPCOR Merchant and Capital L.P.
EPLP — EPCOR Power L.P.
Equistar — Equistar Chemicals, LP
Exelon — Exelon Generation Company, LLC
GCM — Genesee Coal Mine, a joint venture between EPCOR and Prairie Mines & Royalty (PMRL)
NAL — NAL Resources Ltd.
Niagara — Niagara Mohawk Power Corporation
NOVA — Nova Chemicals Corporation
OEFC — Ontario Electricity Financial Corporation
OPA — Ontario Power Authority
Petrobank — Petrobank Energy and Resources Ltd.
PSCo — Public Service Company of Colorado
SCE — Southern California Edison Company
Schering — Schering-Plough Corporation
SDG&E — San Diego Gas & Electric Company
SENA — Shell Energy North America (US) L.P.
SETC — Sempra Energy Trading Corporation
TCPM — TransCanada Power Marketing Ltd.
TPS — Tenaska Power Services

Technical Abbreviations:

AAARP — Anhydrous Ammonia Adsorption Refrigeration Plant
CHP — Combined Heat and Power
CT — Combustion Turbine
EPA — Electricity Purchase Agreement
GWh — Gigawatt Hour
HRSG — Heat Recovery Steam Generator
kW — Kilowatt
mlbs/hr — Million Pounds Per Hour
MW — Megawatt
PPA — Power Purchase Agreement
PUD — Public Utility District
VHP — Very High Pressure

(1) Operated by Capital Power Corporation
(2) Coal provided by GCM on a cost of service basis for duration of operations
(3) Joint Venture with Peigan Indian Utility Corporation
(4) Longlac's supply contract has expired, however EPLP continues to receive supply from this facility
(5) BCH has option exercisable in 2022 and every five years thereafter to buy the Mamquam facility or extend the contract
(6) PSCo has option during latter part of extension term to purchase the Manchief facility
(7) Public Utility Districts include: Benton, Franklin and Grays Harbor
(8) Natural gas is purchased from a local gas distribution company and Sempra Energy Corporation
(9) Curtis Palmer facilities were re-powered in 1986
(10) Approximately 80% of the fuel requirements are satisfied with coal, with the balance from tire-derived fuel and waste wood. The anticipated coal requirements for 2009 and approximately half of 2010 requirements will be purchased under existing fixed price contracts with regional coal suppliers
(11) Thermal capacity

A leading power generation company

Capital Power Corporation

Headquartered in Edmonton, Alberta, Capital Power draws on a 118-year heritage of innovation and reliability and a history of developing, acquiring, operating and optimizing power generation from a diverse range of energy sources.

Capital Power has interests in 31 facilities across North America, with:

- approximately 3,300 megawatts (MW) of owned and/or operated power generation capacity;
- 470 MW of capacity owned through power purchase agreements (PPAs); and
- 448 MW of owned capacity under construction.

Capital Power corporate strengths:

- Large, high quality generation portfolio;
- Modern fleet with excellent operating history;
- Diversified portfolio in attractive North American markets;
- Long-term contracts including PPAs provide predictable cash flows and financial stability;
- Environmental leadership;
- Outstanding platform for growth; and
- Experienced senior management team with a track record of disciplined growth.

Capital Power Corporation

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