EPCOR Utilities Inc.
Interim Report
September 30, 2008

Management's Discussion and Analysis

This management's discussion and analysis (MD&A), dated November 5, 2008, should be read in conjunction with the unaudited interim consolidated financial statements of EPCOR Utilities Inc. (hereinafter "the Company", "EPCOR", "we", "our" or "us") for the three and nine months ended September 30, 2008 and 2007, the audited consolidated financial statements and MD&A for the year ended December 31, 2007 and the cautionary statement regarding forward-looking information on page 25. EPCOR is a wholly-owned subsidiary of The City of Edmonton. Financial information in this MD&A is based on the unaudited interim consolidated financial statements, which were prepared in accordance with Canadian generally accepted accounting principles (GAAP), and is presented in Canadian dollars unless otherwise specified. In accordance with its terms of reference, the Audit Committee of the Company's Board of Directors reviews the contents of the MD&A and recommends its approval by the Board of Directors. The Board of Directors has approved this MD&A upon the recommendation of the Audit Committee.

OVERVIEW

EPCOR's results from operating activities for the third quarter returned to more normal levels after three major turnarounds for scheduled maintenance at our Genesee facilities in the first two quarters. Generation from all three plants increased, maintenance expenses declined and availability incentive income under the terms of the Genesee Power Purchase Arrangement (PPA) increased, compared with the previous quarter. Generally, the generation fleet operated on plan during the quarter. Income from Energy Services operations was down from the second quarter as Alberta power prices declined in the third quarter. However, despite the decrease in Alberta power prices we managed our commodity positions well, contributing to solid earnings for the quarter. Our water and electric distribution and transmission businesses operated solidly during the quarter.

EPCOR Power L.P. (Power LP), a 30.6% subsidiary of EPCOR, contributed a net loss in the quarter due to fair value changes, primarily on natural gas supply contracts, which substantially offset the fair value gains on these contracts in the first two quarters of the year. Fair value changes can cause volatility in Power LP's earnings but are not representative of the underlying economic performance of Power LP's business. Operating margins, excluding fair value changes, from Power LP's plants were $3 million lower in the third quarter compared with the third quarter of 2007.

Progress continued on our capital expenditure program, particularly the Keephills 3 generation plant and the two remaining units at Clover Bar Energy Centre. The first unit at Clover Bar Energy Centre was commissioned in the first quarter of 2008. The Downtown Edmonton Supply and Substation and transmission line (DESS) were substantially completed in the third quarter and energized on October 29, 2008.

In the third quarter, Distribution and Transmission negotiated a settlement with customer groups on its 2007-2009 Distribution and Transmission Tariff Application. The approved rates were slightly higher than interim rates, resulting in the recognition of revenue adjustments for the January 1, 2007 to September 30, 2008 period, in the third quarter.

The timing of the restructuring of asset-backed commercial paper (ABCP) has been delayed again from earlier estimates due to complexities of the restructuring and market volatility. The Pan-Canadian Investors Committee (Investors Committee) overseeing the restructuring anticipates that the restructuring will be completed by the end of November 2008. There was no significant change in our ABCP holdings or assessment of their fair value in the quarter.

SIGNIFICANT EVENTS

EPCOR Power L.P. to acquire Illinois co-generation facility

On September 11, 2008, Power LP announced 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 for an aggregate purchase price of US$77 million subject to finalizing closing adjustments. The purchase price has since been estimated at US$73 million as preliminary closing adjustments have been determined. Morris is a 177 megawatt (MW) natural gas-fired cogeneration facility located on Equistar Chemicals LP's (Equistar) chemical plant in Morris, Illinois.

The acquisition closed on October 31, 2008 and will be financed under the Power LP’s existing credit facilities with permanent long-term financing to be arranged after the close of the transaction, depending on the requirements of Power LP.

All of the steam and a portion of the electricity produced from Morris are sold to Equistar under the terms of a long-term energy services agreement which expires in 2023. Equistar, a wholly-owned subsidiary of Lyondell Chemical Company, 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 market.

Asset-backed commercial paper

At September 30, 2008, the Company held $49 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 $35 billion ABCP market that has been 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, accrued interest or roll over.

An Investors Committee comprised of a consortium representing banks, asset providers and major investors, is overseeing 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. Under the proposed restructuring, the affected ABCP would be converted into term floating-rate notes (notes) maturing no earlier than the scheduled termination dates of the underlying assets. The restructuring documents and subsequent presentations and conference calls provided additional information and clarification on the proposed restructuring. The key information as it relates to EPCOR is as follows:

(i) EPCOR expects its breakdown of new notes under the proposed restructuring, based on EPCOR's original book value of the investments, to be as follows:

Pool	Series	Rating	Amount ($ millions)	
MAV2	Class A-1	AA	$ 48	67%
	Class A-2	AA	9	13%
	Class B	Unrated	2	2%
	Class C	Unrated	1	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 expects to receive), the underlying asset lives are anticipated to average nine years. The remaining notes are expected to come from Master Asset Vehicle 3 (MAV3) in the form of Ineligible Asset Tracking (IA Tracking) notes which represent 16% of the new notes EPCOR expects to receive. These notes are expected to amortize over the lives of the underlying assets which have a weighted average life of approximately 18 years. Under the proposed restructuring, in certain limited circumstances, the expected repayment dates could be longer than the expected asset lives.

(iii) ABCP investors, including EPCOR, expect to be paid the accumulated accrued interest, net of any restructuring fees, collateral requirements and other costs, on their existing ABCP from the date of the standstill in August 2007 to the date of the restructuring.

(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.

On April 25, 2008, ABCP investors voted in favour of the proposed restructuring plan. After extending the time for his review, on June 6, 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. Certain ABCP note-holders filed motions with the Ontario Appeals Court for leave to appeal the ruling subsequent to which, on September 19, 2008, the appeal was denied. A further appeal was taken to the Supreme Court of Canada which was denied on October 17, 2008. This final decision cleared the way for the restructuring to proceed. On October 20, 2008, the Investors Committee announced that the restructuring is taking longer to complete than previously anticipated due to its complexity and market volatility, and they now expect the restructuring will be completed by the end of November 2008.

EPCOR's ABCP is a financial instrument and is classified as held for trading and therefore is recorded at fair value. EPCOR's estimate of the fair value of its ABCP at September 30, 2008 was $49 million compared with $60 million at December 31, 2007. The estimated fair value decreased by $11 million ($2 million for the quarter) primarily due to lower interest rates, higher observed and estimated credit spreads over the yields of long-term Government of Canada bonds and longer expected note lives based on new information provided by the Investors Committee. 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 ABCP conduits under the proposed 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 proposed restructuring, estimated recovery periods based on the estimated lives of the underlying assets of the proposed restructuring conduits and ranges of recoverability based on publicly available default statistics for credit-rated entities. In estimating future cash flows from ABCP the Company assumed that it would earn interest at rates ranging from 2.78% to 3.58% (weighted average rate of 3.00%) depending on the note series, taking into account restructuring costs and margin funding. The future cash flows were discounted at rates ranging from 6.69% to 25.10% (weighted average rate of 9.40%), depending on the note series, over 8.2 to 8.3 years (weighted average amortization period of 8.2 years), taking into account the assumed credit spreads and mortality rates.

The estimate of fair value of ABCP is subject to significant risks and uncertainties including the timing and amount of future cash payments, market liquidity, the quality and tenor of the underlying assets and instruments in the applicable conduits including the possibility of margin calls, and the future market for the restructured notes. Accordingly, the estimate of fair value of ABCP may change materially as events unfold and more information becomes available.

The Company continues to be in compliance with the financial covenants of its credit facilities and publicly issued debt and has sufficient credit facilities and cash flows from operations to satisfy its financial obligations as they come due. Based on current information, the Company does not expect there will be a material adverse impact on its business as a result of this current ABCP liquidity issue.

CONSOLIDATED RESULTS OF OPERATIONS

Net income

(Unaudited, $ millions)		Three months		Nine months
Net income for the periods ended September 30, 2007	**$**	**67**	**$**	**218**
Unrealized fair value changes on derivative instruments and natural gas inventory held for trading, excluding Power LP fair value changes		31		11
Gains on sales of portfolio investments		7		9
Lower (higher) interest expense and preferred share dividends, excluding Power LP interest expense and preferred share dividends		6		(3)
Higher Distribution and Transmission energy margins		5		9
Higher margins for trading activities in the north eastern U.S. and Ontario		4		6
Higher water rates		3		11
Higher (lower) operating income from Genesee 1, 2 and 3, excluding PPA availability and capacity revenue		2		(22)
Impact of recording a net future income tax asset associated with the Energy Services reorganization on January 1, 2007		-		(10)
Fair value reduction in ABCP		(2)		(11)
Higher (lower) Alberta energy margins		(3)		14
Lower Genesee PPA availability and capacity payment income		(5)		(30)
Higher administration expenses, excluding Power LP administration		(13)		(24)
Lower income from Power LP		(28)		(19)
Other		2		1
Increase (decrease) in net income		9		(58)
Net income for the periods ended September 30, 2008	**$**	**76**	**$**	**160**

Net income was $76 million and $160 million for the three and nine months ended September 30, 2008 respectively, compared with $67 million and $218 million for the corresponding periods in 2007. The changes were due to the net impact of the following:

- In the third quarter of 2008, the unrealized fair value changes in our financial electricity contracts, Joffre contract-for-differences (CfD) and forward foreign exchange contracts were all favourable compared with the third quarter of 2007. For the nine months ended September 30, 2008, the unrealized fair value changes in our forward foreign exchange contracts were favourable and the fair value changes in our financial electricity contracts and the Joffre CfD were unfavourable compared to the prior year period.

- Excluding Power LP subsidiary preferred share dividends, there were no preferred share dividends in 2008 as the Company's other subsidiary preferred shares were redeemed on September 30, 2007. In 2007, preferred share dividends for the first two quarters were more than offset by a reduction in the second quarter reflecting the substantive enactment of an income tax rate reduction attributable to preferred share dividends paid commencing in 2003. Interest expense, excluding Power LP interest expense, was higher primarily due to higher debt balances following the $200 million and $400 million public debt offerings in January and April 2008, respectively, partly offset by higher capitalized interest as a result of increased capital construction activity.

- 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 compared to Distribution and Transmission’s interim rates, including the retroactive portion, was recognized in September 2008. Distribution and Transmission’s margins in all three quarters of 2008 also reflect higher interim rates, and volumes due to growth in the Edmonton franchise area, compared with the corresponding periods in 2007.

- Margins on power trading activities in the north eastern United States (U.S.) and Ontario were higher in 2008 primarily due to wider spreads between Ontario and the north eastern U.S. power prices.

- Water revenues, net of franchise fees, were higher primarily due to rate increases which became effective on April 1, 2007 and April 1, 2008.

- The changes in operating income from Genesee 1, 2 and 3 were primarily due to maintenance activities. In the third quarter, maintenance expenses for Genesee outages were lower as there were no planned outages in 2008 compared with one outage at Genesee 1 in the third quarter of 2007. The nine month periods reflect three major turnarounds at our Genesee facilities in the first two quarters of 2008 compared with no outages in the first two quarters of 2007. Regular maintenance work for all three units was also higher in the nine months ended September 30, 2008 compared with the corresponding period in 2007.

- 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.

- In the third quarter of 2008, margins for the procurement, marketing and sale of electricity in retail and wholesale markets in Alberta (Alberta electricity margins) were lower compared with the corresponding period in 2007 primarily due to lower margins from the Joffre plant as a result of plant outages and lower margins from our interests in the Battle River and Sundance Power Purchase Arrangements (acquired PPAs) due to lower Alberta power prices. The decreases were partly offset by higher gains on derivative financial contracts used to hedge the exposure to Alberta power prices, compared with the prior year.

  Alberta electricity margins increased for the nine months ended September 30, 2008 compared with the corresponding period in 2007 primarily due to increased length in the portfolio of derivative financial contracts that settled at higher Alberta power prices. These increases were partly offset by lower generation from the Joffre and Genesee 3 facilities as a result of plant outages, and lower margins from our acquired PPAs.

- In the third quarter of 2008, availability incentive revenue earned under the terms of the Genesee 1 and 2 PPA was lower than in the corresponding period in 2007 due to recognition of availability incentive income in 2007 arising from a significant reduction in the number of outage days for 2007. For the nine month period, a net availability penalty was incurred in 2008 compared with availability incentive revenue recognized in 2007. The net penalty in 2008 was due to the major outages at these units in the first two quarters. Capacity payment revenue under this PPA was also lower due to a lower return from a declining PPA rate-base and reduced tax recoveries related to lower federal income tax rates.

- Administration expenses, excluding Power LP's administration, were higher in the first nine months of 2008 compared with the corresponding period in 2007 primarily due to an increase in the Company's estimated liability for its Long-Term Incentive Plan (LTIP) in the third quarter of 2008 and a reduction of the liability in the first quarter of 2007. A similar but smaller reduction of the liability was recorded in the first quarter of 2008. The LTIP is a notional stock option plan for senior management. Adjustments are recorded based on the results of the quarterly valuations of the plan. In addition, in the first nine months of 2008, costs for regulatory proceedings, bad debt provisions, business development and employees were higher compared with the corresponding period in the prior year.

- Net income from Power LP was lower in the third quarter of 2008 compared with the corresponding period in 2007 primarily due to unrealized changes in the fair value of natural gas supply and forward foreign exchange contracts, and the foreign currency translation of U.S. debt. In the nine months ended September 30, 2008, net income from Power LP was lower primarily due to unrealized changes in the fair value of forward foreign exchange contracts and foreign currency translation of U.S. debt, partly offset by favourable changes in the fair value of natural gas supply contracts compared with the prior year. Power LP's plant operating margins were slightly lower in the nine months ended September 30, 2008 compared with the corresponding period in 2007, primarily due to a milestone payment made for the Frederickson plant under the terms of a long-term service agreement with the turbine manufacturer, lower revenue and generation from the Manchief plant in Colorado due to higher natural gas prices and higher fuel costs at the Greeley plant in Colorado.

Revenues

(Unaudited, $ millions)	Three months	Nine months
Revenues for the periods ended September 30, 2007	**$ 930**	**$ 2,694**
Higher Water Services' commercial and transportation services revenues	29	46
Unrealized fair value changes on derivative instruments and natural gas inventory held for trading, excluding Power LP fair value changes	27	(14)
Higher trading activities in the north eastern U.S. and Ontario	25	44
Sale of portfolio investments	10	13
Higher Distribution and Transmission tariff revenues	6	5
Higher water rates	3	12
Lower Genesee PPA availability and capacity payment revenues	(8)	(42)
Lower energy revenues from trading activities in the western U.S.	(14)	(5)
Lower Power LP revenues	(16)	(55)
Lower Alberta energy revenues	(18)	-
Lower physical natural gas trading activities	(22)	(81)
Other revenues	15	14
Increase (decrease) in revenues	37	(63)
Revenues for the periods ended September 30, 2008	**$ 967**	**$ 2,631**

Consolidated revenues were higher for the three months and lower for the nine months ended September 30, 2008 compared with the corresponding periods in 2007. Further information on the year-over-year changes is as follows:

- Commercial and transportation services revenues were higher primarily due to new water and wastewater facility construction contracts with the City of Wetaskiwin, the Towns of Taber and Chestermere, and Suncor Voyageur Energy, which were entered into in the fourth quarter of 2007 and in 2008.

- Unrealized fair value gains on derivative financial sell contracts that were not designated as hedges for accounting purposes were higher due to larger decreases in forward Alberta power prices for the three months ended September 30, 2008 compared with the corresponding period in 2007.

  For the nine months ended September 30, 2008, the favourable variances noted above for the third quarter were more than offset by higher unrealized fair value losses on derivative financial sell contracts in the first two quarters of 2008 compared with the first two quarters of 2007. The losses were higher due to an increased volume of financial sell contracts and larger increases in the forward Alberta power prices in 2008.

- In 2008, Distribution and Transmission revenues reflect the tariff increases included in the NSA, partly offset by higher rebates from the Alberta Balancing Pool, which are passed on to customers and recognized as a reduction of revenue. These flow-through rebates correspondingly reduce Distribution and Transmission's expenses.

- Water sales were higher primarily due to a rate increase effective April 1, 2007 and an additional smaller increase effective April 1, 2008.

- Revenues from Power LP were lower primarily due to unrealized fair value changes on forward foreign exchange contracts for U.S. dollars used to hedge U.S. dollar operating cash flows, partly offset by higher plant revenues. Revenues from the California facilities were higher as natural gas cost increases were passed on to the counterparties to the facilities' power purchase agreements. Ontario plant revenues were higher due to built-in annual price escalators and increased enhancement activity resulting from higher natural gas prices. These increases in plant revenues were partly offset by lower natural gas sales at the Castleton plant.

- In the three months ended September 30, 2008, revenues for sales of electricity in the retail and wholesale markets in Alberta (Alberta electricity revenues) were lower compared with the corresponding period in 2007 primarily due to decreased generation and lower ancillary services revenue from the Joffre plant due to outages, and lower electricity revenue from our Regulated Rate Tariff (RRT) customers due to lower consumption. Ancillary services are provided to the Alberta Electric System Operator to ensure that the interconnected electric system is operated in a manner that provides a satisfactory level of service with acceptable levels of voltage and frequency.

  Alberta electricity revenues for sales to our RRT customers were higher in the nine months ended September 30, 2008 primarily due to higher pricing, partly offset by lower volumes. Revenues from our acquired PPAs were also higher due to higher Alberta power prices. The increases were offset primarily by an increased volume of derivative financial sell contracts that settled at losses in 2008. The contracts were used to hedge Alberta power price exposure on electricity sales.

Capital spending and investment

(Unaudited, $ millions) **Nine months ended September 30**	**2008**	**2007**
Generation	$ 306	$ 155
Distribution and Transmission	94	72
Energy Services	5	8
Water Services	50	82
Corporate – other	10	14
	$ 465	**$ 331**

Capital expenditures for property, plant and equipment were higher for the nine months ended September 30, 2008 compared with the corresponding period in 2007 primarily due to increased construction activity on the Keephills 3 and Clover Bar Energy Centre generation projects and on the DESS project in Distribution and Transmission.

Keephills 3 is a 495-MW supercritical coal-fired generation plant which is a joint development of EPCOR and TransAlta Corporation at TransAlta's Keephills site. We continue to manage the schedule and costs of our Keephills project with it on track to achieve commercial operations by the end of the first quarter of 2011. To date, we have mitigated our exposure to rising steel prices through early procurement, and 55% of the project cost is now fixed through work completed to date and fixed price contracts. We still have exposure to the Alberta labour market having completed approximately 25% of the total labour hours related to the project. Should this tight market continue or worsen, we would expect to see increasing pressure on costs which could result in up to a 10% increase in the final cost of the project. We continue to monitor this with our partner on a regular basis and overall the project continues to track to plan.

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 and construction of the remaining two units will continue through 2010. The current estimated final cost for the project is $284 million, up slightly from earlier estimates.

In the first quarter of 2007, Distribution and Transmission commenced construction of the DESS project which consists of a new high-voltage transmission line, which will supply electricity to downtown Edmonton. The project was substantially completed in the third quarter of 2008.

Water Services' construction on the E.L. Smith water treatment plant upgrade continued in 2008, but spending decreased compared with 2007 as the project was substantially completed in the second quarter.

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, we announced that the Company and the Ontario Power Authority mutually agreed to terminate the renewable energy supply agreement for the project. Accordingly, EPCOR will not proceed with the project as originally planned and is considering the future of the project. We did not incur any asset write-downs as a result of the decision.

SEGMENT RESULTS

Generation

Generation results (including intersegment transactions) (Unaudited, $ millions)	**Three months ended September 30**		**Nine months ended September 30**	
	2008	**2007**	**2008**	**2007**
Revenues	$ 257	$ 268	$ 712	$ 777
Expenses	367	223	617	552
Operating income	**$ (110)**	**$ 45**	**$ 95**	**$ 225**

(Unaudited, $ millions)	**Three months**	**Nine months**
Operating income for the periods ended September 30, 2007	**$ 45**	**$ 225**
Unrealized fair value changes on derivative instruments	16	18
Gain on sale of portfolio investments	10	13
Higher (lower) operating income from Genesee 1, 2 and 3, excluding PPA availability and capacity revenue	3	(33)
Higher business development expenses	(4)	(1)
Lower Genesee PPA availability and capacity payment revenues	(8)	(42)
Lower Power LP operating income	(167)	(79)
Other	(5)	(6)
Decrease in operating income	(155)	(130)
Operating income for the periods ended September 30, 2008	**$ (110)**	**$ 95**

Generation's operating income for the quarter and nine months ended September 30, 2008 decreased $155 million and $130 million respectively, over the corresponding periods in 2007. Further information on the year-over-year changes is as follows:

- Unrealized fair value changes on derivative financial instruments were favourable in the three and nine months ended September 30, 2008 compared with the corresponding periods in 2007. In the third quarter of 2008, the unrealized change in the fair value of the Joffre CfD was $8 million favourable compared with the corresponding period in 2007 primarily due to a favourable forward spark spread in the current quarter. Spark spread represents the difference between power prices and the cost of natural gas required to produce electricity. If the price of power is higher than the cost of natural gas to produce electricity, the spark spread is favourable and vice versa. In the nine months ended September 30, 2008, the unrealized change in fair value was $4 million unfavourable compared with the corresponding period in 2007 primarily due to a decrease in forward natural gas prices in 2007.

  Generation uses forward foreign exchange contracts for U.S. dollars to hedge anticipated equipment and materials purchases related to the Clover Bar Energy Centre and Keephills 3 projects. The unrealized fair value changes on these contracts were $8 million and $22 million more favourable in the three and nine months ended September 30, 2008, respectively, compared with the corresponding periods in 2007 due to strengthening U.S. dollar forward prices in 2008 and a weakening in 2007.

  The impact of the unrealized fair value changes for both the Joffre CfD and the forward foreign exchange contracts was to decrease revenues and expenses by $5 million and $21 million respectively, in the third quarter of 2008 and to increase revenues and decrease expenses by $2 million and $16 million respectively, in the nine months ended September 30, 2008 compared with the corresponding periods in the prior year.

- The changes in operating income from Genesee 1, 2 and 3 were primarily due to maintenance activities. In the third quarter of 2008, maintenance expenses related to Genesee were lower as there were no planned outages in 2008 compared with one outage at Genesee 1 in the third quarter of 2007. The nine month periods reflect three major turnarounds in the first two quarters of 2008 compared with no outages in the first two quarters of 2007. The turnarounds in 2008 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. The timing of the outages coincided with periods of high Alberta power prices which resulted in significant availability penalties under the terms of the PPA for Genesee 1 and 2. Regular maintenance work for all three units was also higher in the nine months ended September 30, 2008 compared with the corresponding period in 2007.

- Power LP contributed an operating loss of $168 million in the third quarter and operating income of $14 million in the first nine months of 2008. In 2007, Power LP contributed an operating loss of $1 million in the third quarter and operating income of $93 million in the first nine months. These decreases in operating income were primarily due to changes in the fair value of natural gas supply and forward foreign exchange contracts, and the translation of U.S. debt.

  Power LP's revenues decreased $16 million in the third quarter and $55 million in the first nine months of 2008 compared with the corresponding periods in the prior year, primarily due to unrealized changes in the fair value of forward foreign exchange contracts for U.S. dollars used to hedge operating cash flow resulting from a strengthening U.S. dollar in 2008 compared with a weakening U.S. dollar in 2007. The decreases were partly offset by higher revenues at Power LP's California and Ontario facilities.

  Power LP's expenses were $151 million higher in the third quarter of 2008 compared with the corresponding period in the prior year. Unrealized losses for changes in the fair value of the natural gas supply contracts, which were included in fuel expense, were $108 million higher in 2008 due to decreases in forward natural gas prices. Foreign exchange expense was $40 million higher in 2008 primarily due to a loss on the translation of Power LP's U.S. dollar debt due to a strengthening U.S. dollar, compared with a gain in 2007 due to a weakening U.S. dollar. Fuel costs for the California and North Carolina plants were also higher due to increased natural gas and coal prices.

  In the nine months ended September 30, 2008, Power LP's expenses were $24 million higher compared with the corresponding period in 2007. Foreign exchange expense was $83 million higher in 2008 primarily due to a loss on the translation of U.S. dollar debt compared with a gain in 2007, partly offset by realized losses in the first two quarters of 2007 on foreign exchange contracts entered into in anticipation of permanent financing of acquisitions completed in 2006, and losses realized in 2007 on interest rate contracts. The changes in foreign exchange were due to a strengthening U.S. dollar in the nine months ended September 30, 2008 compared with a weakening U.S. dollar in the corresponding period in 2007. Fuel costs were lower due to the fair value changes on the natural gas contracts which resulted in an unrealized gain of $10 million in 2008 compared with an unrealized loss of $68 million in 2007. This decrease in fuel costs was partly offset by higher fuel costs for the Ontario, California and North Carolina plants.

Distribution and Transmission

Distribution and Transmission results (including intersegment transactions) (Unaudited, $ millions)	**Three months ended September 30**		**Nine months ended September 30**	
	2008	**2007**	**2008**	**2007**
Revenues	$ 72	$ 63	$ 190	$ 181
Expenses	58	52	158	150
Operating income	**$ 14**	**$ 11**	**$ 32**	**$ 31**

Distribution and Transmission revenues were $9 million higher for both the three and nine months ended September 30, 2008, compared with the corresponding periods in 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. Accordingly, Distribution and Transmission's revenues reflect the tariff increases agreed to in the NSA, including the retroactive portion. This increase in revenues was partly offset by higher rebates from the Alberta Balancing Pool in 2008, which are passed on to customers and recognized as a reduction of revenues. Expenses were also higher in the three and nine months ended September 30, 2008 compared with the same periods in 2007, primarily due to administration expenses incurred for the NSA proceeding, and partly offset by higher rebates received from the Alberta Balancing Pool. Distribution and Transmission expects the Alberta Utilities Commission's (AUC) approval of the NSA in the fourth quarter of 2008.

Energy Services

Energy Services results (including intersegment transactions) (Unaudited, $ millions)	**Three months ended September 30**		**Nine months ended September 30**	
	2008	**2007**	**2008**	**2007**
Revenues	$ 608	$ 599	$ 1,703	$ 1,759
Expenses	531	548	1,621	1,683
Operating income	**$ 77**	**$ 51**	**$ 82**	**$ 76**

(Unaudited, $ millions)	**Three months**	**Nine months**
Operating income for the periods ended September 30, 2007	**$ 51**	**$ 76**
Unrealized fair value changes in derivative instruments and natural gas inventory	25	(12)
Higher energy margin from trading activities in the north eastern U.S. and Ontario	6	9
Higher (lower) RRT non-energy charge revenue	3	(2)
Higher bad debt expense	(3)	(3)
Higher (lower) Alberta electricity margins	(4)	18
Other	(1)	(4)
Increase in operating income	26	6
Operating income for the periods ended September 30, 2008	**$ 77**	**$ 82**

Energy Services' operating income increased $26 million for the quarter and $6 million for the nine months ended September 30, 2008 compared with the corresponding periods in 2007. Additional information on the year-over-year changes is as follows:

- In the third quarter of 2008, the unrealized fair value changes in our derivative financial electricity contracts that were not designated as hedges for accounting purposes were favourable compared with the corresponding period in 2007 due to the impact of a net short position combined with larger decreases in forward Alberta power prices. Unrealized fair value changes increased energy revenues and purchases by $32 million and $7 million respectively, in the third quarter of 2008 compared with the third quarter of 2007.

In the nine month periods, the unrealized fair value changes in our derivative financial electricity contracts were unfavourable in 2008 compared with the prior year due to the impact of a greater increase in forward Alberta power prices in the first two quarters on a net short position. Unrealized fair value changes for electricity and natural gas derivative contracts and natural gas inventory reduced energy revenues by $17 million and energy purchases by $5 million in the first nine months of 2008 compared with the corresponding period in 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.

- In the third quarter of 2008, Alberta electricity margins were lower than in the corresponding period of 2007 primarily due to lower generation under an intercompany contract between Generation and Energy Services for the Joffre plant and lower ancillary services revenue for the Joffre plant as a result of plant outages. In addition, margins from our acquired PPAs were lower primarily due to lower pricing for penalty payments received from the plant owners under the terms of the PPAs. Merchant trading margins were higher in the third quarter of 2008 primarily due to a shorter position in the portfolio of derivative financial contracts and lower Alberta power prices compared with the prior year.

  In the nine months ended September 30, 2008 Alberta electricity margins increased compared with the corresponding period in 2007 primarily due to increased length in the portfolio of derivative financial contracts that settled at higher Alberta power prices. The increase was partly offset by the impact of lower generation from Joffre and Genesee 3 under intercompany contracts between Generation and Energy Services, and lower margins from our acquired PPAs primarily due to higher pricing for incentive payments paid to the plant owners under the terms of the PPAs.

- In the third quarter of 2008, Energy Services' revenues and expenses, excluding unrealized fair value changes, decreased $23 million and $24 million respectively, compared with the corresponding period in 2007. The decrease in revenue was primarily due to lower physical natural gas trading, lower generation from Joffre, decreased trading activity in the western U.S. and lower sales to RRT customers, partly offset by increased trading activities in the north eastern U.S. and Ontario. The decrease in expenses was primarily due to lower physical natural gas trading and lower Alberta power prices, partly offset by increased trading activities in the north eastern U.S. and Ontario and lower pricing for penalty payments received from our acquired PPA plant owners.

  Energy Services' revenues and expenses, excluding unrealized fair value changes, decreased $39 million and $57 million, respectively in the nine months ended September 30, 2008 compared with the corresponding period in 2007. The decrease in revenues was primarily due to lower physical natural gas trading activities and a higher volume of derivative financial sell contracts that settled at losses in 2008 as Alberta power prices exceeded the contracts' strike prices. The contracts were used to hedge Alberta power price exposure on electricity sales. The decrease in revenues was partly offset by increased revenues from our acquired PPAs due to higher Alberta power prices, increased revenues from our RRT customers due to higher pricing partly offset by lower consumption, and increased trading activities in the north eastern U.S. and Ontario. The decrease in expenses was primarily due to lower physical natural gas trading activities and increased volume of derivative financial buy contracts which settled at higher prices, partly offset by increased trading activities in the north eastern U.S. and Ontario and higher acquired PPA incentive payments paid to the plant owners as a result of higher power prices.

Water Services

Water Services results (including intersegment transactions) (Unaudited, $ millions)	**Three months ended September 30**		**Nine months ended September 30**	
	2008	**2007**	**2008**	**2007**
Revenues	$ 98	$ 70	$ 226	$ 174
Expenses	76	47	178	128
Operating income	**$ 22**	**$ 23**	**$ 48**	**$ 46**

Water Services' revenues from water sales were $3 and $12 million higher in the three and nine months ended September 30, 2008 respectively, compared with the corresponding periods in the prior year primarily due to increased rates effective April 1, 2007 and April 1, 2008. The water rate increases include rate adjustments associated with costs for the E.L. Smith water treatment plant upgrade which officially opened on June 20, 2008.

Transportation and other commercial services revenues and expenses increased in the three and nine month periods of 2008 compared with the corresponding periods in the prior year primarily due to new commercial services construction projects for the City of Wetaskiwin, the Towns of Taber and Chestermere and Suncor Voyageur Energy. Maintenance expenses also increased, primarily due to a higher incidence of water main breaks and additional reservoir maintenance.

CONSOLIDATED BALANCE SHEETS

($ millions)	September 30, 2008	December 31, 2007	Increase (decrease)	Explanation
Cash and cash equivalents	$ 146	$ 79	$ 67	Refer to liquidity and capital resources section.
Accounts receivable (including income taxes recoverable)	478	591	(113)	Two months of Alberta wholesale electricity settlements and Genesee generation revenues at December 31, 2007 compared with one month at September 30, 2008. December balance also reflects excess sinking fund earnings received from The City of Edmonton in the first quarter of 2008.
Derivative instruments assets (current)	123	104	19	Increase in fair value of natural gas derivative contracts acquired in 2008.
Other current assets	95	74	21	Addition of natural gas inventory held for trading and normal increase in prepaid property taxes and insurance at mid year.
Property, plant and equipment	4,517	4,216	301	2008 capital expenditures partly offset by depreciation and amortization expense.
Power purchase arrangements (PPAs)	618	679	(61)	Sale of 10% interest in Battle River PSA and ongoing amortization of remaining PPAs in 2008.
Contract and customer rights and other intangible assets	173	179	(6)	
Derivative instruments assets (non- current)	89	116	(27)	Decrease in fair value of power and natural gas derivative contracts and foreign currency forward contracts, partly offset by increase in fair value of natural gas supply contracts.
Future income tax assets (non-current)	109	103	6	
Goodwill	185	185	-	
Other assets	257	236	21	Increase in rights to Keephills 3 mining asset, in net investment in lease and in long-term receivables associated with the Water Services construction projects, partly offset by a reduction in fair value of ABCP.

($ millions)	September 30, 2008	December 31, 2007	Increase (decrease)	Explanation
Short-term debt	$ 236	$ 138	$ 98	Commercial paper and bankers acceptances issued in 2008.
Accounts payable and accrued liabilities	519	615	(96)	Two months of Alberta wholesale electricity settlements at December 31, 2007 compared with one month at September 30, 2008, and lower payables and accruals for natural gas, merchant and Water Services capital projects at September 30.
Derivative instruments liabilities (current)	111	136	(25)	Settlement in 2008, of power derivative contracts held at December 31, 2007, partly offset by increase in fair value of natural gas derivative sell contracts acquired in 2008.
Other current liabilities	76	98	(22)	Payment of income taxes related to the 2006 Battle River PPA gain on sale, partly offset by increased current future income tax liabilities.
Long-term debt (including current portion)	2,416	2,139	277	Medium-term note debentures issued in January and April 2008 and draws on credit facilities in the third quarter, 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)	65	78	(13)	Decrease in fair value of power and natural gas derivative buy contracts.
Other non-current liabilities	128	125	3	
Future income tax liabilities (non-current)	121	126	(5)	
Non-controlling interests	664	740	(76)	Non-controlling interests' share of Power LP distributions and net loss.
Shareholder’s equity	2,454	2,367	87	Net income and other comprehensive income, partly offset by common share dividends and refundable income taxes.

LIQUIDITY AND CAPITAL RESOURCES

Cash inflows (outflows)

($ millions)	Three months ended September 30 2008	Three months ended September 30 2007	Increase (decrease)	Explanation
Operating	$ 139	$ 149	$ (10)	Higher payments for interest and major maintenance for Genesee outages in 2008, two months of sales receipts for the Oxnard plant in 2008 compared with three months of receipts in 2007 and a turbine milestone payment at the Frederickson plant, partly offset by receipt of higher Genesee PPA availability incentives in 2008 and realized losses on forward foreign exchange and interest rate contracts in 2007.
Investing	(165)	(202)	37	Purchase of ABCP in 2007 and proceeds on sale of portfolio investments in 2008, partly offset by higher capital expenditures in 2008, primarily Keephills 3, Clover Bar Energy Centre and DESS projects.
Financing	45	10	35	Net financing receipts in 2008 included the issuance of commercial paper, partly offset by long-term debt repayments. Net financing receipts in 2007 included Power LP's private placement of senior unsecured notes, partly offset by repayment of Power LP's borrowing under its bridge acquisition credit facility and Power LP's capital lease obligation.

Cash inflows (outflows)				
	Nine months ended September 30			
($ millions)	**2008**	**2007**	**Increase (decrease)**	**Explanation**
Operating	$ 278	$ 368	$ (90)	Payment of Genesee PPA availability penalties 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 and payments for major maintenance for Genesee turnarounds in 2008, partly offset by losses on forward foreign exchange and interest rate contracts realized in 2007.
Investing	(386)	(332)	(54)	Higher capital expenditures in 2008, primarily Keephills 3, Clover Bar Energy Centre and DESS projects, partly offset by proceeds on sale of portfolio investments in 2008 and purchase of ABCP in 2007.
Financing	176	(190)	366	Net financing receipts in 2008 included the issuance of $600 million of medium-term note debentures and $98 million of commercial paper, partly offset by long-term debt repayments. Net financing outlays in 2007 included repayment of Power LP's borrowing under its bridge acquisition credit facility and Power LP's capital lease obligation, partly offset by Power LP's private placement of senior unsecured notes and issuance of preferred shares by a Power LP subsidiary.

The Company's non-cash operating working capital increased $13 million and $38 million in the three and nine months ended September 30, 2008 respectively, compared with the corresponding periods in 2007. Over the next few quarters, we anticipate working capital requirements to fluctuate due to normal seasonal changes in operating cash flows and the effects of plant outages, scheduled or otherwise, including an unplanned outage at Genesee 3 (explained under Outlook below) in the fourth quarter of 2008. No significant increases in working capital requirements are expected over the long term for existing operations. The capital requirements to finance the Company's capital expenditure program are expected to continue at the current pace for at least the next two years. The Company will finance its working capital requirements with existing credit facilities. At September 30, 2008, the Company had undrawn and committed bank credit facilities of $1,322 million, of which $771 million is committed for at least two years.

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 September 30, 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 September 30, 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.

Power LP plans to invest up to US$80 million in 2008 and 2009 for the enhancement of the Southport and Roxboro coal plants to reduce environmental emissions and improve their economic performance. Power LP plans to finance this spending as well as its Morris acquisition (as discussed under Significant Events), with existing credit facilities; with permanent financing to be arranged following completion of the transactions, depending on the requirements of Power LP.

At September 30, 2008, the Company had letters of credit of $221 million (December 31, 2007 - $357 million) outstanding to meet the credit requirements of energy market participants and conditions of certain service agreements, and satisfy legislated reclamation requirements.

Financial market liquidity

Turmoil in the Canadian and U.S. financial markets may adversely impact the Company's access to capital markets. Despite the ABCP liquidity issues discussed under Significant Events, the Company has a solid contractual liquidity position. The Company has undrawn committed credit facilities of $1,322 million, the majority of which are with Canadian tier 1 banks, and its debt maturing within one year is limited to $73 million of long-term debt and $236 million of short-term commercial paper. Power market liquidity is also impacted by the current financial market turmoil. With the withdrawal of two major financial counterparties from the energy trading market and various companies being less active in energy commodity trading, liquidity is a concern and as such it is expected to take longer to enter and exit commodity positions.

We continue to monitor changes in counterparty credit quality. Counterparties to the PPAs, independent system operators, power and steam sales contracts, energy supply agreements and wholesale and merchant trading are primarily investment grade.

The Company does not have any material direct exposure to international banking and insurance company failures.

If the world-wide credit and financial crisis continues, particularly as it relates to Canada and the U.S., it may adversely affect the Company's ability to draw on its existing credit facilities or arrange long-term financing for its capital expenditure programs and acquisitions, and to refinance outstanding indebtedness on its maturity dates. Furthermore, these conditions have resulted in an increase in interest rate spreads 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 expensive, which may make finding accretive acquisitions more difficult for EPCOR and Power LP.

CONTRACTUAL OBLIGATIONS

During the third quarter, the Company drew $20 million on its $490 million of two-year extendible credit facilities and $10 million on its $400 million five-year extendible syndicated bank credit facility and Power LP drew $17 million on its $300 million of three-year revolving extendible credit facilities.

In January 2008, the Company repaid $155 million of long-term debt outstanding under a bank credit facility with proceeds from short-term indebtedness. On January 31, 2008, the Company issued $200 million unsecured medium-term note debentures and the proceeds were used to pay down short-term indebtedness. In April 2008, the Company issued $400 million unsecured medium-term note debentures. 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.

In May 2008, the Company entered into an agreement with Suncor Energy (Suncor) to design, build, own and operate a potable water and wastewater treatment plant for Suncor's Voyageur project over a twenty-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 $30 million to be incurred in 2008 and 2009.

Power LP has committed up to US$80 million for the enhancement of the Southport and Roxboro facilities, to be spent over 2008 and 2009.

On September 11, 2008, Power LP announced an agreement to acquire a 100% interest in Morris for an aggregate purchase price of US$77 million subject to finalizing closing adjustments, as discussed under Significant Events. Based on a preliminary determination of the closing adjustments, the purchase price has been updated to US$73 million.

There have been no other material changes to the Company's purchase obligations, including payments for the next five years and thereafter, during the first and second quarters. For further information on these obligations, refer to the 2007 annual MD&A.

CHANGES IN ACCOUNTING STANDARDS

Accounting changes for 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 prospectively 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 unaudited interim consolidated financial statements and are discussed in Note 5 – Fair Value and Classification of Non-derivative Financial Assets and Liabilities, Note 6 – Derivative Instruments and Hedge Accounting and Note 7 – Risk Management.

Sensitivity analyses of the impact on net income of changes in the fair value of derivative instruments for changes in their underlying risk factors, such as natural gas prices and foreign exchange rates, are included in the unaudited interim consolidated financial statements. 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.

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 8 - Capital Management of the unaudited interim 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. Our adoption of the new standard did not have a material impact on the unaudited interim consolidated financial statements. The additional disclosures required under the new standard are included in Note 9 – Inventories of the unaudited interim 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. They also require rate-regulated enterprises to recognize future income taxes separately from the regulatory asset or liability for the future recovery from or refund to customers for those income taxes. We will assess our accounting for rate-regulated operations in relation to these amendments but do not expect the impact to be material. These amendments are effective January 1, 2009 and will be adopted by the Company as of that date.

Goodwill and intangible assets

In February 2008, the CICA issued Handbook Section 3064 – Goodwill and Intangible Assets and consequential amendments to Section 1000 – Financial Statement Concepts. The new section establishes standards for the recognition, measurement and disclosure of goodwill and intangible assets. The provisions relating to the definition and initial recognition of intangible assets, including internally generated intangible assets, are equivalent to the corresponding provisions in International Financial Reporting Standards (IFRS). We will review our capitalization policies and practices for compliance with the new standard, which will determine the impact of the amendments to the financial statements. These amendments are effective January 1, 2009 and will be adopted by the Company as of that date.

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 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	Q4 2008
IAS 23 Borrowing Costs	Q4 2008
IAS 18 Revenue	Q4 2008
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.

Financial Statements

There are also a number of standards which relate to financial statement presentation. Commencing in the fourth quarter of 2008, 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. It must also be able to accommodate possible changes to foreign currency translation methods, depending on how certain foreign entities are classified under IFRS. A detailed system strategy is being developed to address these issues and will be completed in the fourth quarter of 2008 for implementation 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 have attended a training session, and the Audit Committee receives regular updates on the conversion project. Further training will occur throughout the project.

Financial Instruments

On October 24, 2008, the CICA approved amendments to the requirements for accounting and disclosure of financial instruments. In particular, the guidance permits, but only rarely, the reclassification of certain financial instruments from categories that require fair value changes to be recognized immediately in net income (such as “held for trading”) to categories that do not have that requirement. Such reclassifications would be recorded at their estimated fair values at the time of transfer and would be subject to impairment testing thereafter. Any subsequent increase in such reclassified financial instruments’ future estimated cash flows would not alter their carrying amounts but would be reflected in the effective interest rate of the instruments. In EPCOR’s case, the result is that certain held for trading instruments may be reclassified, and would not be subject to “mark to market” accounting and the associated quarterly net income adjustments.

Apart from the above amendment, the CICA has indicated that it will be providing further guidance on ABCP, in particular, the accounting for the ABCP restructuring transactions.

The Company will consider the above-mentioned amendments and guidance in the fourth quarter and will reflect changes, if any, to its accounting and disclosure in its annual consolidated financial statements.

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 consolidated financial statements: electricity revenues, costs and unbilled consumption, fair values, allowance for doubtful accounts, useful lives of assets, income taxes and PPA availability incentives. For further information on the Company's accounting estimates, refer to the 2007 annual MD&A.

RISK MANAGEMENT

This section should be read in conjunction with the Risk Management section of the most recent annual MD&A. EPCOR faces a number of risks including electricity price and volume risk, natural gas price and volume risk, operational risk, government and regulatory risk, supply risk of acquired PPAs, credit risk, environmental risk, project risk, availability of people risk, weather risk, foreign exchange risk, conflicts of interest risk, and general economic conditions and business environment risks. The Company employs active programs to manage these risks.

As part of ongoing risk management practices, the Company reviews current and proposed transactions to consider their impact on the risk profile of the Company. Except for the risks described under Financial Market Liquidity, there have been no material changes to the risk profile or risk management strategies of EPCOR as described in the annual MD&A for 2007.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

During the first quarter of 2008, the Company implemented a new Human Resources Information System which covers several aspects of human resource management including payroll. The system and related control framework are appropriately designed; however management is still working through post-implementation issues typical of a new application system. There were no other changes in the Company's internal controls over financial reporting during the interim period ended September 30, 2008 that have materially affected, or are reasonably likely to materially affect the Company's internal control over financial reporting.

OUTLOOK

In the quarter ended September 30, 2008, net income before the impact of fair value changes returned to pre-outage levels after the three major outages in the first two quarters. We expect this to continue for the balance of the year except for the potential impact of the following events.

On October 10, 2008, Genesee 3 (a 450MW generation plant, owned equally with TransAlta Corporation) came off line due to a rotor blade failure and the unit is expected to be off line until approximately the end of November 2008. In addition to increasing Generation's maintenance expenses, the outage has shortened our electricity portfolio. At the time the outage occurred, there were other plant outages and derates in the Alberta power system which resulted in increases in Alberta power prices. Higher electricity prices and fewer trading counterparties make it more difficult to manage our electricity portfolio. We estimate the decrease in EPCOR's net income in the fourth quarter related to this outage to be in the range of $12 million to $18 million.

Although expenses for business development activity increased in the quarter ended September 30, 2008, the increase was not as significant as expected primarily due to the timing of the activities compared to plan. Front-end engineering and design (FEED) work on an Integrated Gasification Combined Cycle (IGCC) project reached a milestone in the third quarter when we selected Siemens Fuel Gasification Technology GmbH & Co. KG as the technology provider for the design of the coal gasification facility. EPCOR is conducting this project in partnership with the Alberta Energy Research Institute and Natural Resources Canada and the FEED work is a three year initiative. We expect business development expenses for this and other initiatives to increase in the fourth quarter.

We do not expect material expenditures for the Dodds-Roundhill project in the fourth quarter as the Company has halted work on this project pending analysis by Sherritt International Corporation (Sherritt). In November 2007, EPCOR entered into a memorandum of understanding with the Carbon Development Partnership (CDP), a general partnership indirectly and equally held by Sherritt and the Ontario Teachers' Pension Plan that could see EPCOR construct, own and operate facilities to provide power generation, water and wastewater treatment services to CDP's Dodds-Roundhill coal gasification project. We previously anticipated the power facility to be in operation by 2013, which is now not realistic and we no longer have an expected timing for the commencement of operations.

Power LP's acquisition of Morris, as described under Significant Events, closed on October 31, 2008 and is expected to be moderately accretive to Power LP's cash flow. Power LP is evaluating alternatives to improve future cash flows from the investment by leveraging Power LP's operating expertise and pursuing growth opportunities within the geographic area of the Morris facility.

During September and October 2008, the City of Edmonton (City) conducted a review of the feasibility of transferring the City's Gold Bar Wastewater Treatment Plant to EPCOR. The review related to the associated capital assets and operations, but not the drainage operations which will remain with the City. A report on the review was presented to Edmonton City Council on October 29, 2008, at which time City Council directed that a public hearing into the transfer be held in the first quarter of 2009.

On September 24, 2008, Power LP announced that it was undertaking a sale process that could lead to the sale of its 15.4% interest in Primary Energy Recycling Holdings. If the sale proceeds, it is not anticipated to have a material impact on the Company's net income.

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: (i) the purchase of a 100% equity interest in Morris by Power LP will be financed by existing credit facilities and is expected to be moderately accretive to Power LP's cash flow; (ii) affected ABCP will be converted into term floating-rate notes; (iii) the breakdown of the ABCP term floating-rate notes and the expected lives of the assets underlying these notes; (iv) the Company expects to be paid the accumulated accrued interest on its existing ABCP from the date of the standstill to the date of the restructuring; (v) the ABCP restructuring is expected to be completed by the end of November 2008; (vi) the Company does not expect there will be a material adverse impact on its business as a result of the current ABCP liquidity issue; (vii) Keephills 3 construction will be complete by the end of the first quarter of 2011; (viii) a potential 10% increase in the final cost of Keephills 3 should the cost of labour in Alberta continue to increase; (ix) construction of the remaining two Clover Bar Energy Centre units will be complete in 2010 and the entire Clover Bar Energy Centre project will cost an estimated $284 million; (x) expected approval of Distribution and Transmission NSA in the fourth quarter of 2008; (xi) anticipated fluctuations in working capital requirements over the next few quarters due to normal seasonal changes in operating cash flows and the effects of plant outages; (xii) the expectation of no significant increases in working capital requirements over the long term for existing operations; (xiii) the expectation that capital requirements to finance the Company's capital expenditure program will continue at the current pace for at least the next couple of years; (xiv) the expectation that the Company will finance its working capital requirements with existing credit facilities; (xv) planned capital upgrades at the Southport and Roxboro facilities of US$80 million; (xvi) the expectation that Power LP will arrange permanent long-term financing for the Morris acquisition and capital expenditures for the Southport and Roxboro facilities; (xvii) it is expected to take longer to enter and exit commodity positions due to liquidity concerns in the power market; (xviii) the Company expects to receive $99 million in payments over a 20-year period from Suncor Energy 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; (xix) the expectation of a $30 million capital outlay in 2008 and 2009 for the Suncor Voyageur project; (xx) amendments to Section 1100 of the CICA handbook for rate-regulated operations will not have a material impact on the Company; (xxi) the IFRS plan will proceed as disclosed on pages 22 to 24 of this MD&A and the disclosed standards are those that will have the greatest impact on financial results; (xxii) the Company will consider and may adopt amendments to accounting standards on financial instruments in the fourth quarter; (xxiii) Genesee 3 is expected to be off line until approximately the end of November 2008, which is expected to decrease net income in the fourth quarter of 2008 by $12 million to $18 million; (xxiv) the expectation that business development costs will increase in the fourth quarter of 2008; (xxv) the expectation of no material expenditures for the Dodds-Roundhill project in the fourth quarter of 2008; and (xxvi) the possible sale of Power LP's interest in Primary Energy Recycling Holdings is not expected to have a material impact on the Company's net income.

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 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 interest rates, related credit spreads and mortality rates; (xv) Power LP management's analysis and due diligence of the Morris facility including the related purchase and supply agreements; and (xvi) 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) ABCP market.

This MD&A includes the following updates to previously issued forward-looking statements: (i) the ABCP restructuring is expected to be complete by the end of November 2008, later than previous expectations due to delays as a result of complexities and market volatility; (ii) Distribution and Transmission expects the AUC's approval of the NSA in the fourth quarter of 2008, earlier than the expected timing of the AUC's decision on the rate application of the first quarter of 2009, which was based on the expectation of a regulatory hearing proceeding rather than a negotiated settlement; and (iii) the commencement of operations of a power facility at Dodds-Roundhill was previously expected to be 2013, but is not determinable at this time as the Company has ceased work on this project pending analysis by Sherritt.

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.

QUARTERLY RESULTS

Quarter ended	**Revenues**	**Net income from continuing operations**	**Net income from discontinued operations**	**Net income**
		(Unaudited, $ millions)		
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
December 31, 2006	728	16	1	17

Events for 2008, 2007 and 2006 quarters that have significantly impacted net income from continuing operations, net income and the comparability between quarters are:

- 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.

- December 31, 2006 fourth 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 foreign exchange losses on the translation of U.S. debt. These events were partly offset by increased generation from a short-term tolling arrangement with Calpine Power Income Fund, higher generation incentive income and realized gains on foreign currency forward contracts.

Additional information

Additional information relating to EPCOR, including EPCOR's annual information form, is available on SEDAR at www.sedar.com.

EPCOR UTILITIES INC.
Consolidated Statements of Income
(Unaudited, in millions of dollars)

	Three months ended September 30, 2008	Three months ended September 30, 2007	Nine months ended September 30, 2008	Nine months ended September 30, 2007
Revenues	$ 967	$ 930	$ 2,631	$ 2,694
Operating expenses (income):				
Energy purchases and fuel	689	597	1,622	1,750
Operations, maintenance and administration	184	125	488	352
Franchise fee, property taxes and other taxes	16	17	51	49
Depreciation, amortization, and asset retirement accretion	63	76	192	202
Foreign exchange loss (gain)	12	(17)	20	(39)
Gain on sale of power syndicate agreement (note 10)	-	-	(34)	(34)
Net financing expenses (note 14)	41	47	129	122
	1,005	845	2,468	2,402
Net (loss) income before income taxes and non-controlling interests	(38)	85	163	292
Income taxes (recoveries) (note 11)	(9)	21	2	77
Net (loss) income before non-controlling interests	(29)	64	161	215
Non-controlling interests (note 13)	(105)	(3)	1	(3)
Net income	$ 76	$ 67	$ 160	$ 218

See accompanying notes to consolidated financial statements.

EPCOR UTILITIES INC.
Consolidated Balance Sheets
(Unaudited, in millions of dollars)

	September 30, 2008	December 31, 2007
Assets		
Current assets:		
Cash and cash equivalents	$ 146	$ 79
Accounts receivable	467	581
Income taxes recoverable	11	10
Inventories (note 9)	75	62
Prepaid expenses	16	9
Derivative instruments assets (note 6)	123	104
Future income tax assets	4	3
	842	848
Property, plant and equipment	4,517	4,216
Power purchase arrangements	618	679
Contract and customer rights and other intangible assets	173	179
Derivative instruments assets (note 6)	89	116
Future income tax assets	109	103
Goodwill	185	185
Other assets	257	236
	$ 6,790	$ 6,562
Liabilities and Shareholder's Equity		
Current liabilities:		
Short-term debt	$ 236	$ 138
Accounts payable and accrued liabilities	519	615
Income taxes payable	5	44
Derivative instruments liabilities (note 6)	111	136
Other current liabilities	22	15
Future income tax liabilities	49	39
Current portion of long-term debt (note 12)	73	388
	1,015	1,375
Long-term debt (note 12)	2,343	1,751
Derivative instruments liabilities (note 6)	65	78
Other non-current liabilities	128	125
Future income tax liabilities	121	126
	3,672	3,455
Non-controlling interests (note 13)	664	740
Shareholder's equity	2,454	2,367
Commitments (note 15)		
	$ 6,790	$ 6,562

See accompanying notes to consolidated financial statements.

EPCOR UTILITIES INC.
Consolidated Statements of Changes in Shareholder’s Equity
(Unaudited, in millions of dollars)

	Three months ended September 30,		Nine months ended September 30,	
	2008	2007	2008	2007
Retained earnings				
Balance at beginning of period	$ 2,443	$ 2,337	$ 2,430	$ 2,245
Adjustment for changes in accounting policies	-	-	-	12
Net income	76	67	160	218
Common share dividends paid	(33)	(32)	(98)	(96)
Refundable taxes (note 10)	1	-	(5)	(7)
Balance at end of period	2,487	2,372	2,487	2,372
Accumulated other comprehensive loss				
Balance at beginning of period	(39)	(46)	(63)	(2)
Adjustment for changes in accounting policies	-	-	-	(41)
Other comprehensive income (loss)	6	(24)	30	(27)
Balance at end of period	(33)	(70)	(33)	(70)
Total shareholder’s equity at end of period	$ 2,454	$ 2,302	$ 2,454	$ 2,302

See accompanying notes to consolidated financial statements.

EPCOR UTILITIES INC.
Consolidated Statements of Comprehensive Income
(Unaudited, in millions of dollars)

	Three months ended September 30,		Nine months ended September 30,	
	2008	2007	2008	2007
Net income	$ 76	$ 67	$ 160	$ 218
Other comprehensive income (loss), net of income taxes:				
Unrealized gains (losses) on derivative instruments designated as cash flow hedges (1)	1	(19)	30	(59)
Reclassification of losses (gains) on derivative instruments designated as cash flow hedges to net income (2)	12	(4)	3	25
Unrealized gains on financial instruments designated as available for sale (3)	1	-	7	9
Reclassification of gains on financial instruments designated as available for sale to net income (4)	(8)	-	(10)	-
Unrealized loss in self-sustaining foreign operations (5)	-	(1)	-	(2)
	6	(24)	30	(27)
Comprehensive income	$ 82	$ 43	$ 190	$ 191

(1) For the three and nine months ended September 30, 2008, net of income tax expense of nil and $13, respectively. For the three and nine months ended September 30, 2007, net of income tax recovery of $10 and $27, respectively.
(2) For the three and nine months ended September 30, 2008, net of reclassification of income tax recoveries of $5 and $1, respectively. For the three and nine months ended September 30, 2007, net of reclassification of income tax recovery of nil and $13, respectively.
(3) For the three and nine months ended September 30, 2008, net of income tax expense of nil and $2, respectively. For the three and nine months ended September 30, 2007, net of income tax expense of nil and $2, respectively.
(4) For the three and nine months ended September 30, 2008, net of reclassification of income tax expense of $2 and $3, respectively.
(5) For the three and nine months ended September 30, 2007, net of income tax expense of nil.

See accompanying notes to consolidated financial statements.

EPCOR UTILITIES INC.
Consolidated Statements of Cash Flows
(Unaudited, in millions of dollars)

	Three months ended September 30, 2008	Three months ended September 30, 2007	Nine months ended September 30, 2008	Nine months ended September 30, 2007
Operating activities:				
Net income	$ 76	$ 67	$ 160	$ 218
Adjustments to reconcile net income to funds from operating activities:				
Depreciation, amortization, and asset retirement accretion	63	76	192	202
Gain on sale of power syndicate agreement (note 10)	-	-	(34)	(34)
Non-controlling interests in EPCOR Power L.P. (note 13)	(107)	(10)	(4)	(9)
Fair value changes on derivative instruments	107	19	16	50
Unrealized foreign exchange losses (gains)	15	(25)	28	(74)
Other	(7)	(1)	(21)	(8)
Future income taxes	(6)	12	11	55
	141	138	348	400
Change in non-cash operating working capital	(2)	11	(70)	(32)
	139	149	278	368
Investing activities:				
Property, plant, equipment and other assets	(171)	(144)	(465)	(331)
Change in non-cash working capital	(8)	12	5	21
Third party asset backed commercial paper (note 5)	-	(71)	-	(71)
Proceeds on sale of power syndicate agreement (note 10)	-	-	53	59
Proceeds on sale of portfolio investments	16	-	16	-
Other	(2)	1	5	(10)
	(165)	(202)	(386)	(332)
Financing activities:				
Net proceeds from issue of short-term debt	66	-	98	-
Repayment of short-term debt	-	-	-	(200)
Proceeds from issue of long-term debt (note 12)	47	314	647	314
Repayment of long-term debt	(12)	(249)	(396)	(331)
Issue of subsidiary preferred shares (note 13)	-	-	-	121
Distributions to non-controlling interests (note 13)	(23)	(23)	(70)	(67)
Issue of limited partnership units of EPCOR Power L.P. to non-controlling interests (note 13)	-	-	-	69
Common share dividends paid	(33)	(32)	(98)	(96)
Other	-	-	(5)	-
	45	10	176	(190)
Foreign exchange gain (loss) on cash held in a foreign currency	1	(1)	(1)	(4)
Increase (decrease) in cash and cash equivalents	20	(44)	67	(158)
Cash and cash equivalents, beginning of period	126	146	79	260
Cash and cash equivalents, end of period	$ 146	$ 102	$ 146	$ 102
Supplemental cash flow information:				
Interest paid net of interest received	$ 41	$ 31	$ 109	$ 113
Income taxes paid net of income taxes recovered	8	4	66	27

See accompanying notes to consolidated financial statements.

1. Basis of presentation:

These unaudited interim consolidated financial statements of EPCOR Utilities Inc. (the Company or EPCOR) have been prepared in accordance with Canadian generally accepted accounting principles (GAAP) for interim financial statements and do not include all of the disclosures normally found in the Company's annual consolidated financial statements. These unaudited interim consolidated financial statements should be read in conjunction with the Company's audited consolidated financial statements for the year ended December 31, 2007.

These financial statements have been prepared following the same accounting policies and methods as those used in preparing the most recent annual financial statements except for the changes in accounting policies as described in note 4.

2. Nature of operations:

Interim results will fluctuate due to plant maintenance schedules, the seasonal demands for electricity and water, changes in energy prices and the timing and recognition of regulatory decisions. Consequently, interim results are not necessarily indicative of annual results.

3. Measurement uncertainty:

In accordance with Canadian GAAP, the Company uses estimates in preparing its consolidated financial statements. Interim consolidated financial statements necessarily employ a greater use of estimates than the annual consolidated financial statements.

4. Changes in significant accounting policies:

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 prospectively and the comparative financial statements have not been restated.

Financial instruments – disclosures and presentation

The new standards establish requirements for the reporting and presentation of quantitative and qualitative information that is intended to provide users of the financial statements with additional insight into the 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 these interim consolidated financial statements and discussed in note 5 – Fair value and classification of non-derivative financial assets and liabilities, note 6 – Derivative instruments and hedge accounting and note 7 – Risk management.

Capital disclosures

The new 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 8 – Capital management.

4. Changes in significant accounting policies, continued:

Inventories

The new standard requires the Company's inventories to be measured at the lower of cost and net realizable value except for natural gas inventories held in storage for trading purposes which are measured at fair value less costs to sell. The Company's adoption of the standard did not have a material impact on these interim consolidated financial statements. The additional disclosures required under the new standard are provided in note 9.

Future accounting changes

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. They also require rate-regulated enterprises to recognize future income taxes separate from the regulatory asset or liability for the future recovery from or refund to customers for those income taxes. The Company will assess its accounting for rate-regulated operations in relation to these amendments but does not expect the impact to be material. These amendments are effective January 1, 2009, and will be adopted by the Company as of that date.

In February 2008, the CICA issued Handbook Section 3064 – Goodwill and Intangible Assets and consequential amendments to Section 1000 – Financial Statement Concepts. The new section establishes standards for the recognition, measurement and disclosure of goodwill and intangible assets. The provisions relating to the definition and initial recognition of intangible assets, including internally generated intangible assets, are equivalent to the corresponding provisions in International Financial Reporting Standards (IFRS). The Company will review its capitalization policies and practices for compliance with the new standard which will determine the impact of the amendments to its financial statements. These amendments are effective January 1, 2009, and will be adopted by the Company as of that date.

The CICA has announced that Canadian reporting issuers will need to begin reporting under IFRS, including comparative figures, by the first quarter of 2011. The Company is currently assessing the impact of the differences in accounting standards on the Company's future financial reporting requirements.

On October 24, 2008, the CICA approved amendments to the requirements for accounting and disclosure of financial instruments. In particular, the guidance permits, but only rarely, the reclassification of certain financial instruments from categories that require fair value changes to be recognized immediately in net income to categories that do not have that requirement. Such reclassifications would be recorded at their estimated fair values at the time of transfer and would be subject to impairment testing thereafter. Any subsequent increase in such reclassified financial instruments future estimated cash flows would not alter their carrying amounts but would be reflected in the effective interest rate of the instruments. The Company will consider these amendments and guidance in the fourth quarter and will reflect changes, if any, to its accounting and disclosure in its annual consolidated financial statements.

(Unaudited, in millions of dollars)

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

The Company classifies its cash and cash equivalents and current and non-current derivative instruments assets and liabilities as held for trading and measures them at fair value. Accounts receivable are classified as loans and receivables; 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 Company's beneficial interest in the Sinking Fund related to The City of Edmonton debentures is classified as available for sale.

The classification, carrying amount and fair value of the Company's other financial instruments at September 30, 2008 and December 31, 2007 are summarized as follows:

		September 30, 2008		December 31, 2007	
Financial asset or liability	Classification	Carrying amount	Fair value	Carrying amount	Fair value
Other assets					
Non-bank sponsored asset-backed commercial paper (ABCP)	Held for trading	$ 49	$ 49	$ 60	$ 60
Investment in preferred shares of Primary Energy Recycling Holdings LLC (PERH)	Available for sale	15	15	15	15
Loans and other long-term receivables	Loans and receivables	89	86	70	70
Net investments in leases	Loans and receivables	40	38	29	28
Portfolio investments	Available for sale	7	6	13	16
Long-term debt (including current portion)	Other financial liabilities	2,416	2,382	2,139	2,226

Non-bank sponsored asset-backed commercial paper

There are no observable market prices for ABCP as at the balance sheet date. Accordingly, EPCOR has 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 ABCP conduits under the proposed 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 proposed restructuring, estimated recovery periods based on the estimated lives of the underlying assets of the proposed restructuring conduits and ranges of recoverability based on publicly available default statistics for credit-rated entities. In estimating future cash flows from ABCP the Company assumed that it would earn interest at rates ranging from 2.78% to 3.58% (weighted average rate of 3.00%) depending on the note series, taking into account restructuring costs and margin funding. The future cash flows were discounted at rates ranging from 6.69% to 25.10% (weighted average rate of 9.40%), depending on note series, over 8.2 to 8.3 years (weighted average amortization period of 8.2 years), taking into account the assumed credit spreads and mortality rates.

(Unaudited, in millions of dollars)

5. Fair value and classification of non-derivative financial assets and liabilities, continued:

Non-bank sponsored asset-backed commercial paper, continued

The estimated fair value of ABCP decreased by $11 million since December 31, 2007 ($2 million for the quarter) primarily due to lower interest rates, higher observed and estimated credit spreads over the yields of long-term Government of Canada bonds and longer expected note lives based on new information provided by the Pan-Canadian Investors Committee (Investors Committee) for Canadian non-bank sponsored ABCP.

The estimate of fair value of ABCP is subject to significant risks and uncertainties including the timing and amount of future cash payments, market liquidity, the quality and tenor of the underlying assets and instruments in the applicable conduits including the possibility of margin calls, and the future market for the restructured notes. Accordingly, the estimate of fair value of ABCP may change materially as events unfold and more information becomes available. As the estimate of fair value of ABCP is not solely based on available observable 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 key valuation assumptions, holding all other assumptions constant, is as follows:

Assumption	Change	Impact on estimated fair value and net income
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 Investors Committee, comprised of a consortium representing banks, asset providers and major investors, is overseeing 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. Under the proposed restructuring, the affected ABCP would be converted into term floating-rate notes (notes) maturing no earlier than the scheduled termination dates of the underlying assets. The restructuring documents and subsequent presentations and conference calls provided additional information and clarification on the proposed restructuring. The key information as it relates to EPCOR is as follows:

(i) EPCOR expects its breakdown of new notes under the proposed restructuring, based on EPCOR’s original book value of the investments, to be as follows:

Pool	Series	Rating	Amount	
MAV2	Class A-1	AA	$ 48	67%
	Class A-2	AA	9	13%
	Class B	Unrated	2	2%
	Class C	Unrated	1	2%
MAV3	IA Tracking	Unrated	11	16%
			$ 71	100%

5. Fair value and classification of non-derivative financial assets and liabilities, continued:

Non-bank sponsored asset-backed commercial paper, continued

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

(iii) ABCP investors, including EPCOR, expect to be paid the accumulated accrued interest, net of any restructuring fees, collateral requirements and other costs, on their existing ABCP from the date of the standstill in August 2007 to the date of the restructuring.

(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.

On April 25, 2008, ABCP investors voted in favour of the proposed restructuring plan. After extending the time for his review, on June 6, 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. Certain ABCP note holders filed motions with the Ontario Appeals Court for leave to appeal the ruling subsequent to which, on September 19, 2008, the appeal was denied. A further appeal was taken to the Supreme Court of Canada which was denied on October 17, 2008. This final decision cleared the way for the restructuring to proceed. On October 20, 2008 the Investors Committee announced that the restructuring is taking longer to complete than previously anticipated due to its complexity and market volatility and they now expect the restructuring will be completed by the end of November 2008.

Net investments in leases

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 September 30, 2008 and December 31, 2007.

5. Fair value and classification of non-derivative financial assets and liabilities, continued:

Long-term debt and Sinking Fund

The fair value of the Company's long-term debt is based on determining a current yield for the Company's debt as at September 30, 2008 and December 31, 2007. This yield is based on an estimated credit spread for the Company over the yields of long-term Government of Canada and U.S. Government bonds that have similar maturities to the Company's debt. The estimated credit spread is based on the Company's indicative spread as published by independent financial institutions. Long-term debt (including current portion) includes The City of Edmonton debentures which are offset by payments made by the Company into the Sinking Fund. The Company's beneficial interest in the Sinking Fund is a related party transaction and is therefore recorded at the exchange amount. It is not quoted in an active market.

Other financial instruments

Fair values on the remaining financial instruments are determined by reference to quoted bid or ask prices, as appropriate, in active markets at period-end dates. The effects of illiquidity on certain shares held and that are quoted in an active market were included in determining fair value. Financial instruments are recorded at the original exchange amount less impairment when prices are not quoted in active markets.

The fair value of the preferred share interest held in PERH and certain common share interests in certain capital venture investments cannot be measured reliably as the shares are not quoted in an active market. Investments in common shares held at their carrying amount have not been offered for sale and in the event the Company elected to dispose of the shares, they would most likely be sold in a private transaction. The Company has elected to dispose of the preferred share interest held in PERH, which will most likely be sold in a private transaction.

6. Derivative instruments and hedge accounting:

Derivative financial and non-financial instruments are generally held for the purpose of energy purchases, merchant trading or financial risk management. All derivative instruments are recorded at fair value on the balance sheet as derivative instruments assets or derivative instruments liabilities except for embedded derivatives instruments that are clearly and closely linked to their host contract and the combined instrument is not measured at fair value. Any contract to buy or sell a non-financial item is not treated as a derivative or financial instrument if that contract was entered into and continues to be held for the purpose of the receipt or delivery of a non-financial item in accordance with the Company's expected purchase, sale or usage requirements. All changes in the fair value of derivative financial and non-financial instruments are recorded in net income unless cash flow hedge accounting is used, in which case changes in fair value of the effective portion of the derivatives are recorded in other comprehensive income.

(Unaudited, in millions of dollars)

6. Derivative instruments and hedge accounting, continued:

The derivative instruments assets and liabilities used for risk management purposes as described in note 7 consist of the following:

	September 30, 2008			
	Energy		Foreign exchange	
	Cash flow hedges	Non-hedges	Non-hedges	Total
Derivative instruments assets:				
Current	$ 16	$ 100	$ 7	$ 123
Non-current	8	75	6	89
Derivative instruments liabilities:				
Current	(39)	(70)	(2)	(111)
Non-current	(31)	(30)	(4)	(65)
Net fair value	$ (46)	$ 75	$ 7	$ 36
Net notional buys (sells):				
Megawatt hours of electricity (millions)	(2)	(3)		
Gigajoules of natural gas (millions)	-	66		
Foreign currency (U.S. dollars)			$ (298)	
Range of contract terms in years	0.1 to 8.3	0.1 to 8.3	0.1 to 6.2	

	December 31, 2007			
	Energy		Foreign exchange	
	Cash flow hedges	Non-hedges	Non-hedges	Total
Derivative instruments assets:				
Current	$ 30	$ 60	$ 14	$ 104
Non-current	12	82	22	116
Derivative instruments liabilities:				
Current	(95)	(33)	(8)	(136)
Non-current	(40)	(34)	(4)	(78)
Net fair value	$ (93)	$ 75	$ 24	$ 6
Net notional buys (sells):				
Megawatt hours of electricity (millions)	-	(2)		
Gigajoules of natural gas (millions)	-	75		
Foreign currency (U.S. dollars)			$ (196)	
Range of contract terms in years	0.1 to 9.0	0.1 to 9.0	0.2 to 6.0	

(Unaudited, in millions of dollars)

6. Derivative instruments and hedge accounting, continued:

Fair values of derivative instruments are determined, when possible, using exchange or over-the-counter price quotations by reference to bid or asking price as appropriate, in active markets. When there are limited observable prices due to illiquid or inactive markets, the Company uses appropriate valuation and price modeling techniques commonly used by market participants to estimate fair value. The Company may also rely on price forecasts prepared by third party market experts to estimate fair value when there are limited observable prices available. Fair values determined using valuation models require the use of assumptions concerning the amounts and timing of future cash flows. Fair value amounts reflect management's best estimates using external readily observable market data such as future prices, interest rate yield curves, foreign exchange rates, quoted Canadian dollar swap rate as the discount rate for time value, and volatility when available. It is possible that the assumptions used in establishing fair value amounts will differ from future outcomes and the impact of such variations could be material.

The extent to which fair values of derivatives are based on observable market data is determined by the extent to which the market for the underlying commodity is judged to be active. With respect to natural gas, the Company has determined the market is active within five years. As the natural gas supply contracts extend beyond the active period of the market, fair value is determined by reference in part to published price quotations where there is observable market data and in part by relying on price forecasts prepared by an independent third party where there are limited observable natural gas prices. While external market forecasts outside the active period of the market reasonably reflect all factors that market participants would consider in setting a price, these expectations are not currently supportable by active forward market quotes. The fair values of these contracts could change significantly if the assumptions were changed to reasonably possible alternatives. The natural gas price forecasts for the period, where limited observable natural gas prices are available, range from $7.63 to $7.89 per gigajoule. The Company has determined that a reasonably possible increase (decrease) of $1.00 per gigajoule in the natural gas price forecast would have a $59 million impact on the fair value estimate of these contracts. Included in this sensitivity is a $20 million impact for contract periods beyond the next five years where prices are not based on observable natural gas prices. This valuation technique resulted in unrealized pre-tax fair value losses of $43 million and unrealized pre-tax fair value gains of $8 million recognized in energy purchases and fuel for the three and nine months ended September 30, 2008 respectively ($16 million of unrealized pre-tax fair value losses and nil for the three and nine months ended September 30, 2007 respectively).

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

	Three months ended September 30,			
	2008		2007	
	Unrealized gains (losses)	Realized gains (losses)	Unrealized gains (losses)	Realized gains (losses)
Energy cash flow hedges	$ 18	$ (18)	$ (33)	$ 4
Energy non-hedges	(96)	(4)	(28)	-
Foreign exchange non-hedges	(12)	3	8	-
Interest rate non-hedges	-	-	1	(8)

(Unaudited, in millions of dollars)

6. Derivative instruments and hedge accounting, continued:

	Nine months ended September 30,			
	2008		2007	
	Unrealized gains (losses)	Realized gains (losses)	Unrealized gains (losses)	Realized gains (losses)
Energy cash flow hedges	$ 47	$ (4)	$ (48)	$ (38)
Energy non-hedges	-	3	(67)	-
Foreign exchange non-hedges	(17)	6	18	(14)
Interest rate non-hedges	-	-	(1)	(3)

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

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

The Company has elected to apply hedge accounting on certain derivatives it uses to manage commodity price risk relating to electricity prices. For the three and nine months ended September 30, 2008, the change in the fair value of the ineffective portion of hedging derivatives required to be recognized in the income statement was nil (2007 - nil). Of the $31 million (December 31, 2007 - $64 million) of net losses related to derivative instruments designated as cash-flow hedges included in accumulated other comprehensive loss at September 30, 2008, net losses of $16 million (December 31, 2007 - $45 million), net of income taxes of $6 million (December 31, 2007 - $20 million) are expected to settle and be reclassified to net income over the next twelve months. The Company's cash flow hedges extend up to 2016.

7. Risk management:

Risk management overview

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

7. Risk management, continued:

Risk management overview, continued

The Vice President, Risk Management, reports regularly to the Board of Directors on ROC activities. Risk management strategies, policies, and limits are designed to help ensure the risk exposures are managed within the Company's business objectives and established risk tolerance. The Company's financial risk management objective is to protect and minimize volatility in earnings and cash flow.

Commodity price risk management and the associated credit risk management are carried out in accordance with financial risk management policies, as approved by the ROC and the Board of Directors. Financial risk management including foreign exchange risk, interest rate risk, liquidity risk, and the associated credit risk management, is carried out by a centralized Treasury function in accordance with applicable policies. The Audit Committee of the Board of Directors, in its oversight role, performs regular and ad-hoc reviews of risk management controls and procedures to help ensure compliance.

Market risk

Market risk is the risk of loss that results from changes in market factors such as commodity prices, foreign currency exchange rates, interest rates, and equity prices. The level of market risk to which the Company is exposed at any point in time varies depending on market conditions, expectations of future price or market rate movements and the composition of the Company's financial assets and liabilities held, non-trading physical asset and contract portfolios, and trading portfolios.

To manage the exposure related to changes in market risk, the Company uses various risk management techniques including derivative instruments. Derivative instruments may include forward contracts, fixed-for-floating swaps (or contracts-for-differences), and option contracts. Such derivative instruments may be used to establish a fixed price for an energy commodity, an interest-bearing obligation or an obligation denominated in a foreign currency. Commodity market risk exposures are monitored daily against approved risk limits, and control processes are in place to monitor that only authorized activities are undertaken.

The sensitivities provided in each of the following risk discussions disclose the effect of reasonably possible changes in relevant prices and rates on net income at the reporting date. The sensitivities are hypothetical and should not be considered to be predictive of future performance or indicative of earnings on these contracts. The Company's actual exposure to market risks is constantly changing as the Company's portfolio of debt, foreign currency and commodity contracts changes. Changes in fair values or cash flows based on market variable fluctuations cannot be extrapolated since the relationship between the change in the market variable and the change in fair value or cash flows may not be linear. In addition, the effect of a change in a particular market variable on fair values or cash flows is calculated without considering interrelationships between the various market rates or mitigating actions that would be taken by the Company.

7. Risk management, continued:

Market risk, continued

Commodity price risk

The Company is exposed to commodity price risk as part of its normal business operations, including energy procurement activities in Alberta, Ontario, and the U.S. The Company's energy procurement activities consist of power generation, non-market traded and market traded electricity and natural gas purchase and sales contracts, and derivative contracts. The Company is primarily exposed to changes in the prices of electricity, and to a lesser extent is exposed to changes in the prices of natural gas and coal. The Company actively manages commodity price risk by optimizing its asset and contract portfolios utilizing the following methods variously:

- The Company reduces its exposure to the volatility of commodity prices related to electricity sales by entering into offsetting contracts such as contracts-for-differences and firm price physical contracts for periods of varying duration.
- The Company enters into fixed-price energy sales contracts and power purchase arrangements which limit the exposure to electricity prices. The Company has entered into long-term tolling arrangements whereby variable changes linked to the price of natural gas and coal are assumed by the counterparty.
- When it is economically feasible, the Company purchases natural gas under long-term fixed-price supply contracts to reduce the exposure to fluctuating natural gas prices on its natural gas-fired generation plants and physical obligations arising from retail customers.
- The Company enters into back-to-back electricity and natural gas physical and financial contracts in order to lock in a margin.

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

The fair value of the Company's energy related derivatives at September 30, 2008 that are required to be measured at fair value with the respective changes in fair value recognized in net income are disclosed in note 6.

7. Risk management, continued:

Market risk, continued

Commodity price risk, continued

The Company employs specific volumetric limits and a Value-at-Risk (VaR) methodology to manage risk exposures to commodity prices. VaR measures the estimated potential loss in a portfolio of positions associated with the movement of a commodity price for a specified time or holding period and a given confidence level. The Company's VaR uses a statistical confidence interval of 95% over a twenty business day holding period. This measure reflects a 5% probability that, over the twenty day period commencing with the point in time that the VaR is measured, the fair value of the Company's commodity portfolio could decrease by an amount in excess of the VaR amount. The VaR methodology is a statistically-defined, probability-based approach that takes into consideration market volatilities and risk diversification by recognizing offsetting positions and correlations between products and markets. This technique makes use of historical data and makes an assessment of the market risk arising from possible future changes in commodity prices over the holding period.

The Company's VaR should be interpreted in light of the limitations of the methodologies used. These limitations include the following:

- VaR calculated based on a holding period may not fully capture the market risk of positions that cannot be liquidated or hedged within the holding period.
- The Corporation computes VaR of the portfolios at the close of business and positions may change substantially during the course of the day.
- VaR, at a 95% confidence level, does not reflect the extent of potential losses beyond that percentile. Losses on the other 5% of occasions could be substantially greater than the estimated VaR.

These limitations and the nature of the VaR measurements mean that the Company can neither guarantee that losses will not exceed the VaR amounts or that losses in excess of the VaR amounts will not occur more frequently than 5% of the time. As VaR is not a perfect measure of risk, the Company applies a safety factor to the calculated VaR amount to estimate total exposure (TE) which attempts to capture unaccounted for exposures due to the assumptions and limitations inherent in the calculation of VaR and to improve the confidence level beyond 95%.

The Company's estimation of TE takes into account positions from all wholly-owned subsidiaries and subsidiaries in which the Company has controlling interest, and reflects the Company's aggregate commodity positions from its trading and asset portfolios. The Company's Board of Directors has established an aggregate TE limit, under the Company's risk management policy, which is monitored and reported to the ROC and other senior management on a daily basis. The portfolios are stress tested regularly to observe the effects of plausible scenarios taking into account historical maximum volatilities and maximum observed price movements. Based on the commodity portfolio as at September 30, 2008, there is a higher than 95% probability that unfavorable daily market variations would not reduce the 12 month portfolio by more than $15 million.

7. Risk management, continued:

Market risk, continued

Foreign exchange risk

The Company is exposed to foreign exchange risk on foreign currency denominated forecasted transactions, firm commitments, and monetary assets and liabilities denominated in a foreign currency and on its net investments in foreign operations. The Company operates internationally and therefore, is exposed to foreign exchange risk arising from transactions denominated in foreign currencies. The Company's foreign exchange risk arises primarily with respect to the U.S. dollar but it is potentially exposed to changes in other currencies if and when it transacts in other currencies. The risk is that the functional currency value of cash flows will vary as a result of the movements in exchange rates.

The Company's foreign exchange management policy is to minimize economic and material transactional exposures arising from movements in the Canadian dollar relative to the U.S. dollar or other foreign currencies. The Company's exposure to foreign exchange risk arises from future anticipated cash flows from its U.S. operations, debt service obligations on U.S. dollar borrowings, and from certain capital expenditure commitments denominated in U.S. dollars or other foreign currencies. The Company co-ordinates and manages foreign exchange risk centrally, by identifying opportunities for naturally-occurring opposite movements wherever possible, and then dealing with any material residual foreign exchange risks; these are hereinafter referred to as being economically hedged.

The Company primarily uses foreign currency forward contracts to fix the functional currency of its non-functional currency cash flows thereby reducing its anticipated U.S. dollar denominated transactional exposure. The Company looks to limit foreign currency exposures as a percentage of estimated future cash flows. The percentage amount to be fixed will generally be higher, the shorter the period into the future that the cash flows relate to. At September 30, 2008, US$341 million or approximately 82% of expected future net cash flows from EPCOR Power L.P.'s (Power LP) U.S. plants had been economically hedged for 2008 to 2014 at a weighted average exchange rate of $1.08 per U.S. dollar. At September 30, 2008, US$43 million or approximately 82% of expected future net cash flows from the Company's capital expenditure commitments, denominated in U.S. dollars, had been economically hedged for 2008 to 2010 at a weighted average exchange rate of $1.08 per U.S. dollar.

(Unaudited, in millions of dollars)

7. Risk management, continued:

Market risk, continued

Foreign exchange risk, continued

The following table summarizes the non-derivative and derivative financial instruments denominated in U.S. dollars:

	September 30, 2008 (USD)	December 31, 2007 (USD)
Non-derivative financial instruments:		
Cash and cash equivalents	$ 46	$ 26
Accounts receivables	54	49
Accounts payables and accrued liabilities	(28)	(53)
Other assets	71	79
Long-term debt	(415)	(415)
	(272)	(314)
Derivative financial instruments:		
Forward foreign exchange sales	7	37
Forward foreign exchange purchases	(1)	(12)
	6	25
Net exposure	$ (266)	$ (289)
Range of contract terms in years	0.1 to 6.2	0.2 to 6.0
Significant exchange rates in Canadian dollars per U.S. dollar:		
Average reporting date closing	1.06	0.99
Average forward rate inherent in sales contracts	1.08	1.11
Average forward rate inherent in purchase contracts	1.07	1.07

The impacts of reasonably possible changes in foreign currency exchange rates on net income, based on the assumptions provided below, are as follows:

	Change in variable	Increase (decrease) in net income
Canadian dollars per U.S. dollar	+C$0.10	$ (10)
	-C$0.10	10

Changes in foreign currency exchange rates would have no impact on other comprehensive income.

This sensitivity analysis assumes that the instruments held remain unchanged from those held at September 30, 2008.

7. Risk management, continued:

Market risk, continued

Interest rate risk

The Company is exposed to changes in interest rates on its cash and cash equivalents, and floating rate short-term and long-term loans and obligations. The Company is exposed to interest rate risk from the possibility that changes in the interest rates will affect future cash flows or the fair values of its financial instruments. In some circumstances, floating rate funding may be used for short-term borrowings and other liquidity requirements. At September 30, 2008, the proportion of fixed rate debt was approximately 89% (December 31, 2007 - 87%) of total long-term debt outstanding. The Company may also use derivative instruments to manage interest rate risk. At September 30, 2008 and December 31, 2007, the Company did not hold any interest rate derivative instruments.

Assuming that the amount and mix of fixed and floating rate loans and net debt remains unchanged from that held at September 30, 2008, a 100 basis point change to interest rates would not have a material impact on full year net income and would have no impact on other comprehensive income.

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

Equity price risk

The Company is exposed to changes in equity prices arising from equity investments which are classified as available-for-sale financial assets. The Company periodically invests in equities and venture capital investments which are focused on strategic elements of the energy and water value chain. Investments that are quoted in active markets are re-measured at their fair value with changes recognized in other comprehensive income. On disposal, accumulated fair value changes are reclassified to net income. Equity investments that are not quoted in active markets are carried at their original exchange amount less any impairment. On July 8, 2008, the Company disposed of its equity investment that was not quoted in an active market and recognized a $9 million pre-tax gain in net income. Prior to the sale, fair value gains on the investment were previously recorded as a fair value change in accumulated other comprehensive income. Refer to note 5 for disclosures on available-for-sale financial assets.

(Unaudited, in millions of dollars)

7. Risk management, continued:

Credit risk

Credit risk is the possible financial loss associated with the inability of counterparties to satisfy their contractual obligations to the Company. The Company's Counterparty Credit Risk Management Policy is established by ROC and approved by the Board of Directors and the associated procedures and practices are designed to manage the credit risks associated with the various business activities throughout the Company. Credit and counterparty risk management procedures and practices generally include assessment of individual counterparty creditworthiness and establishment of exposure limits prior to entering into a transaction with the counterparty. Exposures and concentrations are subsequently monitored and are regularly reported to ROC. Creditworthiness continues to be evaluated after transactions have been initiated, at minimum, on an annual basis. To manage and mitigate credit risk, the Company employs various credit mitigation practices such as master netting agreements, margining to reduce energy trading risks, pre-payment arrangements from retail customers, credit derivatives and other forms of credit enhancements including cash deposits, parent company guarantees, and bank letters of credit.

Maximum credit risk exposure

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

	September 30, 2008	December 31, 2007
Cash and cash equivalents	$ 146	$ 79
Accounts receivable	467	581
Derivative instruments assets	212	220
ABCP	49	60
Loans and other long-term receivables	89	70
Net investments in leases	40	29
Financial guarantees to third parties	29	27
Loan commitments to third parties	6	6
	$ 1,038	$ 1,072

This table does not take into account collateral held. At September 30, 2008, the Company held cash deposits of $59 million (December 31, 2007 - $36 million) as security for certain counterparty accounts receivable and derivative contracts. The Company is not permitted to sell or re-pledge this collateral in the absence of default of the counterparties providing the collateral. At September 30, 2008, the Company also held other forms of credit enhancement in the form of letters of credit of $18 million (December 31, 2007 - $1 million) and parental guarantees of $710 million (December 31, 2007 - $669 million).

(Unaudited, in millions of dollars)

7. Risk management, continued:

Credit risk, continued

Credit quality and concentrations

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

The credit quality of the Company's accounts receivable, by major credit concentrations, and other financial assets are the following:

	September 30, 2008		
	Investment grade[1] or secured	Non-investment grade[1]	Unrated
Accounts receivable and financial derivative instruments[2]			
Generation	100%	-	-
Wholesale[3]	78%	22%	-
Rate-regulated customers[4]	-	-	100%
Cash and cash equivalents	100%	-	-
Loans and other long-term receivables[5]	-	-	100%
ABCP[6]	80%	-	20%

[1] Credit ratings are based on the Company's internal analyses which take into account the ratings of external credit rating agencies.

[2] Percentages are based on potential 60 day accounts receivables.

[3] Includes industrial end-use customers, trading and position management counterparties.

[4] Rate-regulated customer trade receivables include distribution and transmission, water sales, rate-regulated residential power, and default power supply receivables. Under the Alberta Electric and Utilities Act, the Company 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.

[5] Loans and other long-term receivables are considered to have low credit risk as the financial assets are either secured by the underlying assets or the counterparties are local or provincial governments.

[6] Based on proposed ABCP restructuring.

7. Risk management, continued:

Credit risk, continued

Generation credit risk

Credit risk exposure from power purchase arrangements, agreements with independent system operators, power and steam sales contracts, and certain energy supply agreements is predominantly restricted to accounts receivables and contract default. In certain cases, the Company relies on a single or small number of customers to purchase all or a significant portion of a facility's output. The failure of any one of these counterparties to fulfill its contractual obligations could negatively impact the Company's financial results. Financial loss resulting from events of default by counterparties in certain power purchase arrangements and steam purchase agreements may not be recovered since the contracts may not be replaceable on similar terms under current market conditions. Consequently, the Company's financial performance depends on the continued performance by customers and suppliers of their obligations under these long-term agreements. Credit risk exposure is mitigated by dealing with creditworthy counterparties, netting amounts by legally enforceable set-off rights, and, when appropriate, taking back security from the counterparty. Credit risk with government-owned or sponsored entities and regulated public utility distributors is generally considered low.

Wholesale and merchant credit risk

Credit risk exposure for wholesale and merchant trading counterparties is measured by calculating the costs (or proceeds) of replacing the commodity position (physical and derivative contracts), adjusting for settlement amounts due to or due from the counterparty and, if permitted, netting amounts by legally enforceable set-off rights. Financial loss on wholesale contracts could include, but is not limited to, the cost of replacing the obligation, amounts owing from the counterparty or any loss incurred on liability settlements. Credit risk exposure is mitigated by dealing with creditworthy counterparties, monitoring credit exposure limits, margining to reduce energy trading risks, parent company guarantees, and when appropriate taking back security from the counterparty.

Rate-regulated customer credit risk

Credit risk exposure for residential and commercial customers under default power and regulated water supply rates is generally limited to amounts due from customers for electricity and water consumed but not yet paid for. The Company mitigates credit risk from counterparties under default power supply rates by performing credit checks and on higher risk customers, by taking pre-payments or cash deposits. For rate-regulated customers, regulations allow for the recovery of a percentage of unforecasted credit losses through a deferral account. The Company monitors credit risk for this portfolio at the gross exposure level.

(Unaudited, in millions of dollars)

7. Risk management, continued:

Credit risk, continued

Accounts receivable and allowance for doubtful accounts

Accounts receivable consist primarily of amounts due from retail customers including industrial and commercial customers, other retailers, independent system operators from various regions, government-owned or sponsored entities, regulated public utility distributors, and other counterparties. Larger commercial and industrial customer contracts and contracts-for-differences provide for performance assurances including letters of credit. For other retail customers, represented by a diversified customer base, credit losses are generally low and the Company provides for an allowance for doubtful accounts to absorb credit losses. The Company also has credit exposures to large suppliers of electricity and natural gas. The Company mitigates these exposures by dealing with creditworthy counterparties and, when appropriate, taking back appropriate security from the supplier.

The aging of accounts receivable was:

	September 30, 2008		
	Gross accounts receivable	Allowance for doubtful accounts	Net accounts receivable
Current	$ 425	$ -	$ 425
Past due 30 to 60 days	15	-	15
Past due 61 to 90 days	6	3	3
Past due more than 90 days[1]	27	3	24
Total	$ 473	$ 6	$ 467

[1] Includes $19 million which is subject to regulatory approval prior to collection but has low associated credit risk.

Bad debt expense, exclusive of recoveries, of $4 million and $6 million recognized in the three and nine month periods ended September 30, 2008 respectively, relates to customer amounts that the Company determined would not be fully collectable. Allowances for doubtful accounts are determined by each business unit considering the unique factors of the business unit's accounts receivable. Allowances and write-offs are determined by each business unit, either by applying specific risk factors to customer groups' aged balances in accounts receivable or by reviewing material accounts on a case-by-case basis. Accounts receivable and the related allowance for doubtful accounts amount are both written off or decreased when the Company has determined that recovery is not possible.

(Unaudited, in millions of dollars)

7. Risk management, continued:

Credit risk, continued

Accounts receivable and allowance for doubtful accounts, continued

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

	Three months ended September 30, 2008	Three months ended September 30, 2007	Nine months ended September 30, 2008	Nine months ended September 30, 2007
Balance, beginning of period	$ 4	$ 7	$ 6	$ 6
Allowance of receivables	4	-	6	4
Receivables written off	(2)	(1)	(7)	(5)
Recovery of receivables	-	1	1	2
Balance, end of period	$ 6	$ 7	$ 6	$ 7

At September 30, 2008, the Company held $20 million of customer deposits for the purpose of mitigating the credit risk associated with accounts receivable from residential and business customers.

At September 30, 2008, there was no provision for credit losses associated with accounts receivable from treasury, trading and energy procurement counterparties as all balances are considered to be fully collectable.

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The Company's liquidity is managed centrally by the Treasury function. The Company manages liquidity risk through regular monitoring of cash and currency requirements by preparing short-term and long-term cash flow forecasts and also by matching the maturity profiles of financial assets and liabilities to identify financing requirements. The financing requirements are addressed through a combination of committed and demand revolving credit facilities and financings in public capital debt markets.

As at September 30, 2008, the Company had undrawn and committed bank credit facilities of $1,322 million, of which $771 million is committed for at least 2 years. The Company has a long-term debt rating of BBB+ and A (low), assigned by Standard and Poor's (S&P) and DBRS Limited (DBRS), respectively. Power LP also has a long-term debt rating of BBB+ and BBB(high), assigned by S&P and DBRS respectively.

In addition, the Company has in place a Canadian shelf prospectus, which expires in November 2009, under which it may raise up to $1 billion of debt, with maturities of not less than one year. As at September 30, 2008, the available amount remaining under the Canadian shelf prospectus was $400 million. As of July 10, 2008, Power LP renewed its Canadian universal shelf prospectus, which expires in August 2010, under which Power LP may raise up to $1 billion in partnership units or debt, of which a maximum of $600 million can be debt. As at September 30, 2008, the Power LP has not drawn on the Power LP shelf prospectus.

(Unaudited, in millions of dollars)

7. Risk management, continued:

Liquidity risk, continued

The following are the undiscounted cash flow requirements and contractual maturities of the Company's financial liabilities, including interest payments, as at September 30, 2008:

	Due within 1 year	Due between 1 and 2 years	2 and 3 years	3 and 4 years	4 and 5 years	Due after more than 5 years	Total contractual cash flows
Non-derivative financial liabilities:							
Short-term debt	$ 236	$ -	$ -	$ -	$ -	$ -	$ 236
Long-term debt	73	23	20	12	9	2,296	2,433
Interest payments on long-term debt	194	185	159	135	119	1,279	2,071
Accounts payable and accrued liabilities [1]	467	-	-	-	-	-	467
Other current liabilities	22	-	-	-	-	-	22
Loan commitments	6	-	-	-	-	-	6
Derivative financial liabilities:							
Net forward foreign exchange contracts	2	1	1	-	1	2	7
Net commodity contracts-for-differences	92	37	15	3	-	1	148
Total	$ 1,092	$ 246	$ 195	$ 150	$ 129	$ 3,578	$ 5,390

[1] Excluding accrued interest on long-term debt of $52 million.

8. Capital management:

The Company's primary objectives when managing capital are to safeguard the Company's ability to continue as a going concern, pay dividends to its shareholder in accordance with the Company's dividend policy, maintain a suitable credit rating, and to facilitate the acquisition or development of projects in Canada and the U.S. consistent with the growth strategy of the Company. The Company manages its capital structure in a manner consistent with the risk characteristics of the underlying assets. This overall objective and policy for managing capital remained unchanged in the current quarter of 2008 from the prior comparative period.

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

(Unaudited, in millions of dollars)

8. Capital management, continued:

The Company considers its capital structure to consist of long-term and short-term debt net of cash and cash equivalents, non-controlling interests (including preferred shares issued by subsidiary companies) and shareholder's equity. The following table represents the total capital of the Company:

	September 30, 2008	December 31, 2007
Short-term debt	$ 236	$ 138
Long-term debt	2,416	2,139
Cash and cash equivalents	(146)	(79)
Net debt	2,506	2,198
Non-controlling interests	664	740
Shareholder's equity	2,454	2,367
Total equity	3,118	3,107
Total capital	$ 5,624	$ 5,305

The Company has the following externally imposed requirements on its capital as a result of its credit facilities and certain debt covenants:

- Maintenance of modified consolidated net tangible assets to consolidated net tangible assets ratio, as defined in the debt agreements, of not less than 80%;
- Maintenance of senior debt to consolidated capitalization ratio, as defined in the debt agreements, of not more than 70%; and
- Limitation on debt issued by subsidiaries.

Power LP has the following externally imposed requirements on its capital:

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

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

For the nine months ended September 30, 2008, the Company and Power LP complied with all externally imposed capital restrictions.

To manage or adjust its capital structure, the Company can issue new debt, issue new Power LP units, repay existing debt or issue or redeem preferred shares.

(Unaudited, in millions of dollars)

9. Inventories:

The carrying amount of the Company's inventories is summarized below:

	September 30, 2008	December 31, 2007
General stock	$ 54	$ 51
Natural gas held in storage for trading purposes	11	-
Coal	8	10
Other	2	1
	$ 75	$ 62

General stock, coal and other, the majority of which are consumed by the Company in the provision of its goods and services, are valued at the lower of cost and net realizable value. Cost includes the purchase price, transportation costs and other costs to bring the inventories to their present location and condition. The cost of any assembled inventory includes direct labour, materials and attributable overhead. The cost of inventory items that are interchangeable are determined on an average cost basis. For inventory items that are not interchangeable, cost is assigned using specific identification of their individual costs. Natural gas inventory held in storage for trading purposes is recorded at fair value less costs to sell, as measured by the one-month forward price of natural gas.

Inventories expensed during the three and nine months ended September 30, 2008 of $21 million (2007 - $15 million) and $53 million (2007 - $43 million) respectively were charged to energy purchases and fuel and operations, maintenance and administration. No write-down of inventory or reversal of a previous write-down was recognized in the three and nine months ended September 30, 2008 or in the same periods of 2007. At September 30, 2008, no inventories were pledged as security for liabilities (December 31, 2007 – nil).

10. Sale of power syndicate agreement:

During the first quarter of 2008, 10% of the Battle River Power Syndicate Agreement (Battle River PSA) was sold, pursuant to a June, 2006 sales agreement. This transaction was incremental to the previous sales of 65% of the Battle River PSA that were reported in prior years. The transactions in the current and comparative periods are summarized as follows:

	Nine months ended September 30, 2008	2007
Cash proceeds from sale	$ 53	$ 59
Less net book value and costs of disposal	19	25
Gain on sale before income taxes	34	34
Less future income taxes	4	4
Gain on sale after income taxes	$ 30	$ 30

Refundable taxes of $6 million (2007 - $7 million), which arose from the taxable capital gains on the sale of the Battle River PSA, have been charged to retained earnings.

(Unaudited, in millions of dollars)

11. Income taxes:

	Three months ended September 30, 2008	Three months ended September 30, 2007	Nine months ended September 30, 2008	Nine months ended September 30, 2007
Current income taxes	$ 2	$ 7	$ 24	$ 73
Future income taxes	(11)	14	(22)	4
	$ (9)	$ 21	$ 2	$ 77

Income taxes consisted of:

	Three months ended September 30, 2008	Three months ended September 30, 2007	Nine months ended September 30, 2008	Nine months ended September 30, 2007
Income taxes (recoveries) on income for the period	$ (10)	$ 26	$ 2	$ 35
Income taxes arising on sale of power syndicate agreement (note 10)	-	-	4	4
Corporate income tax rate reductions	1	-	(4)	1
Reduction of income taxes resulting from corporate restructuring within the Energy Services segment	-	-	-	(10)
Income taxes arising on enactment of Specified Investment Flow-through Legislation	-	(5)	-	47
	$ (9)	$ 21	$ 2	$ 77

12. Long-term debt:

On January 31, 2008, the Company completed a $200 million public offering of unsecured medium term note debentures. On April 15, 2008, the Company completed an additional $375 million public offering of unsecured medium-term note debentures consisting of issues of $200 million and $175 million followed by an April 28, 2008 issue of $25 million of unsecured medium-term note debentures. The two $200 million issues have 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 the quarter, the Company drew $17 million on its $300 million three-year Power LP revolving extendible credit facility. The amounts outstanding under this facility mature within one year of the balance sheet date and bear interest at 3.14%.

During the quarter, the Company drew $20 million on its $490 million two-year extendible credit facility. The amounts outstanding under this facility mature within one year of the balance sheet date and bear interest at 3.57%.

(Unaudited, in millions of dollars)

12. Long-term debt, continued:

During the quarter, the Company drew $10 million on its $400 million five-year extendible syndicated bank credit facility. The amounts outstanding under this facility mature within one year of the balance sheet date and bear interest at 3.62%. In addition, the Company extended this facility as well as its $400 million three-year extendible syndicated bank credit facility for an additional year.

13. Non-controlling interests:

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

	Three months ended September 30, 2008	Three months ended September 30, 2007	Nine months ended September 30, 2008	Nine months ended September 30, 2007
Non-controlling interests in Power LP	$ (107)	$ (10)	$ (4)	$ (9)
Preferred share dividends paid (dividend taxes recovered) by subsidiary companies	2	4	5	3
Preferred share issue costs recognized on redemption of preferred shares	-	3	-	3
	$ (105)	$ (3)	$ 1	$ (3)

Non-controlling interests reflected in the consolidated balance sheets for the nine months ended September 30, 2008 and the year ended December 31, 2007 consisted of:

	September 30, 2008	December 31, 2007
Non-controlling interests in Power LP, beginning of year	$ 618	$ 554
Partnership units issued to non-controlling interests	-	69
Earnings attributable to non-controlling interests	(4)	19
Other comprehensive loss attributable to non-controlling interests	(2)	(2)
Opening accumulated other comprehensive income adjustments attributable to non-controlling interests	-	4
Opening retained earnings adjustments attributable to non-controlling interests	-	66
Distributions to non-controlling interests	(70)	(92)
Non-controlling interests in Power LP, end of period	542	618
Preferred shares issued by subsidiary companies, beginning of year	122	197
Issue of preferred shares	-	122
Redemption of preferred shares	-	(197)
Preferred shares issued by subsidiary companies, end of period	122	122
	$ 664	$ 740

(Unaudited, in millions of dollars)

14. Net financing expenses:

	Three months ended September 30, 2008	Three months ended September 30, 2007	Nine months ended September 30, 2008	Nine months ended September 30, 2007
Interest on long-term debt	$ 45	$ 41	$ 133	$ 122
Interest on short-term debt and other financing costs	2	-	5	7
Fair value changes on financial instruments	2	3	11	5
Interest on capital lease obligations	-	1	-	4
Capitalized interest and allowance for funds used during construction	(6)	(4)	(16)	(11)
Interest and dividend income	(2)	(2)	(5)	(9)
Realized losses on interest rate contracts	-	8	-	3
Other	-	-	1	1
	$ 41	$ 47	$ 129	$ 122

15. Commitments:

(a) On September 11th, 2008, the Company, through its Power LP subsidiary, announced an agreement to acquire a 100% interest in Morris Cogeneration LLC (Morris) from Diamond Generating Corporation and MIC Nebraska, Inc., both wholly-owned subsidiaries of Mitsubishi Corporation, for an aggregate purchase price of US$73 million subject to closing adjustments. Morris is a 177 megawatt (MW) natural gas-fired cogeneration facility located on Equistar Chemicals LP's (Equistar) chemical plant in Morris, Illinois.

The acquisition closed on October 31, 2008 and will be financed under the Power LP's existing credit facilities with permanent financing to be arranged after the close of the transaction, depending on the requirements of Power LP.

All of the steam and a portion of the electricity produced from Morris are sold to Equistar under the terms of a long-term energy services agreement which expires in 2023. Equistar, a wholly-owned subsidiary of Lyondell Chemical Company, 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 that terminates in 2011, for capacity and electricity in excess of the needs of Equistar and can participate in the Pennsylvania, New Jersey, and Maryland market.

15. Commitments, continued:

(b) In May 2008, the Company entered into an agreement with Suncor Energy (Suncor) to design, build, own and operate a potable water and wastewater treatment plant for Suncor's Voyageur project over a twenty-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 $30 million to be incurred in 2008 and 2009.

This agreement is considered to be a sales-type lease for accounting. During the construction of the assets, the revenue on the design and build work is recognized based on the percentage completed. The current portion of the net investment in lease of nil is included in accounts receivable. The recognition of financing income will begin upon the completion of the design-build phase and the commencement of the lease payments.

(c) The Power LP has committed up to US$80 million for the enhancement of the Southport and Roxboro facilities, to be spent over 2008 and 2009.

16. Guarantees:

At September 30, 2008, the Company had letters of credit outstanding of $221 million (December 31, 2007 - $357 million) to meet the credit requirements of energy market participants, to meet conditions of certain service agreements, and to satisfy legislated reclamation requirements.

17. Segment disclosures:

The Company operates in the following reportable business segments, which follow the organization, management and reporting structure within the Company.

Generation

Generation is involved in the development and operation of rate-regulated and non-rate-regulated electrical generation plants in Alberta, British Columbia, Ontario, and in the U.S. in California, Colorado, New Jersey, New York, North Carolina and Washington.

Distribution and Transmission

Distribution and Transmission is involved in the transmission and distribution of electricity within The City of Edmonton.

Energy Services

Energy Services is involved in the procurement, marketing and sale of electricity and natural gas in retail and wholesale markets in Alberta, Ontario, the North Eastern U.S. and the Pacific North West.

Water Services

Water Services is primarily involved in the treatment and distribution of water within The City of Edmonton and other communities throughout Western Canada. This segment also provides complementary commercial services including the maintenance and repair of City of Edmonton-owned streetlighting and transportation support facilities.

Corporate

Corporate reflects the costs of the Company's net unallocated corporate office expenses and net financing income earned from intercompany guarantee fees and intercompany interest charges.

(Unaudited, in millions of dollars)

17. Segment disclosures (continued):

Three months ended September 30, 2008

	Generation	Distribution and Transmission	Energy Services	Water Services	Corporate	Intersegment Eliminations	Consolidated
Revenues - external	$ 225	$ 44	$ 602	$ 96	$ -	$ -	$ 967
Intersegment revenues	32	28	6	2	-	(68)	-
Total revenues	257	72	608	98	-	(68)	967
Energy purchases and fuel	233	21	493	-	-	(58)	689
Operations, maintenance, administration and foreign exchange gain (loss)	81	19	22	63	21	(10)	196
Franchise fee, property taxes and other taxes	4	9	-	3	-	-	16
Depreciation, amortization and asset retirement accretion	41	7	7	5	3	-	63
Operating expenses	359	56	522	71	24	(68)	964
Operating income (loss) before corporate charges	(102)	16	86	27	(24)	-	3
Corporate charges	8	2	9	5	(24)	-	-
Operating income (loss)	$ (110)	$ 14	$ 77	$ 22	$ -	$ -	$ 3
Net financing expenses							(41)
Income before income taxes and non-controlling interests							$ (38)
Capital additions	$ 109	$ 31	$ 3	$ 24	$ 4	$ -	$ 171

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17. Segment disclosures (continued):

Three months ended September 30, 2007

	Generation	Distribution and Transmission	Energy Services	Water Services	Corporate	Intersegment Eliminations	Consolidated
Revenues - external	$ 239	$ 33	$ 593	$ 65	$ -	$ -	$ 930
Intersegment revenues	29	30	6	5	-	(70)	-
Total revenues	268	63	599	70	-	(70)	930
Energy purchases and fuel	121	20	514	-	-	(58)	597
Operations, maintenance, administration and foreign exchange gain (loss)	24	10	21	38	27	(12)	108
Franchise fee, property taxes and other taxes	4	11	-	2	-	-	17
Depreciation, amortization and asset retirement accretion	56	7	7	4	2	-	76
Operating expenses	205	48	542	44	29	(70)	798
Operating income (loss) before corporate charges	63	15	57	26	(29)	-	132
Corporate charges	18	4	6	3	(31)	-	-
Operating income	$ 45	$ 11	$ 51	$ 23	$ 2	$ -	$ 132
Net financing expenses							(47)
Income before income taxes and non-controlling interests							$ 85
Capital additions	$ 68	$ 36	$ 1	$ 33	$ 6	$ -	$ 144

(Unaudited, in millions of dollars)

17. Segment disclosures (continued):

Nine months ended September 30, 2008

	Generation	Distribution and Transmission	Energy Services	Water Services	Corporate	Intersegment Eliminations	Consolidated
Revenues - external	$ 618	$ 103	$ 1,687	$ 223	$ -	$ -	$ 2,631
Intersegment revenues	94	87	16	3	-	(200)	-
Total revenues	712	190	1,703	226	-	(200)	2,631
Energy purchases and fuel	227	47	1,523	-	-	(175)	1,622
Operations, maintenance, administration and foreign exchange gain (loss)	230	48	56	143	56	(25)	508
Franchise fee, property taxes and other taxes	13	31	-	7	-	-	51
Depreciation, amortization and asset retirement accretion	125	22	21	15	9	-	192
Operating expenses	595	148	1,600	165	65	(200)	2,373
Operating income (loss) before corporate charges	117	42	103	61	(65)	-	258
Corporate charges	22	10	21	13	(66)	-	-
Operating income	$ 95	$ 32	$ 82	$ 48	$ 1	$ -	$ 258
Gain on sale of power syndicate agreement							34
Net financing expenses							(129)
Income before income taxes and non-controlling interests							$ 163
Capital additions	$ 306	$ 94	$ 5	$ 50	$ 10	$ -	$ 465

(Unaudited, in millions of dollars)

17. Segment disclosures (continued):

Nine months ended September 30, 2007

	Generation	Distribution and Transmission	Energy Services	Water Services	Corporate	Intersegment Eliminations	Consolidated
Revenues - external	$ 694	$ 89	$ 1,744	$ 166	$ 1	$ -	$ 2,694
Intersegment revenues	83	92	15	8	-	(198)	-
Total revenues	777	181	1,759	174	1	(198)	2,694
Energy purchases and fuel	278	51	1,589	-	-	(168)	1,750
Operations, maintenance, administration and foreign exchange gain (loss)	82	39	59	99	64	(30)	313
Franchise fee, property taxes and other taxes	13	30	-	6	-	-	49
Depreciation, amortization and asset retirement accretion	139	20	21	14	8	-	202
Operating expenses	512	140	1,669	119	72	(198)	2,314
Operating income (loss) before corporate charges	265	41	90	55	(71)	-	380
Corporate charges	40	10	14	9	(73)	-	-
Operating income	$ 225	$ 31	$ 76	$ 46	$ 2	$ -	$ 380
Gain on sale of power syndicate agreement							34
Net financing expenses							(122)
Income before income taxes and non-controlling interests							$ 292
Capital additions	$ 155	$ 72	$ 8	$ 82	$ 14	$ -	$ 331

Geographic information:

	Three months ended September 30, 2008				Three months ended September 30, 2007			
	Canada	U.S.	Intersegment Eliminations	Total	Canada	U.S.	Intersegment Eliminations	Total
Revenues - external	$ 792	$ 175	$ -	$ 967	$ 818	$ 112	$ -	$ 930
Intersegment revenues	21	2	(23)	-	9	6	(15)	-
Total revenues	$ 813	$ 177	$ (23)	$ 967	$ 827	$ 118	$ (15)	$ 930

	Nine months ended September 30, 2008				Nine months ended September, 2007			
	Canada	U.S.	Intersegment Eliminations	Total	Canada	U.S.	Intersegment Eliminations	Total
Revenues - external	$2,246	$ 385	$ -	$2,631	$2,351	$ 343	$ -	$ 2,694
Intersegment revenues	48	7	(55)	-	20	18	(38)	-
Total revenues	$2,294	$ 392	$ (55)	$2,631	$2,371	$ 361	$ (38)	$ 2,694

18. Comparative figures:

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