EPCOR Utilities Inc.
Interim Report
June 30, 2008

Management’s Discussion and Analysis

This management’s discussion and analysis (MD&A), dated July 31, 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 six months ended June 30, 2008 and 2007 and in conjunction with the audited consolidated financial statements and MD&A for the year ended December 31, 2007. 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.

FORWARD-LOOKING STATEMENTS

Certain information in this MD&A is forward-looking and related to anticipated financial performance, events and strategies. When used in this context, words such as “will”, “anticipate”, “believe”, “plan”, “intend”, “target”, and “expect” or similar words suggest future outcomes. By their nature, such statements are subject to significant risks, assumptions and uncertainties, which could cause EPCOR’s actual results and experience to be materially different than the anticipated results. Such risks, assumptions and uncertainties include, but are not limited to, operating performance, commodity prices and volumes, load settlement, regulatory and government decisions including changes to environmental and tax legislation, weather and economic conditions, competitive pressures, construction risks, availability and cost of financing, foreign exchange risks, availability of labour and management resources and the performance of partners, contractors and suppliers.

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.

OVERVIEW

Despite three major turnarounds at our Genesee facilities, EPCOR maintained good operating results for the second quarter by managing our commodity positions well. It was a period of high power prices in Alberta and the length in our merchant portfolio resulted in healthy contributions to our earnings.

The turnarounds at Genesee commenced in March and were completed in June. These turnarounds were for required maintenance and were scheduled back-to-back to accommodate the Alberta

Electric System Operator’s upgrade of the new high-voltage transmission lines in the Genesee and Keephills area. The timing of the outages coincided with periods of high Alberta power prices which increased the cost of replacement power and resulted in significant availability penalties under the terms of the Genesee Power Purchase Arrangement (PPA).

The E.L. Smith water treatment plant upgrade was substantially completed in June and is now capable of serving the growing Edmonton region for the next 15 years. The first unit of the Clover Bar Energy Centre, which was commissioned in the first quarter, contributed positively to operating earnings in the second quarter. Construction of the remaining two Clover Bar units, the Downtown Edmonton Supply Station and the Keephills 3 power plant continues.

In the second quarter, we received the Alberta Utilities Commission’s decision on our 2007-2009 Regulated Rate Tariff Application for non-energy charges. Although the approved rates were lower than interim rates, the adjustment to earnings for prior periods was insignificant and we were able to manage our costs to the new rates.

We successfully raised $400 million in 10 year and 30 year medium-term note financing in April. The proceeds from these financings were used to repay short-term and maturing long-term indebtedness, to fund a portion of the 2008 capital program and for general corporate purposes. The timing of the restructuring of asset-backed commercial paper (ABCP) has been delayed from our earlier estimates by motions filed with the Ontario Appeals Court for leave to appeal the judge’s ruling on the fairness of the restructuring plan. There was no significant change in our ABCP holdings or assessment of their fair value in the quarter. We now expect the restructuring to be completed in the third quarter of 2008.

SIGNIFICANT EVENTS

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

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

$400 million of debt offerings

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

Asset-backed commercial paper

At June 30, 2008, the Company held $51 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.

A Pan-Canadian Investors Committee (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 new 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) The expected lives of the assets underlying the new notes that EPCOR expects to receive are longer than previously forecast. 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. Our previous expectation for these notes was seven 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 higher than originally expected, but not material to our valuation.

(v) The 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. On June 25, 2008, the Appeals Court reserved judgement resulting in further extensions of the standstill. These events have delayed the timing of the restructuring from our earlier estimates and we now expect the restructuring will be completed in the third quarter of 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 June 30, 2008 was $51 million compared with $60 million at December 31, 2007. The estimated fair value decreased by $9 million 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.

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		Six months
Net income for the periods ended June 30, 2007	**$**	**53**	**$**	**151**
Higher income from Power LP		14		10
Higher Alberta energy margins		4		17
Higher water rates		3		8
Lower (higher) administration expenses, excluding Power LP administration		2		(11)
Impact of recording a net future income tax asset associated with the Energy Services reorganization on January 1, 2007		1		(10)
Fair value reduction in ABCP		-		(9)
Higher interest expense and preferred share dividends, excluding Power LP interest expense and preferred share dividends		(9)		(7)
Maintenance expenses for Genesee outages in 2008		(11)		(19)
Lower Genesee PPA availability and capacity payment income		(19)		(24)
Unrealized fair value changes on derivative instruments and natural gas inventory held for trading		(22)		(21)
Other		-		(1)
Decrease in net income		(37)		(67)
Net income for the periods ended June 30, 2008	**$**	**16**	**$**	**84**

Net income was $16 million and $84 million for the three and six months ended June 30, 2008 respectively, compared with $53 million and $151 million for the corresponding periods in 2007. The decreases were due to the net impact of the following:

- Net income from EPCOR Power L.P. (Power LP) was higher primarily due to unrealized fair value changes on natural gas supply, forward foreign exchange and interest rate contracts. In the three months ended June 30 these increases were partly offset by a smaller foreign exchange gain in 2008 compared with 2007, on the translation of United States (U.S.) debt. In the six months ended June 30, 2008, foreign exchange losses were incurred on the translation of U.S. debt whereas foreign exchange gains were incurred in the corresponding period in 2007. The U.S. dollar strengthened relative to the Canadian dollar in the first half of 2008 and weakened in the corresponding period in 2007.

- Alberta electricity margins increased primarily due to increased length in the portfolio of derivative financial contracts that settled at higher Alberta 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.

- Administration expenses, excluding Power LP's administration, increased in the first half of 2008 compared with the corresponding period in 2007 primarily due to a reduction of the Company's liability for its Long-Term Incentive Plan (LTIP) in the first quarter of the prior year. A similar but smaller adjustment was recorded in the first quarter of 2008. The LTIP is a notional stock option plan for senior management. Adjustments were recorded based on the results of the quarterly valuations of the plan. In addition, in the first six months of 2008, costs for management incentive compensation other than LTIP were higher and there were fewer staff vacancies compared with the corresponding period in the prior year.

- 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.

- 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. 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 three and six month periods ended June 30 were more than offset by a reduction reflecting the substantive enactment of an income tax rate reduction attributable to preferred share dividends paid commencing in 2003.

- Maintenance expenses for Genesee outages were higher as there were no outages in the first half of 2007. In 2008, the Genesee 1 outage started in the first quarter and was completed in the second quarter, and the Genesee 2 and 3 outages occurred in the second quarter.

- A net availability penalty was incurred in the first half of 2008 under the terms of the Genesee 1 and 2 PPA compared with availability incentive revenue recognized in the corresponding period in 2007. The net penalty in 2008 was due to the major outages at these units. Capacity payment revenue under this PPA was also lower as a result of a lower return from a declining PPA rate-base and reduced tax recoveries related to lower federal income tax rates.

- The unrealized fair value changes in our financial electricity contracts that were not designated as hedges for accounting purposes were unfavourable in the first half of 2008 compared with the corresponding period in 2007 due to larger net short positions combined with greater increases in Alberta forward power prices in 2008. The unrealized fair value changes in our natural gas portfolio were also unfavourable due to net short positions in both years combined with increases in forward prices in the first half of 2008 compared with decreases in forward prices in the corresponding period in 2007. An unrealized fair value loss was recognized on the Joffre contract-for-differences (CfD) in 2008 due to an unfavourable forward spark spread compared with an unrealized fair value gain and favourable forward spark spread in 2007. 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. These unfavourable changes were partly offset by unrealized fair value gains on forward foreign exchange contracts for U.S. dollars in the first half of 2008 compared with unrealized fair value losses in the corresponding period in 2007.

Revenues

(Unaudited, $ millions)		Three months		Six months
Revenues for the periods ended June 30, 2007	**$**	**865**	**$**	**1,764**
Higher (lower) physical natural gas trading activities		31		(59)
Higher trading activities in the north eastern U.S. and Ontario		17		19
Higher Alberta energy revenues		4		16
Higher water rates		3		9
Higher energy revenues from trading activities in the western U.S.		1		9
Lower Power LP revenues		(17)		(39)
Unrealized fair value changes on derivative instruments and natural gas inventory held for trading		(25)		(41)
Lower Genesee PPA availability and capacity payment revenues		(27)		(34)
Commercial and other revenues		13		20
Decrease in revenues		-		(100)
Revenues for the periods ended June 30, 2008	**$**	**865**	**$**	**1,664**

Consolidated revenues for the three months ended June 30, 2008 were unchanged from the corresponding period in 2007, and for the six months ended June 30, 2008 were lower than for the corresponding period in 2007. Further information on the year over year changes is summarized as follows:

- Alberta energy revenues included higher electricity pricing for our Regulated Rate Tariff (RRT) customers and increased revenues from the Alberta Power Pool due to higher prices. These increases were partly offset by derivative financial sell contracts that settled at losses in 2008 resulting from Alberta power prices that exceeded the contracts' strike prices.

- 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. Sales of natural gas to utilize excess transmission capacity at the Castleton facility were also lower.

- Unrealized fair value losses on derivative financial sell contracts that were not designated as hedges for accounting purposes were higher due to an increased short position and larger increases in forward Alberta power prices.

- Commercial services and other revenues were higher primarily due to new water and wastewater facility construction contracts with the City of Wetaskiwin and the Towns of Taber and Chestermere and higher transportation revenues from The City of Edmonton. Transportation revenues were primarily derived from the construction and maintenance of street lighting, traffic signal, light rail transit and trolley assets owned by The City of Edmonton.

Capital spending and investment

(Unaudited, $ millions) **Six months ended June 30**		**2008**		**2007**
Generation	$	197	$	87
Distribution and Transmission		63		36
Energy Services		2		7
Water Services		26		49
Corporate – other		6		8
	$	**294**	**$**	**187**

Capital expenditures for property, plant and equipment were higher for the six months ended June 30, 2008 compared with the same period in 2007 primarily due to increased construction activity on the Keephills 3 and Clover Bar Energy Centre generation projects and on the Downtown Edmonton Supply and Substation (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. Construction is expected to be completed by 2011.

The Clover Bar Energy Centre will be composed of three natural gas-fired peaking power generation units. The first unit was commissioned in the first quarter of 2008 and construction of the remaining two units will continue through 2010.

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 is scheduled for completion in 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 is now substantially complete.

SEGMENT RESULTS

Generation

Generation results (including intersegment transactions) (Unaudited, $ millions)	**Three months ended June 30**		**Six months ended June 30**	
	2008	**2007**	**2008**	**2007**
Revenues	$ 234	$ 265	$ 455	$ 509
Expenses	118	212	250	329
Operating income	**$ 116**	**$ 53**	**$ 205**	**$ 180**

(Unaudited, $ millions)		**Three months**		**Six months**
Operating income for the periods ended June 30, 2007	**$**	**53**	**$**	**180**
Higher Power LP operating income		106		88
Unrealized fair value changes on derivative instruments		(2)		2
Increased maintenance for Genesee outages in 2008		(15)		(26)
Lower Genesee PPA availability and capacity payment revenues		(27)		(34)
Other		1		(5)
Increase in operating income		63		25
Operating income for the periods ended June 30, 2008	**$**	**116**	**$**	**205**

Generation's operating income for the quarter and half year ended June 30, 2008 increased $63 million and $25 million respectively, over the corresponding periods in 2007. Further information on the year over year changes is as follows:

- Power LP contributed $118 million of operating income in the second quarter and $182 million in the first six months of 2008 compared with $12 million and $94 million respectively, for the corresponding periods in 2007.

  Power LP's revenues decreased $17 million in the second quarter and $39 million for the first half 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.

  Power LP's expenses decreased $123 million in the second quarter and $127 million in the first half of 2008 compared with the corresponding periods in the prior year primarily due to unrealized gains in 2008 and unrealized losses in 2007 for changes in the fair value of the natural gas supply contracts. The decrease in expenses was also due to losses realized in 2007 on forward foreign exchange and interest rate contracts that were entered into in anticipation of permanent financing of acquisitions completed in 2006, whereas no similar contracts were settled in 2008. The decrease in expenses was partly offset by higher foreign exchange expense on the translation of U.S. debt in 2008.

- Unrealized changes in the fair value of the Joffre contract-for-differences (CfD) increased expenses and revenues in the three and six month periods ended June 30, 2008 compared with the corresponding periods in the prior year. The net impact of the fair value changes on the Joffre CfD was to decrease operating income by $9 million in the second quarter and $12 million in the first half of 2008 due to a decrease in the forward spark spread in 2008 and an increase in 2007. These decreases in operating income were offset by unrealized fair value changes on forward foreign exchange contracts for U.S. dollars entered into in anticipation of asset purchases related to the Clover Bar Energy Centre and Keephills 3 projects, which decreased expenses by $7 million in the three months and $14 million in the six months ended June 30, 2008 compared with the corresponding periods in 2007. The impact of the unrealized fair value changes for both the Joffre CfD and the forward foreign exchange contracts was to increase revenues and expenses by $6 million and $8 million respectively, in the second quarter and by $8 million and $6 million respectively, in the six months ended June 30, 2008 compared with the corresponding periods in the prior year.

- The new Clover Bar Energy Centre turbine, included in other in the table above, contributed $2 million in revenues and incurred $1 million in expenses since it commenced operations in the first quarter of 2008.

Distribution and Transmission

Distribution and Transmission results (including intersegment transactions) (Unaudited, $ millions)	**Three months ended June 30**		**Six months ended June 30**	
	2008	**2007**	**2008**	**2007**
Revenues	$ 59	$ 59	$ 118	$ 118
Expenses	53	50	100	98
Operating income	**$ 6**	**$ 9**	**$ 18**	**$ 20**

There were no material changes in Distribution and Transmission revenues, expenses and operating income, for the three and six months ended June 30, 2008 compared with the same periods in the prior year. Distribution and Transmission expects to receive a final decision from the Alberta Utilities Commission on its 2007-2009 General Tariff Application in early 2009.

Energy Services

Energy Services results (including intersegment transactions) (Unaudited, $ millions)	**Three months ended June 30**		**Six months ended June 30**	
	2008	**2007**	**2008**	**2007**
Revenues	$ 567	$ 544	$ 1,095	$ 1,160
Expenses	575	528	1,089	1,135
Operating income (loss)	**$ (8)**	**$ 16**	**$ 6**	**$ 25**

(Unaudited, $ millions)	**Three months**	**Six months**
Operating income for the periods ended June 30, 2007	**$ 16**	**$ 25**
Higher Alberta electricity margins	5	23
Unrealized fair value change in natural gas inventory held for trading	3	3
Higher energy margin from trading activities in the north eastern U.S. and Ontario	3	3
Lower natural gas margin	(1)	(3)
Unrealized fair value changes in derivative instruments	(35)	(40)
Other	1	(5)
Decrease in operating income	(24)	(19)
Operating income (loss) for the periods ended June 30, 2008	**$ (8)**	**$ 6**

Energy Services' operating income decreased $24 million for the quarter and $19 million for the six months ended June 30, 2008 compared with the corresponding periods in 2007. Additional information on the year over year changes is as follows:

- Alberta electricity margins increased primarily due to increased length in the portfolio of derivative financial contracts that settled at higher Alberta power prices compared with the prior year.

  The generation from our interests in the Battle River and Sundance acquired PPAs was sold at higher prices to the Alberta Power Pool subsequent to the expiry of a long-term sales contract with a third party customer at the end of 2007. The impact of this favourable pricing more than offset the impact of our reduced interest in the Battle River PSA (Power Syndicate Agreement) following the sale on January 15, 2008.

  The increase was partly offset by the impact of lower generation from Genesee 3 under an intercompany contract between Generation and Energy Services, and our acquired PPAs resulting from plant outages and incidences of reduced plant availability in the second quarter of 2008.

- In the second quarter of 2008 Energy Services' revenues and expenses, excluding unrealized fair value changes, increased $54 million and $46 million respectively, compared with the corresponding period in 2007. These increases were primarily due to higher physical natural gas revenues and expenses, $31 million and $32 million respectively, increased trading activities in the north eastern U.S. and Ontario and higher prices for energy sales and purchases in Alberta. In addition, energy revenues from our RRT customers increased due to higher pricing. These increases were partly offset by derivative financial sell contracts that settled at losses in 2008 resulting from Alberta power prices that exceeded the contracts' strike prices.

  Energy Services' revenues and expenses, excluding unrealized fair value changes, decreased $17 million and $34 million, respectively in the six months ended June 30, 2008 compared with the corresponding period in 2007. These decreases were primarily due to lower physical natural gas trading activities in the first quarter of 2008 which more than offset the increase in activity in the second quarter. Natural gas sales and purchases decreased $59 million and $56 million respectively, in the six months ended June 30, 2008 compared with the corresponding period in 2007. In the six months ended June 30, the lower physical gas trading activity was partly offset by the same items identified above for the second quarter as well as increased trading activities in the western U.S. in the first quarter.

- The unrealized fair value changes in our derivative financial electricity contracts that were not designated as hedges for accounting purposes were unfavourable compared with the prior year due to the impact of a greater increase in forward Alberta power prices on larger net short positions in the three and six month periods ended June 30, 2008. Unrealized fair value changes reduced energy revenues by $31 million and increased energy purchases by $1 million in the second quarter and reduced energy revenues by $48 million and energy purchases by $12 million in the first half of 2008. Fair value reductions on a net short position of derivative financial contracts are not necessarily indicative of economic performance as EPCOR's overall position for both physical and derivative financial contracts, including hedges, was long and we therefore benefited economically when power prices increased.

On April 30, 2008, the Alberta Utilities Commission released its decision on the Company's 2007 – 2009 Regulated Rate Tariff Application related to its RRT operations. The impact of the decision was recorded in the second quarter of 2008 and did not have a material impact on Energy Services' revenues, expenses or net income.

Water Services

Water Services results (including intersegment transactions) (Unaudited, $ millions)	**Three months ended June 30**		**Six months ended June 30**	
	2008	**2007**	**2008**	**2007**
Revenues	$ 70	$ 61	$ 128	$ 104
Expenses	55	46	102	81
Operating income	**$ 15**	**$ 15**	**$ 26**	**$ 23**

Water Services' revenues from water sales were $3 and $9 million higher in the three and six months ended June 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. Transportation and other commercial services revenues and expenses were higher by $6 million and $9 million respectively, in the second quarter and $15 million and $17 million respectively, in the first half of 2008 compared with the corresponding periods in the prior year. The increases were primarily due to new commercial services construction projects for the City of Wetaskiwin and the Towns of Taber and Chestermere and higher business development costs. Maintenance expenses were higher in the first half of 2008 compared with the corresponding period in 2007 primarily due to a higher incidence of water main breaks and additional reservoir maintenance.

CONSOLIDATED BALANCE SHEETS

Significant changes in consolidated assets

($ millions)	June 30, 2008	December 31, 2007	Increase (decrease)	Explanation
Cash and cash equivalents	$ 126	$ 79	$ 47	Refer to liquidity and capital resources section.
Accounts receivable (including income taxes recoverable)	473	591	(118)	Two months of Alberta wholesale electricity settlements and Genesee generation revenues at December 31, 2007 compared with one month at June 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)	249	104	145	Increase in fair value of natural gas and power derivative contracts due to increased forward prices.
Other current assets	100	74	26	Addition of natural gas inventory held for trading and normal increase in prepaid property taxes and insurance at mid year.
Property, plant and equipment	4,405	4,216	189	2008 capital expenditures partly offset by depreciation and amortization expense.
Power purchase arrangements (PPAs)	631	679	(48)	Sale of 10% interest in Battle River PSA and ongoing amortization of remaining PPAs in 2008.
Contract and customer rights and other intangible assets	175	179	(4)	
Derivative instruments assets (non- current)	257	116	141	Increase in fair value of natural gas and power derivative contracts due to increases in forward prices, partly offset by decrease in fair value of foreign currency forward contracts.
Future income tax assets (non-current)	135	103	32	Change in the expected timing of the use of tax loss carryforward balances from current to long-term and increase in deductions available for tax purposes for unrealized fair value changes in derivative instruments.
Goodwill	185	185	-	
Other assets	250	236	14	Increase in rights to Keephills 3 mining asset and in long-term receivables associated with the Taber, Wetaskiwin and Chestermere projects, partly offset by a reduction in fair value of ABCP.

Significant changes in consolidated liabilities and shareholder's equity				
($ millions)	**June 30, 2008**	**December 31, 2007**	**Increase (decrease)**	**Explanation**
Short-term debt	$ 171	$ 138	$ 33	Commercial paper issued during the first six months of 2008.
Accounts payable and accrued liabilities	517	615	(98)	Two months of Alberta wholesale electricity settlements at December 31, 2007 compared with one month at June 30, 2008, and lower payables and accruals for natural gas, merchant and Water Services capital projects at June 30, partly offset by increased payables and accruals for Generation capital projects and Genesee operations at June 30.
Derivative instruments liabilities (current)	229	136	93	Increase in fair value of derivative natural gas and power contracts due to increases in forward prices.
Other current liabilities	86	98	(12)	Reflects 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)	2,362	2,139	223	Medium-term note debentures issued in January and April 2008, partly offset by ongoing debt repayments to The City of Edmonton and repayment of debt issued under credit facilities.
Derivative instruments liabilities (non-current)	151	78	73	Increase in fair value of derivative power and natural gas contracts due to increases in forward prices.
Other non-current liabilities	121	125	(4)	
Future income tax liabilities (non-current)	150	126	24	Increase in taxable temporary differences relating to unrealized fair value changes in derivative instruments.
Non-controlling interests	795	740	55	Reflects non-controlling interests' share of Power LP income less distributions.
Shareholder's equity	2,404	2,367	37	Reflects net income and other comprehensive income, partly offset by common share dividends and refundable income taxes.

LIQUIDITY AND CAPITAL RESOURCES

Cash inflows (outflows)				
	Three months ended June 30		Increase	
($ millions)	2008	2007	(decrease)	Explanation
Operating	$ 41	$ 55	$ (14)	Payment of Genesee PPA availability penalties in the second quarter of 2008 compared with receipt of incentive income in 2007, payments for major maintenance for Genesee turnarounds in 2008, partly offset by realized losses on forward foreign exchange and interest rate contracts in 2007 and changes in non-cash operating working capital, primarily four months of sales receipts for the Ontario plants in 2008 compared with three months of receipts in 2007.
Investing	(146)	(91)	(55)	Higher capital expenditures in 2008, primarily on the Keephills 3, Clover Bar Energy Centre and DESS projects.
Financing	129	(104)	233	Net financing receipts in 2008 included the issuance of $400 million of medium-term note debentures, 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, partly offset by the issuance of preferred shares by a subsidiary.

Cash inflows (outflows)				
	Six months ended June 30		Increase	
($ millions)	2008	2007	(decrease)	Explanation
Operating	$ 139	$ 219	$ (80)	Payment of Genesee PPA availability penalties in 2008 compared with the receipt of availability incentive income 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	(221)	(130)	(91)	Reflects higher capital expenditures, primarily on the Keephills 3, Clover Bar Energy Centre and DESS projects.
Financing	131	(200)	331	Net financing receipts in 2008 included the issuance of $600 million of medium-term note debentures and $32 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, partly offset by the issuance of preferred shares by a subsidiary.

At June 30, 2008 the Company had letters of credit outstanding of $219 million (December 31, 2007 - $357 million) to meet the credit requirements of energy market participants, to meet conditions of certain debt and service agreements, and to satisfy legislated reclamation requirements.

CONTRACTUAL OBLIGATIONS

In January 2008, the Company repaid its $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 as described under Significant Events. 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.

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 separate 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 April 2008, the CICA released an exposure draft of the coming standards. We have developed a high level IFRS implementation plan, and an assessment of the impact of the accounting standard differences to the financial statements is currently in progress. Based on our analysis to date, the most significant differences for EPCOR are anticipated to be related to property, plant and equipment, joint arrangements, business combinations, emission credits, asset retirement obligations and financial statement disclosure. We also expect to make changes to certain processes and systems before 2010 to ensure transactions are recorded in accordance with IFRS for comparative reporting purposes on the required implementation date. We will report on the key elements and timing of our IFRS implementation plan in our interim MD&A for the third quarter of 2008.

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. 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 June 30, 2008 that have materially affected, or are reasonably likely to materially affect the Company’s internal control over financial reporting.

OUTLOOK

With the major outages at Genesee now complete, net income before the impact of fair value changes is expected to return to pre-outage levels. The major outages at Genesee combined with the high Alberta power prices in the second quarter resulted in higher Genesee PPA availability penalties and higher major maintenance costs than anticipated. For the balance of the year we expect higher generation from Genesee 3, reduced Genesee availability penalties and lower Generation maintenance costs compared to the first half of the year. However, we expect increased costs for business development activity related to water and power initiatives. On July 8, 2008 we disposed of an equity investment and recognized a $9 million pre-tax gain in net income which was previously recorded as a fair value change in accumulated other comprehensive income.

QUARTERLY RESULTS

Quarter ended	Revenues	Net income from continuing operations	Net income (loss) from discontinued operations	Net income
	(Unaudited, $ millions)			
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
September 30, 2006	702	47	9	56

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

- March 31, 2008 first quarter results included a $30 million gain on the sale of a 10% interest in the Battle River PSA and the favourable impact of high Alberta power prices on our financial contract portfolio which was in a net long position. 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.

- September 30, 2006 third quarter results included an increase in net income from discontinued operations of $10 million for the reduction of the Clover Bar asset retirement obligation offset by reduced Alberta electricity margins from the Battle River and Sundance PPAs resulting from the sale of partial interests in these agreements in the second quarter of 2006.

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 June 30,		Six months ended June 30,	
	2008	2007	2008	2007
Revenues	$ 865	$ 865	$ 1,664	$ 1,764
Operating expenses (income):				
Energy purchases and fuel	490	588	933	1,153
Operations, maintenance and administration	165	125	304	227
Franchise fee, property taxes and other taxes	17	16	35	32
Depreciation, amortization, and asset retirement accretion	65	63	129	126
Foreign exchange (gain) loss	(2)	(19)	8	(22)
Gain on sale of power syndicate agreement (note 10)	-	-	(34)	(34)
Net financing expenses (note 14)	41	34	88	75
	776	807	1,463	1,557
Income before income taxes and non-controlling interests	89	58	201	207
Income taxes (note 11)	5	57	11	56
Income before non-controlling interests	84	1	190	151
Non-controlling interests (note 13)	68	(52)	106	-
Net income	$ 16	$ 53	$ 84	$ 151

See accompanying notes to consolidated financial statements.

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

	June 30, 2008	December 31, 2007
Assets		
Current assets:		
Cash and cash equivalents	$ 126	$ 79
Accounts receivable	462	581
Income taxes recoverable	11	10
Inventories (note 9)	75	62
Prepaid expenses	19	9
Derivative instruments assets (note 6)	249	104
Future income tax assets	6	3
	948	848
Property, plant and equipment	4,405	4,216
Power purchase arrangements	631	679
Contract and customer rights and other intangible assets	175	179
Derivative instruments assets (note 6)	257	116
Future income tax assets	135	103
Goodwill	185	185
Other assets	250	236
	$ 6,986	$ 6,562
Liabilities and Shareholder's Equity		
Current liabilities:		
Short-term debt	$ 171	$ 138
Accounts payable and accrued liabilities	517	615
Income taxes payable	11	44
Derivative instruments liabilities (note 6)	229	136
Other current liabilities	19	15
Future income tax liabilities	56	39
Current portion of long-term debt (note 12)	27	388
	1,030	1,375
Long-term debt (note 12)	2,335	1,751
Derivative instruments liabilities (note 6)	151	78
Other non-current liabilities	121	125
Future income tax liabilities	150	126
	3,787	3,455
Non-controlling interests (note 13)	795	740
Shareholder's equity	2,404	2,367
	$ 6,986	$ 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 June 30,		Six months ended June 30,	
	2008	2007	2008	2007
Retained earnings				
Balance at beginning of period	$ 2,460	$ 2,316	$ 2,430	$ 2,245
Adjustment for changes in accounting policies	-	-	-	12
Net income	16	53	84	151
Common share dividends paid	(33)	(32)	(65)	(64)
Refundable taxes (note 10)	-	-	(6)	(7)
Balance at end of period	2,443	2,337	2,443	2,337
Accumulated other comprehensive loss				
Balance at beginning of period	(40)	(66)	(63)	(2)
Adjustment for changes in accounting policies	-	-	-	(41)
Other comprehensive income (loss)	1	20	24	(3)
Balance at end of period	(39)	(46)	(39)	(46)
Total shareholder's equity at end of period	$ 2,404	$ 2,291	$ 2,404	$ 2,291

See accompanying notes to consolidated financial statements.

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

	Three months ended June 30, 2008	Three months ended June 30, 2007	Six months ended June 30, 2008	Six months ended June 30, 2007
Net income	$ 16	$ 53	$ 84	$ 151
Other comprehensive income (loss), net of income taxes:				
Unrealized gains (losses) on derivative instruments designated as cash flow hedges (1)	22	(7)	29	(40)
Reclassification of (gains) losses on derivative instruments designated as cash flow hedges to net income (2)	(25)	19	(9)	29
Unrealized gains on financial instruments designated as available for sale (3)	6	9	6	9
Reclassification of gains on financial instruments designated as available for sale to net income (4)	(2)	-	(2)	-
Unrealized loss in self-sustaining foreign operations (5)	-	(1)	-	(1)
	1	20	24	(3)
Comprehensive income	$ 17	$ 73	$ 108	$ 148

(1) For the three and six months ended June 30, 2008, net of income tax expense of $10 and $13, respectively. For the three and six months ended June 30, 2007, net of income tax recovery of $2 and $17, respectively.
(2) For the three and six months ended June 30, 2008, net of reclassification of income tax expense of $11and $4, respectively. For the three and six months ended June 30, 2007, net of reclassification of income tax recovery of $9 and $13, respectively.
(3) For the three and six months ended June 30, 2008, net of income tax expense of $2. For the three and six months ended June 30, 2007, net of income tax expense of $2.
(4) For the three and six months ended June 30, 2008, net of reclassification of income tax expense of $1.
(5) For the three and six months ended June 30, 2008 and June 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 June 30, 2008	Three months ended June 30, 2007	Six months ended June 30, 2008	Six months ended June 30, 2007
Operating activities:				
Net income	$ 16	$ 53	$ 84	$ 151
Adjustments to reconcile net income to funds from operating activities:				
Depreciation, amortization, and asset retirement accretion	65	63	129	126
Gain on sale of power syndicate agreement (note 10)	-	-	(34)	(34)
Non-controlling interests in EPCOR Power L.P. (note 13)	67	(48)	103	1
Fair value changes on derivative instruments	(57)	51	(91)	31
Unrealized foreign exchange (gains) losses	(1)	(43)	13	(49)
Other	(17)	(9)	(14)	(7)
Future income taxes	9	52	17	43
	82	119	207	262
Change in non-cash operating working capital	(41)	(64)	(68)	(43)
	41	55	139	219
Investing activities:				
Property, plant, equipment and other assets	(186)	(112)	(294)	(187)
Change in non-cash working capital	35	20	13	9
Proceeds on sale of power syndicate agreement (note 10)	-	-	53	59
Other	5	1	7	(11)
	(146)	(91)	(221)	(130)
Financing activities:				
Net proceeds from issue of short-term debt	2	-	32	-
Repayment of short-term debt	-	(200)	-	(200)
Proceeds from issue of long-term debt (note 12)	400	-	600	-
Repayment of long-term debt	(213)	(40)	(384)	(82)
Issue of subsidiary preferred shares (note 13)	-	121	-	121
Distributions to non-controlling interests (note 13)	(23)	(22)	(47)	(44)
Issue of limited partnership units of EPCOR Power L.P. to non-controlling interests (note 13)	-	69	-	69
Common share dividends paid	(33)	(32)	(65)	(64)
Other	(4)	-	(5)	-
	129	(104)	131	(200)
Foreign exchange loss on cash held in a foreign currency	(1)	(3)	(2)	(3)
Increase (decrease) in cash and cash equivalents	23	(143)	47	(114)
Cash and cash equivalents, beginning of period	103	289	79	260
Cash and cash equivalents, end of period	$ 126	$ 146	$ 126	$ 146
Supplemental cash flow information:				
Interest paid net of interest received	$ 40	$ 51	$ 68	$ 82
Income taxes paid net of income taxes recovered	7	5	58	23

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.

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.

(Unaudited, in millions of dollars)

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

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

		June 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	$ 51	$ 51	$ 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	79	76	70	70
Net investment in lease	Loans and receivables	29	28	29	28
Portfolio investments	Available for sale	18	18	13	16
Long-term debt (including current portion)	Other financial liabilities	2,362	2,380	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.

The estimated fair value of ABCP decreased by $9 million since December 31, 2007 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.

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

Non-bank sponsored asset-backed commercial paper, continued

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 new 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) The expected lives of the assets underlying the new notes that EPCOR expects to receive are longer than previously forecast. 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. Our previous expectation for these notes was seven 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 higher than originally expected, but are not material to our valuation.

(v) The 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. On June 25, 2008, the Appeals Court reserved judgment resulting in further extensions of the standstill. These events have delayed the timing of the restructuring from our earlier estimates and we now expect that the restructuring will be completed in the third quarter of 2008.

Net investment in lease

The fair value of the Company's net investment in lease is based on the estimated interest rate implicit in a comparable lease arrangement plus an estimated credit spread based on the counterparty risk as at June 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 June 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.

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, including embedded derivatives, are recorded at fair value on the balance sheet as derivative instruments assets and derivative instruments liabilities unless exempted from derivative treatment as an expected purchase, sale or usage. All changes in their fair value are recorded in net income unless cash flow hedge accounting is used, in which case changes in fair value of the effective portion of the derivatives are recorded in other comprehensive income.

(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:

	June 30, 2008				
	Energy		Foreign exchange	Interest rate	
	Cash flow hedges	Non-hedges	Non-hedges	Non-hedges	Total
Derivative instruments assets:					
Current	$ 52	$ 186	$ 11	$ -	$ 249
Non-current	20	223	14	-	257
Derivative instruments liabilities:					
Current	(80)	(145)	(4)	-	(229)
Non-current	(56)	(93)	(2)	-	(151)
Net fair value	$ (64)	$ 171	$ 19	$ -	$ 126
Net notional buys (sells):					
Megawatt hours of electricity (millions)	(1)	(5)			
Gigajoules of natural gas (millions)	-	69			
Foreign currency (U.S. dollars)			$ (304)		
Range of contract terms in years	1 to 9	1 to 9	1 to 6		

	December 31, 2007				
	Energy		Foreign exchange	Interest rate	
	Cash flow hedges	Non-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	1 to 9	1 to 9	1 to 6		

(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 $9.80 to $10.18 per gigajoule. The Company has determined that a reasonably possible increase (decrease) of $1.00 per gigajoule in natural gas prices would have a $60 million impact on the fair value estimate of these contracts. Included in this sensitivity is a $19 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 gains of $33 million and $51 million recognized in fuel expense for the three and six months ended June 30, 2008 respectively ($5 million fair value losses and $16 million fair value gains for the three and six months ended June 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 June 30,			
	2008		2007	
	Unrealized gains (losses)	Realized gains (losses)	Unrealized gains (losses)	Realized gains (losses)
Energy cash flow hedges	$ (4)	$ 37	$ 19	$ (28)
Energy non-hedges	52	(6)	(68)	5
Foreign exchange non-hedges	5	1	18	(20)
Interest rate non-hedges	-	-	(1)	5

(Unaudited, in millions of dollars)

6. Derivative instruments and hedge accounting, continued:

	Six months ended June 30,			
	2008		2007	
	Unrealized gains (losses)	Realized gains (losses)	Unrealized gains (losses)	Realized gains (losses)
Energy cash flow hedges	$ 29	$ 14	$ (15)	$ (42)
Energy non-hedges	96	7	(39)	-
Foreign exchange non-hedges	(5)	3	10	(14)
Interest rate non-hedges	-	-	(2)	5

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 risk relating to electricity prices. For the three and six months ended June 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 $43 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 June 30, 2008, net losses of $20 million (December 31, 2007 - $45 million), net of income taxes of $8 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 policy guidelines. 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 commodity related derivatives at June 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 June 30, 2008, there is a higher than 95% probability that unfavorable daily market variations would not reduce the 12 month portfolio by more than $10 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 June 30, 2008, US$326 million or approximately 76% 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 $1.10 per U.S. dollar. At June 30, 2008, US$48 million or approximately 85% 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 $1.09 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:

	June 30, 2008 (USD)	December 31, 2007 (USD)
Non-derivative financial instruments:		
Cash and cash equivalents	$ 64	$ 26
Accounts receivables	64	49
Accounts payables and accrued liabilities	(50)	(53)
Other assets	74	79
Long-term debt	(415)	(415)
	(263)	(314)
Derivative financial instruments:		
Forward foreign exchange sales	24	37
Forward foreign exchange purchases	(5)	(12)
	19	25
Net exposure	$ (244)	$ (289)
Range of contract terms in years	1 to 7	1 to 6
Significant exchange rates in Canadian dollars per U.S. dollar:		
Average reporting date closing	1.02	0.99
Average forward rate inherent in sales contracts	1.09	1.11
Average forward rate inherent in purchase contracts	1.06	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	$ 3
	-C$0.10	(3)

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 June 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 June 30, 2008, the proportion of fixed rate debt was approximately 93% (December 31, 2007 - 87%) of total long-term debt outstanding. The Company may also use derivative instruments to manage interest rate risk. At June 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 June 30, 2008, a 1% 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. At June 30, 2008, $10 million of the carrying amount of available-for-sale financial assets, representing one equity investment, was quoted in an active market. Therefore, the Company's exposure is limited to changes in the share price of this investment. Refer to note 5 for disclosures on available-for-sale financial assets. On July 8, 2008, the Company disposed of this equity investment and recognized a $9 million pre-tax gain in net income which was previously recorded as a fair value change in accumulated other comprehensive income.

(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. Credit risk policies are established by ROC and approved by the Board of Directors and the associated techniques and practices are designed to manage the credit risks associated with the various business activities throughout the Company. Credit management techniques 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:

	June 30, 2008	December 31, 2007
Cash and cash equivalents	$ 126	$ 79
Accounts receivable	462	581
Derivative instruments assets	506	220
ABCP	51	60
Loans and other long-term receivables	79	70
Net investment in lease	29	29
Financial guarantees to third parties	29	27
Loan commitments to third parties	6	6
	$ 1,288	$ 1,072

This table does not take into account collateral held. At June 30, 2008, the Company held cash deposits of $46 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 June 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 $691 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:

	June 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:

	June 30, 2008		
	Gross accounts receivable	Allowance for doubtful accounts	Net accounts receivable
Current	$ 421	$ -	$ 421
Past due 30 to 60 days	14	-	14
Past due 61 to 90 days	5	1	4
Past due more than 90 days[1]	26	3	23
Total	$ 466	$ 4	$ 462

[1] Includes $14 million which is subject to regulatory approval prior to collection but has low associated credit risk.

Bad debt expense, exclusive of recoveries, of $1 million and $2 million recognized in the three and six month periods ended June 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 June 30, 2008	Three months ended June 30, 2007	Six months ended June 30, 2008	Six months ended June 30, 2007
Balance, beginning of period	$ 6	$ 7	$ 6	$ 6
Allowance of receivables	1	1	2	4
Receivables written off	(3)	(2)	(5)	(4)
Recovery of receivables	-	1	1	1
Balance, end of period	$ 4	$ 7	$ 4	$ 7

At June 30, 2008, the Company held $16 million of customer deposits for the purpose of mitigating the credit risk associated with accounts receivable from residential and business customers.

At June 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 June 30, 2008, the Company had undrawn and committed bank credit facilities of $1,372 million, of which $484 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 registration under which it may raise up to $1 billion of debt, with maturities of one month or longer. As at June 30, 2008, the available amount remaining under the Canadian shelf registration was $400 million. As of July 10, 2008, Power LP renewed its Canadian universal shelf prospectus, expiring in August 2010, under which it may raise up to $1 billion in partnership units or debt, of which a maximum of $600 million can be debt. As at June 30, 2008, the available amount remaining under the Power LP's shelf prospectus then in effect was up to $685 million of equity or debt, of which up to $390 million could be debt.

(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 June 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	$ 171	$ -	$ -	$ -	$ -	$ -	$ 171
Long-term debt	27	226	20	213	9	1,885	2,380
Interest payments on long-term debt	198	198	163	144	124	1,284	2,111
Accounts payable and accrued liabilities [1]	463	-	-	-	-	-	463
Other current liabilities	19	-	-	-	-	-	19
Loan commitments	6	-	-	-	-	-	6
Derivative financial liabilities:							
Net forward foreign exchange contracts	4	1	-	-	-	-	5
Net commodity contracts-for-differences	169	76	37	11	1	1	295
Total	$ 1,057	$ 501	$ 220	$ 368	$ 134	$ 3,170	$ 5,450

[1] Excluding accrued interest on long-term debt of $54 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:

	June 30, 2008	December 31, 2007
Short-term debt	$ 171	$ 138
Long-term debt	2,362	2,139
Cash and cash equivalents	(126)	(79)
Net debt	2,407	2,198
Non-controlling interests	795	740
Shareholder's equity	2,404	2,367
Total equity	3,199	3,107
Total capital	$ 5,606	$ 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 six months ended June 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:

		June 30, 2008		December 31, 2007
General stock	$	52	$	51
Natural gas held in storage for trading purposes		14		-
Coal		7		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 six months ended June 30, 2008 of $19 million (2007 - $16 million) and $32 million (2007 - $28 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 six months ended June 30, 2008 or in the same periods of 2007. At June 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:

		Six months ended June 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 June 30, 2008	Three months ended June 30, 2007	Six months ended June 30, 2008	Six months ended June 30, 2007
Current income taxes	$ 6	$ 5	$ 22	$ 66
Future income taxes	(1)	52	(11)	(10)
	$ 5	$ 57	$ 11	$ 56

Income taxes consisted of:

	Three months ended June 30, 2008	Three months ended June 30, 2007	Six months ended June 30, 2008	Six months ended June 30, 2007
Income taxes on income for the period	$ 10	$ 3	$ 12	$ 9
Income taxes arising on sale of power purchase arrangement and related transactions	-	-	4	4
Corporate income tax rate reductions	(5)	1	(5)	1
Reduction of income taxes resulting from corporate restructuring within the Energy Services segment	-	1	-	(10)
Income taxes arising on enactment of Specified Investment Flow-through Legislation	-	52	-	52
	$ 5	$ 57	$ 11	$ 56

(Unaudited, in millions of dollars)

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.

13. Non-controlling interests:

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

	Three months ended June 30, 2008	Three months ended June 30, 2007	Six months ended June 30, 2008	Six months ended June 30, 2007
Non-controlling interests in Power LP	$ 67	$ (48)	$ 103	$ 1
Preferred share dividends paid (dividend taxes recovered) by subsidiary companies	1	(4)	3	(1)
	$ 68	$ (52)	$ 106	$ -

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

	June 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	103	19
Other comprehensive loss attributable to non-controlling interests	(1)	(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	(47)	(92)
Non-controlling interests in Power LP, end of period	673	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
	$ 795	$ 740

(Unaudited, in millions of dollars)

14. Net financing expenses:

	Three months ended June 30, 2008	Three months ended June 30, 2007	Six months ended June 30, 2008	Six months ended June 30, 2007
Interest on long-term debt	$ 46	$ 40	$ 88	$ 81
Interest on short-term debt and other financing costs	1	3	3	7
Fair value changes on financial instruments	-	1	9	2
Interest on capital lease obligations	-	1	-	3
Capitalized interest and allowance for funds used during construction	(5)	(4)	(10)	(7)
Interest and dividend income	(2)	(3)	(3)	(7)
Realized gains on interest rate contracts	-	(5)	-	(5)
Other	1	1	1	1
	$ 41	$ 34	$ 88	$ 75

15. Commitments:

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.

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 June 30, 2008, the Company had letters of credit outstanding of $219 million (December 31, 2007 - $357 million) to meet the credit requirements of energy market participants, to meet conditions of certain debt and 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.

(Unaudited, in millions of dollars)

17. Segment disclosures (continued):

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.

Three months ended June 30, 2008

	Generation	Distribution and Transmission	Energy Services	Water Services	Corporate	Intersegment Eliminations	Consolidated
Revenues – external	$ 203	$ 30	$ 561	$ 71	$ -	$ -	$ 865
Intersegment revenues	31	29	6	(1)	-	(65)	-
Total revenues	234	59	567	70	-	(65)	865
Energy purchases and fuel	(12)	14	547	-	-	(59)	490
Operations, maintenance, administration and foreign exchange gain (loss)	74	15	17	44	19	(6)	163
Franchise fee, property taxes and other taxes	4	11	-	2	-	-	17
Depreciation, amortization and asset retirement accretion	42	8	7	5	3	-	65
Operating expenses	108	48	571	51	22	(65)	735
Operating income (loss) before corporate charges	126	11	(4)	19	(22)	-	130
Corporate charges	10	5	4	4	(23)	-	-
Operating income (loss)	$ 116	$ 6	$ (8)	$ 15	$ 1	$ -	$ 130
Net financing expenses							(41)
Income before income taxes and non-controlling interests							$ 89
Capital additions	$ 120	$ 42	$ 1	$ 19	$ 4	$ -	$ 186

(Unaudited, in millions of dollars)

17. Segment disclosures (continued):

Three months ended June 30, 2007

	Generation	Distribution and Transmission	Energy Services	Water Services	Corporate	Intersegment Eliminations	Consolidated
Revenues – external	$ 238	$ 28	$ 541	$ 58	$ -	$ -	$ 865
Intersegment revenues	27	31	3	3	-	(64)	-
Total revenues	265	59	544	61	-	(64)	865
Energy purchases and fuel	130	15	497	-	-	(54)	588
Operations, maintenance, administration and foreign exchange gain (loss)	21	15	19	35	26	(10)	106
Franchise fee, property taxes and other taxes	4	10	-	2	-	-	16
Depreciation, amortization and asset retirement accretion	42	6	7	5	3	-	63
Operating expenses	197	46	523	42	29	(64)	773
Operating income (loss) before corporate charges	68	13	21	19	(29)	-	92
Corporate charges	15	4	5	4	(28)	-	-
Operating income (loss)	$ 53	$ 9	$ 16	$ 15	$ (1)	$ -	$ 92
Net financing expenses							(34)
Income before income taxes and non-controlling interests							$ 58
Capital additions	$ 44	$ 24	$ 4	$ 35	$ 5	$ -	$ 112

(Unaudited, in millions of dollars)

17. Segment disclosures (continued):

Six months ended June 30, 2008

	Generation	Distribution and Transmission	Energy Services	Water Services	Corporate	Intersegment Eliminations	Consolidated
Revenues – external	$ 393	$ 59	$ 1,085	$ 127	$ -	$ -	$ 1,664
Intersegment revenues	62	59	10	1	-	(132)	-
Total revenues	455	118	1,095	128	-	(132)	1,664
Energy purchases and fuel	(6)	26	1,029	-	-	(116)	933
Operations, maintenance, administration and foreign exchange gain (loss)	149	29	34	80	35	(15)	312
Franchise fee, property taxes and other taxes	9	22	-	4	-	-	35
Depreciation, amortization and asset retirement accretion	84	15	14	10	6	-	129
Operating expenses	236	92	1,077	94	41	(131)	1,409
Operating income (loss) before corporate charges	219	26	18	34	(41)	(1)	255
Corporate charges	14	8	12	8	(42)	-	-
Operating income	$ 205	$ 18	$ 6	$ 26	$ 1	$ (1)	$ 255
Gain on sale of power syndicate agreement							34
Net financing expenses							(88)
Income before income taxes and non-controlling interests							$ 201
Capital additions	$ 197	$ 63	$ 2	$ 26	$ 6	$ -	$ 294

(Unaudited, in millions of dollars)

17. Segment disclosures (continued):

Six months ended June 30, 2007

	Generation	Distribution and Transmission	Energy Services	Water Services	Corporate	Intersegment Eliminations	Consolidated
Revenues – external	$ 455	$ 56	$ 1,151	$ 101	$ 1	$ -	$ 1,764
Intersegment revenues	54	62	9	3	-	(128)	-
Total revenues	509	118	1,160	104	1	(128)	1,764
Energy purchases and fuel	157	31	1,075	-	-	(110)	1,153
Operations, maintenance, administration and foreign exchange gain (loss)	58	29	38	61	37	(18)	205
Franchise fee, property taxes and other taxes	9	19	-	4	-	-	32
Depreciation, amortization and asset retirement accretion	83	13	14	10	6	-	126
Operating expenses	307	92	1,127	75	43	(128)	1,516
Operating income (loss) before corporate charges	202	26	33	29	(42)	-	248
Corporate charges	22	6	8	6	(42)	-	-
Operating income	$ 180	$ 20	$ 25	$ 23	$ -	$ -	$ 248
Gain on sale of power syndicate agreement							34
Net financing expenses							(75)
Income before income taxes and non-controlling interests							$ 207
Capital additions	$ 87	$ 36	$ 7	$ 49	$ 8	$ -	$ 187

Geographic information:

	Three months ended June 30, 2008				Three months ended June 30, 2007			
	Canada	U.S.	Intersegment Eliminations	Total	Canada	U.S.	Intersegment Eliminations	Total
Revenues - external	$ 766	$ 99	$ -	$ 865	$ 741	$ 124	$ -	$ 865
Intersegment revenues	17	1	(18)	-	6	6	(12)	-
Total revenues	$ 783	$ 100	$ (18)	$ 865	$ 747	$ 130	$ (12)	$ 865

	Six months ended June 30, 2008				Six months ended June, 2007			
	Canada	U.S.	Intersegment Eliminations	Total	Canada	U.S.	Intersegment Eliminations	Total
Revenues - external	$1,454	$ 210	$ -	$1,664	$1,533	$ 231	$ -	$ 1,764
Intersegment revenues	27	5	(32)	-	11	12	(23)	-
Total revenues	$1,481	$ 215	$ (32)	$1,664	$1,544	$ 243	$ (23)	$ 1,764

18. Comparative figures:

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