Management's discussion and analysis

This management's discussion and analysis (MD&A) dated March 13, 2009 should be read in conjunction with the audited consolidated financial statements of EPCOR Utilities Inc. and its subsidiaries for the years ended December 31, 2008 and 2007 and the cautionary statement regarding forward-looking information on page 69 of this MD&A. In this MD&A, any reference to "the Company", "EPCOR", "we", "our" or "us", except where otherwise noted or the context otherwise indicates, means EPCOR Utilities Inc., together with its subsidiaries. In accordance with its terms of reference, the Audit Committee of the Company's Board of Directors reviews the contents of the MD&A and recommends its approval by the Board of Directors. The Board of Directors has approved this MD&A.

OVERVIEW

EPCOR is wholly-owned by The City of Edmonton. EPCOR builds, owns and operates power plants, electrical transmission and distribution networks, water and wastewater treatment facilities and infrastructure in Canada and the United Sates (U.S.). We also provide energy and water services to residential and commercial customers. Our power and water businesses consist of a mix of regulated, contracted and merchant operations, and our trading group manages the underlying energy commodity and emission portfolios. EPCOR also has electricity generation operations in California, Colorado, New Jersey, New York State, North Carolina, Washington State, Illinois and Indiana, through its investment in 30.6% of the outstanding units of EPCOR Power L.P. (Power LP). Through its subsidiaries, EPCOR is contracted as Power LP's manager and operator.

Net income for the year ended December 31, 2008 was $175 million compared with $277 million for 2007. As more fully described later in this MD&A, the results for 2008 were lower than 2007 primarily due to maintenance outages at our Genesee facilities and asset impairment charges. Aside from these items, EPCOR's results were consistent with our 2008 plan.

In the first half of 2008, EPCOR was able to achieve its results in part through strong commodity management. It was a period of high power prices in Alberta and the length in our electricity portfolio resulted in positive contributions that partially offset the impact of three major maintenance turnarounds at our Genesee facilities. The turnarounds were for required maintenance and were scheduled back-to-back to accommodate the Alberta Electric System Operator's upgrade of the new high-voltage transmission lines in the Genesee and Keephills area. Due to high Alberta power prices at the time, replacement power was costly and significant availability penalties under the terms of the Genesee Power Purchase Arrangement (PPA) were incurred.

In the third quarter, the Genesee plants were back on line and results from operations returned to more normal levels. However, on October 10, 2008, a turbine blade failure occurred at the Genesee 3 plant which we own jointly with TransAlta Utilities Corporation (TransAlta), and the plant was unavailable for 39 days. The reduction in generation resulted in approximately $15 million of lost net income. The impact of the Genesee 3 outage was partly offset by gains from our commodity positions due to continuing high Alberta power prices which averaged $95 per megawatt hour (MWh) in the fourth quarter.

Our capital program was marked by the successful completion of the following projects: the first unit of the Clover Bar Energy Centre, the E.L. Smith water treatment plant upgrade and the Downtown

Edmonton Supply and Substation transmission line (DESS). Construction continues on the remaining two units at Clover Bar Energy Centre and the Keephills 3 power plant (jointly owned with TransAlta). These projects have experienced cost increases and schedule delays. However, EPCOR management is working to minimize further cost increases.

In 2008, we received final decisions from the Alberta Utilities Commission (AUC) for our 2007-2009 rate applications for Regulated Rate Tariff (RRT) non-energy charges and Distribution and Transmission tariffs. The Distribution and Transmission approved rates were higher than the interim rates and the associated revenue adjustments were recorded in the third quarter. Although the final rates for RRT non-energy charges were lower than interim rates, the revenue adjustment was not material and we managed our costs to the new rates.

In the fourth quarter we recognized an impairment loss of $28 million on the goodwill associated with our investment in Power LP. This reduction in value of the premium that we paid for our investment in Power LP is primarily a reflection that current economic conditions are substantially different than they were in September 2005, when we acquired our Power LP units. In our opinion, the write-down is not a reflection of future prospects for Power LP's plant operations or cash flows which are supported by long-term sales contracts. Power LP contributed a net loss in 2008 due to decreases in the fair value of its forward foreign exchange contracts, translation of its U.S. dollar-denominated debt and an impairment of its 15.4% equity investment in Primary Energy Recycling Holdings LLC (PERH).

Despite the deterioration of capital markets, we raised $600 million in medium-term notes by April 2008. The proceeds from these financings were used to repay short-term and maturing long-term indebtedness, to fund a portion of the 2008 capital program and for general corporate purposes. In December 2008, we negotiated a $600 million liquidity credit facility that expires in December 2009 and draws under this facility will be used for general corporate purposes. The Asset Backed Commercial Paper (ABCP) restructuring plan took effect on January 21, 2009 whereby our investment in ABCP was exchanged for new floating rate long-term notes. A fair value loss of $7 million on our ABCP was recognized in the fourth quarter of 2008 ($18 million for the full year), due to increased credit spreads and changes in assumptions about recovery.

STRATEGY

In the opinion of EPCOR management, the long-term outlook for the power and water industries of North America remains relatively strong. The current economic recession combined with the weakness of credit markets has resulted in a reduction in demand for electricity and the cancellation and deferral of new projects across North America. On a more positive note, the current recession may result in greater availability of labour and equipment, which have challenged the schedule and cost of our plants under construction. Over the longer term, with economic recovery, the demand for power is expected to grow and the demand for new generation capacity is expected to be greater due to expected plant retirements across North America. Similarly, the demand for water and wastewater infrastructure in North America is also expected to increase due to population growth, aging infrastructures, reduced water supply and increased expectations for quality.

EPCOR's vision is to become a premier essential services utility in North America. To achieve this vision, EPCOR must excel at its existing power and water operations and win new business growth opportunities. EPCOR's power strategy includes developing or acquiring large, conventional fossil fuel generation, specifically supercritical coal, natural gas combined cycle and natural gas simple cycle technologies, augmented by large-scale renewable and cogeneration facilities. EPCOR's water strategy is to focus on: (a) developing municipal infrastructure; (b) providing design, build, finance and operate services for water and wastewater treatment and distribution infrastructure; and (c) providing potable and process water and wastewater treatment for industrial customers. Subject to acceptable business risk and the availability of financing, we intend to increase net income and shareholder value by growing our portfolio of power and water assets in both our regulated and competitive businesses.

Over the next five years, we will focus on investment opportunities in essential infrastructure in the water, wastewater and power sectors, including commercial, regulated and contracted facilities. We intend to take a measured approach as environmental regulations for greenhouse gas emissions solidify and capital costs stabilize. We expect our regulated business investment opportunities to be in water distribution infrastructure upgrades, transmission infrastructure development and power distribution system upgrades.

We have modified our near-term strategy in light of current economic uncertainties by reducing our planned rate of growth. We will continue work to complete construction of projects already underway and to complete the transfer and integration of the Gold Bar Wastewater Treatment Plant (Gold Bar) operation from The City of Edmonton. We will only invest in new generation or water assets in the short term where appropriate returns are expected, cost effective financing is available and the environmental footprint is acceptable. This will include taking advantage of opportunities for potential distressed asset purchases that the current economy may produce. We plan to continue to increase our operating efficiency. As a utility with regulated and contract operations based in Alberta, we believe we are in relatively good shape to withstand the impact of the current economic recession, although we will remain vigilant to minimize the risk of growing beyond our financial means.

KEY PERFORMANCE INDICATORS

Our performance in meeting the goals of our strategy is measured through both financial and non-financial measures that are approved by the Board of Directors. The measurement categories include such items as net income, operational excellence, safety, business development and reputation, and are generally common to all of our business units operating within each business segment, and our shared service units.

Within each category, there are specific measures established for each business unit and shared service unit that are important to the results of the respective unit and in alignment with the Company's strategy. For example, in Generation, plant availability is a key measure of operational excellence. In the customer service area of Energy Services, a key operational measure relates to call answer and handle times. Environment and safety performance are measured based on outcomes (for example, the number of incidents and accidents) and proactive activities (for example, applicable training) that are designed to minimize the potential for negative events such as lost time accidents or environmental incidents. Business unit measures under the reputation category are focused on customer related measures relevant to the particular business unit, such as customer satisfaction or reputation survey results.

In 2008, EPCOR's financial results were on plan aside from the asset impairments and the impact of planned and unplanned outages at our Genesee facilities. The unplanned outage at Genesee 3 also resulted in Generation's failure to meet its overall plant availability target for the year. Generation's plants, excluding Power LP's plants, achieved a combined availability factor of 88.8% (2007 – 96.5%)

compared with a target of 90.7% (2007 – 91.4%). We missed some of our construction project deadlines, but otherwise we met all of our other non-financial performance measures. We were particularly successful in our safety performance as we significantly reduced our lost time injury frequency and performed better than target and the previous year. Segment performance measures are also discussed by segment under "Segment Results" of this MD&A.

SIGNIFICANT EVENTS

Sale of percentage interest in power syndicate agreement

On January 15, 2008, we sold a 10% interest in the Battle River Power Syndicate Agreement (PSA) for cash proceeds of $53 million resulting in a pre-tax gain of $34 million. The associated income taxes were $4 million of expense, and $6 million of refundable taxes which were charged to retained earnings. This sale was pursuant to the purchase and sale agreement entered into in June 2006 whereby EPCOR will sell its Battle River Power Purchase Arrangement (PPA) and related interest in the Battle River PSA to ENMAX Corporation over a four-year period ending in January 2010. An initial interest of 55% was sold for cash proceeds of $343 million on June 5, 2006 followed by the sale of a 10% interest on January 1, 2007 for cash proceeds of $59 million. The after-tax gains on sale were the same for both 2008 and 2007.

Financings

On January 31, 2008, the Company completed a $200 million public offering in Canada of unsecured medium-term note debentures with a coupon rate of 5.80% and maturity date of January 31, 2018. Net proceeds from the offering were used to repay EPCOR's short-term indebtedness and for general corporate purposes.

On April 15, 2008, the Company completed a $375 million public offering of unsecured medium-term note debentures consisting of issues of $200 million and $175 million. On April 28, 2008 the Company completed an additional issue of $25 million of unsecured medium-term note debentures. The $200 million issue has a coupon rate of 5.80% and a maturity date of January 31, 2018. The $175 million and $25 million issues have a coupon rate of 6.65% and a maturity date of April 15, 2038. Net proceeds from these offerings were used to repay short-term indebtedness, to repay debentures which matured in June 2008, to fund a portion of the 2008 capital program and for general corporate purposes.

On December 19, 2008, the Company arranged a $600 million 364-day liquidity credit facility. The facility was arranged to provide financing capability while the credit markets remain uncertain. Draws under the facility will be used for general corporate purposes.

New turbine at Clover Bar Energy Centre

During the first quarter of 2008, a new 43-megawatt (MW) natural gas-fired turbine commenced operations at our Clover Bar Energy Centre. The unit is the first of three new turbines being installed at the site and the net capacity upon completion of all three units will be 243 MW. Installation of one of the remaining two 100-MW units is planned for completion in 2009 and the other in 2010. These new high-efficiency units are designed to use 85% less water and produce 70% less nitrogen oxides (NOx) than the four turbines in the old Clover Bar plant which was decommissioned in 2007. The expected cost of the full project is $284 million.

Opening of the upgraded E.L. Smith water treatment plant

On June 20, 2008, the Company officially opened the newly upgraded E.L. Smith water treatment plant. The upgrades, which cost approximately $140 million, are designed to increase drinking water supply by 25% for Edmonton and the capital region, and are expected to meet demand until at least 2023. The water rate increases that were previously approved by The City of Edmonton Council for 2007 and 2008 under the performance-based rates bylaw include costs associated with the E.L. Smith water treatment plant upgrade.

Power LP acquisition of Illinois co-generation facility

On September 11, 2008, Power LP entered into an agreement to acquire a 100% equity interest in Morris Cogeneration LLC (Morris) from Diamond Generating Corporation and MIC Nebraska, Inc., both wholly-owned subsidiaries of Mitsubishi Corporation. The aggregate purchase price was $89 million (US$74 million). The acquisition closed on October 31, 2008 and was financed under the Power LP's existing credit facilities. Due to the short time frame between closing of the Morris transaction and release of the financial statements, the fair value estimates of certain assets and liabilities are preliminary and are anticipated to be finalized in the first quarter of 2009. Finalization of the fair value estimates could result in material adjustments to the fair value purchase price allocation in subsequent periods.

Morris owns a 177-MW natural gas-fired cogeneration facility located on Equistar Chemicals LP's (Equistar) chemical plant site in Morris, Illinois. Equistar, a wholly-owned subsidiary of LyondellBasell AF S.C.A. (LyondellBasell), produces ethylene and its co-products and derivatives including polyethylene plastic, at its plant in Morris. Morris also has an electric capacity agreement with Exelon Generation Company, LLC (Exelon) that terminates in 2011, for capacity and electricity of 100 MW. Any excess capacity and energy above the needs of Exelon and Equistar may be sold into the Pennsylvania, New Jersey, and Maryland markets.

On January 6, 2009, Equistar, along with LyondellBasell's other North American operating entities, filed a voluntary petition for reorganization under Chapter 11 of the U.S. Bankruptcy Code. Under the provisions of the U.S. Bankruptcy Code, Equistar obtained approval to make payments for post-petition services. As a result, Equistar's operations at Morris have not been affected to date and Equistar has made payments for post-petition services.

All of the steam and a portion of the electricity produced by Morris are sold to Equistar under the terms of a long-term energy services agreement (ESA) which expires in 2023. The ESA is an "executory contract" under the U.S. Bankruptcy Code, which Equistar may either assume or reject. Management believes that it is likely that the ESA will be assumed as part of Equistar's plan of organization.

Power LP goodwill impairment

EPCOR's recognized goodwill was primarily acquired with the purchase of its interest in Power LP in September 2005 and Power LP's purchase of Primary Energy Ventures LLC (Primary Energy Ventures) in 2006, representing the difference between the purchase price and the fair value of the underlying net assets. In the fourth quarter of 2008, as determined by our 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 (DCF) 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. Our estimates of the future cash flows from Power LP's plant operations did not change materially from the previous year as Power LP's reliable 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 and investors' expectations, 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 our DCF analysis, we also considered the year-end Power LP unit price, which has decreased with capital markets generally. Since the fair value estimate is subject to significant risks and uncertainties, it could change materially in the future.

Asset-backed commercial paper

At December 31, 2008, the Company held $42 million ($71 million original cost) in Canadian non-bank sponsored ABCP, all of which was purchased during the third quarter of 2007. The Company's ABCP is part of the broader ABCP market that was disrupted by the significant lack of liquidity that emerged in August 2007 and as a result, all of the Company's ABCP matured with no payment of principal or accrued interest.

An Investors Committee comprised of a consortium representing banks, asset providers and major investors, oversaw the proposed restructuring of the ABCP. In March 2008, the Investors Committee distributed to affected ABCP investors an information package and voting materials in respect of the restructuring and on April 25, 2008, ABCP investors voted in favour of the proposed restructuring plan. In June 2008, the judge presiding over the restructuring process ruled that the restructuring plan was fair after giving effect to amendments to the restructuring to allow for certain claims for fraud. In September and October 2008, appeals to the Ontario Appeals Court and Supreme Court of Canada by certain ABCP note holders were heard and denied. This final decision cleared the way for the restructuring to proceed. On December 24, 2008, the Investors Committee announced that an agreement had been reached with all key stakeholders, including the governments of Canada, Quebec and Alberta, which will provide additional margin facilities and further enhancements to support the restructuring. On January 21, 2009, the restructuring was implemented.

Under the restructuring, the affected ABCP was exchanged on January 21, 2009 for term floating-rate notes (notes) maturing no earlier than the scheduled termination dates of the underlying assets. The key information related to EPCOR's new notes is as follows:

(i) EPCOR's allocation of new notes under the restructuring is as follows:

Pool	**Series**	**Rating**	**Amount** ($ millions)	
MAV2	Class A-1	A	$ 47	67%
	Class A-2	A	9	13%
	Class B	Unrated	2	2%
	Class C	Unrated	2	2%
MAV3	IA Tracking	Unrated	11	16%
			$ 71	100%

(ii) For the Master Asset Vehicle 2 (MAV2) pool notes (84% of the new notes EPCOR received), the underlying asset lives are anticipated to average nine years. The remaining notes came from Master Asset Vehicle 3 (MAV3) in the form of Ineligible Asset Tracking (IA Tracking) notes which represent 16% of EPCOR's new notes. These notes are expected to amortize over the lives of the underlying assets which have a weighted average life of approximately 18 years. In certain limited circumstances, the expected repayment dates could be longer than the expected asset lives.

(iii) ABCP investors, including EPCOR, will be paid the accumulated accrued interest, net of restructuring costs, collateral requirements and other costs, on their existing ABCP from the date of the standstill in August 2007 to the date of the restructuring. EPCOR received its share of accumulated accrued interest, net of restructuring costs, of approximately $2 million after January 21, 2009.

(iv) The costs of the restructuring are factored into but are not material to our valuation.

(v) The March 2008 note-holder information included indicative valuation data on the various ABCP conduits which was used by the Investors Committee for allocating the existing notes among the classes and series of new notes. EPCOR considered this information in assessing its valuation.

Aside from the timing of the implementation (previously expected to be in November 2008) and additional credit enhancements announced in December 2008, the restructuring is substantially the same as that approved by the ABCP investors in June 2008 and used in our estimate of the fair value at September 30, 2008.

At December 31, 2008, EPCOR's ABCP financial instruments were classified as held for trading and therefore were recorded at fair value. EPCOR's estimate of the fair value of its ABCP at December 31, 2008 was $42 million compared with $60 million at December 31, 2007. The estimated fair value decreased by $18 million primarily due to lower interest rates, higher observed and estimated credit spreads over the yields of long-term Government of Canada bonds and the longer lives of the new notes. EPCOR estimated the fair value using a probability-weighted discounted cash flow approach based on the assumed credit ratings and potential ratings actions on the applicable new notes under the ABCP restructuring, observable interest rates and credit spreads for estimating future interest payments and applicable discount rates, the cost of margin call facilities, the cost of the restructuring, estimated recovery periods based on the estimated lives of the underlying assets associated with the new notes and ranges of recoverability based on publicly available default statistics for credit-rated entities. The fourth quarter decrease in the estimated fair value of ABCP was $7 million in 2008 (2007 - $7 million) primarily due to higher observed and estimated credit spreads over the yields of long-term Government of Canada bonds.

In estimating future cash flows from the new notes, the Company assumed that it will earn interest at rates ranging from 1.00% to 12.50% (weighted average rate of 2.82%) depending on the note series, taking into account restructuring costs and margin funding. The future cash flows were discounted at rates ranging from 7.93% to 46.70% (weighted average rate of 15.20%), depending on the note series, over 8.1 to 26.0 years (weighted average amortization period of 9.2 years), taking into account the assumed credit spreads and mortality rates. In estimating future cash flows from the new notes, the Company also assumed that cash flows from MAV2 Class B and Class C notes would be nil due to their subordination to the MAV2 Class A notes.

The estimate of fair value of ABCP (new notes after January 21, 2009) is subject to significant risks and uncertainties including the timing and amount of future cash payments, market liquidity, the quality and tenor of the assets and instruments underlying the new notes, including the possibility of margin calls and the future market for the restructured notes. Accordingly, the fair value estimate of the new notes may change materially. As the estimate of fair value of ABCP (new notes) is not solely based on market data, changing one or more of the assumptions to other reasonably possible alternative assumptions could change the fair value and correspondingly, net income. The sensitivity of the estimated fair value to changes in our key valuation assumptions, holding all other assumptions constant is as follows:

Assumption	Change	Impact on estimated fair value and net income ($ millions)
Amortization term	+/- 1 year	-/+ $1
Interest rate on floating rate notes or cost of margin call facilities	+/- 1.00%	+/- $4
Credit ratings downgrade (increase in loss probability and losses realized)	3 notch downgrade	- $3 to -$5

The Company recorded the exchange of ABCP for new notes at the estimated fair value of the new notes on January 21, 2009. The exchange did not have a material impact on EPCOR's net income, since the ABCP was recorded at estimated fair value at December 31, 2008, based on the characteristics of the new notes. As held for trading financial assets, the new notes will be subject to ongoing fair value adjustments at each reporting date.

CONSOLIDATED FINANCIAL INFORMATION

($ millions)	2008	2007	2006
Revenues	$3,442	$3,663	$2,931
Net income from continuing operations	175	277	632
Net income from discontinued operations	-	-	10
Net income	175	277	642
Total assets	6,948	6,562	6,383
Long-term debt	2,728	2,139	2,179
Common share dividends	130	128	125

Analysis of net income

($ millions)

Net income from continuing operations and net income for the year ended December 31, 2006	**$**	**632**
Impact of 2006 and 2007 income tax rate reductions on future income tax assets and liabilities, excluding Power LP		20
Higher water rates		16
Lower financing expenses and preferred share dividends excluding Power LP financing, partly offset by ABCP fair value reduction in 2007		15
Impact of recording a net future income tax asset associated with the Energy Services reorganization in 2007		10
Unrealized fair value changes in derivative instruments and foreign exchange contracts, excluding Power LP fair value changes		8
Higher income from Power LP		8
Cumulative translation account adjustment for the sale of Frederickson to Power LP in 2006		6
Lower maintenance costs on Genesee 1 and 2		5
Regulatory decisions for 2005 distribution and transmission tariffs and 2005 RRT non-energy charges received in 2006		(7)
Net losses on forward foreign exchange contract settlements in 2007 and net gains in 2006		(18)
Impact of recording a net future income tax asset associated with the restructuring of EPCOR Generation Inc. in 2006		(117)
Gain on sale of Battle River PSA and related transactions		(297)
Other		(4)
Decrease in net income from continuing operations and net income		(355)
Net income from continuing operations and net income for the year ended December 31, 2007	**$**	**277**

Net income from continuing operations and net income for the year ended December 31, 2007	**$**	**277**
Impact of 2007 income tax rate reductions on future income tax assets and liabilities, excluding Power LP		19
Higher Distribution and Transmission energy margins		14
Higher water rates		13
Higher Alberta energy margin		12
Lower foreign exchange expenses		9
Higher gains on sales of portfolio investments		9
Higher margins for trading activities in the north eastern U.S. and Ontario		8
Higher fair value reduction in ABCP		(7)
Higher depreciation expense		(8)
Unrealized fair value changes in derivative instruments, natural gas inventory held for trading and foreign exchange contracts, excluding Power LP fair value changes		(9)
Impact of recording a net future income tax asset associated with the Energy Services reorganization in 2007		(10)
Higher Water Services operations and maintenance costs		(10)
Higher Genesee 1, 2 and 3 maintenance and fuel costs		(23)
Higher administration expenses, excluding Power LP administration		(26)
Write-down of Power LP goodwill in 2008		(28)
Lower Genesee PPA availability and capacity payment revenue		(30)
Lower income from Power LP		(50)
Other		15
Decrease in net income from continuing operations and net income		(102)
Net income from continuing operations and net income for the year ended December 31, 2008	**$**	**175**

Net income from continuing operations and net income for the year ended December 31, 2008 was $175 million compared with $277 million for 2007. Net income from continuing operations and net income decreased by $102 million for the year ended December 31, 2008 compared with the previous year primarily due to the net impact of the following items:

- In June and December 2007, the Government of Canada substantively enacted tax legislation which reduced general corporate income tax rates. The impact of these rate reductions on our future income tax balances resulted in a $13 million charge to net income in 2007, consisting of $19 million for reductions in net future income tax assets partly offset by a $6 million future income tax recovery relating to future income tax balances for Power LP. The impact of the 2007 rate reductions relating to Power LP is included in the lower income from Power LP in the table above.

- In the third quarter of 2008, Distribution and Transmission negotiated a settlement agreement (NSA) with customer groups on its 2007-2009 General Tariff Application and the impact of the tariff increases was recognized in the third quarter of 2008. The amount of the increase that related to 2007 was insignificant.

- Water revenue was higher in 2008 compared with 2007 primarily due to increased rates under the performance-based rate tariff (PBR) as approved by The City of Edmonton.

- In 2008, margins for the procurement, marketing and sale of electricity in retail and wholesale markets in Alberta (Alberta electricity margins) were higher compared with 2007 primarily due to the impact of higher Alberta power prices on our electricity portfolio. The Alberta electricity portfolio was in a net long position as we had more physical supply from our generating stations and our interests in the Battle River and Sundance PPAs (acquired PPAs) than we had contracted to sell. This was partly offset by reduced generation from Genesee 3 and the acquired PPAs, due to plant outages and de-rates (reduced production).

- Foreign exchange expense was lower in 2008 compared with 2007 primarily due to the translation of U.S. net assets of a U.S. subsidiary company which conducts our U.S. energy trading business. The unfavourable change reflected a strengthening U.S. dollar relative to the Canadian dollar in 2008 compared with a weakening U.S. dollar in 2007.

- Depreciation expense was higher in 2008 compared with 2007 due to an increased depreciable asset base with the completion of the following projects in 2008: E.L. Smith Water Treatment Plant upgrade, the Downtown Energy Supply and Service (DESS) project and the first generating unit at the Clover Bar Energy Centre.

- In 2008, the unrealized fair value changes in our financial electricity contracts that were not designated as hedges for accounting purposes were unfavourable compared with 2007, as discussed under “Energy Services” later in this MD&A. These changes were partly offset by unrealized fair value changes in our forward foreign exchange contracts that were favourable compared with 2007, as discussed under “Generation” later in this MD&A.

- On January 1, 2007, the Company reorganized two subsidiaries within the Energy Services segment that operate the regulated retail business. As part of the reorganization, one of the subsidiaries, which was previously exempt from income taxes became subject to income tax under the Income Tax Act and recognized future income tax assets of $10 million and a corresponding reduction in income tax expense. There was no similar transaction in 2008.

- Operations and maintenance expenses for Water Services increased in 2008 from 2007 primarily due to a higher incidence of water main breaks.

- The increase in maintenance expenses for Genesee 1, 2 and 3 reflects three major turnarounds at our Genesee facilities and two unplanned outages in 2008 compared with one short outage and no turnarounds in 2007. Fuel costs for the Genesee facilities were also higher primarily due to higher coal mining costs in 2008 compared with 2007.

- Administration expense, excluding Power LP's administration, was higher in 2008 compared with 2007 primarily due to increased costs for business development, increased bad debt provisions and the cost of Distribution and Transmission's regulatory proceedings.

- A net availability penalty was incurred under the terms of the Genesee 1 and 2 PPA in 2008 compared with availability incentive revenue recognized in 2007. The net penalty in 2008 was due to major maintenance turnarounds 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 and reduced tax recoveries related to lower federal income tax rates.

- Net income from Power LP decreased primarily due to foreign exchange losses recognized in 2008 on the translation of U.S. dollar net monetary liabilities, primarily long-term debt, compared to foreign exchange gains in 2007. Power LP also recorded unrealized fair value losses on its forward foreign exchange contracts in 2008 compared with unrealized fair value gains in 2007. These changes were primarily due to a strengthening U.S. dollar (and forward exchange rate) in 2008 compared with a weakening U.S. dollar (and forward exchange rate) in 2007. Power LP's plant operating margins were slightly lower in 2008 compared with 2007, primarily due to its Northwest U.S. plants.

  In the fourth quarter of 2008, Power LP recorded an impairment loss of $24 million before tax to write down its investment in PERH to its estimated fair value. The fair value estimate was based on the quoted market price of the common shares and the yield of comparable preferred shares and the decline was considered other than temporary. In September 2008 Power LP announced that it was undertaking a sale process that could lead to the sale of its investment in PERH. In 2007, an impairment charge of $13 million before tax was recorded for EPCOR Energy Ventures management contracts.

Revenues

($ millions)

Revenues for the year ended December 31, 2006	**$**	**2,931**
Higher trading activities for physical natural gas		381
Higher Power LP revenues, primarily business acquisitions in the second half of 2006 and impact of fair value changes of forward foreign exchange contracts		229
Higher energy trading activities in the western U.S. region		67
Unrealized fair value changes on derivative instruments		17
Higher water revenues		17
Higher other energy revenues		9
Regulatory decisions for 2005 Distribution and Transmission tariffs and 2005 RRT non-energy charges received in 2006		(9)
Commercial and other sales		21
Increase in revenues		732
Revenues for the year ended December 31, 2007		**3,663**
Higher Water Services' commercial and transportation services revenues		56
Higher trading activities in the north eastern U.S. and Ontario region		43
Higher water rates		14
Higher Distribution and Transmission tariff revenues		11
Sale of portfolio investments		11
Lower Alberta energy revenues		(24)
Lower trading activities in the western U.S. region		(38)
Lower Genesee PPA availability and capacity payment revenues		(42)
Unrealized fair value changes in derivative instruments and natural gas inventory held for trading, excluding Power LP fair value changes		(62)
Lower Power LP revenues		(69)
Lower trading activities for physical natural gas		(127)
Other		6
Decrease in revenues		(221)
Revenues for the year ended December 31, 2008	**$**	**3,442**

Revenues decreased $221 million in 2008 compared with 2007 and further information on the year-over-year changes is as follows:

- Water Services' commercial and transportation services revenues were higher primarily due to increased revenues from the water and wastewater treatment facilities and infrastructure construction projects that were initiated in the fourth quarter of 2007 as well as new contracts added in 2008. Construction and maintenance activities for street lighting and traffic signal assets owned by The City of Edmonton also increased.

- Water revenues were higher in 2008 compared with 2007 primarily due to increased rates under the PBR as approved by The City of Edmonton.

- In 2008, Distribution and Transmission's revenues reflected the tariff increases included in the NSA partly offset by higher rebates from the Alberta Balancing Pool, which were passed on to customers and recognized as a reduction of revenue.

- Revenues from the marketing and sale of electricity in retail and wholesale markets in Alberta (Alberta electricity revenues) were lower compared with 2007 primarily due to a reduction in wholesale power contracts with commercial and industrial customers reflecting a continuation of our strategy to exit the competitive retail electricity business. In addition, the outages at Genesee

3 for the turbine failure and maintenance turnaround resulted in decreased sales of generation from the facility. These reductions in revenue were partly offset by increased revenues from the RRT business, primarily due to higher pricing under the Regulated Rate Option and Energy Price Setting Plan.

- Unrealized fair value losses were recognized in 2008 on our Alberta financial sales contracts that were not designated as hedges for accounting purposes due to an increase in forward Alberta electricity prices. In 2007, unrealized fair value gains were recognized on these contracts as a result of decreasing forward prices in the second half of 2007. The financial sales contracts were used to economically hedge anticipated energy revenues.

- Power LP's revenues were lower in 2008 primarily due to unrealized fair value changes on forward foreign exchange contracts for U.S. dollars, used to economically hedge U.S. dollar operating cash flows. This decrease was partly offset by higher revenue from the plants; primarily the Morris facility which was acquired in the fourth quarter of 2008 and the California facilities where the higher cost of natural gas supply was passed on to the PPA counterparties.

Capital spending and investment

($ millions)	2008	2007	2006
Generation	$ 436	$ 240	$ 63
Distribution and Transmission	120	105	61
Energy Services	10	12	11
Water Services	74	122	104
Corporate – other	18	20	19
	658	499	258
Investment in Primary Energy Ventures	-	-	354
Investment in Morris	89	-	-
Other investment	-	-	2
	$ 747	$ 499	$ 614

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 Energy Centre generation projects.

EPCOR continued construction of Keephills 3, a 495-MW supercritical coal-fired generation plant which is a joint development and equal ownership by EPCOR and TransAlta Corporation at TransAlta's Keephills site. EPCOR'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 $1.8 billion, up from earlier estimates of $1.6 billion due to higher labour and material costs. We continue to manage the schedule and costs of our Keephills project and it remains on track to achieve commercial operations by the end of the first quarter of 2011.

The Clover Bar Energy Centre will be composed of three natural gas-fired peaking power generation units. The first unit was commissioned in the first quarter of 2008, the second unit is expected to be commissioned in the second quarter of 2009 and construction of the third unit will continue through to 2010. The current estimated final cost for the project is $284 million. Capital expenditures on the Clover Bar Energy Centre were $119 million in 2008 and $61 million in 2007.

In the first quarter of 2007, Distribution and Transmission commenced construction of the DESS project which consisted of a new high-voltage transmission line to supply electricity to downtown

Edmonton. The project was substantially completed in the third quarter of 2008 at a cost of $84 million, including $40 million incurred in each of 2008 and 2007.

Water Services' E.L. Smith water treatment plant upgrade was substantially completed in the second quarter of 2008. Capital expenditures on this project were $11 million in 2008 and $61 million in 2007.

SEGMENT RESULTS

Generation

At the end of 2008, Generation operated more than 3,600 MW of generating capacity produced from 37 generating stations in Alberta, British Columbia, Ontario, Colorado, New York State, Washington State, California, New Jersey, North Carolina, Illinois and Indiana. EPCOR began decommissioning the Rossdale generation plant in early 2009.

The facilities owned by EPCOR include two generating units in Alberta that are subject to PPAs and have a generating capacity of 820 MW. We also own 495 MW of coal-fired, gas-fired, hydro-electric, wind-powered and landfill gas-fired commercial generating capacity from six additional plants in Alberta, 40 MW of commercial generating capacity from two hydro-electric plants in British Columbia and approximately 40 MW of commercial generating capacity from a wind-powered project in Ontario.

Generation, as the manager, has the contractual right and obligation to operate Power LP's portfolio of 8 power generation plants in Canada with electric capacity of 320 MW, and a further 13 power generation and combined heat and power facilities in the U.S. with electric capacity of approximately 1,144 MW and a thermal energy capacity of approximately 4 million pounds per hour (lbs/hr). These power plants generate electricity from natural gas, waste heat, wood waste, water flow, coal and tire-derived fuel.

The Genesee 1 and Genesee 2 power generation units, which were previously rate-regulated through annual tariff applications, became subject to PPAs effective January 1, 2001 and continue to be rate-regulated by the guidelines of the *Electric Utilities Act* (Alberta). The electricity generated from these units is provided to the Alberta Balancing Pool as the PPA holder. In exchange for the rights to the electricity, we receive formula-based fixed capacity and variable payments which are intended to provide us with a reasonable opportunity to recover unit operating costs, a formula-based provision for income taxes and a rate of return on investment. The return on equity component is set at 4.5% over the rate of long-term Canada bonds. In addition, we receive incentives and pay penalties when the output available from the generation unit exceeds or falls below target availability levels set out in the PPAs. The target availability levels were originally set with the expectation that the incentives and penalties would net to zero over the life of the PPAs.

Although the units operating under PPAs are rate-regulated, they do not meet the criteria for rate-regulated accounting under generally accepted accounting principles. Accordingly, the generation units are accounted for as unregulated facilities in accordance with the commercial terms and conditions inherent in the PPAs. Key to the earnings performance of generation units operating under PPAs is managing the costs of the units and ensuring that they are able to meet or exceed the target availability levels.

The Clover Bar PPA was terminated effective September 30, 2005 at which time decommissioning of the plant commenced. All operating results relating to the Clover Bar facility subsequent to the PPA termination were reported under discontinued operations and excluded from the Generation segment results.

The Rossdale PPA expired on December 31, 2003 and the plant was operated as a commercial generation unit throughout 2004. An ancillary services contract with the Alberta Electric System Operator (AESO) for continued operation of the Rossdale plant was finalized in 2005. The agreement deferred decommissioning of the Rossdale generation plant until 2009 to provide ongoing transmission system reliability for The City of Edmonton and back-up generating capacity for the province of Alberta. The ancillary services contract with the AESO for continued operation of the Rossdale plant expired on December 31, 2008 and decommissioning of the facility began in early 2009.

Electricity generated from commercial generation plants is sold either under long-term contracts to creditworthy third parties or into the wholesale market where the plant is located. Our general objective is to contract the majority of our non-base-loaded commercial plants' capacity. Key to the earnings of these plants is ensuring that the plants are dispatched (directed to supply electricity to the power grid) as economically as possible, as well as ensuring that operating costs, including fuel, are appropriately managed and that the plants are well maintained.

Generation operating income

Year ended December 31		2008	2007
Generation results			
(including intersegment transactions, $ millions)			
Revenues		$ 932	$ 1,016
Expenses	Energy purchases and fuel	347	312
	Operations, maintenance, administration and foreign exchange	300	148
	Franchise fees, property taxes and other taxes	17	17
	Depreciation, amortization and asset retirement accretion	168	159
		832	636
Operating income before corporate charges		100	380
Corporate charges		22	45
Operating income		**$ 78**	**$ 335**

Operating income for the year ended December 31, 2007	**$ 335**
Unrealized fair value changes in derivative financial instruments	25
Gain on sale of portfolio investments	11
Higher Genesee 1, 2 and 3 maintenance and fuel expenses	(32)
Lower Genesee PPA availability and capacity payment revenue	(42)
Lower Power LP operating income	(215)
Other	(4)
Decrease in operating income	(257)
Operating income for the year ended December 31, 2008	**$ 78**

For the year ended December 31, 2008, Generation's operating income decreased by $257 million from the prior year primarily due to the net impact of the following items:

- Unrealized fair value changes on foreign exchange contracts entered into in anticipation of equipment purchases related to the Clover Bar Energy Centre and Keephills 3 generation projects increased operating income and decreased expenses year over year by $26 million due to a strengthening U.S. dollar in 2008 compared with a weakening U.S. dollar in 2007. These foreign exchange contracts are expected to substantially hedge the economic changes caused by foreign currency movements on these asset purchases. However, they have not been recognized as hedges for accounting purposes.

- The increase in maintenance expense for Genesee 1, 2 and 3 reflects three major turnarounds and two unplanned outages in 2008 compared with one short outage in 2007. The turnarounds in 2008 were for required maintenance and were scheduled back-to-back to accommodate the AESO's upgrade of the new high-voltage transmission lines in the Genesee and Keephills area. An unplanned outage at Genesee 3 was the result of a turbine rotor blade failure which kept the unit offline for 39 days during the fourth quarter of 2008 and a boiler leak at Genesee 2 resulted in a short unplanned outage in the second quarter of 2008. Fuel expense for the Genesee facilities also increased in 2008 compared with 2007 primarily due to higher coal mine operating costs incurred by our 50% interest in the Genesee Coal Mine joint venture. Coal for the Genesee plants is supplied under long-term agreements with the joint venture.

- The Genesee PPA incentive for 2008 was a net penalty compared with net income in 2007. As there was no deferred availability incentive balance at December 31, 2007, the penalties and incentives were recognized as incurred in 2008. Penalties were incurred in 2008 due to the major outages at Genesee 1 and 2 in the first six months of 2008 and the unscheduled outage at Genesee 2 in the third quarter of 2008 which all coincided with periods of high Alberta spot power prices.

  In accordance with the PPAs for Genesee 1 and Genesee 2, we receive capacity payments from the Alberta government's Balancing Pool. Income taxes, based on statutory rates, and the PPA rate base are two of the factors in the formula for determining capacity payments and reductions in both of these variables resulted in lower payments in 2008 compared with 2007.

- Power LP contributed a $58 million operating loss in 2008 compared with $157 million of operating income in 2007. Revenues and expenses from Power LP decreased $69 million and increased $146 million respectively, from 2007 to 2008. The majority of this decline was due to unrealized fair value adjustments.

  Unfavourable changes in the fair value of Power LP's forward foreign exchange contracts used to economically hedge U.S. dollar operating cash flows decreased revenues and operating income by $103 million from 2008 to 2007. In addition, unrealized foreign exchange losses in 2008 compared with gains in 2007 on the translation of U.S. dollar net monetary liabilities (primarily long-term debt), increased expenses and decreased operating income by $103 million. These changes were due to a strengthening U.S. dollar and its forward exchange rate in 2008 compared with a weakening U.S. dollar and its forward exchange rate in 2007. The unrealized foreign currency translation loss in 2008 was for only the first three quarters of the year as the corresponding loss for the fourth quarter of $62 million was recognized in other comprehensive income. During the fourth quarter of 2008, changes in economic circumstances caused Power LP to re-evaluate the functional currency of its indirectly-owned U.S. subsidiaries. Accordingly, commencing in the fourth quarter of 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 shareholder's equity within accumulated other comprehensive income rather than as foreign exchange expense in the income statement.

Revenues and expenses from plant operations were higher in 2008 compared with 2007, primarily due to the Morris facility which was acquired in the fourth quarter of 2008, and the California facilities where the higher cost of natural gas supply was passed on to the PPA counterparties. Power LP's plant operating margin was lower by $4 million in 2008 compared with 2007 primarily due to the Northwest U.S. plants. In particular, a 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. Generation and revenue for the Manchief plant were lower due to higher natural gas prices in Colorado, and in order to meet the minimum generation requirements in its PPA, higher fuel costs were incurred at the Greeley plant.

	2008	2007
Electricity generation (gigawatt-hours)		
Generation units owned by EPCOR		
Coal generation units	7,424	8,147
Natural gas generation units	408	305
Hydro and wind generation units	293	316
	8,125	8,768
Generation units owned by Power LP		
Natural gas or waste heat units	3,250	3,495
Wood waste or waste heat units	1,217	1,387
Hydro generation units	573	574
	5,040	5,456
Total	**13,165**	**14,224**

	2008	2007
Generation plant availability (%)		
Generation units owned by EPCOR		
Coal generation units	87	97
Natural gas generation units	96	87
Hydro and wind generation units	94	91
Generation units owned by Power LP		
Natural gas or waste heat generation units	93	93
Coal/tire-derived fuel, wood-waste or waste-heat generation units	92	95
Hydro generation units	86	89
Total	**91**	**94**

Generation maintains a fleet of high quality power plants with good geographic, fuel source and counterparty diversification. Historically, we have had a strong track-record of maximizing efficiency, productivity and reliability of our facilities. The overall availability of our facilities was 91% in 2008 and 94% in 2007. The lower availability of EPCOR's coal generation units in 2008 was primarily due to the unplanned outage at Genesee 3 and the lower availability of Power LP's units was primarily due to extended outages at the Manchief, Mamquam and Williams Lake plants in 2008.

As most of Generation's revenues are under PPAs or long-term contracts and the demand for power in the regions that we operate remains relatively strong, management believes that Generation's operations are in a relatively strong competitive position for these economic times. In the Alberta market, the current recessionary trend may increase the availability of labour, which has been in short supply for capital and maintenance projects. A significant exposure in the current environment is foreign exchange risk relating to purchases of U.S. equipment and materials for our capital projects and risks associated with U.S. assets, debt and cash flows. We will continue to manage this exposure with the use of forward foreign exchange contracts. With the change in functional currency, the impact of volatility in the U.S. foreign exchange rate on the translation of Power LP's U.S. operations will be reflected in other comprehensive income rather than the income statement.

We will continue to operate and maintain EPCOR's Generation assets with an emphasis on safety. As the three planned outages at Genesee in the first half of 2008 were required to accommodate AESO's upgrade of the high-voltage transmission lines, EPCOR will be compensated by AESO for certain direct and indirect costs of the outage. These costs amounted to approximately $5 million, of which $3 million has been recovered and $2 million is expected to be received once AESO has completed their audit of the costs. For 2009, we have planned one outage at Genesee 1. There will also be outages in 2009 at Power LP's North Island, Southport and Roxboro plants for enhancements to improve their economic performance and reduce their environmental impact.

The Company continues to pursue commercially and environmentally viable acquisition and development opportunities for generation plants in both Canada and the U.S. The Company's first of three new gas-fired generating units at the Clover Bar Energy Centre site commenced commercial operations in the first quarter of 2008 and the second and third units are scheduled for completion in 2009 and 2010, respectively. The construction of Keephills 3, jointly owned by EPCOR and TransAlta, continues and is scheduled for completion in 2011.

Distribution and Transmission

Distribution and Transmission earns income principally by transmitting high-voltage electricity from generation plants to points of distribution and, from there, distributing low-voltage electricity to retailers' end-use customers. Our distribution and transmission assets are located in and around The City of Edmonton and are regulated by the AUC. We earn provincially regulated distribution and transmission tariffs intended to allow us to recover our prudent costs and earn a fair rate of return on our distribution and transmission infrastructure. Distribution and Transmission is also responsible for meter reading for all electricity suppliers within The City of Edmonton service area and acting as the load settlement agent for The City of Edmonton.

Distribution and Transmission operating income

Year ended December 31		2008	2007
Distribution and Transmission results			
(including intersegment transactions, $ millions)			
Revenues	Distribution	$ 206	$ 201
	Transmission	43	36
	Commercial and other	12	10
		261	247
Expenses	Energy purchases and fuel	69	72
	Operations, maintenance, administration and foreign exchange	62	56
	Franchise fee, property taxes and other taxes	41	39
	Depreciation, amortization and asset retirement accretion	30	27
		202	194
Operating income before corporate charges		59	53
Corporate charges		16	14
Operating income		**$ 43**	**$ 39**

Operating income for the year ended December 31, 2007	**$**	**39**
Higher distribution and transmission energy margins		14
Administration costs for the 2008 NSA proceeding		(5)
Operations, maintenance, administration and other		(5)
Increase in operating income		4
Operating income for the year ended December 31, 2008	**$**	**43**

For the year ended December 31, 2008, Distribution and Transmission's operating income increased $4 million from the prior year. In the third quarter of 2008, Distribution and Transmission negotiated a settlement agreement with customer groups on its 2007-2009 General Tariff Application and received AUC approval in the fourth quarter of 2008. Accordingly, Distribution and Transmission's revenues reflect the tariff increases agreed to in the NSA and the portion of the increase relating to 2007 was insignificant. This increase in revenues was partly offset by higher rebates to customers set by the Alberta Balancing Pool in 2008, which were recognized as a reduction of revenues. Expenses were also higher in 2008 compared with 2007, primarily due to administration expenses incurred for the NSA proceeding, partly offset by lower energy purchases reflecting the increase in Alberta Balancing Pool rebates.

	2008	2007
Distribution reliability and volumes		
Reliability (system average interruption duration index in hours)	0.96	1.14
Electricity distribution (gigawatt-hours)	7,215	7,076

The strategic focus of Distribution and Transmission continues to be operational excellence, primarily the safe and reliable distribution of electricity to our customers. Our primary measure of distribution system reliability is System Average Interruption Duration Index (SAIDI) which we attempt to minimize. This measure captures the annual average number of hours of interruption experienced by our customers, including scheduled and unscheduled interruptions to our primary distribution circuits. In 2008, we experienced a SAIDI of 0.96 hours compared with 1.14 hours in 2007. This improvement was primarily due to EDTI's reliability improvement efforts including, but not limited to, the rejuvenation or replacement of underground distribution cables to mitigate cable failures, the installation of automated switches on selected circuits to allow Distribution and Transmission to isolate faults and restore service to customers in a more timely manner and the construction of new circuits to strengthen Distribution and Transmission's system. Although improvements have been experienced, the leading causes of customer interruptions continue to be major storms and cable faults. Distribution and Transmission will continue with its reliability improvement programs to further address these issues and improve overall system reliability. Electricity distribution volumes increased modestly from 2007 to 2008 due to higher commercial and residential consumption resulting from overall growth in the Edmonton region.

As a regulated utility service provider, Distribution and Transmission has not been and does not expect to be materially impacted by the recent downturn in economic conditions. Demand for our services is secure, we have limited credit exposure, we source the majority of our materials and labour from Canada and our inventory is for our own use. In fact, we may experience some benefit from the economic slowdown as the availability of contract labour for our capital and maintenance work increases.

Energy Services

Energy Services earns income from the supply of electricity and to a lesser extent natural gas, to end-use customers in Alberta. Electricity revenues are earned at regulated rates from RRT customers and at rates set by competitive retail contracts to commercial and industrial customers, both designed to cover the costs of supplying electricity (including the costs of the commodity, credit risk, and volume risks) and provide an appropriate margin. Natural gas revenues are earned under competitive retail contracts. In addition, Energy Services has wholesale contracts with Alberta Energy Savings Limited Partnership (AESLP) to supply their retail customers with both natural gas and electricity.

Energy Services also manages our overall electricity and natural gas portfolio in all markets in which we operate. To balance supply and demand, electricity and natural gas are purchased and sold under physical and financial transactions with the objective of matching volumes and terms or taking positions within limits established under prudent risk management policies. Electricity supply is also provided through EPCOR's interests in the Sundance and Battle River PPAs (acquired PPAs) and EPCOR's merchant plants, Genesee 3, Joffre and Clover Bar Energy Centre. The electricity from all these sources is used to help balance and optimize the Company's electricity portfolio and satisfy customer electricity requirements. As part of its mandate, Energy Services also participates in the ancillary services (electricity reserves) market with its merchant plants.

Energy Services operating income

Year ended December 31		2008	2007
Energy Services results			
(including intersegment transactions, $ millions)			
Revenues	Energy revenues	$ 2,170	$ 2,382
	Commercial and other	37	35
		2,207	2,417
Expenses	Energy purchases	1,965	2,149
	Operations, maintenance, administration and foreign exchange	71	80
	Depreciation, amortization and asset retirement accretion	28	30
		2,064	2,259
Operating income before corporate charges		143	158
Corporate charges		30	26
Operating income		**$ 113**	**$ 132**

Operating income for the year ended December 31, 2007	**$ 132**
Higher Alberta electricity margins	16
Higher energy margin from trading activities in the north eastern U.S. and Ontario	11
Unrealized fair value changes in derivative instruments and natural gas inventory	(48)
Other	2
Decrease in operating income	(19)
Operating income for the year ended December 31, 2008	**$ 113**

For the year ended December 31, 2008, Energy Services' operating income decreased by $19 million from the prior year due to the net impact of the following items:

- Alberta electricity margins were higher in 2008 compared with 2007 primarily due to the impact of higher Alberta power prices on our Alberta electricity portfolio. The portfolio was in a net long position as we had more physical supply from our generating stations and our interests in the

Battle River and Sundance PPAs than we had contracted to sell, and Alberta spot power prices averaged $90/MWh in 2008 compared to $67/MWh in 2007.

The impact of the higher Alberta power prices was partly offset by reduced generation from Genesee 3 and the acquired PPAs due to plant outages and de-rates (reduced production). The Genesee 3 facility is operated by the Generation segment under a tolling arrangement with Energy Services, whereby Energy Services pays a fixed capacity fee plus a variable cost fee in exchange for the right to control the dispatch of generation from the facility. The outages at Genesee 3 were driven by the turbine failure in the fourth quarter and the maintenance turnaround in the second quarter.

Alberta electricity revenues and purchases decreased primarily due to a reduction in wholesale power contracts with commercial and industrial customers and reduced generation from Genesee 3 and the acquired PPAs. Pursuant to our business decision to exit from the competitive retail electricity business, we did not renew the commercial and industrial customer contracts that expired during the year. These decreases were partly offset by increased revenues and purchases for the RRT business. The pricing for our RRT customers is regulated by the Regulated Rate Option (RRO) which uses a combination of long-term and monthly forward hedges. Accordingly, the higher Alberta power prices in 2008 resulted in higher energy revenues and purchases compared with 2007, but the RRT electricity margin was substantially unchanged.

- Energy Services' unrealized fair value changes relate primarily to a net short position in both 2008 and 2007 for derivative financial electricity contracts that were not designated as hedges for accounting purposes. In 2008, forward Alberta power prices increased which reduced the fair value, whereas in 2007 forward Alberta power prices decreased which increased the fair value. These unrealized fair value changes reduced energy revenues by $62 million and energy purchases by $14 million in 2008 compared with the prior year.

  Fair value reductions on a net short position of derivative financial electricity contracts are not necessarily indicative of economic performance as EPCOR's overall position for both physical and derivative financial electricity contracts, including hedges, was long and we therefore benefited economically when power prices increased.

- Lower trading activities for physical natural gas also contributed to lower energy sales and purchases, but had minimal impact on energy margins.

- Operations and administration expenses were lower in 2008 compared with 2007 primarily due to lower employee short-term incentive compensation for the non-regulated portion of Energy Services and lower information technology costs as a result of system hardware upgrades completed in the fourth quarter of 2007, partly offset by higher bad debt expense. Corporate charges were higher in 2008 primarily due to increased business development and higher staffing levels.

Energy Services' retail customer sales volumes, which exclude electricity and natural gas trading activities, were as follows:

	2008	2007
Retail sales		
Electricity (gigawatt-hours)		
RRT	5,638	5,711
Default	780	868
Competitive	3,027	3,267
	9,445	9,846
Natural gas (000s of gigajoules)	1,727	1,880

	2008	2007
Energy supply (gigawatt-hours)		
Battle River PPA generation	1,222	1,301
Sundance PPA generation	2,524	2,514
Genesee 3 generation	1,498	1,796
Clover Bar Landfill Gas generation	35	36
Clover Bar Energy Centre generation	29	-
Joffre generation	273	270
	5,581	5,917

Electricity sales volumes for our competitive customers declined in 2008 from 2007, primarily due to the expiry of commercial and industrial customer contracts. The reduction in RRT and default customer sales was primarily due to a reduction in the number of customers. Natural gas sales volumes declined due to a reduction in industrial customer contracts. The decrease in energy supply from Battle River reflects our reduced interest in the PPA, and the decrease in supply from Genesee 3 was due to more plant outages in 2008 than in 2007.

In 2006, we began repositioning our power portfolio by selling interests in our Battle River and Sundance PPAs. The subsequent sales of additional interests in the Battle River PSA are reducing our power supply volumes, which will be replaced over time with new production from the Clover Bar Energy Centre and Keephills 3 facilities as they come on line. Energy Services intends to optimize the value of the new assets by selling the electricity to the forward energy market. Energy Services is also working to expand into new electricity markets and trading instruments.

The recent downturn in the economy did not have a significant impact on Energy Services' performance in 2008, as power is an essential commodity regardless of the state of the economy. However, we expect the condition of the economy will present challenges as well as opportunities for us in 2009. Electricity consumption by commercial and industrial customers is expected to decrease as their businesses slow down. This decline in demand should translate into lower prices in the spot and forward markets for electricity. Crude oil and natural gas prices have suffered from a decrease in demand but this can be viewed as being positive for Energy Services as the cost to produce power from its gas-fired generation will decrease. We do not expect the economic slowdown to have a significant impact on our RRT business as our rates for RRT electricity sales are regulated based on our cost of supply. The possibility for a slight decrease in the number of RRT and default customers is based on the RRO pricing framework which is transitioning over a five-year period to a month ahead forward price by 2010. These customers may opt for competitive contracts to eliminate their exposure to price volatility, but we do not anticipate that the economy will necessarily impact this trend. In addition, 75% of the RRT bad debt expense variance from an AUC-approved target is charged or refunded to the RRT customers in future rates for the non-energy charge.

Some of Energy Services' trading counterparties have been affected by the economy which has resulted in a decrease in forward market liquidity. Banks, hedge funds and utility companies have either slowed or stopped forward trading as credit costs have increased and their willingness to take on credit risk has declined. With the decrease in demand by end users for power contracts and the decline in our trading counterparties' activity, Energy Services' ability to hedge EPCOR's commodity portfolio and execute trading strategies has been restricted. Some of the counterparties that we have contracts with are subsidiaries of international financial institutions that have come under financial distress, some of which have received capital funding under the U.S. Troubled Asset Relief Program. Our exposure to these counterparties was approximately $10 million at December 31, 2008 and there have been no defaults on the agreements or transactions with this group of wholesale counterparties to date. Energy Services remains focused on dealing with only creditworthy counterparties and has implemented position management strategies to provide maximum flexibility to mitigate the effects of low market liquidity and price volatility.

Water Services

Water Services earns income primarily from the treatment, distribution and sale of water while ensuring public health standards are exceeded. The majority of Water Services' income is earned through a PBR tariff charged to its Edmonton customers. The PBR tariff is intended to allow Water Services to recover its costs and earn a fair rate of return while providing an incentive to manage costs below the inflationary adjustment built into the PBR rate. The key to maintaining earnings on water sales is to provide sufficient quantities of high quality water while controlling costs.

Water Services manages EPCOR's Transportation Services business which provides competitive contract-based commercial services related to installation, maintenance and repair of street lighting, traffic signal, light rail transit and trolley facilities. In addition, Water Services provides competitive contract-based water and wastewater services, including financing in certain arrangements, to commercial, industrial and municipal customers. The key to earning satisfactory operating margins on these contracts is to satisfy the terms of the contract while controlling or reducing operating costs.

Water Services operating income

		2008	2007
Water Services results			
(including intersegment transactions, $ millions)			
Revenues	Water revenues	$ 150	$ 136
	Commercial and other	166	128
		316	264
Expenses	Operations, maintenance, administration and foreign exchange	206	163
	Franchise fees, property taxes and other taxes	10	10
	Depreciation, amortization and asset retirement accretion	20	18
		236	191
Operating income before corporate charges		80	73
Corporate charges		16	14
Operating income		**$ 64**	**$ 59**

Operating income for the year ended December 31, 2007	**$**	**59**
Increased water rates		14
Higher commercial services activity		3
Higher operations and maintenance		(10)
Higher depreciation, administration and other		(2)
Increase in operating income		5
Operating income for the year ended December 31, 2008	**$**	**64**

For the year ended December 31, 2008, Water Services' operating income increased by $5 million from the prior year due to the net impact of the following items:

- Water revenues were higher in 2008 compared with 2007 primarily due to increased rates under the PBR as approved by the regulator, The City of Edmonton, which were implemented in the second quarter of 2008.

- Transportation and other commercial services revenues and expenses increased in 2008 over 2007 by $36 million and $33 million respectively, primarily due to an increase in streetlight and traffic signal construction activities for The City of Edmonton and increased construction activity on water and wastewater facility projects for third parties. These increases were partly offset by lower contracting revenue from Distribution and Transmission and associated expenses for the DESS project. Our Transportation department was contracted for some of the work on the DESS project, which commenced in the first quarter of 2007 and was substantially completed in the third quarter of 2008.

- Operations and maintenance costs increased in 2008 from 2007 due to a higher incidence of distribution main breaks and additional reservoir maintenance.

	2008	2007
Water volumes for The City of Edmonton and surrounding region		
Water sales (megalitres)	125,307	124,696

Water Services owns 4 and operates 19 water treatment and distribution facilities. As well, it operates 21 wastewater and collection facilities in Alberta and British Columbia. At the end of 2008, water and wastewater facilities were under construction at the Suncor Voyageur site in Fort McMurray, Alberta and are anticipated to be in service by the second quarter of 2009. Water Services will own and operate the Suncor Voyageur facilities in a commercial arrangement with the Suncor Energy Inc. (Suncor) group of companies. Our core market is stable as we are the sole supplier of water within The City of Edmonton. In 2008, we saw a slight increase in water volumes, primarily due to higher customer counts within The City of Edmonton and higher consumption by our regional customers, partly offset by lower commercial and multi-residential customer water use. Operationally, the facilities we own or manage performed well in both 2007 and 2008.

The EL Smith upgrade, which was completed in 2008, is expected to provide water capacity necessary to meet the anticipated growth in The City of Edmonton until at least 2023. Asset components were added to the rate base as they were placed into service. The water rates for 2007 and 2008 reflect the costs of the upgrade project resulting in additional cash flow and earnings.

The economic downturn did not have a material impact on Water Services' business in 2008, as much of these services are rate-regulated essential services or are under contracts with municipalities. In

2009, the economy could have an impact on water sales to our City of Edmonton customers, particularly the commercial and industrial customers, and their ability to pay. However, we have not experienced a noticeable decrease in volumes or increase in credit losses to date. Our commercial services work is largely subcontracted at fixed prices and we may benefit from a higher availability of labour for our City of Edmonton water mains repair and transportation work in 2009. The cancellation or postponement of oil upgrader projects in the Edmonton's northeast region will reduce our opportunities for new commercial water contracts. However, government funding announcements in support of economic stimulus should bode well for new public-private partnerships for water and wastewater infrastructure opportunities. Although we plan to pursue new commercial contracts, we recognize that we may have to apply stricter investment criteria, including potentially higher financing costs.

CONSOLIDATED BALANCE SHEETS

Significant changes in consolidated assets:
December 31, 2008 and 2007

($ millions)	2008	2007	Increase (decrease)	Explanation
Cash and cash equivalents	$ 111	$ 79	$ 32	Refer to cash flows summary below.
Accounts receivable (including income taxes recoverable)	509	591	(82)	One month of Alberta wholesale electricity settlements and Genesee generation revenues at the end of 2008 compared with two months at the end of 2007, partly offset by higher Alberta power prices at the end of 2008. December 31, 2007 balance includes excess sinking fund earnings received from The City of Edmonton in the first quarter of 2008.
Derivative instruments assets (current)	130	104	26	Increase in fair value of natural gas derivative contracts acquired in 2008, partly offset by decrease in fair value of foreign exchange and natural gas supply contracts.
Other current assets	96	74	22	Addition of natural gas inventory held for trading and increase in coal, small parts and consumables inventories.
Property, plant and equipment	4,728	4,216	512	2008 capital expenditures in excess of depreciation and amortization expense.
Power purchase arrangements	593	679	(86)	Sale of 10% interest in Battle River PSA, amortization of remaining PPAs in 2008 and decrease in Power LP PPAs due to lower foreign exchange rate in the translation of U.S. PPAs.
Contract and customer rights and other intangible assets	207	192	15	Increase in rights to mining assets for coal supply for Keephills 3.
Derivative instruments assets (non-current)	75	116	(41)	Decrease in fair value of foreign exchange and natural gas supply contracts.
Future income tax assets (non-current)	103	103	-	
Goodwill	161	185	(24)	Write-down of Power LP goodwill partly offset by foreign currency translation adjustment.
Other assets	235	223	12	Increase in net investment in lease and in long-term receivables associated with the Water Services commercial construction projects, partly offset by a decrease in fair value of ABCP and equity loss and write-down of investment in PERH.

Significant changes in consolidated liabilities and shareholder's equity:
December 31, 2008 and 2007

($ millions)	2008	2007	Increase (decrease)	Explanation
Short-term debt	$ 140	$ 138	$ 2	
Accounts payable and accrued liabilities	587	615	(28)	One month of Alberta wholesale electricity settlements at December 31, 2008 compared with two months at December 31, 2007 and lower power and natural gas trading payables, partly offset by higher payables for capital projects, primarily Keephills 3, at December 31, 2008.
Derivative instruments liabilities (current)	131	136	(5)	Settlement in 2008, of power derivative contracts held at December 31, 2007, partly offset by decrease in fair value of forward foreign exchange contracts and natural gas derivative buy contracts acquired in 2008.
Other current liabilities	58	98	(40)	Lower income taxes payable, due to payment in 2008 of income taxes related to the 2006 Battle River PPA gain on sale.
Long-term debt (including current portion)	2,728	2,139	589	Medium-term note debentures issued in January and April 2008, draws on credit facilities and higher foreign exchange on the translation of U.S. debt, partly offset by ongoing debt repayments to The City of Edmonton, repayment of debt issued under credit facilities and repayment of a medium-term note.
Derivative instruments liabilities (non-current)	110	78	32	Increased liability associated with the reduction in fair value of forward foreign exchange contracts.
Other non-current liabilities	125	125	-	
Future income tax liabilities (non-current)	100	126	(26)	Primarily reflects decreased future income taxes in Power LP relating to increased net derivative liabilities and changes in temporary differences between the tax and accounting bases for property, plant and equipment.
Non-controlling interests	540	740	(200)	Non-controlling interests' share of Power LP distributions, net loss and other comprehensive loss.
Shareholder's equity	2,429	2,367	62	Net income and other comprehensive income, partly offset by common share dividends.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Cash inflows (outflows) and cash position:

	($ millions)					
	Years ended December 31					
	2008	2007	Change	2007	2006	Change
Operating	$ 403	$ 541	$ (138)	$ 541	$ 589	$ (48)
Investing	(643)	(469)	(174)	(469)	(303)	(166)
Financing	272	(253)	525	(253)	(116)	(137)
Opening cash and cash equivalents	79	260	(181)	260	90	170
Closing cash and cash equivalents	$ 111	$ 79	$ 32	$ 79	$ 260	$ (181)

Operating changes:

The 2007 to 2008 decrease in cash inflows reflects changes in non-cash working capital due to the timing of receipts and payments, reduced cash flow from the Battle River PPA, payment of Genesee PPA availability payments in 2008 compared with the receipt of availability incentive income in 2007, payment in 2008 of income taxes related to the 2006 gain on sale of the Battle River PPA, purchase in 2008 of natural gas held in storage for trading purposes and payments for major maintenance for Genesee turnarounds in 2008. These decreases were partly offset by losses on forward foreign exchange and interest contract settlements in 2007.

Investing changes:

The 2007 to 2008 increase in investing activities reflects higher capital expenditures in 2008, primarily for the Keephills 3 and Clover Bar Energy Centre generation projects, and the acquisition of the Morris facility, partly offset by the sale of portfolio investments in 2008 and the purchase of ABCP in 2007.

Financing changes:

The 2007 to 2008 increase in financing receipts reflects higher long-term debt issues in 2008. In addition, there were short-term debt repayments and subsidiary company preferred share redemptions in 2007 with no corresponding financing outflows in 2008. This increase was partly offset by higher short-term debt issues in 2007 and a subsidiary company preferred share issue in 2007 with no corresponding financing receipts in 2008, and higher repayments of long-term debt in 2008.

LIQUIDITY AND CAPITAL RESOURCES

($ millions) Years ended December 31	2008	2007	2006
Funds from operations[1]	$ 484	$ 517	$ 547
Long-term borrowings during the year	910	395	406
Cash and cash equivalents, at end of year	111	79	260
Short-term debt, at end of year	(140)	(138)	(216)
Ratios[1]			
Debt to equity[2]	49:51	42:58	44:56
Interest coverage (excluding gain on sale of PPA and impairment charges) on long-term debt:			
Income before financing, taxes and non-controlling interest[3]	1.7 X	3.3 X	3.0 X
Income from continuing operations before financing, taxes and non-controlling interest[4]	1.7 X	3.3 X	2.9 X
Income before financing, taxes, non-controlling interest, and depreciation and amortization[5]	3.1 X	4.7 X	4.4 X
Income from continuing operations before financing, taxes, non-controlling interest and depreciation and amortization[6]	3.1 X	4.7 X	4.3 X
Funds from operations to interest bearing debt (%)[7]	16.9	22.7	22.8
Credit ratings[8]			
Standard & Poor's			
Long-term debt	BBB+	BBB+	BBB+
Preferred shares of subsidiary companies	P-2 (Low)	P-2 (Low)	P-2 (Low)
Dominion Bond Rating Service's			
Short-term debt	R-1 (low)	R-1 (low)	R-1 (low)
Long-term debt	A (low)	A (low)	A (low)
Preferred shares of subsidiary companies	Pfd-3 (high)	Pfd-2 (low) / Pfd-3 (high)	Pfd-2 (low)

(1) Funds from operations and ratios in this table are non-GAAP (Generally Accepted Accounting Principles) financial measures that do not have any standardized meaning prescribed by GAAP and are unlikely to be comparable to similar statistics published by other entities. They are presented since they are commonly referred to by debt holders and other interested parties in evaluating the Company's financial position and in assessing its credit worthiness. See "Non-GAAP Measures" for a reconciliation of funds from operations. The ratios are explained in the following notes.

(2) Debt to equity is expressed as a ratio of debt as a percentage of total capital to equity as a percentage of total capital. Debt is the sum of short-term debt and long-term debt (including the current portion). Equity is the sum of non-controlling interests and shareholder's equity. Total capital is the sum of debt and equity.

(3) Revenue and foreign exchange gains less energy purchases, fuel, operations, maintenance and administration, franchise fee, property taxes and other taxes and depreciation, amortization and asset retirement accretion, for continuing and discontinued operations, divided by interest on long-term debt and capital lease obligation for continuing and discontinued operations.

(4) Revenue and foreign exchange gains less energy purchases, fuel, operations, maintenance and administration, franchise fee, property taxes and other taxes and depreciation, amortization and asset retirement accretion, for continuing operations, divided by interest on long-term debt and capital lease obligation for continuing operations.

(5) Revenue and foreign exchange gains less energy purchases, fuel, operations, maintenance and administration and franchise fee, property taxes and other taxes, for continuing and discontinued operations, divided by interest on long-term debt and capital lease obligation for continuing and discontinued operations.

(6) Revenue and foreign exchange gains less energy purchases, fuel, operations, maintenance and administration and franchise fee, property taxes and other taxes, for continuing operations divided by interest on long-term debt and capital lease obligation for continuing operations.

(7) Funds from operations to interest bearing debt (expressed as a percentage) is cash flow from operations divided by short-term debt plus long-term debt (including the current portion).

(8) Rating agencies have disclosed that all current ratings are stable.

Generally, our external capital is raised at the corporate level and invested in the operating business units. However, some of the businesses that we own jointly with parties unrelated to EPCOR, such as Power LP and Joffre, have their own external financing. By centralizing our finance function we are able to access capital markets appropriate for our growth strategy and to minimize financing costs. Our external financing has consisted of borrowings under committed credit facilities, debentures payable to The City of Edmonton, public debentures, and preferred and common shares. Power LP's external financing has been raised through the issuance of partnership units and preferred shares, borrowings under lines of credit and long-term notes payable.

Financing

On January 31, 2008, the Company completed a $200 million public offering in Canada of unsecured medium-term note debentures with a coupon rate of 5.80% and maturity date of January 31, 2018. Net proceeds from the offering were used to repay EPCOR's short-term indebtedness and for general corporate purposes.

On April 15, 2008, the Company completed a $375 million public offering of unsecured medium-term note debentures consisting of issues of $200 million and $175 million. On April 28, 2008 the Company completed an additional issue of $25 million of unsecured medium-term note debentures. The $200 million issue has a coupon rate of 5.80% and a maturity date of January 31, 2018. The $175 million and $25 million issues have a coupon rate of 6.65% and a maturity date of April 15, 2038. Net proceeds from these offerings were used to repay short-term indebtedness, to repay debentures which matured in June 2008, to fund a portion of the 2008 capital program and for general corporate purposes.

During 2008, EPCOR secured financing through its credit facilities to fund its capital expenditures, including $87 million drawn by Power LP on its revolving credit facilities to fund its Morris acquisition and capital projects at the Southport, Roxboro and North Island facilities.

On December 19, 2008, the Company negotiated a $600 million liquidity credit facility, expiring on December 17, 2009. The facility was arranged to provide financing capability while the credit markets remain uncertain. Draws under the facility will be used for general corporate purposes.

As of March 13, 2009 there were three common shares of the Company outstanding, all of which are owned by The City of Edmonton. EPCOR's dividend policy for these common shares has remained unchanged since 2000. Under the policy, the annual dividend is set at the greater of the previous year's dividend adjusted for the forecast change in the consumer price index, and 60% of the current year's earnings available to the common shareholder. This policy is subject to amendment in the event of a significant change in EPCOR's business or financial condition. Dividends for the year are generally established in the fall of the previous year based on forecast earnings. In accordance with the policy, the annual dividends for 2008 were $130 million (2007 - $128 million).

Subsidiaries of EPCOR paid preferred share dividends and related income taxes of $7 million (2007 - $12 million). The decrease from 2007 was due to the redemption of 8 million subsidiary preferred shares at par for $200 million effective September 30, 2007. Power LP paid $94 million (2007 - $92 million) of distributions to the non-controlling unit holders.

Operating activities

Cash flow from operating activities, which includes changes in non-cash working capital, decreased to $403 million in 2008 from $541 million in 2007. The decrease was primarily due to changes in non-cash working capital resulting from the timing of receipts and payments, reduced cash flow from the Battle River PPA, payment of Genesee PPA availability payments in 2008 compared with the receipt of availability incentive income in 2007, payments for major maintenance for Genesee turnarounds in 2008, payment in 2008 of income taxes related to the 2006 gain on sale of the Battle River PPA and purchase in 2008 of natural gas held in storage for trading purposes. These decreases were partly offset by net realized losses on forward foreign exchange and interest rate contracts in 2007.

Cash flow from operating activities is anticipated to increase in 2009 from 2008 due to higher income from operations. Lower power prices and the scheduled sale of a further 10% interest in the Battle River PSA will reduce electricity revenues in 2009 and apart from energy purchases and fuel, our costs are primarily fixed. However, we plan to partially offset the impact of the lower revenues from the Battle River PPA with higher revenues from the Genesee units as they are expected to have higher availability due to fewer maintenance outages than in 2008. Lower maintenance costs at Genesee will also improve earnings income from operations in 2009. Earnings will benefit from a full year of operation of the first unit at Clover Bar Energy Centre and the addition of the Gold Bar wastewater treatment and Morris facilities and the second unit at Clover Bar Energy Centre. Working capital requirements are expected to be substantially lower in 2009 than in 2008 due to unusually large accounts payable and income taxes payable balances at December 31, 2007 relating to the timing of payments. We also anticipate working capital requirements to fluctuate due to normal seasonal changes in operating cash flows and the effects of scheduled or unplanned plant outages. The Company will finance its working capital requirements with existing credit facilities. No significant increases in working capital requirements are expected over the long term for existing operations.

2009 cash requirements

EPCOR's 2009 projected cash requirements include approximately $800 million for capital expenditures, $26 million for long-term debt repayments and $134 million for common dividends. In addition, EPCOR will commit to payment and financing for the transfer of Gold Bar from The City of Edmonton in the first quarter of 2009 and any associated dividends. However, the specific amounts have not yet been determined.

Due to the uncertain capital markets and rising capital costs, EPCOR plans to apply stricter investment criteria to new development or acquisitions. We will continue the construction of Keephills 3 which we own equally with TransAlta, and the Clover Bar Energy Centre. EPCOR's share of the total cost of constructing Keephills 3 is expected to be approximately $903 million compared to the original estimate of $820 million and the project is expected to be completed by 2011. The increase reflects higher material and labour costs. As much of the cost increase is committed, the recent economic downturn should not have a significant impact on these costs going forward. The estimated cost of constructing the generation units at Clover Bar Energy Centre is $284 million. The second and third units are expected to be completed in the second quarter of 2009 and in 2010, respectively. Due to the recent deferral and cancellation of large construction projects in Alberta, both projects may benefit from improved labour productivity and availability and lower material costs in 2009 compared with 2008. The projects remain viable and are expected to be within the range of the project economics we originally contemplated.

In 2008, Power LP commenced construction of enhancements of the Southport and Roxboro coal plants to reduce environmental emissions and improve their economic performance. Capital expenditures in 2009 to complete the two projects as well as turbine upgrades at the North Island plant are expected to be approximately $101 million (US$83 million). Power LP plans to finance this spending with existing credit facilities.

If total cash requirements for 2009 remain as planned, the sources of capital will be from cash on hand, operating cash flows, the scheduled sale of a further 10% interest in the Battle River PSA and existing credit facilities. Additional requirements for growth opportunities that emerge may be funded by new public debt borrowings or public equity markets (Power LP). The Company does not expect that the funds invested in ABCP, which were exchanged for floating-rate notes in January 2009, will impede the Company's ability to fulfill its capital requirements for 2009.

Turmoil in the Canadian and U.S. financial markets and an ongoing economic recession may adversely impact the Company's access to capital markets. Despite the ABCP liquidity issues discussed under "Significant Events", the Company has a good contractual liquidity position. The Company continues to be in compliance with the financial covenants of its credit facilities and publicly issued debt, and at December 31, 2008 it had $111 million (2007 - $79 million) in cash and cash equivalents, and the following bank lines of credit:

($ millions) December 31,	2008	2007	2008	2007
	EPCOR		Power LP	
Bank lines of credit – committed	$ 1,890	$ 1,200	$ 300	$ 300
Bank lines of credit – uncommitted	49	45	20	20
	1,939	1,245	320	320
Outstanding loans	(251)	(155)	(87)	-
Letters of credit outstanding	(253)	(357)	-	-
Bank lines of credit available	$ 1,435	$ 733	$ 233	$ 320

Committed bank lines are used principally for the purpose of providing capital and letters of credit. Letters of credit are issued to meet the credit requirements of energy market participants and conditions of certain service agreements, and to satisfy legislated reclamation requirements. At December 31, 2008, the Company including Power LP had undrawn bank credit facilities of $1,668 million (2007 - $1,053), of which $562 million (2007 - $626 million) is committed for at least two years. The majority of the credit facilities are with Canadian tier 1 banks.

The committed bank lines also back the Company's commercial paper program which has an authorized capacity of $500 million, of which $113 million was outstanding at December 31, 2008 (2007 - $138 million).

The Company has a Canadian shelf prospectus under which it may raise up to $1 billion of debt with maturities of not less than one year. The shelf prospectus expires in November 2009. At December 31, 2008, the available amount remaining under this shelf prospectus was $400 million. In addition, Power LP has 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 with a maximum debt amount of $600 million. At December 31, 2008, Power LP had not drawn on the shelf prospectus and if Power LP requires major investments of capital it may obtain new capital from external markets at the time of the required investment, market conditions permitting.

The Company's debt maturing within one year was $26 million of long-term debt and $140 million of short-term commercial paper and bankers' acceptances as at December 31, 2008. Accordingly, with the amounts available to be drawn under its committed credit facilities, the Company expects to have sufficient liquidity for its plans in 2009.

Two of the Company's bilateral credit facilities totaling $200 million expire in 2009. While EPCOR plans to renew these facilities, draws under the facilities are expected to be at higher market rates and there can be no assurance that counterparty banks will want to renew.

Power market liquidity is also impacted by the current financial market instability. As there is less active energy commodity trading in our markets, power market liquidity is a concern. However, given the strength of our trading counterparties, we have been able to continue to effectively manage our portfolio.

Over 90% of the Company's employees are either members of the Local Authority Pension Plan (LAPP) or a registered defined contribution plan. The LAPP portfolio of investments incurred significant losses in 2008 as a result of the value erosion in capital markets. EPCOR's 2009 LAPP premiums increased by over 9% from 2008 and we anticipate a further increase for 2010 but will not be advised of the new rates until mid 2009.

The Company does not have any material direct exposure to international banking and insurance company failures that occurred in 2008 and there were no significant liquidity risks with respect to the Company's financial instruments at December 31, 2008.

Credit ratings

In November 2008, DBRS reaffirmed EPCOR's credit rating for long-term debt at A (low). Standard & Poor's also reaffirmed EPCOR's credit rating for long-term debt at BBB+ in February 2008. The significant increase in debt and interest expense to fund capital expenditures planned for 2009 will weaken certain credit rating ratios but is not expected to result in ratings action. A ratings downgrade for EPCOR could result in higher interest costs on new borrowings and reduce the availability of sources of investment capital.

Effects of Economic Downturn and Market Uncertainty

If the world-wide economic recession and credit and financial instability continues, particularly as they relate to Canada and the U.S., there may be an adverse affect on the Company's ability to 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, including the market price of Power LP's partnership units, making debt financing and LP equity financing more difficult and expensive, which may make finding accretive acquisitions more difficult for EPCOR and Power LP. While the current deteriorated financial market conditions prevail, the Company does not expect to rely on public equity markets through Power LP for funding as was originally planned.

Should market conditions worsen, the Company may suffer a credit rating downgrade and be unable to renew its bilateral credit facilities or access the public debt markets. While we believe that these circumstances have a low probability of occurring, we are mindful of how quickly market conditions changed in 2008. Management is therefore reviewing EPCOR's capital and operating programs and 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 honor 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

$ millions	Payments due by period					
	2009	2010	2011	2012	2013 and thereafter	Total
Acquired PPA obligations[1]	$ 135	$ 93	$ 96	$ 99	$1,089	$1,512
Capital projects[2]	525	187	10	-	-	722
Water and wastewater infrastructure projects[3]	58	15	14	12	17	116
Energy purchase/transportation contracts[4][5]	156	122	93	77	256	704
Asset retirement obligations	16	17	13	13	352	411
Long-term debt[6]	26	308	215	52	2,145	2,746
Interest on long-term debt	209	185	164	140	1,390	2,088
Short-term debt	140	-	-	-	-	140
Forward foreign exchange contracts and commodity contracts-for-differences	109	59	18	12	15	213
Operating leases	3	3	3	11	205	225
Operating and maintenance contracts[7]	27	28	29	30	172	286
Total contractual obligations	$1,404	$1,017	$655	$446	$5,641	$9,163

(1) EPCOR's obligation to make payments on a monthly basis for fixed and variable costs under the terms of its acquired PPAs will vary depending on generation volume and scheduled plant outages.

(2) EPCOR's obligations for capital projects include obligations for Keephills 3, Clover Bar Energy Centre and various Distribution and Transmission projects.

(3) EPCOR's obligations for water and wastewater projects include obligations for the City of Wetaskiwin, the towns of Chestermere and Taber and Suncor projects and the transfer fee related to the purchase of Gold Bar from The City of Edmonton.

(4) 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.

(5) 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.

(6) Obligations assumed by EPCOR upon transfer of Gold Bar from The City of Edmonton are not included as the amounts and terms have not yet been determined. The transfer fee obligation is included in water and wastewater infrastructure projects above.

(7) Operating and maintenance contracts are based on fixed fees escalated annually and have expiry terms ranging from 2017 to 2018.

In the normal course of business, EPCOR provides financial support and performance assurances, including guarantees, letters of credit and surety bonds, to third parties in respect of its subsidiaries.

The liabilities associated with these underlying subsidiary obligations are included in the consolidated balance sheet. In connection with the sale of Alberta mass-market competitive contracts to AESLP, effective February 1, 2005, EPCOR made arrangements to provide AESLP's prudential obligations with AESO and Alberta's wire service providers and gas distributors. On December 31, 2008, prudential obligations posted under this arrangement, in the form of letters of credit and guarantees, were $31 million (2007 - $27 million).

EPCOR is legally required to remove its power generation facilities and Genesee coal mine at the end of their useful lives and restore the plants and mine sites to their original condition. The Company estimates that the undiscounted amount of cash flow required to settle its asset retirement obligations is approximately $411 million, calculated using inflation rates ranging from 2% to 3%. The expected timing for settlement of the obligations ranges from 2009 to 2090. The majority of the payments to settle the obligations are expected to occur from 2023 to 2064 for the power generation plants, and from 2009 to 2013 for sections of the Genesee coal mine.

As part of a 2003 disposition, EPCOR agreed to indemnify certain liabilities of UE Waterheater Operating Trust (the Trust) until 2010 primarily consisting of potential tax liabilities that could arise relating to operations of the water heater rental business prior to the sale by EPCOR to the Trust. Any known liabilities associated with this indemnification are reflected on the balance sheet at December 31, 2008 and it is uncertain what, if any, additional amounts may be incurred in the future.

The June 2006 sale of the initial 55% interest in the Battle River PSA was completed through a series of transactions. Before the sale, we owned approximately 70% of the PSA. To facilitate the eventual sale of a 100% interest to ENMAX Corporation, we acquired the remaining 30% interest in the PSA from non-EPCOR syndicate members for cash and an ownership interest in the Company's Sundance Power Syndicate Agreement (Sundance Swap). As part of the agreement for the Sundance Swap, we committed to providing interest-free notes of approximately $19 million to the counterparties to fund any income tax liabilities that they incur for the dispositions of their interests in the Battle River PSA. At December 31, 2008, the Company had advanced approximately $13 million (2007 - $13 million) and the remaining $6 million of potential advances is not included in the contractual obligations table above.

In October 2007, the Company entered into an agreement with the Town of Chestermere to provide upgrading and retrofitting of the town's water and wastewater infrastructure along with related operations and maintenance services. Pursuant to the agreement, EPCOR will manage a series of capital projects for the water and wastewater infrastructure as approved by the Chestermere Town Council (Town Council). The Company has agreed to provide financing of the capital outlays over the 20-year term of the agreement to a maximum of $35 million, unless otherwise agreed to by the parties. At December 31, 2008, capital outlays of $10 million were incurred. While the actual timing and amounts of the capital outlays will vary based on Town Council resolutions, we may be required to finance the remaining $25 million in 2009.

In December 2007, the Company entered into a 20-year lease for space in a new office tower for its headquarters in downtown Edmonton. The lease will commence January 1, 2012 or earlier and the existing lease for Edmonton offices will expire at the end of 2011.

In May 2008, EPCOR entered into an agreement with Suncor to design, build, own and operate a potable-water and wastewater treatment plant for Suncor's Voyageur project over a 20-year term, in return for payments totaling approximately $99 million commencing upon completion of the design-build phase in 2009. The project will require a capital outlay of approximately $31 million, of which $16 million had been incurred to the end of 2008.

In December 2008, Power LP signed an agreement to sell its Castleton facility, located in the state of New York, to Castleton Energy Center, LLC (CEC) for approximately US$10 million, subject to closing adjustments. The sale is expected to close in the second quarter of 2009, subject to certain closing conditions and regulatory approvals. This commitment is not included in the contractual obligations table above.

On January 21, 2009, the Edmonton City Council approved a motion to transfer the Gold Bar assets and associated long-term debt to EPCOR. Gold Bar handles wastewater requirements for 700,000 residents of The City of Edmonton and has a current treatment capacity of 310 megalitres per day. The transaction is to be completed no later than March 31, 2009, for a transfer fee of $75 million payable over seven years commencing in 2009, which is included in the above table. At December 31, 2008, the estimated book value of the Gold Bar assets was $266 million and the estimated book value of the long-term debt to be assumed by EPCOR was $110 million. The terms of the long-term debt and any other potential financing for the transaction have not yet been determined and are not included in the contractual obligations table above.

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) was incurred in 2008.

In January 2007, we announced that we would re-examine the design and schedule of the Kingsbridge II wind power development project in Ontario. In October 2008, the Company and the Ontario Power Authority mutually agreed to terminate the renewable energy supply agreement for Kingsbridge II. Accordingly, EPCOR will not proceed with the project as originally planned and is considering its future. We did not incur any asset write-downs in 2008 as a result of the decision.

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

OUTLOOK

In 2008, we focused on operational excellence, power and water development projects including the Morris acquisition and new commercial contracts in Water Services, completion of the EL Smith upgrade and DESS projects as well as continued construction of Keephills 3 and Clover Bar Energy Centre. In 2009, we intend to continue with this strategy although we will temper the pace of business growth, as is appropriate in the face of a weakening economy.

Our 2009 capital expenditure program is expected to be approximately $800 million and will focus primarily on continuing with the construction of Keephills 3 and Clover Bar Energy Centre. We anticipate a slow down in the construction of generation plants in 2009 due to reduced access to capital and environmental and regulatory uncertainty. We also anticipate that there will continue to be an appetite, but at a slower pace, for wind power generation as governments appear to remain committed to offering long-term power purchase contracts for this type of generation. In 2009, we will continue our power business development activities but intend to apply stricter investment criteria.

Demand for water is expected to continue to increase and we anticipate increased requirements for better water management practices including watershed management and conservation. With the lack of capital available, there is a current trend for municipal governments to turn to public-private partnerships. We will pursue expanding our portfolio of commercial water contracts.

The existing transmission infrastructure in Alberta is increasingly inadequate and we will continue to strongly support government and public approval for the construction of additional transmission capacity in the province.

The addition of the Gold Bar business to our portfolio will expand our wastewater management expertise which should strengthen our competitive position for developing new wastewater treatment plants outside Edmonton.

Government environmental policy remains uncertain and new stringent emission standards could evolve and have a material impact on EPCOR's operations. EPCOR is supportive of thoughtful and prudent initiatives to decrease emissions. This situation requires us to continue to be vigilant in discussing policy initiatives with legislators to help ensure they are fair and do not result in impractical or damaging policies. We plan to be actively engaged in raising our public profile as an environmentally responsible water and power provider.

Our strategy of improving our existing power and water operations continues which means extracting the maximum efficiency and effectiveness from our existing operations.

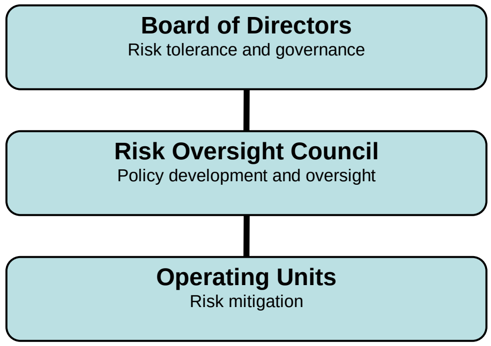
We expect our earnings to be higher in 2009 and factors that will impact EPCOR in 2009 include:

- No items similar to the sale of portfolio investments in 2008;
- 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;
- A full year of earnings from Morris and the first unit of the Clover Bar Energy Centre in 2009 compared to three months and ten months, respectively in 2008 and six months of earnings from the second unit of the Clover Bar Energy Centre in 2009;
- Net income from nine months of Gold Bar operations;
- Increased earnings from our expanding portfolio of commercial water services contracts;
- Increased expenses for business development activity emphasizing water and environmentally responsible power; and
- Higher financing costs to support our 2009 capital expenditure program, partly offset by higher capitalized interest.

In addition, fair value changes and asset impairments due to changes in the economy could occur and lower power prices in 2009 could reduce Alberta electricity margins on the unhedged portion of our portfolio.

RISK MANAGEMENT

Approach to risk management



Our approach to risk management is to identify, monitor and manage the key controllable risks facing the Company and consider appropriate actions to respond to uncontrollable risks. Risk management includes the controls and procedures implemented to reduce controllable risks to acceptable levels and the identification of the appropriate management actions in the case of events occurring outside of management's control. Acceptable levels of risk for EPCOR are established by the Board of Directors, representing the shareholder, and are embodied in the decisions and corporate policies associated with risk. Risk management is generally carried out at three levels. Firstly, general oversight, policy review and recommendation, and reviews of risk compliance are provided by the Risk Oversight Council, a senior executive group including the Vice President, Risk Management. Secondly, the Vice President, Risk Management is generally responsible for monitoring compliance with risk management policies. His responsibilities include oversight of the enterprise risk management program and leadership of our commodity risk management (or middle office) function. Thirdly, the business units and shared service units are responsible for carrying out the risk management and mitigation activities associated with the risks in their respective operations. These risk management activities are integral aspects of the business units' and shared service units' operations. We believe that risk management is a key component of the Company's culture and we have put into place cost-effective risk management practices. At the same time, we view risk management as an ongoing process and continually review our risks and look for ways to enhance our risk management processes.

We maintain a Compliance and Ethics Policy which includes an Accounting and Auditing Complaint Procedures Policy which provides for confidential disclosure of any wrong-doing relating to accounting, reporting and auditing matters. The policy prohibits any retaliation against any person making a complaint.

Electricity price and volume risk

We buy and sell electricity in the wholesale markets of Alberta, Ontario, and the U.S. Such exchanges are settled at the spot market prices of the respective markets. We currently use purchase and sale arrangements including contracts for differences (CfDs) and firm price physical contracts for periods of varying duration to manage our exposure to spot price variability within specified risk limits. The CfD is a contract whereby the seller pays to the buyer the difference between the reference market price and the contract price at the contract expiry date. If the difference is negative then the buyer pays the seller. Due to limited market liquidity and the varying shape of electricity consumption during peak usage hours compared with off-peak usage hours, it is not possible to hedge all positions every hour.

Our policy specifies limits, such as total exposure and stop-loss limits, and generally we trade in electricity to reduce the Company's exposure to changes in electricity prices or to match physical and financial obligations. A limited portion of our trading is speculative.

When aggregate customer electricity consumption (load shape) changes unexpectedly, EPCOR is exposed to electricity price risk. Load shape refers to the different pattern of consumption for peak hours and off-peak hours. Consumption is higher during peak hours when people and organizations are active, than during off-peak hours. We purchase blocks of electricity in advance of consumption to minimize exposure to extreme price fluctuations, especially during higher priced peak-hour periods. In order to do this, we rely on historical aggregate consumption data 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, we are exposed to the prevailing market prices because we must either buy electricity if we have less than we need (short) or sell electricity if we have more than we need (long). Exposures can be exacerbated by other events such as unexpected generation plant outages and unusual weather patterns.

With the withdrawal of certain financial counterparties from the energy trading market, particularly in Alberta, and various companies being less active in energy commodity trading due to current economic conditions, power markets are less liquid which means it takes longer to enter and exit commodity positions.

Electricity sales associated with EPCOR's Genesee units 1 and 2 are governed by the terms of the associated PPAs. 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. Our other plants, such as Brown Lake, Miller Creek, and Kingsbridge I operate under long-term commercial contracts with creditworthy counterparties. Our 40% interest in Joffre is governed by a long-term commercial contract. However, its operations are subject to market price variability as there are provisions in the contract that require the facility to run to provide steam to the host facility, irrespective of market prices. Although our 50% interest in Genesee 3 is not covered by a long-term commercial contract, it is a base-load coal-fired generating unit with a relatively low variable cost and it will generally run when it is available. It is subject to spot price exposure when those prices are below its price for corresponding variable costs or the unit suffers an unplanned outage. Since its commissioning, the occasions when Alberta electricity prices have been below Genesee 3's variable cost have been very limited and the turbine blade failure in 2008 was the only major incident. We are pursuing new operating asset improvement, critical spares and management incentive programs to minimize this exposure.

Electricity price and volume risks for Power LP are lower than they would be in a merchant environment since the facilities generally operate under long-term power sales contracts with investment-grade power and steam buyers.

In order to stabilize future cash flows, we will seek to re-contract existing generation plants under new or extended contracts and acquire new plants that meet our investment criteria. Although commercial contracts provide better electricity price and volume protection than if the plant operations were completely subject to spot market risk, the contract provisions must be met and the Company can incur charges in the event of unplanned outages or variations from the contract performance benchmarks.

Natural gas price and volume risk

Price risk associated with natural gas purchased for our natural gas-fired generation plants operating under commercial contracts is mitigated by the provisions of the contracts which generally require the contract power buyer to pay the generator a market indexed price or buy the gas outright on behalf of the plant. Natural gas price risk associated with Joffre is partly flowed through to its electricity sale prices. For Power LP's natural gas-fired plants, the natural gas price risks have been minimized by executing fixed price long-term contracts for a significant portion of the supply of natural gas or through the use of tolling agreements. However, certain Power LP plants are at risk for the fuel supply after the term of the fixed price contract if it expires before the termination of the power purchase agreement. For example, for its Tunis plant, Power LP will be exposed to commodity price risk on its natural gas purchases commencing with the expiry of its natural gas contract in 2010 until the expiry of the power purchase agreement in 2014, unless Power LP is able to secure another fixed-price natural gas supply contract for that period. We will attempt to bridge these gaps by securing new natural gas contracts.

For our retail and wholesale natural gas contracts, we balance our exposure by purchasing natural gas back-to-back with our sales contracts to the fullest extent possible. That is, we normally purchase only enough physical natural gas delivery in advance to satisfy the natural gas load represented by expected volumes from signed contracts. Natural gas exposures are managed to the specific limits established by our risk management policies.

EPCOR 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 held for resale in current or forward markets and is subject to the volatility of natural gas prices.

The initial term of a block of retail natural gas contracts that we acquired in 2000 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, EPCOR will experience losses on servicing these contracts. We will also have exposure to losses from another five-year renewal period expiring in 2014, to the extent customers choose to renew. Upon renewal of the contracts in 2009, we will record any estimated loss in servicing the remaining contracts over the term ending in 2014. This potential loss could be material depending on the renewal rate and the difference between the contract price and our estimate of future natural gas prices. As we are no longer active in the retail natural gas market, we will continue to seek opportunities to exit from these contracts.

Commodity risk measures and limits

Our tolerance for energy commodity price and volume risk is based on our assessment of the trade-off between risk and return for the underlying commodity. The risk tolerance of our consolidated energy commodity portfolio is established by total exposure limits as set out in policy and approved by the Board of Directors.

We use Value-at-Risk (VaR) as the basic component to measure the risk in our energy commodity portfolio. VaR is the maximum expected loss over a given period of time at a given level of confidence. Our VaR is calculated at a 95% statistical confidence level over a holding period of 20 business days. In other words, over the 20-day period commencing with the point in time that the VaR is measured, there is a 1 in 20 likelihood that the fair value of our 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, we apply 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. EPCOR's one year energy commodities total exposure, when considering the portfolio on a net basis, as at December 31, 2008 was $22 million (2007 - $8 million).

To supplement the total exposure estimates, we use 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 the Company's total exposure limits. We employ a series of operational limits for our 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 Risk Oversight Council and quarterly to the Board of Directors.

Operational risk

The ability of EPCOR's power plants to generate the expected amount of electricity that will be sold under contract or to the applicable market has a significant 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 power purchase agreement, revenue may be insufficient to cover contractual or financial obligations.

Our plant operations are susceptible to outages due to equipment failure, which could make plants unavailable to provide service. A good example of this was the blade failure at Genesee 3 in 2008. This is also true for the generation units associated with the acquired PPAs. Such risks are partly mitigated by our, and the acquired PPA plant owners' operating and maintenance practices that are intended to minimize the likelihood of prolonged unplanned down time. We have a very strong record of availability, as measured against our peers by the Canadian Electricity Association. The penalty provisions within the PPAs provide appropriate incentives to owners to keep the plants well maintained and operational. The terms of the PPAs also provide force majeure protection for high-impact low probability events including major equipment failures. Our maintenance practices are augmented by an inventory of strategic spare parts, which can reduce down time considerably in the event of failure. We are also in the process of reviewing our critical spares program for improvement opportunities. Finally, we have secured appropriate business interruption insurance to reduce the impact of prolonged outages caused by insured events at our generation plants and at the plants supporting our acquired PPAs. Our business interruption insurance coverage applies after 45 days of interruption. Appropriate insurance claims for the turbine blade failure have been made and recognized in our financial results for 2008.

Operational risk in Distribution and Transmission, and Water Services is also managed through sound maintenance and safety practices. In addition, Water Services performs continuous and rigorous quality control testing of water purification consistent with government and industry standards. The ability of the water treatment plants to maintain adequate treatment and testing of water on a continuous basis is essential so that the prescribed requirements under regulation or conventional industry standards are met. Failure to properly maintain fully functioning treatment and measurement systems could result in regulatory fines, lost revenue or the occurrence of public health issues.

Fuel expense for the Genesee plants is predominantly comprised of coal supply. Coal is supplied under long-term agreements with the Genesee Coal Mine joint venture, of which we hold a 50% interest. The price of coal is based on a cost-of-service model with annual updates to inflation, interest rate and capital budget parameters and is therefore not subject to coal market price volatility. EPCOR and the Genesee Coal Mine joint venture maintain coal stock-pile inventories which are available as fuel supply in the event that the coal mine equipment and operations suffer significant disruption.

Existing coal supply contracts will meet the 2009 requirements for Power LP's coal-fired power plants (Roxboro and Southport) with options in place for approximately one-half of the anticipated requirements for 2010. While we believe that coal supply will be available for these facilities, there can be no assurance of when or on what terms.

The level of waste heat fuel at Power LP's Ontario plants, provided by TransCanada PipeLines Limited's adjacent compressor stations, is dependent upon the amount of natural gas throughput on the pipeline and the output of the compressor stations. In addition, the availability of waste heat gases is dependent upon the compressor stations remaining in use and their ability to supply the waste heat gases. The decline in waste heat availability that began in 2007 and continued in 2008 was due to lower throughput on the TransCanada pipeline system. We expect waste heat availability to continue to decrease during 2009 with marginal declines thereafter and the potential for recovery of volumes beginning in 2012.

Performance of our hydroelectric facilities is dependent upon the availability of water and regulatory limits for the protection of fish. Variances in water flows are caused by uncontrollable weather related factors affecting precipitation and 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 an impact on revenues from the associated plants.

We manage the wood waste fuel risk at Power LP's biomass and wood waste plants through contracts with a number of wood waste suppliers, and a two-year wood supply agreement for the Calstock plant was negotiated in August 2007. However, the current economic downturn is affecting the forestry industry particularly hard which may impact our suppliers and increase our exposure to risk for this type of fuel.

We use several key computer application systems to support our various operations such as electricity and water distribution network control systems, electricity and water plant control systems and electricity settlement and billing systems. We take measures to reduce the risk of malicious corruption or failure of these systems and the hardware and network infrastructure on which they operate, as well as electronic theft of data.

Environment, health and safety risk

Environment

EPCOR's power and water operations are subject to laws, regulations, and operating approvals which are designed to reduce the impacts on the environment. Furthermore, the Company's facilities could experience incidents that result in spills or emissions in excess of those permitted by law, regulations or operating approvals.

EPCOR seeks to ensure that it complies, in all material respects, with the laws, regulations and operating approvals affecting its facilities, and minimizes the potential for incidents by incorporating environmental management practices in its strategy, policies, processes and procedures. To achieve this EPCOR requires each plant and facility to have an environmental management system (EMS) which is based on the ISO 14001 standard. These systems encompass the identification of the scope, objectives, training and stewardship of our environmental responsibility. Each plant and facility is also subject to environmental audits to help ensure compliance with the EMS and all regulations.

EPCOR's strategy includes a commitment to environmental performance on existing and new facilities, renewable energy and investment in the development of clean coal technology for use with carbon capture and storage. In addition, EPCOR's environmental policy commits the Company and all of its employees to environmental compliance and stewardship.

Our operations, technical support and environment departments work on technology solutions to emerging environmental issues such as mercury emission mitigation. We are active in the development of the carbon dioxide (CO2) offset market by designing protocols, developing projects that will qualify for offsets and trading offsets.

EPCOR complies, in all material respects, with federal, provincial, state and local environmental, health and safety legislation and guidelines with respect to its operations. Compliance with future environmental legislation may require significant capital and operating expenditures and failure to comply could result in fines and penalties or the regulator could force the curtailment of operations.

Canada

EPCOR's generation business is a significant emitter of CO2 (a greenhouse gas), NOx and sulfur dioxide (SO2). The Alberta government is the only North American jurisdiction which has implemented regulations relating to such emissions that were in effect in 2008. The federal government and several provincial and state governments have proposed various forms of greenhouse gases (GHG) regulations, and it is expected that other jurisdictions will also propose GHG regulations.

The Alberta Government's Specified Gas Emitters Regulation (SGER) came into effect in 2007. The SGER is applicable to all facilities in Alberta that produce over 100,000 tonnes of CO2 equivalent (CO2E or greenhouse gas) per year. Accordingly, EPCOR's Genesee generating units 1, 2 and 3 and the generating units subject to PPAs in which EPCOR holds interests (i.e. Sundance 5 and 6 and Battle River) are subject to the regulation. The regulation imposes a CO2E intensity reduction of 12% from the average CO2E emissions intensity for the 2003 to 2005 period. Regulated entities can meet their compliance requirements by (1) reducing their facility's emissions by 12%; (2) paying into the Climate Change Emission Management Fund at $15 per tonne for all emission in excess of their emission intensity target or; (3) retiring GHG emission offsets created from Alberta based projects. The reporting deadline for the 2008 calendar year is March 31, 2009.

The costs associated with compliance with the SGER for our Genesee 1 and 2 generating units are recoverable from the PPA holder under the terms of the PPA. These costs amounted to approximately $5 million in 2008 and are estimated to be approximately $5 million per year in the future. EPCOR's Genesee 3 unit is considered a new unit under the SGER and will receive a three-year grace period, after which its compliance obligation will be phased in over five years, starting at a 2% intensity reduction and increasing to 12% by the end of the five years. EPCOR's share of the estimated compliance cost for Genesee 3, after the grace and phase-in periods, is approximately $3 million per year. EPCOR's share of the compliance costs for the Sundance 5 & 6 PPA is estimated to be approximately $6 million per year and approximately $2 million for the Battle River PPA in 2009. These cost estimates assume that no GHG emission offsets will be used to comply with the SGER.

EPCOR has actively participated in the development of the GHG offset markets in Alberta and has developed several offset projects. EPCOR is a member of both the International Emission Trading Association which actively develops emission trading policy, and the Industry Provincial Offset Group which contributes to policy supporting the use of offsets in emissions trading programs and offset quantification protocols.

Moreover, EPCOR has been purchasing offsets for over four years, has entered into more than 12 offset purchase agreements, purchased approximately $4 million of offsets in 2008 and $1 million in 2007, and retired approximately 540,000 tonnes of offsets against the 2008 compliance obligations associated with its ownership of the Sundance 5 & 6 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 $5 million.

The current state of federal green house gas and air pollutant policy is very uncertain. On April 26, 2007, and March 10, 2008 the Canadian Environment Minister released information regarding a proposed regulatory framework referred to as "Turning the Corner", to reduce greenhouse gas (GHG) emissions and air pollution, including CO2, NOx and SO2, in Canada. The recommendation proposed a 20% absolute reduction in greenhouse gases from 2006 levels by 2020 and a 50% reduction in air pollution by 2015. Late in 2008, the Canadian federal government indicated that it will work closely with the United States to establish a North America-wide GHG emission cap and trade system which would replace the Turning the Corner regulatory framework. To date, there has been no policy direction provided by the federal government.

If the federal government were to implement GHG cap and trade regulation with targets similar to those proposed in the Turning the Corner, EPCOR estimates that its pre-tax costs of federal GHG compliance could range from $8 million to $12 million for 2010, escalating proportionately with the increasing emission reduction targets after 2010. There are a number of uncertainties associated with the estimate which include, but are not limited to, whether the regulations enacted reflect the proposed targets, the extent to which future costs will be recoverable from customers, the future composition of EPCOR's generation assets, the future production of electricity from EPCOR's generation assets, the extent and timing of the development of a carbon offset market, whether economically feasible emission-reducing technology emerges, the market price for carbon offset credits and other measures that the Company might undertake to reduce its emissions.

EPCOR participates in the Clean Air Strategic Alliance which has recommended to the Alberta government a framework on NOx, SO2, mercury and particulate emissions, for both natural gas-fired and coal-fired generation plants. EPCOR will participate in tests and install equipment over the next 3 years to meet Alberta requirements to reduce mercury emissions by 70% by 2011.

As part of its strategy to reduce its GHG emission, EPCOR is participating in a $33 million research project to complete a front-end engineering design (FEED) study of a clean coal project. EPCOR, Alberta Energy Research Institute (AERI) and Natural Resources Canada have each contributed $11 million to the study and it is to be completed in early 2010. In addition, EPCOR has submitted two proposals for the Government of Alberta's Invitation for an Expression of Interest – Carbon Capture and Storage (CCS) Projects in Alberta. The first project is an Amine project which focuses on technology that can be applied to existing coal-fired generation plants. The second is the Genesee Integrated Gasification and Combined Cycle with Carbon Capture technology. Both EPCOR projects have been invited to participate in the second stage and submit full project proposals.

In 2008, EPCOR participated with industry, government and non-government organization stakeholders in the 5-year Clean Air Strategic Alliance Review of the Alberta Electricity Framework. This review is scheduled to culminate in mid-2009 with recommendations to the Minister of Alberta Environment on new air pollutant emission standards for coal and natural gas-fired electricity generating plants to be approved after 2010. These new standards will be based on Best Available Technology Economically Achievable and will cover emissions of NOx, SO2, particulate matter (PM) and mercury. These standards will likely require the installation of additional and more expensive emission controls on generation facilities that are permitted and built after 2010. Existing generating units will not be affected by these standards until they reach the defined end of their lives. The electricity framework requires a review of the PM emissions from existing coal-fired units in 2009, which may result in additional control costs in subsequent years; however, there is insufficient information at this time to determine the financial implications.

In 2008, EPCOR completed full scale activated carbon injection demonstration testing on Genesee 3. The results from the testing indicate that EPCOR 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 with sufficient time to test and commission the equipment. Estimates of the costs of installing mercury removal equipment are approximately $2 million per generating unit, but these estimates are subject to change based on the engineering and design work to be done in 2009.

Our water and wastewater operations comply in all material respects with federal, provincial, and local environmental, health and safety legislation and guidelines. These operations are controlled through stringent water treatment standards and controls covering the quality of treated water and the number, frequency and form of water quality testing, as well as mandatory improvements to the water treatment process. We are actively involved in a watershed management program, which involves the protection and management of our Edmonton water source from impurities such as soil particles, excess nutrients, fertilizers, microbiological contaminants and organic materials. Activities undertaken include river water quality monitoring, forming stakeholder partnerships to work on watershed issues, and acting as a resource and leader on quality issues of the North Saskatchewan River Basin. Based on our current knowledge, EPCOR does not foresee any material environmental issues arising as a result of the transfer of the Gold Bar facility, which is expected to close by March 31, 2009.

United States

We continually assess the potential impact on Power LP assets of future legislation and regulatory requirements for certain air emissions regulations including climate change.

U.S. President Barack Obama has indicated that his administration will work to implement a cap-and-trade system to reduce the U.S. GHG emissions. As there is currently no proposed framework or regulation, there is no way of estimating the financial implications to Power LP. However, there are two regional GHG regulatory programs that have been or will likely be implemented in several states: the Regional Green House Gas Initiative (RGGI) applicable to the seven New England states, and the

Western Climate Initiative (WCI) which impacts several western states. The RGGI regulations are implemented on a state by state basis and the Castleton facility in New York and the Kenilworth facility in New Jersey could potentially be affected by the regulations. Power LP has five plants that may be affected by the WCI, four plants in California and one in Washington. There is insufficient information at this time to estimate the financial impact of the WCI on Power LP.

On July 11, 2008, the U.S. Washington District Court vacated the United States' Clean Air Act (US CAA) Clean Air Interstate Rule (CAIR) which was designed to control SO2 and NOx emission through a regional cap-and-trade program. On December 23, 2008 a full panel of the same court decided to remand CAIR to the Environmental Protection Agency rather than vacating the rules. As a result, commencing in 2009, CAIR will require reductions in NOx and SO2 at Power LP's Southport and Roxboro facilities. Despite the earlier vacating of CAIR, the Power LP had elected to move forward with capital upgrades at these facilities to substantially reduce NOx and SO2 emissions and improve economic performance. Assuming that CAIR remains in effect, Power LP will have to purchase additional SO2 and NOx 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, Power LP will continue to monitor and assess the situation. The Clean Air Mercury Rule (CAMR) will continue to affect both plants, but emissions are currently well below the maximum permitted levels.

Compliance with new regulatory requirements may require Power LP to incur significant capital expenditures or additional operating expenses.

Health and safety

We manage our health and safety risks through a company-wide health and safety management system and measure our health and safety performance against recognized industry and internal performance measures. We conduct numerous external and internal compliance audits to verify that our health and safety management system meets and/or exceeds the regulatory requirements in which we operate our business. We have committed to working with industry partners to share and improve health and safety within the industry based on our expertise.

Our operations are subject to the risks of a widespread influenza outbreak or other pandemic illness. We have developed plans to respond to a potential pandemic influenza to help maintain a sufficient healthy workforce and enable the Company to deliver reliable power and water to customers in such an event.

Political, legislative and regulatory risk

EPCOR is subject to risks associated with changing political conditions and changes in federal, provincial, state, local or common law, regulations and permitting requirements in Canada and the United States. It is not possible to predict changes in laws or regulations that could impact the Company's operations, income tax status or ability to renew permits as required.

Under the Settlement System Code of the *Electric Utilities Act* (Alberta*),* a retailer must rely on load settlement agents to provide customer consumption data to be used in computing its customers' bills. Under the *Alberta Regulated Default Supply Regulation*, regulated rate providers may not collect from customers an amount undercharged due to a billing error if the error occurred more than 12 months before the date of the revised billing.

The AUC sets rates intended to permit the regulated Distribution and Transmission and RRT customer services businesses to recover estimated costs of providing service and a fair rate of return on investment in distribution and transmission and customer service assets. Our ability to recover the actual costs of providing service and to earn a fair return is dependent upon achieving the forecasts established in the rate-setting process. In 2008, the AUC set final rates for the 2007-2009 Distribution and Transmission tariffs and RRT non-energy charges. These application processes have risks customarily associated with rate-regulated tariff filings.

Commencing on July 1, 2006, our charges to residential, farm and small commercial Alberta customers for energy are regulated under the AUC's 5-year Regulated Rate Option (RRO). The RRO is the default option for consumers in the aforementioned customer segments who have not entered into contracts with an electricity retailer. Electricity rates under the RRO are based on a combination of long-term and monthly forward hedges, with an increasing percentage of monthly forward hedges over the 5-year transition period. At the end of the transition period in 2010, the RRO is intended to be similar to the design of the current Alberta natural gas default rate, which is based on monthly forward prices. As this electricity pricing model results in increasing volatility in prices to our customers over the transition period, it may impact our volume of electricity sales, as well as electricity margins. To date the financial impact to EPCOR has been insignificant.

EPCOR's water treatment and distribution services to customers within The City of Edmonton are rate-regulated by The City of Edmonton Council pursuant to a PBR bylaw. Rates approved under this bylaw are intended to allow the Company to recover its operating costs and earn a return on equity, as well as provide an incentive to manage cost increases below inflation. If the performance targets outlined in the bylaw are achieved, water rates are increased by the change in the rate of inflation less an efficiency factor. The City of Edmonton Council approved a renewal of the PBR bylaw on July 4, 2006 for the 5-year period commencing April 1, 2007. Our ability to fully recover operating and capital costs and to earn a fair return is dependent upon achieving the performance targets prescribed in the Bylaw, maintaining cost increases below inflation and managing operational risks.

Rates for water sales to regional water commissions that supply water to communities surrounding Edmonton are regulated by the AUC on a complaints-only basis, whereby such communities may apply to the AUC to resolve disputes related to rates, tolls or charges determined by the Company. EPCOR sets the rates it charges to these regional water commissions to recover related operating and capital costs plus a reasonable rate of return. Actual operating and capital costs associated with the provision of water to the commissions, and a fair return on rate-base, are recovered in accordance with a full cost-of-service method which has been approved by the AUC.

In December 2008, the Regional Water Customers Group, which represents the interests of these regional water customers, requested that the AUC issue a Notice of Application in respect of its complaints regarding wholesale water rates for the years 2004 to 2007. In January 2009, the AUC issued a Notice of Application inviting any parties wishing to intervene in the proceeding to submit a Statement of Interest to Participate by February 20, 2009. In March 2009, the AUC requested comments regarding a process to address the rate application. The AUC has not yet issued a timeline in respect of the proceeding.

Income Tax Risk

On December 15, 2008, the U.S. - Canada Income Tax Treaty (Treaty) was ratified and contains extensive changes. The Treaty includes the addition of treaty denial provisions applicable to payments obtained from or through certain hybrid entities. A hybrid entity in this context means one with different tax treatments under different tax jurisdictions, which is the case for Power LP. The treaty denial provisions will be effective in 2010. EPCOR continues to evaluate the potential impact, if any, that the treaty denial provisions will have but management expects to be able to address the denial provisions without realizing any materially adverse tax consequences. The Treaty also contains changes to withholding tax rates on various items, which based on our review, did not have a material impact on the Company's income taxes payable in 2008.

Canadian tax legislation (SIFT Legislation) related to specified investment flow-through entities (SIFTs) 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. It is expected that under the SIFT Legislation, Power LP will become taxable commencing in 2011 as long as it does not exceed the Canadian Department of Finance's normal growth guidelines by issuing greater than $1.7 billion of new equity before 2011. All other things being equal, the SIFT Legislation will likely result in a reduction of cash available for distribution by Power LP commencing after 2010.

Project risk

Our construction and development of generation, electric transmission and distribution, and water treatment facilities and acquisition activities are subject to various engineering, construction, stakeholder, government and environmental risks, many of which are beyond our control. Furthermore, rapid cost escalation has occurred in a number of regions in which we operate. These risks can translate into performance issues, delays and cost overruns. We attempt to mitigate these risks by performing detailed project analysis and due diligence prior to and during construction or acquisition, and by entering into favourable long-term contracts for output and services to be provided where and when available.

Credit risk

Credit risk is the possible financial loss associated with the ability of counterparties to satisfy their contractual obligations to EPCOR, including payment and performance. EPCOR attempts to manage credit risk and limits exposures through its credit policies and procedures. These include an established credit review and monitoring process, specific terms and limits, daily monitoring of wholesale exposures against credit limits, appropriate allowance provisioning and use of credit mitigation strategies, including collateral arrangements. Counterparties to the PPAs, power and steam sales contracts, energy supply agreements and wholesale and merchant trading, and independent system operator counterparties are primarily investment grade.

Wholesale credit risk

Exposure to credit risk for wholesale and 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 netting amounts if permitted by legally enforceable set-off rights.

Due to price volatilities of electricity and natural gas, the market value of individual credit exposures could exceed the credit limits granted to those counterparties. If the counterparty fails to perform its obligations, EPCOR could incur a material loss. This could include, but is not limited to, the cost of replacing the obligation, a loss on amounts owed from the counterparty or a loss incurred on liability settlements. EPCOR's exposure to wholesale and trading counterparties is summarized below. Exposures represent 60 days of potential accounts receivable plus the fair value of the contracts.

December 31 ($ millions)	2008	2007
Wholesale (includes industrial end-use customers, trading and position management counterparties)		
Investment grade[(1)]	$108	$117
Below-investment grade[(1)]	13	19
Total	$121	$136

(1) Credit ratings are based on EPCOR's internal analyses which take into account the ratings of external credit rating agencies.

The year-over-year decrease in the credit exposure of both investment grade and below-investment grade counterparties was primarily due to reduced tenure on current exposures. During 2008, a number of international financial institutions suffered serious losses and ultimately failed, were sold or received capital injections under the U.S. Troubled Asset Relief Program. Some of these institutions have Canadian subsidiaries which are trading counterparties with EPCOR. The total exposure to these companies at December 31, 2008 was approximately $10 million. There have been no defaults on these agreements or transactions with this group of wholesale counterparties to date.

Economic conditions in Canada and the U.S. have significantly deteriorated in recent months, which may impact the creditworthiness of some of EPCOR's counterparties. EPCOR has taken credit mitigation strategies, including collateral arrangements, to mitigate potential credit losses. However, there is no assurance that EPCOR will not incur a credit loss due to non-performance of a counterparty.

RRT and default supply credit risk

Exposure to credit risk for residential and commercial customers under default power supply rates are generally limited to amounts due from the customers for electricity consumed but not yet paid for. As the electricity procurement for these customers has evolved to shorter terms, our potential exposure to losses for the purchase of electricity that is not consumed has been largely mitigated.

This portfolio is reasonably well diversified with no significant credit concentrations. Historically, credit losses in these customer segments have not been significant and depend in large measure on the strength of the economy and the ability of the customers to effectively manage their affairs through economic cycles and competitive pressures. While economic conditions deteriorated worldwide over the course of the reporting period, the effects had not yet significantly impacted the RRT and default supply market in Alberta. However, EPCOR may experience additional credit losses in 2009 and 2010.

EPCOR's exposure to RRT and default customer credit risk, which is primarily the risk of non-payment for electricity consumed by these end-use customers, is summarized below. Exposures represent a 60-day potential accounts receivable value for this portfolio.

December 31 ($ millions)	2008	2007
Unrated RRT and default supply customers[1]	$137	$144

(1) Under the *Alberta Electric and Utilities Act*, EPCOR provides electricity supply in its service area to residential, irrigation and small commercial customers and those commercial and industrial customers in its service areas who have not chosen a competitive offer and consume electricity under default supply arrangements.

(2) EPCOR monitors credit risk for this portfolio at the gross exposure level rather than by individual customer account. RRT regulations allow for a recovery of a percentage of forecasted credit losses relating to RRT.

The year-over-year decrease in exposure relates to the 60-day potential accounts receivable and was driven mainly by the RRO pricing structure.

Power LP credit risk

Power LP has exposure to credit risk associated with counterparty default under its power and steam sales contracts, energy supply agreements and foreign exchange contracts. In the event of default by a counterparty, existing PPAs and steam purchase agreements may not be replaceable on similar terms as many of these agreements have favourable pricing relative to their current markets.

The reorganization of Equistar under Chapter 11 of bankruptcy code has not affected the operations of Morris. Based on LyondellBasell's public comments regarding the scope of the reorganization and the competitive position of the Morris facilities within the LyondellBasell portfolio, management believes that the facility will continue to operate in the ordinary course. However, Equistar retains the right to reject the long-term energy services agreement for the purchase of the electricity produced from Morris' plant and in such an event, the pre-petition amounts owing to Power LP of $13 million may not be recovered.

The economic downturn in the forestry industry has resulted in mill closures in Canada and could limit the availability of new capital for wood waste suppliers, limiting the ability of these suppliers to meet their contractual commitments to Power LP.

Financial liquidity risk

The Company's future development, enhancement or acquisition initiatives may require additional financing. The ability of the Company to arrange such financing will depend in part upon prevailing market conditions at the time as well as the Company's business performance. If the Company's revenues or cash flows decline, it may not have the capital necessary to undertake or complete the initiatives. In addition, Power LP's unit price is exposed to market volatility which impacts the Company's plans for Power LP's equity financing. 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 meet these requirements or for other corporate purposes. Furthermore, if the foregoing are available there can be no assurance that they will be on terms acceptable to the Company. The inability of the Company to access sufficient capital for its operations could have a material adverse effect on the Company's business, prospects and financial condition. Further discussion is included in Liquidity and Capital Resources in this MD&A.

Supply risk of Alberta PPAs

EPCOR holds interests in acquired PPAs, which entitle the Company to its proportionate interest in the electricity produced from specific generating units up to their committed capacity. In most cases, when plant capability falls below committed capacity, we are entitled to receive our relative portion of the availability payments from the plant owners based on the 30-day rolling average spot electricity 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 the PPAs, preventing the PPA owners from fulfilling their obligations under the PPAs, could have a material negative impact on our ability to generate revenue. In such circumstances, we may be required to replace unavailable generation output with electricity at prevailing market rates, while being relieved of the obligation to pay the unit capacity fee. Depending on market liquidity, the prices could be significantly higher than the prices inherent in the PPA, thus increasing the cost of our energy purchases.

Availability of people

Our ability to continuously operate and grow the business is dependent upon retaining and developing sufficient labour and management resources. As with most organizations, we are facing the demographic shift where a large number of employees are expected to commence retirement over the next few years. In addition, the market for labour and management particularly in Alberta and British Columbia is extremely competitive, posing a risk to the timing and cost of our projects in those provinces. However the current economic downturn may improve labour availability. We believe that we employ good human resource practices and have been named a top 100 employer in Canada by MediaCorp Canada Inc. for 9 consecutive years. We continue to monitor developments and review our human resource strategies so that we have an adequate supply of labour and management.

Weather risk

Weather can have a significant impact on our operations. Temperature, seasonality and precipitation within the markets EPCOR operates in and adjacent geographies affect the demand for electricity and natural gas, thus contributing to electricity and natural gas price and volume volatility. In addition, the level of precipitation affects the availability of our hydro generating units.

Melting snow, freeze/thaw cycles and seasonal precipitation in the North Saskatchewan River watershed affect the quality of water entering our Edmonton water treatment plants and the resulting cost of purification. Weather variability and seasonality also impact the demand and supply of water.

Extreme weather can impact the physical operation of our facilities. Two of Power LP’s facilities are situated in North Carolina, a region susceptible to hurricanes.

Financial exposures associated with extreme weather are partially mitigated through our insurance programs.

Foreign exchange risk

Fluctuations in the exchange rate between the Canadian dollar and either the U.S. dollar or the Euro affect some of our revenues, capital costs, operating costs and cash flows, and could have an adverse impact on our financial performance and condition. Foreign currency management is governed by our foreign exchange management policies.

The foreign exchange risk of anticipated U.S. dollar denominated cash flows from Power LP’s U.S. plants, net of debt service obligations on U.S. dollar borrowings, is managed through the use of forward foreign exchange contracts for periods of up to 7 years. At December 31, 2008, US$457 million (2007 - US$281 million) or approximately 96% (2007 – 83%) of these future cash flows were economically hedged for 2009 to 2014 (2007 – 2008 to 2013) at a weighted average exchange rate of 1.12 (2007 – 1.13).

In situations where EPCOR contracts to purchase large value parts for Generation and, Distribution and Transmission operations from suppliers outside of Canada, we generally fix the purchase price in Canadian dollars by contracting in Canadian dollars or using forward foreign exchange contracts.

Conflicts of interest

Certain conflicts of interest could arise as a result of EPCOR's relationship with The City of Edmonton, EPCOR's sole common shareholder and regulator for water utility rates in Edmonton.

In addition, certain conflicts of interest could arise as a result of EPCOR's relationship with Power LP. The Company is, through wholly-owned subsidiaries, Power LP's principal unitholder, 100% owner of the general partner, EPCOR Power Services Ltd. (GP), and through wholly-owned subsidiaries of the Company in both Canada and the U.S., manager of the assets and operations of Power LP.

Other conflicts of interest could arise as a result of Power LP's relationship with Primary Energy Recycling Corporation (PERC). Primary Energy Ventures, an indirect wholly-owned subsidiary of Power LP, also has a 15.4% equity ownership of and provides management and administrative services to PERC, PERH and PERH's subsidiaries under a management agreement. PERC, through PERH and its subsidiaries, engages in activities similar to those of Power LP and Primary Energy Ventures. PERC owns the remaining 84.6% equity in PERH.

Certain senior officers of EPCOR are officers and directors of GP and Power LP's subsidiaries. The board of directors of GP currently has eight members, four of whom are EPCOR elect directors and four of whom are independent directors within the meaning of applicable Canadian securities laws. The chairman of the board of directors of GP is an executive officer of EPCOR and has a casting vote or second vote in the case of a tie vote at any meeting of the GP board of directors.

General economic conditions, business environment and other risks

The Company is exposed to potential recovery and fair value measurement uncertainty in respect of its investment in ABCP (now floating-rate notes) and investment in goodwill. See Asset-Backed Commercial Paper and Power LP Goodwill Impairment under "Significant Events".

Transmission risk relates to blackouts or constraints on the system which result in curtailment of output at generation facilities or restrictions on the development of interconnections with new generation facilities. This risk is mitigated by the terms of our PPAs and long-term power contracts. We also manage our relationships with regulators and governments to support the timely development of appropriate transmission capability and technology.

Fluctuations in interest rates, product supply and demand, market competition, risks associated with technology, general economic and business conditions, EPCOR'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 EPCOR and its subsidiaries, political and economic conditions in the geographic regions in which EPCOR and its subsidiaries operate, difficulty in obtaining necessary regulatory approvals, a significant decline in EPCOR's reputation and such other risks and uncertainties described from time to time in EPCOR's reports and filings with the Canadian Securities authorities could materially adversely impact EPCOR's business, prospects, financial condition, results of operations or cash flows. Our ability to mitigate these risks is dependent upon management's ability to anticipate such risks and, where possible, to develop appropriate mitigation plans.

The following table outlines our 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 ($ millions)	Change	Annual Cash Flow	Annual Net Income
Wholesale price of electricity – Alberta[1]	+ $5/MWh	nominal	- 11
Wholesale price of natural gas[1]	+ $1/Gj	+ 1	+ 15
US exchange rate – strengthening CDN dollar	+ $0.10	- 2	+ 1
Short-term interest rates	+1.0%	- 2	- 2
Increase in water consumption – Alberta	+3.0%	+4	+4
Canadian federal and provincial income tax rates	-1.0%	+ 1	+ 2

(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.

Changes in the fair value of Power LP's natural gas contracts has limited economic impact on the Company as the majority of the 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.

CONTROLS AND PROCEDURES

For purposes of certain Canadian securities regulations, EPCOR is a "Venture Issuer". As such, it is exempt from certain of the requirements of National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings. Accordingly, the Chief Executive Officer and Chief Financial Officer have reviewed the annual information form, annual financial statements and annual MD&A, for the year ended December 31, 2008. Based on their knowledge and exercise of reasonable diligence they have concluded that these materials fairly present in all material respects the financial condition, results of operations and cash flows of the Company for the periods presented and they do not contain any misrepresentations.

ACCOUNTING CHANGES IN 2008

Commencing January 1, 2008, the Company adopted new accounting standards as issued by the Canadian Institute of Chartered Accountants (CICA) for Capital Disclosures, Financial Instruments –

Disclosures and Presentation, and Inventories. The new accounting standards have been applied retrospectively and the comparative financial statements have not been restated.

Financial instruments – presentation and disclosures

The new accounting 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 Company'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 the audited consolidated financial statements and are discussed in Note 21 – Fair Value and Classification of Financial Assets and Liabilities, Note 22 – Derivative Instruments and Hedge Accounting and Note 23 – Risk Management.

Capital disclosures

The new accounting standard requires qualitative information about the Company's objectives, policies and processes for managing capital and quantitative data related to the Company's capital, as discussed in Note 24 - Capital Management of the audited consolidated financial statements.

Inventories

The new accounting standard requires the Company's inventories to be measured at the lower of cost and net realizable value except for natural gas inventories held for trading purposes which are measured at fair value less costs to sell. The new standard is harmonized with International Financial Reporting Standards (IFRS). Our adoption of the new standard did not have a material impact on the audited consolidated financial statements in 2008. The additional disclosures required under the new standard are included in Note 5 – Inventories of the audited consolidated financial statements.

FUTURE ACCOUNTING CHANGES

Rate-regulated operations

In December 2007, the CICA amended Handbook Sections 1100 – Generally Accepted Accounting Principles and 3465 – Income Taxes, and made consequential amendments to Accounting Guideline 19 – Disclosures by Entities Subject to Rate Regulation. The amendments removed the temporary exemption from the requirement to apply Section 1100 to the recognition and measurement of assets and liabilities arising from rate regulation. These amendments are effective January 1, 2009.

As permitted by Canadian GAAP, the Company will apply the U.S. Financial Accounting Standards Board (FASB) standard, Statement of Financial Accounting Standards No. 71 – Accounting for the Effects of Certain Types of Regulation (SFAS 71), which provides guidance for the recognition and measurement of rate-regulated assets and liabilities. We do not expect these CICA Handbook amendments and adoption of the SFAS 71 guidance effective January 1, 2009 to have a material impact on our consolidated financial statements in the future.

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 IFRS. EPCOR has reviewed its capitalization policies and practices for compliance with the new standard and expects to reclassify approximately $89 million of net assets from property, plant and equipment to contract and customer rights and other intangible assets effective January 1, 2009. We do not expect the new standard to have any other material impacts on our 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 the counterparty should be taken into account in determining the fair value of financial assets and liabilities, including derivative instruments. EIC-173 is to be applied restrospectively without restatement of prior periods in interim and annual financial statements for periods ending on or after January 20, 2009. EPCOR will adopt this recommendation in its fair value determinations as at March 31, 2009 and is currently assessing the impact of this change on its consolidated financial statements.

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, we established a core team to develop a plan which will result in the Company's 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, we 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.

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

Financial Statement Adjustments

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 later in the schedule depending on the expected timing of the revised standard.

International Financial Reporting Standard	Planned Initial Review by Audit Committee (Quarter Year)
IFRS 7, IAS 32, IAS 39 Financial Instruments	Q1 2009
IAS 23 Borrowing Costs	Q1 2009
IAS 18 Revenue	Q1 2009
IAS 16 Property, Plant and Equipment	Q3 2009
IAS 31 Interests in Joint Ventures	Q3 2009
IAS 21 The Effects of Changes in Foreign Exchange Rates	Q3 2009
IFRS 3 Business Combinations	Q3 2009
IAS 12 Income Taxes	Q3 2009
IAS 17 Leases	Q4 2009
IAS 37 Provisions, Contingent Liabilities and Contingent Assets	Q4 2010
IAS 36 Impairment of Assets	Q4 2010

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

As the project progresses, the timing of completion of certain items is updated as changes to standards and other external factors such as discussions with certain stakeholders result in a change in priorities. However, management believes that the project has sufficient resources to meet the overall project timeline.

Financial Statements

There are also a number of standards which relate to financial statement presentation. Commencing in the first quarter of 2009, sample financial statements reflecting revised presentation and disclosure requirements will be developed and brought forward to the Audit Committee for feedback. Accordingly, the development of the financial statement presentation will evolve throughout the project.

Systems Updates

The diagnostic phase identified two key accounting system requirements. The system must be able to capture 2010 financial information under both the prevailing GAAP and IFRS to allow comparative reporting in 2011, the first year of reporting under IFRS. EPCOR has developed a systems strategy and the conversion will commence in early 2009 with planned completion by the third quarter of 2009.

Policies and Internal Controls

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

The impact of IFRS on certain agreements, such as debt, shareholder and compensation agreements, has also been included in the plan. Strategies to address these issues are being developed and will be completed by the second quarter of 2009.

Training

The Company recognizes that training at all levels is essential to a successful conversion and integration. Accounting staff have attended an initial IFRS training session, and periodic sessions will occur throughout the conversion process. The Board of Directors and Audit Committee attended a training session in October 2008, and the Audit Committee receives an update on the conversion project at each regularly scheduled meeting. Further training will occur throughout the project.

SIGNIFICANT ACCOUNTING POLICIES

Revenue recognition under PPAs

Our Genesee power generation units 1 and 2 operate under a PPA. Under the terms of the Genesee 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 term of the PPA. The Company records the electricity revenue from the 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 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.

Revenues from the Company's other power generation plants 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 Power LP's Curtis Palmer PPA are recognized at the lower of (1) the cumulative billable contract price per MWh and (2) an amount determined by the MWhs made available during the period, multiplied by the average price per MWh over the term of the contract. Any excess of the contract price over the average price is recorded as deferred revenue.

Financial commodity contracts

EPCOR uses financial CfDs for risk management purposes. These derivative instruments are recorded at fair value on the balance sheet. Changes in the fair value of CfDs are recognized in energy revenues or energy purchases unless they are designated as hedges and are effective. For CfDs that are designated as effective hedges, unrealized gains and losses for changes in fair value are recorded in other comprehensive income and reclassified to net income as energy revenues or energy purchases when realized upon settlement of the contract.

Consolidation of Power LP

While EPCOR owns only 30.6% of the outstanding units of Power LP, it controls Power LP under GAAP. Accordingly, EPCOR's interest in Power LP is accounted for using the purchase method and is fully consolidated in the balance sheets and statements of income, comprehensive income, equity and cash flow.

CRITICAL ACCOUNTING ESTIMATES

In preparing the 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.

Electricity revenues, costs and unbilled consumption

Due to the imprecision in customer consumption data received from load settlement agents, the lag between billing dates and meter reading dates and the lag between billing dates and financial reporting dates, we must use estimates for determining the amount of energy consumed but not yet billed. These estimates affect accrued revenues and accrued energy costs of the Energy Services segment. There are a number of variables in the computation of these estimates, and the underlying energy settlement processes within EPCOR and the Alberta electric systems are complex. Owing to the factors above and the statutory delays in final load settlement determinations and information, adjustments to previous estimates could be material. Estimates for unbilled consumption averaged approximately $95 million (2007 - $90 million) at the end of each month and these estimates varied from $86 million to $120 million (2007 - $75 million to $115 million). Adjustments of estimated revenues to actual billings were less than $8 million (2007 - $6 million) per month.

Fair values

We are required to estimate the fair value of certain assets or obligations for determining the valuation of asset impairments, asset retirement obligations and purchase price allocations for business combinations, and for determining certain disclosures.

Fair values of financial commodity contracts and forward natural gas contracts are determined, when possible, using exchange or over-the-counter price quotations by reference to quoted bid, ask or closing market prices in active markets. When there are limited observable prices, due to an absence of an active market, the Company uses valuation and price modeling techniques that refer to observable market data or estimated market prices. Fair values determined using valuation models require the use of assumptions concerning the amounts and timing of future cash flows and discount rates.

The Company has determined that the natural gas market is active within five years. As Power LP's natural gas supply contracts extend beyond five years, the fair value of these contracts is determined by reference to published price quotations where there is observable market data, and to price forecasts prepared by an independent third party where there are limited observable natural gas prices. The fair values of these contracts could change significantly if the assumptions were changed to reasonably possible alternatives.

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 to 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 reporting unit for the annual test of the Power LP goodwill as described under "Significant Events" is the Company's investment in Power LP.

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 long-lived asset impairments, as well as purchase price allocations and goodwill impairment 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. Refer to notes 2(r) and 14 to the audited consolidated financial statements for more detailed information.

Allowance for doubtful accounts

We continually review our aged accounts receivable and assess the underlying credit quality of the customers or counterparties. The allowance for doubtful accounts reflects an estimate of the accounts receivable that are ultimately expected to be uncollectible. It is based on a number of factors including the aging of receivables, historical write-offs within customer groups, assessments of the collectibility of amounts from individual customers and general economic conditions, including the current recession in Canada and the U.S. EPCOR's allowance account averaged $6 million (2007 - $6 million) and reported bad debts net of recoveries were $8 million (2007 - $1 million). The estimate of the allowance affects accounts receivable and all segments' operations, maintenance and administration expenses.

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

EPCOR follows the asset and liability method of accounting for income taxes. Income taxes are determined based on estimates of our 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 more likely than not, 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, 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 will vary with taxable income and, under certain conditions, with fair values of assets and liabilities. Accordingly, it is not possible to provide a reasonable quantification of the range of these estimates that would be meaningful to readers.

PPA availability incentives

Electricity revenue from the Genesee 1 and 2 units operating under PPAs 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. At December 31, 2008 and December 31, 2007 no amounts were deferred on the balance sheet and no amounts of previously deferred incentives were recognized in energy sales during 2008 and 2007.

Impact of current market conditions on estimates

Although the current condition of the economy has not impacted our methods of estimating accounting values, it has impacted the inputs in those determinations and the resulting values. Future cash flow estimates for assessing long-lived assets for impairment were updated to reflect any increased uncertainties of recoverability. The assessments did not result in any impairment losses because a large portion of the Company’s long-lived assets are subject to rate-regulation or PPAs with credit-worthy counterparties. Similarly, our assessment of the useful lives of our long-lived assets did not change since many of our generation plant assets are amortized over the life of the underlying PPA and our distribution and transmission assets and water assets located in the City of Edmonton and surrounding area are amortized based on rates approved by the applicable regulator. Our valuation models for estimating the fair value of financial commodity contracts, forward natural gas contracts, goodwill and long-lived asset impairments depend partly on discount rates which were updated to reflect increased credit spreads and market volatility. The fair value estimates of financial commodity and natural gas supply contracts are partly based on observable market data which inherently incorporate market expectations for prices in the respective markets. Our methods for determining the allowance for doubtful accounts are based on historical rates of bad debts in relation to the aged accounts receivable balances by customer group for our RRT and default customer bases. For the large individual customer accounts the allowance is based on analysis of the specific counterparty’s credit profile and reflects the impact of the current recession on specific customer operations. These analyses did not reveal any significant changes in our assessment of the recoverability of our accounts receivable at December 31, 2008.

NON-GAAP FINANCIAL MEASURES

We use funds from operations to measure the Company’s ability to generate funds from current operations. Funds from operations is a non-GAAP financial measure, does not have any standardized meaning prescribed by GAAP and is unlikely to be comparable to similar measures published by other entities. However, it is presented since it is commonly referred to by debt holders and other interested parties in evaluating the Company's financial position and in assessing its credit worthiness. A reconciliation of funds from operations to cash flows from operating activities is as follows:

Year ended December 31	2008	2007	2006
Funds from operations	**$ 484**	**$ 517**	**$ 547**
Change in non-cash operating working capital	(81)	24	42
Cash flows from operating activities	**$ 403**	**$ 541**	**$ 589**

FINANCIAL INSTRUMENTS

We classify our cash, cash equivalents and current and non-current derivative instruments assets and liabilities as held for trading, and measure them at fair value. Accounts receivable are classified as loans and receivables; and short-term debt, accounts payable and accrued liabilities and other current liabilities are classified as other financial liabilities; all of which are measured at amortized cost and their fair values are not materially different from their carrying amounts due to their short-term nature.

The classification, carrying amounts and fair values of the Company's other financial instruments held at December 31, 2008 and December 31, 2007 were as follows:

December 31, 2008	Carrying amount					
($ millions)	Held for trading	Available for sale	Loans and receivables	Other financial liabilities	Total	Total fair value
Other assets	$ 42	$ 22	$ 154	$ -	$ 218	$ 206
Long-term debt (including current portion)	-	-	-	2,728	2,728	2,471

December 31, 2007	Carrying amount					
($ millions)	Held for trading	Available for sale	Loans and receivables	Other financial liabilities	Total	Total fair value
Other assets	$ 60	$ 28	$ 99	$ -	$ 187	$ 189
Long-term debt (including current portion)	-	-	-	2,139	2,139	2,226

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. Our interest in the PERH preferred shares is included in available for sale other assets. The accumulated contributions to the sinking fund and our 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. If the process results in a transaction, the shares will most likely be sold in a private transaction.

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 December 31, 2008 and December 31, 2007.

Risk management and hedging activities

We are exposed to changes in energy commodity prices, foreign currency exchange rates and interest rates. We use 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:

	Carrying amount at fair value			
	Energy		Foreign exchange	
($ millions)	Cash flow hedges	Non-hedges	Non-hedges	Total
Total derivative instruments net assets (liabilities) as at December 31, 2008	$ (41)	$ 39	$ (34)	$ (36)
Total derivative instruments net assets (liabilities) as at December 31, 2007	(93)	75	24	6

We use various open-market derivative instruments including CfDs, with arm's-length parties to manage our 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 we elect 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 our expected purchase, sale or usage requirements.

Energy derivatives designated as accounting hedges

At December 31, 2008, the net fair value of energy financial derivative instruments designated and qualifying for hedge accounting was a liability of $41 million and is included in derivative instruments assets and derivative instruments liabilities on the 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 and foreign exchange derivatives not designated as accounting hedges

At December 31, 2008, the net fair value of energy financial derivative instruments not designated as hedges for accounting was a net asset of $39 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 our natural gas supply contracts resulting from increased forward natural gas prices relative to the contract prices.

At December 31, 2008, the fair value of our forward foreign currency contracts were in a net derivative liability position due to the impact of a strengthening U.S. dollar in the current year on forward foreign exchange sales contracts used to economically hedge $U.S.-denominated revenues. This derivative liability was partly offset by a net derivative asset for changes in the fair value of forward foreign exchange purchase contracts used to hedge anticipated $U.S.-denominated purchases. The weighted average fixed exchange rate for contracts, including Power LP contracts, outstanding at December 31, 2008 was $1.12 (December 31, 2007 - $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.

Unrealized changes in the fair value of financial and non-financial derivatives that either do not qualify or we elect 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 recognized 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, we have more physical supply of power in Alberta from our generating stations and power purchased under PPAs than we have contracted to physically sell. We utilize financial sells to reduce our exposure to changes in the price of power in Alberta. Economically, we benefit from higher Alberta power prices due to our net long position, as our expected physical supply is in excess of our 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 prices.

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 our expected purchase, sale or usage requirements. We hold 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 our 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 our 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 and in part by relying on price forecasts prepared by an independent third party. 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. Unrealized fair value losses of $5 million that were recognized in energy purchases and fuel expense for the year ended December 31, 2008 (2007 - $19 million of unrealized fair value gains) were based on this valuation technique for estimating forward prices beyond the active period.

OTHER COMPREHENSIVE INCOME

As of January 1, 2007, the changes in the fair value of the effective hedge portion of the financial derivative contracts used to manage our 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 year ended December 31, 2008, an unrealized gain, net of income taxes, of $26 million (2007 - $72 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 $7 million (2007 - $46 million) was reclassified to energy purchases and revenues as appropriate. There was no ineffective portion of cash flow hedges for which unrealized gains or losses were required to be recognized in income. Of the $29 million (2007 – $62 million) in net losses related to derivative instruments designated as cash flow hedges included in accumulated other comprehensive income at December 31, 2008, net losses of $15 million (2007 - $45 million), net of taxes of $7 million (2007- $20 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 and water value chain. Some of the shares held are not typically traded on an exchange and therefore are difficult to value. During 2008, an unrealized fair value gain of $7 million (net of taxes of $2 million) on venture capital investments was recognized in other comprehensive income. In the second and third quarters of 2008, venture capital investments were sold and the total realized gain of $10 million (net of taxes of $3 million) was reclassified from other comprehensive income to net income.

During the fourth quarter of 2008, changes in economic circumstances caused Power LP 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 shareholder's 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, Power LP's foreign currency translation gains and losses were recognized in net income.

RELATED PARTY TRANSACTIONS

EPCOR enters into various transactions with its sole shareholder, The City of Edmonton. These transactions are in the normal course of operations and are recorded at the exchange value generally based on normal commercial rates or as agreed to by the parties.

We recorded financing expenses of $44 million in 2008 ($54 million - 2007) on EPCOR's debt obligation to The City of Edmonton. This debt obligation relates to debt capital raised by The City of

Edmonton prior to 1996 when EPCOR 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 $189 million at December 31, 2008 (2007 - $243 million).

Sales from EPCOR to The City of Edmonton included electricity and water, and the provision of maintenance, repair, construction and customer care services totaling $98 million in 2008 (2007 - $77 million). We paid franchise fees and property taxes to The City of Edmonton of $51 million (2007 - $49 million). The City of Edmonton provided miscellaneous services to EPCOR totaling $8 million (2007 - $7 million).

Included in the Company's revenues is $4 million (2007 - $3 million) for the provision of management services by Power LP to PERC under a long-term management agreement. At December 31, 2008, there were no accounts receivable due from PERC (2007 - $1 million).

FOURTH QUARTER REVIEW AND QUARTERLY RESULTS

Quarters ended	Revenues	Net income from continuing operations	Net income (loss) from discontinued operations	Net income
	(Unaudited, in $ millions)			
December 31, 2008	$ 811	$ 15	$ -	$ 15
September 30, 2008	967	76	-	76
June 30, 2008	865	16	-	16
March 31, 2008	799	68	-	68
December 31, 2007	969	59	-	59
September 30, 2007	930	67	-	67
June 30, 2007	865	53	-	53
March 31, 2007	899	98	-	98

For the quarter ended December 31, 2008, consolidated net income from continuing operations decreased by $44 million from the corresponding quarter in the prior year primarily due to the write-down of Power LP goodwill in 2008 compared with no write-down in 2007. In addition, unrealized fair value gains on derivative financial instruments in our Alberta wholesale and merchant power portfolio were recognized in the fourth quarter of 2007 compared with an insignificant change in the fair value of the portfolio in 2008.

Income from Power LP was also lower primarily due to an asset impairment charge on its investment in PERH and unrealized fair value losses on its natural gas supply contracts in the fourth quarter of 2008 compared with unrealized fair value gains on these contracts in the fourth quarter of 2007. Unrealized fair value losses were also recognized in the fourth quarter of 2008 for a reduction in the fair value of Power LP's forward foreign exchange contracts used to economically hedge U.S. cash flows, whereas the change in fair value in the corresponding period in 2007 was insignificant.

These decreases were partly offset by the impact of future tax rate reductions on future income tax assets and liabilities, which was recognized in the fourth quarter of 2007 with no corresponding adjustment in 2008.

Events for 2008 and 2007 quarters that have significantly impacted net income from continuing operations and net income and cash flows and the comparability between quarters are:

- September 30, 2008 third quarter results reflected unrealized fair value gains on financial electricity contracts, Joffre CfD and forward foreign exchange contracts and gains on the sale of portfolio investments. These gains were partly offset by administration costs resulting from Long-Term Incentive Plan (LTIP) adjustments, and lower income from Power LP.

- June 30, 2008 second quarter results reflected maintenance costs and Genesee PPA availability penalties resulting from major turnarounds at all three Genesee plants partly offset by the favourable impact of high Alberta power prices on our financial contract portfolio, and unrealized fair value gains on Power LP's natural gas supply contracts.

- March 31, 2008 first quarter results included a $30 million gain on the sale of a 10% interest in the Battle River PSA, the favourable impact of high Alberta power prices on our financial contract portfolio which was in a net long position and unrealized fair value gains on Power LP's natural gas supply contracts. These gains were partly offset by maintenance costs and Genesee PPA availability penalties resulting from a major planned outage at Genesee 1, and a fair value reduction of ABCP.

- December 31, 2007 fourth quarter results included unrealized fair value gains on derivative financial instruments in our Alberta merchant and wholesale portfolio which were not designated as hedges for accounting purposes, and unrealized fair value gains on Power LP's natural gas supply contracts. These gains were partly offset by a reduction in the fair value of ABCP and a future income tax charge for the impact of future tax rate reductions which were substantively enacted in December 2007.

- September 30, 2007 third quarter results included higher Alberta electricity margins due to favourable settlements on financial sales as a result of higher contract prices and lower Alberta power prices. In addition, the results included favourable unrealized fair value changes in financial and non-financial derivative instruments, which were not designated as hedges for accounting purposes, in Alberta merchant and wholesale positions due to lower forward power prices combined with a net short position.

- June 30, 2007 second quarter results included unrealized fair value decreases in derivative financial instruments which were not designated as hedges for accounting purposes, resulting from increasing forward market prices. In addition, income from Power LP included unrealized fair value decreases for the natural gas supply contracts resulting from decreasing forward natural gas prices and contract price changes for the Tunis plant.

- March 31, 2007 first quarter results included a $30 million gain from the sale of a 10% interest in the Battle River PSA, an $11 million reduction of future income tax expense resulting from a reorganization of two subsidiaries within the Energy Services segment, and income from Power LP due to favourable fair value changes in the natural gas supply contracts for its Ontario generation plants which were required under the implementation of the new accounting standard for financial instruments effective January 1, 2007. These gains were partly offset by unrealized fair value decreases in derivative financial instruments resulting from a combination of increasing volumes of financial sales contracts not qualifying for hedge accounting and increasing Alberta forward electricity prices.

FORWARD-LOOKING INFORMATION

Certain information in this MD&A is forward-looking within the meaning of Canadian securities laws as it is related to anticipated financial performance, events or strategies. When used in this context, words such as “will”, “anticipate”, “believe”, “plan”, “intend”, “target” and “expect” or similar words suggest future outcomes.

Forward-looking information in this MD&A includes, but is not limited to: (i) expectations regarding the impact on the Company of current and future economic conditions; (ii) expectations regarding future Company growth and operating plans; (iii) installation of the remaining two units at the Clover Bar Energy Centre is planned for completion in the second quarter of 2009 and in 2010, respectively, and the expected cost of the full Clover Bar Energy Centre project is $284 million; (iv) anticipated fewer maintenance outages from, and lower maintenance costs of, the Genesee units; (v) expectations for the continued operation of Morris during and after the Chapter 11 proceeding of Equistar; (vi) the current estimated final cost for the Keephills 3 project is $1.8 billion with EPCOR’s share expected to be $903 million; (vii) Keephills 3 construction will be completed by the end of the first quarter of 2011; (viii) net income and cash flow from operating activities will increase in 2009 from 2008; (ix) electricity revenue will be lower in 2009 due to lower power prices and the scheduled sale of a further 10% interest in the Battle River PSA; (x) 2009 earnings will benefit from a full year of operation of the first unit at Clover Bar Energy Centre and Morris and the addition of the Gold Bar wastewater facility; (xi) cash requirements for working capital are expected to be substantially lower in 2009; (xii) 2009 projected cash requirements include approximately $800 million for capital expenditures, $26 million for long-term debt repayments, $134 million for common dividends, and $17 million for the transfer of the Gold Bar assets; (xiii) planned capital upgrades at the Southport, Roxboro and North Island facilities of $119 million; (xiv) the Company has sufficient liquidity for its plans in 2009; (xv) the significant increase in debt and interest expense to fund capital expenditures planned for 2009; (xvi) the Company expects to receive $99 million in payments over a 20-year period from Suncor for the design, construction and operation of a potable water and wastewater treatment plant beginning in 2009 upon completion of the design-build phase of the project; (xvii) expectation of losses on natural gas contracts with a low embedded price; (xviii) the Company expects to address the denial provisions in the U.S. - Canada Income Tax Treaty without realizing any material adverse tax consequences; (xix) expectations with respect to impact of the SIFT Legislation on cash available for distribution by Power LP; (xx) expectations of the costs to comply with anticipated environmental regulations; (xxi) availability of coal supply for Power LP's coal-fired power plants, Roxboro and Southport; (xxii) timing of installation of certain equipment to meet requirements to reduce emissions; (xxiii) cost and timing of installation of mercury removal systems at Genesee; (xxiv) expectations regarding the impact on the Company of the capital and credit market instability; and (xxv) expectations regarding Equistar's ability to operate in the ordinary course of business while undergoing reorganization under Chapter 11 of bankruptcy code.

These 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. The material factors and assumptions underlying this forward-looking information include, but are not limited to: (i) the operation of the Company’s facilities; (ii) power plant availability, including those subject to acquired PPAs (iii) the Company’s assessment of commodity and power markets; (iv) the Company’s assessment of the markets and regulatory environments in which it operates; (v) weather; (vi) availability and cost of labour and management resources; (vii) performance of contractors and suppliers; (viii) availability and cost of financing; (ix) foreign exchange rates; (x) management's analysis of applicable tax legislation; (xi) the currently applicable and proposed tax laws will not change and will be implemented; (xii) proposed environmental regulations will be implemented; (xiii) counterparties will perform their obligations; (xiv) expected ABCP (new notes) interest rates, related credit spreads and mortality rates; and (xv) ability to implement strategic initiatives which will yield the expected benefits.

Whether actual results, performance or achievements will conform to the Company's expectations and predictions is subject to a number of known and unknown risks and uncertainties which could cause actual results and experience to differ materially from EPCOR's expectations. Such risks and uncertainties include, but are not limited to risks relating to: (i) operation of the Company's facilities (ii) power plant availability and performance; (iii) unanticipated maintenance and other expenditures; (iv) availability and price of energy commodities; (v) electricity load settlement; (vi) regulatory and government decisions including changes to environmental, financial reporting and tax legislation; (vii) weather and economic conditions; (viii) competitive pressures; (ix) construction; (x) availability and cost of financing; (xi) foreign exchange; (xii) availability of labour and management resources; (xii) performance of counterparties, partners, contractors and suppliers in fulfilling their obligations to the Company; and (xiv) the market for the new notes exchanged for ABCP.

This MD&A includes the following updates to previously issued forward-looking statements: (i) the ABCP restructuring was implemented on January 21, 2009, later than previous expectations due to delays as a result of complexities and market volatility; (ii) long-term debt repayments of $411 million in 2008 compared to an expected $388 million due to prepayments made on The City of Edmonton debt obligation with earnings from the associated sinking fund in 2008; and (iii) the increase in total cost and the Company's share of the Keephills 3 project as a result of increased labour and material costs.

Readers are cautioned not to place undue reliance on forward-looking statements as actual results could differ materially from the plans, expectations, estimates or intentions expressed in the forward-looking statements. Except as required by law, EPCOR disclaims any intention and assumes no obligation to update any forward-looking statement even if new information becomes available, as a result of future events or for any other reason.

ADDITIONAL INFORMATION

Additional information relating to EPCOR including the Company's 2008 Annual Information Form is available on SEDAR at www.sedar.com.