Management's discussion and analysis

This management's discussion and analysis ("MD&A") dated March 23, 2007 should be read in conjunction with the audited consolidated financial statements of EPCOR Utilities Inc. (hereinafter the "Company", "EPCOR", "we", "our" or "us") for the years ended December 31, 2006 and 2005. 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 and uncertainties, which could cause EPCOR's actual results and experience to be materially different than the anticipated results. Such risks and uncertainties include, but are not limited to, operating performance, commodity prices and volumes, load settlement, regulatory and government decisions, weather and economic conditions, competitive pressures, construction risks, obtaining financing 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.

STRATEGY

EPCOR builds, owns and operates power plants, electrical transmission and distribution networks, water and wastewater treatment facilities, and infrastructure in Alberta, British Columbia, Ontario and the U.S. Pacific Northwest. We also provide energy and water services to residential and commercial customers. Through its investment in EPCOR Power L.P. ("Power LP"), EPCOR also has electricity generation operations in California, Colorado, New Jersey, New York, North Carolina and Washington State. Our strategy is delivered through an integrated structure with a balanced portfolio of regulated and competitive businesses. We continue to look for opportunities for growth consistent with our balanced portfolio of businesses. By maintaining a strong base in regulated wires and water businesses and growing our commercial electricity and water operations, we intend to increase shareholder value as a leading North American supplier of energy and water services.

KEY PERFORMANCE INDICATORS

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

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

For 2006, EPCOR's results were ahead of target for both its non-financial and financial performance measures.

CONSOLIDATED FINANCIAL INFORMATION

($ millions)	2006	2005	2004 (restated)[(1) (2)]
Revenues	$ 2,930.8	$ 2,639.6	$ 2,594.6
Net income from continuing operations	632.5	158.7	182.7
Net income from discontinued operations	9.6	28.4	15.3
Net income	642.1	187.1	198.0
Total assets	6,383.3	5,663.8	4,202.0
Long-term debt	2,178.6	2,082.7	1,610.3
Common share dividends	125.1	122.7	120.5

(1) Restated on a retroactive basis to reflect the impact of adopting the new accounting standard for asset retirement obligations.

(2) Restated to reflect the operations of the Clover Bar generation plant as discontinued operations.

Net income

Net income from continuing operations for the year ended December 31, 2004	**$**	**182.7**
Net income from discontinued operations		15.3
Net income for the year ended December 31, 2004	**$**	**198.0**

Net income from continuing operations for the year ended December 31, 2004	**$**	**182.7**
Genesee 3 results of operations from March 1, 2005 commencement		37.4
Gains on the sale of Alberta competitive electricity and natural gas contracts and settlement of litigation		13.3
2004 loss on disposal of interest in Frederickson generation plant		10.9
Lower general and administration expenses		10.9
Decreased financing expenses excluding impact of Genesee 3 financing, PILOT settlement and investment in and consolidation of Power LP		13.9
Lower acquired Alberta power purchase arrangement results		(12.6)
Non-recurrence of 2004 increased estimates of deferred availability incentives for plants operating under PPAs		(22.1)
Lower Alberta electricity margins		(26.5)
2005 PILOT settlement		(38.1)
Other		(11.1)
Decrease in net income from continuing operations		(24.0)
Net income from continuing operations for the year ended December 31, 2005		**158.7**
Net income from discontinued operations		28.4
Net income for the year ended December 31, 2005	$	**187.1**

Net income from continuing operations for the year ended December 31, 2005	**$**	**158.7**
Gain on sale of Battle River PSA and related transactions		327.3
Impact of recording a net future income tax asset associated with additional deductions available for income tax purposes due to the restructuring of EPCOR Generation Inc. on January 3, 2006		117.1
2005 PILOT settlement adjustment		38.1
Higher income from Genesee 3, Calpine, Kingsbridge I, and Joffre generation operations		24.5
2005/2006 regulatory decisions for distribution and transmission tariffs and RRT non-energy charge		12.8
Higher realized gains on forward foreign exchange contracts		11.6
Lower financing expenses and preferred share dividends excluding Power LP financing		11.2
Cumulative translation account adjustment for the sale of Frederickson to Power LP		(5.6)
2005 gain on sale of Alberta competitive electricity contracts and favourable settlement of litigation		(13.3)
Lower Ontario electricity margins		(20.6)
2006 impact of income tax rate reductions on future income tax assets and liabilities		(22.5)
Other		(6.8)
Increase in net income from continuing operations		473.8
Net income from continuing operations for the year ended December 31, 2006		**632.5**
Net income from discontinued operations		9.6
Net income for the year ended December 31, 2006	**$**	**642.1**

Net income for the year ended December 31, 2006 was $642.1 million compared to $187.1 million for 2005. Net income increased by $455.0 million for the year ended December 31, 2006 compared to the previous year for the following reasons.

- On June 5, 2006, we sold a 55% interest in the Battle River Power Syndicate Agreement (“Battle River PSA”) to ENMAX Corporation (“ENMAX”) for $343.3 million. We also sold a 5.4% interest in the Sundance Power Syndicate Agreement (“Sundance PSA”) to non-EPCOR syndicate members for $57.5 million. These transactions resulted in a pre-tax gain of $378.3 million and $51.0 million of associated income tax expense.

- On January 3, 2006, the Company reorganized certain subsidiaries within the Generation segment to realize efficiencies by better aligning its legal structure with its operating structure. As a result of the restructuring, EPCOR Generation Inc. ("EGI") has additional deductions available for income tax purposes. The resulting net reduction in income taxes of $117.1 million was recognized in the first quarter of 2006.

- In the first quarter of 2005, we recorded a $38.1 million charge for amounts in lieu of income taxes resulting from the settlement with Alberta Revenue, Tax and Administration with respect to the value of goodwill for purposes of the Payment in Lieu of Tax ("PILOT") Regulation.

- Genesee 3 and Kingsbridge I generation facilities were commissioned on March 1, 2005 and March 16, 2006, respectively thereby providing additional generation and income in 2006. Higher Alberta pool prices in 2006 also positively impacted income from Genesee 3. In addition, we entered into a short-term tolling arrangement with Calpine Power Income Fund ("Calpine") for operation of their Calgary Energy Centre for the periods February 16, 2006 to June 30, 2006 and from September 1, 2006 to December 31, 2006. Lower natural gas prices and higher ancillary service revenues all contributed to higher energy sales from the Joffre co-generation facility in 2006.

- In the second quarter of 2006, the Alberta Energy and Utilities Board ("EUB") issued its decisions relating to our general tariff applications for electricity transmission, distribution and Regulated Rate Tariff ("RRT") services in respect of the period from January 1, 2005 through December 31, 2006. The January 1, 2005 to June 30, 2006 effect of these decisions was recognized in the second quarter resulting in a $9.8 million increase in net income, of which $7.1 million related to 2005 service. Third and fourth quarter 2006 regulated revenues were recognized at the final approved rates resulting in a $3.0 million increase in net income compared to the same period in 2005.

- Preferred share dividends decreased due to the redemption of $150.0 million of subsidiary company preferred shares on June 30, 2006. Financing expenses were lower due to interest earned on positive cash balances, repayment of the $98.3 million loan issued under the three-year credit facility and scheduled repayments of non-recourse debt and obligations to the City of Edmonton.

- On August 1, 2006 the Company sold its subsidiaries associated with its interest in its Frederickson power plant to Power LP, a subsidiary of the Company. The recognition of previously deferred foreign exchange losses on the investment in Frederickson was partly offset by the recognition of a foreign exchange gain on repayment of the U.S. dollar debt designated as a hedge of the net investment in the foreign operations. The result was a net foreign exchange loss of $5.6 million.

- Ontario electricity margins decreased as a result of the Market Power Mitigation Rebate program which was terminated by the Ontario Government in March 2006.

- On April 10, 2006 and June 6, 2006, the Government of Alberta and the Government of Canada, respectively, reduced corporate income tax rates. The impact of these rate reductions on our future income tax assets and liabilities resulted in a $16.1 million charge to net income. This charge consisted of a $6.4 million future income tax recovery relating to future income tax balances for Power LP and a $22.5 million charge relating to all other future income tax balances.

- In the third quarter of 2005, we received a termination payment of $82.7 million from Alberta's Balancing Pool upon termination of the Clover Bar power purchase arrangement ("PPA"). This was offset by the write-down of the Clover Bar generation plant and other termination costs of $64.4 million, which were incurred pursuant to our decision to decommission the generation units. In 2006, the estimate of costs to de-commission the facility was determined to be lower than originally estimated resulting in $9.6 million being included in income from discontinued operations.

Revenues

Revenues for the year ended December 31, 2004[1]	**$**	**2,536.7**
Power LP revenues from date of acquisition		104.4
Commercial and other sales		61.0
2005 gain on sale of Alberta competitive electricity contracts and settlement of litigation		20.5
Lower energy sales		(83.0)
Increase in revenues		102.9
Revenues for the year ended December 31, 2005		**2,639.6**
Higher Power LP revenues		246.3
Unrealized fair value changes in derivative financial instruments		57.4
2005/2006 rate decisions for distribution and transmission tariffs and RRT non-energy charge		16.6
Higher energy sales		6.8
2005 gain on sale of Alberta competitive electricity contracts and settlement of litigation		(20.5)
Commercial and other sales		(15.4)
Increase in revenues		291.2
Revenues for the year ended December 31, 2006	**$**	**2,930.8**

(1) Restated to reflect classification adopted in 2006.

Revenues increased $291.2 million in 2006 compared with 2005 due to the following:

- Power LP revenues were higher in 2006 as it was acquired on September 1, 2005 and contributed only four months of revenue in 2005.

- Favourable unrealized fair value changes in derivative financial instruments resulted from gains on the forward sale of power on a financial contracted basis ("financial sell") which hedged anticipated energy revenues, but were not designated as hedges for accounting purposes. The unrealized gains relating to the Ontario financial sell derivatives are due to the forward price for the Hourly Ontario Energy Price ("Ontario pool price") which was lower in 2006 than in 2005. This was partly offset by the impact of higher forward Alberta Pool Prices on our Alberta financial sell contracts.

- Energy sales for the Distribution and Transmission segment were higher due to higher Alberta Electric System Operator ("AESO") charges as a result of new *Transmission Regulation*, effective January 1, 2006. Energy sales for Energy Services and Generation (excluding Power LP) were lower due to decreased generation sales related to the sale of an interest in the Battle River PSA and Sundance PSA, sale of competitive contracts in

September 2005, and lower revenues on the settlement of financial derivatives, which were partly offset by increased generation sales from Genesee 3, Calpine, and Kingsbridge I facilities, and higher Alberta pool prices.

- Commercial and other sales were lower due to a decrease in commercial water services activities and Generation ancillary services revenue.

Capital spending and investment

($ millions)	2006	2005	2004
Generation	$ 55.1	$ 118.2	$ 102.3
Distribution and Transmission	61.0	64.5	47.6
Energy Services	10.8	7.9	14.6
Water Services	104.2	47.5	46.7
Corporate – other	18.6	5.8	9.2
	249.7	243.9	220.4
Investment in Primary Energy Ventures LLC	370.4	-	-
Investment in Power LP	-	534.4	-
Other investment	2.6	0.1	-
	$ 622.7	$ 778.4	$ 220.4

Capital expenditures for property, plant and equipment decreased in 2006 compared to 2005 primarily due to completion of the Kingsbridge I wind-power project in Ontario in March, 2006 and Genesee 3 in 2005. Capital expenditures on Kingsbridge I were $10.2 million in 2006 compared to $63.2 million in 2005 and capital expenditures on Genesee 3 were $1.0 million in 2006 compared to $15.3 million in 2005. Offsetting these reductions, Water Services' had capital expenditures of $60.0 million in 2006 for construction work in progress on the EL Smith water treatment plant expansion. We acquired a 30.6% interest in Power LP and 100% of the General Partner of Power LP on September 1, 2005 for a total purchase price of $534.4 million. On November 1, 2006, Power LP acquired 100% of Primary Energy Ventures LLC ("PEV") for $365.8 million (US $325.7 million) plus acquisition costs of $4.6 million for a total purchase price of $370.4 million.

SIGNIFICANT EVENTS

Sale of power purchase arrangement and related transactions

EPCOR acquired the Battle River Power Purchase Arrangement ("Battle River PPA") in August 2000 through an auction conducted by the Government of Alberta as part of provincial electricity deregulation. The Battle River PPA includes Alberta Power (2000) Ltd.'s Battle River generation units 3, 4 and 5 with a total committed capacity of 662.8 megawatts. Following acquisition of the Battle River PPA, the rights under the PPA were assigned under the Battle River PSA to the syndicate members, including an EPCOR subsidiary. As a result, the syndicate members held the beneficial ownership of the committed capacity and ancillary services produced by the Battle River generation units.

On June 5, 2006, we finalized an agreement to sell our Battle River PPA and related interest in the Battle River PSA to ENMAX. EPCOR's interest in the Battle River PSA will be sold over a four year period. The agreement called for the initial sale of a 55% interest in the Battle River PSA for gross cash proceeds of $343.3 million on June 5, 2006. The remaining

45% interest will be sold for gross proceeds of $224.0 million, subject to closing adjustments, and recognized when the interest and associated risks and rewards of beneficial ownership are legally transferred to ENMAX over the next four years. The timing of these future sales include the sale of 10% interests closing on each of January 1, 2007, 2008 and 2009, followed by the sale of the final 15% interest on January 1, 2010.

The sale of the initial 55% interest in the Battle River PSA was completed through a series of transactions. Immediately prior to the sale, EPCOR owned approximately 70% of the total interest in the Battle River PPA via the Battle River PSA, with the remaining 30% interest owned by various third parties (non-EPCOR syndicate members). To facilitate the eventual sale to ENMAX of a 100% interest in the Battle River PSA, we acquired the remaining 30% interest in the Battle River PSA from the non-EPCOR syndicate members for cash consideration and a non-monetary exchange of an equivalent value ownership interest in our Sundance Power Syndicate Agreement ("the Sundance Swap"). The acquired 30% interest in the Battle River PSA was measured at the exchange amount of the Sundance Swap of $134.1 million and cash consideration of $52.3 million, for a resulting carrying amount of the 30% interest in the Battle River PSA of $186.4 million prior to its sale to ENMAX.

Following our acquisition of the 30% interest in the Battle River PSA, we completed the sale of the initial 55% interest in the Battle River PSA for cash consideration of $343.3 million. A pre-tax gain of $329.3 million was recognized on the initial interest sold.

In addition to the Sundance Swap, the Company sold an additional interest in the Sundance PSA ("the Sundance Extension") to non-EPCOR syndicate members for cash consideration of $17.1 million and notes receivable of $40.4 million. The notes receivable bear interest at 5.35% per annum and are to be repaid in monthly payments of principal and interest through to December 31, 2020. At December 31, 2006, the non-current portion of the notes receivable of $37.2 million is recorded in other assets and the current portion of $1.9 million is recorded in accounts receivable. The pre-tax gain recognized on the sale of the Sundance Extension, after final purchase price adjustments, was $49.0 million. In total, we sold 25.5% of our previously-held 70% interest in the Sundance PSA through the non-monetary exchange for the Battle River PSA interest and the Sundance Extension sale.

Our net gain before income taxes from these transactions was $378.3 million. The associated income taxes included $51.0 million of expense and $42.4 million of refundable taxes, which were charged to retained earnings. The Company's refundable tax balance was reduced by $5.2 million as a result of the sale of its interest in the Frederickson power plant and related subsidiaries.

Generation reorganization

We reorganized certain subsidiaries within our Generation segment to realize efficiencies by better aligning our legal structure with our operating structure. As a result of the restructuring, EGI became subject to income taxes on its taxable income pursuant to section 149 of the Income Tax Act ("ITA") effective January 3, 2006. Prior to this change, EGI was subject to and made payments under PILOT. Upon becoming subject to the ITA, EGI was deemed to have disposed of and reacquired all its property at fair market value. Since the fair market value of its property was greater than its underlying net book values, EGI has additional deductions available for income tax purposes. The net tax effect has been recognized as non-current future income tax assets in the consolidated balance sheet with a corresponding increase in net income of $117.1 million for the reduction of income tax expense.

Acquisition of Primary Energy Ventures

On November 1, 2006, Power LP acquired a 100% interest in Primary Energy Ventures LLC ("PEV"). PEV owns eight combined heat and power facilities located in the United States and 17.0% of the common interests and 14.2% of the preferred interests in Primary Energy Recycling Holdings LLC ("PERH"). PERH owns four waste heat recovery power facilities and a coal pulverization facility in the United States. In addition, PEV provides management and administrative services to PERH and Primary Energy Recycling Corporation ("PERC"). PERC owns the balance of PERH not owned by PEV.

The total purchase price was $370.4 million. The results of operations of PEV from the date of acquisition are included in the Generation segment of the consolidated financial statements.

Corporate income tax rate reductions

Effective April 1, 2006 the Government of Alberta enacted an amendment to the Alberta Corporate Tax Act that reduced corporate income taxes from 11.5% to 10% of taxable income. On June 6, 2006, the Government of Canada passed Bill C-13 which included changes in corporate income tax rates. The federal corporate income tax rate is scheduled to be reduced in increments over the period from January 1, 2008 to December 31, 2010, for a total reduction of 3.12%. The estimated impact of these tax rate reductions based on the expected timing of the reversal of taxable and deductible temporary differences was a $16.1 million charge to consolidated net income and a corresponding reduction in net future income tax assets and liabilities in the second quarter. This charge consists of a $6.4 million future income tax recovery relating to future income tax balances for Power LP and a $22.5 million charge relating to all other future income tax balances.

Redemption of preferred shares

On June 30, 2006, EPCOR Finance Corporation, a subsidiary of the Company redeemed six million Cumulative Redeemable Perpetual First Preferred Shares, Series A ("Preferred Shares") at their stated redemption price, for $150.0 million cash. The preferred dividends on these shares were approximately $8.6 million per year. The redemption was funded with cash.

Regulatory decisions

In the second quarter of 2006, the EUB issued its decisions relating to the Company's general tariff applications for its electricity transmission, distribution and RRT services in respect of the period from January 1, 2005 through December 31, 2006. Prior to receiving the Decisions, the Company had billed customers and recorded revenues based on EUB-approved interim rates for 2005 and 2006. The effects of these decisions were recorded in the second quarter.

On July 4, 2006, The City of Edmonton Council approved the renewal of the Performance

Based Rates (“PBR”) bylaw under which the Company’s rate-regulated water business will operate for the five years commencing April 1, 2007. In addition to updating performance measures, the bylaw sets out rules for water rate adjustments for the 2007 to 2011 period.

Kingsbridge II project asset impairment

In December 2006, we recorded an impairment loss of $3.4 million in respect of property, plant and equipment relating to the Kingsbridge II wind power development project in Ontario. The book value of the assets developed to December, 2006 was determined to exceed their net recoverable amount. This determination was made following our decision to re-examine the project design and schedule and terminate arrangements with certain suppliers in 2007 due to the status of required local and provincial approvals, and uncertainties about the timeline for certain future approval processes. Contract termination costs, estimated at $5.9 million, will be recorded in the period that the contract terminations take place.

Sale of Frederickson power plant and related entities

On August 1, 2006, we finalized the sale of certain subsidiaries associated with our interest in the Frederickson power plant to Power LP. No gain or loss was recognized on the inter-company sale.

As a result of the sale of the Frederickson plant operations to Power LP, we recognized a reduction in the net investment in the Frederickson operations to the extent of the 69.4% non-controlling interest in Power LP. Previously deferred foreign exchange losses associated with Frederickson were recognized on the sale. These losses were partly offset by recognition of a foreign exchange gain on repayment of the U.S. dollar debt which had been designated as a hedge of the net investment in the foreign operations. The resulting net foreign exchange loss was $5.6 million.

To partially finance the acquisition of Frederickson Power L.P., Power LP issued 2,460,000 subscription receipts on April 27, 2006. We maintained our 30.6% interest in Power LP by purchasing 752,760 subscription receipts for $25.1 million cash. The balance of 1,707,240 subscription receipts was purchased by non-controlling interests for $54.9 million cash, net of issue costs. On August 1, 2006 the subscription receipts were converted on a one-for-one basis to limited partnership units of Power LP.

SEGMENT RESULTS

Effective January 1, 2006, we changed our measure of profit or loss for segment reporting purposes. Management now uses “operating income” to measure performance, which is income before non-operating gains and losses, financing expenses, income taxes and amounts in lieu of income taxes, non-controlling interests and net income from discontinued operations. Shared corporate charges are identified separately from other operating costs. Refer to the Segment Disclosures note to the Consolidated Financial Statements.

Generation

Generation earns income from generation units operating under PPAs, and from commercial power generation units. Our Genesee 1, Genesee 2, Rossdale, and Clover Bar power generation units, previously rate-regulated through annual tariff applications, became subject to PPAs effective January 1, 2001 while continuing to be rate-regulated as determined under the guidelines of the *Electric Utilities Act* (Alberta). The electricity generated from the generation units operating under PPAs is provided to the PPA holders, not the owner-operators of the units. In exchange for the rights to the electricity, we receive formula-based fixed capacity and variable payments which are intended to provide us with a reasonable opportunity to recover unit operating costs and provide a fair rate of return. The return on equity component is set at 4.5% over the rate of long-term Canada bonds. In addition, we receive incentives and pay penalties when the output available from the generation unit exceeds or falls below target availability levels set out in the PPAs. The target availability levels were originally set with the expectation that the incentives and penalties would net to zero over the life of the PPAs. While the units operating under PPAs are rate-regulated under the *Electric Utilities Act* (Alberta), they do not meet the criteria for rate-regulated accounting under generally accepted accounting principles. Accordingly, the generation units are accounted for as non-rate-regulated facilities in accordance with the commercial terms and conditions inherent in the PPAs. Key to the earnings performance of generation units operating under PPAs is managing the costs of the units and ensuring that they are able to meet or exceed the target availability levels.

The Clover Bar PPA was terminated effective September 30, 2005 at which time decommissioning of the plant commenced. All operating results relating to the Clover Bar facility are reported under discontinued operations and are not included in these Generation segment results.

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

Other commercial generating plants consist of plants directly owned by EPCOR and plants owned by Power LP. With Power LP's acquisition of PEV, Power LP now owns 20 power plants located in Canada and the United States and has a 15.4% equity interest in PERH which owns four power plants and a 50% interest in a pulverized coal facility, all located in the state of Indiana. These power plants generate electricity from a combination of natural gas, waste heat, wood waste, water flow, coal and tire-derived fuel.

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

Generation operating income

Year ended December 31			2006		2005
Generation results					
(including intersegment transactions, $ millions)					
Revenues		$	776.9	$	578.5
Expenses	Energy purchases and fuel		101.9		112.7
	Operations, maintenance, administration and foreign exchange		175.8		127.5
	Franchise fees and taxes other than income taxes		17.9		10.7
	Depreciation, amortization and asset retirement accretion		150.8		92.2
			446.4		343.1
Operating income before corporate charges			330.5		235.4
Corporate charges			26.0		19.0
Operating income		**$**	**304.5**	**$**	**216.4**

Operating income for the year ended December 31, 2005	**$**	**216.4**
Higher Power LP operating income		41.4
Unrealized fair value changes in derivative financial instruments		43.5
Increased estimates of deferred availability incentives		12.8
Higher operating income from Genesee Phase 3 operations		6.0
Higher operating income from Kingsbridge I operations		3.0
Cumulative translation account adjustment for the sale of Frederickson to Power LP		(5.6)
Lower operating income from Joffre operations		(5.7)
Lower operating income from Frederickson operations		(5.4)
Other		(1.9)
Increase in operating income		88.1
Operating income for the year ended December 31, 2006	**$**	**304.5**

For the year ended December 31, 2006, Generation’s operating income increased by $88.1 million from the prior year primarily due to the following.

- Power LP contributed $81.5 million of operating income in 2006 compared to $40.1 million in 2005 as the 2005 results included only four months of operations from the date of acquisition on September 1, 2005. As well, 2006 Power LP results included results from the Frederickson and PEV acquisitions commencing on their respective purchase dates of August 1, 2006 and November 1, 2006. Accordingly, revenues and expenses from Power LP increased $246.3 million and $204.9 million, respectively, from 2005 to 2006.

- The generation from the Joffre plant is subject to a contract-for-differences (“CfD”) which is a financial agreement whereby the difference between the AESO pool price and the AECO-C price (Alberta gas trading price), and the contracted price, is remitted by one counterparty to the other. Revenues and expenses related to the unrealized fair value changes on the CfD decreased $39.9 million and $83.4 million respectively, over the corresponding period in 2005. The net gains for the unrealized fair value changes recognized in 2006 on this financial contract were due to higher forward Alberta Pool prices and lower natural gas prices compared to the respective forward prices in 2005.

- In the fourth quarter of 2006, changes in estimates of the retained availability incentives on the generation units operating under PPAs increased operating income and revenues, primarily as a result of increasing forward Alberta pool prices.

- Genesee 3 was commissioned on March 1, 2005, and is operated under a tolling arrangement on an inter-company basis with Energy Services, whereby Energy Services pays a fixed capacity fee plus a variable cost fee in exchange for the right to control the dispatch of generation from the facility. The revenues under the tolling arrangement increased $8.8 million and expenses increased $2.8 million from 2005 to 2006 primarily due to the full year of operations in 2006. Inter-company revenues and expenses were eliminated on consolidation.

- The Kingsbridge I generation facilities were commissioned on March 16, 2006. The power from Kingsbridge I is sold under a 20 year long-term power supply arrangement to the Ontario Power Authority. Revenues in 2006 under the arrangement were $6.5 million while the associated operating expenses were $3.5 million.

- Power from the Joffre facility is sold on an inter-company basis from the Generation segment to the Energy Services segment under a tolling arrangement. Energy Services pays a fixed capacity fee plus a variable cost fee in exchange for the right to the power from the facility. Generation's revenues under the tolling arrangement decreased $11.3 million from 2005 to 2006 due to lower maintenance and variable energy cost recoveries and decreased production due to lower dispatch. Expenses decreased $5.6 million from 2005 to 2006 due to lower maintenance and variable energy costs as well as lower realized payments on the CfD to the Joffre Joint Venture as a result of lower spot natural gas prices and higher spot Alberta pool prices in 2006 compared to 2005. Inter-company revenues and expenses are eliminated on consolidation.

- The sale of the Frederickson facility to Power LP resulted in higher Power LP operating income and lower operating income for the balance of the Generation segment for the period from the date of sale on August 1, 2006 to December 31, 2006. Other than the loss recorded on the cumulative foreign currency translation this sale had no overall impact on the Generation segment results.

	2006	2005
Electricity generation (000s of megawatt-hours)		
Generation units owned by EPCOR		
Coal generation units	8,136	7,805
Natural gas generation units	451	740
Hydro and wind generation units	250	144
	8,837	8,689
Generation units owned by Power LP[1]		
Natural gas and/or waste heat units	1,934	390
Wood waste and/or waste heat units	817	246
Hydro generation units	648	197
	3,399	833
Total	**12,236**	**9,522**

	2006	2005
Generation plant availability (%)		
Generation units owned by EPCOR		
Coal generation units	96	92
Natural gas generation units	94	96
Hydro and wind generation units	93	63
Generation units owned by Power LP[1]		
Natural gas and/or waste heat units	96	98
Wood waste and/or waste heat units	95	93
Hydro generation units	91	83
Total	**95**	**93**

(1) EPCOR acquired a 30.6% interest in the Power LP plants effective September 1, 2005. The electricity generation volumes and availability measures reflect 100% of the generation of the Power LP generation units for the twelve months ended December 31, 2006 and four months ended December 31, 2005.

Generation maintains a fleet of high quality power plants with good geographic, fuel source and counterparty diversification. We have a strong track record of maximizing efficiency, productivity and reliability of our facilities. The overall availability of our facilities improved from 93% in 2005 to 95% in 2006 in part due to better performance from our hydro facilities where we continue to focus on improving reliability. Availability at our coal generation units was lower than normal in 2005 due to a transformer failure at the Genesee 2 unit. The acquisition of PEV in 2006 adds eight plants to the generation portfolio.

Generation will continue to operate and safely maintain EPCOR's generation assets. In July 2007, the Genesee generating station (including units 1, 2 and 3) will be required to shut down to accommodate AESO's upgrade of the high voltage transmission lines in the Genesee Keephills area and EPCOR will be compensated for these outages. The Company continues to pursue commercially and environmentally viable generation plants to help grow the business both in Canada and the United States. The Company has commenced construction of three new gas fired generating units with a total generating capacity of 240 MW at its Clover Bar site for completion in 2010. In February, 2007 the Company and TransAlta announced the development and construction of Keephills 3, a 450 MW supercritical coal-fired generation plant at TransAlta's Keephills site for completion in 2011. These generation plants will assist in providing capacity to Alberta's electric system and provide additional growth for EPCOR. The Company continues to review the design and schedule of the Kingsbridge II wind farm.

Distribution and Transmission

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

Distribution and Transmission operating income

Year ended December 31		2006	2005
Distribution and Transmission results			
(including intersegment transactions, $millions)			
Revenues	Distribution	$ 205.9	$ 168.0
	Transmission	40.1	32.8
	Commercial and other	11.4	10.7
		257.4	211.5
Expenses	Energy purchases and fuel	78.7	48.8
	Operations, maintenance, administration and foreign exchange	59.8	56.7
	Franchise fees and taxes other than income taxes	37.6	36.1
	Depreciation, amortization and asset retirement accretion	25.9	24.4
		202.0	166.0
Operating income before corporate charges		55.4	45.5
Corporate charges		12.9	11.1
Operating income		**$ 42.5**	**$ 34.4**

Operating income for the year ended December 31, 2005	**$ 34.4**
2005/2006 regulatory decisions for distribution and transmission tariffs	8.7
Operations, maintenance and administration and other	(0.6)
Increase in operating income	8.1
Operating income for the year ended December 31, 2006	**$ 42.5**

For the year ended December 31, 2006, Distribution and Transmission operating income increased by $8.1 million from the prior year primarily due to higher tariffs. In 2005 revenues were recognized at the approved interim rates. Upon receipt of the EUB rate decision in the second quarter of 2006, the difference between interim and final rates for the period from January 1, 2005 to June 30, 2006 was recognized, of which $6.2 million related to 2005. Revenues for the balance of 2006 were recognized at final approved rates.

Revenues and expenses increased $45.9 million and $37.8 million respectively, from 2005 to 2006 due to the rate decision and higher charges from the AESO for the Alberta Interconnected Electric System. In accordance with a new *Transmission Regulation*, effective January 1, 2006, load customers such as Distribution and Transmission, are responsible for 100% of the transmission system costs, replacing the previous cost allocation framework whereby load customers and supplying generators shared the costs equally. In addition, revenues and expenses increased due to higher distribution volumes and electricity wholesale market prices. This was partly offset by decreased revenues and expenses in commercial and other activity costs reflecting a lower volume of contract-based commercial services work.

	2006	2005
Distribution reliability and volumes		
Reliability (system average interruption duration index in hours)	0.73	0.69
Electricity distribution (000s megawatt-hours)	7,096	6,988

The strategic focus of Distribution and Transmission continues to be operational excellence. Reliability rates for our Edmonton distribution system continue to be among the best in Canada. Our primary measure of distribution system reliability is System Average Interruption Duration Index (“SAIDI”) which we attempt to minimize. This measure captures the average number of hours of interruption experienced by our customers. These include scheduled and unscheduled interruption to our primary distribution circuits in a year. In 2006, we experienced a SAIDI of 0.73 hours compared to 0.69 hours in 2005. This increase was primarily due to an AESO requirement on July 24, 2006 to curtail customer load because of a shortage of generation supply on the Alberta electrical transmission grid. Growth in the Edmonton region, offset by slightly lower consumption per customer, contributed to power distribution volumes increasing modestly from 6,988 GWh in 2005 to 7,096 GWh in 2006.

Distribution and Transmission's earnings and cash flow are driven from its rate-base, which requires continuous maintenance and upgrading to accommodate growth in the City of Edmonton. Distribution and Transmission will be constructing a new high voltage transmission line and adding a new substation. Once completed in 2010, this investment will be added to Distribution and Transmission's rate base and provide additional earnings and cash flows.

Energy Services

Energy Services earns income through the provision of electricity and to a lesser extent natural gas, to end-use customers in Alberta and Ontario. Electricity revenues are earned through the sale of electricity under regulated rates or rates set by contracts, both designed to cover the costs of supplying electricity (including the commodity cost, distribution and transmission charges, credit risk, and electricity price and volume risks) and provide a competitive margin. Natural gas revenues are earned through sales of natural gas under contract.

Energy Services also manages our overall electricity and natural gas portfolio in all markets in which we operate. To balance supply and demand, electricity and natural gas are purchased and sold under physical and financial transactions with the objective of matching volumes and terms or taking positions within limits established under prudent risk management policies. Electricity is also provided through EPCOR's interest in the Sundance and Battle River PPAs, EPCOR's commercial plants and, in 2006, short-term tolling arrangements with Calpine. The electricity from all of these sources was used to help balance and optimize the Company's electricity portfolio and satisfy customer electricity requirements. As part of its mandate, Energy Services also participates in the ancillary services (electricity reserves) market.

Energy Services operating income

Year ended December 31			2006		2005
Energy Services results					
(including intersegment transactions, $ millions)					
Revenues	Energy sales	$	1,926.4	$	1,853.3
	Commercial and other		36.4		53.0
			1,962.8		1,906.3
Expenses	Energy purchases		1,744.8		1,628.4
	Operations, maintenance, administration and foreign exchange		79.0		82.2
	Franchise fees and taxes other than income taxes		0.2		0.2
	Depreciation, amortization and asset retirement accretion		28.4		39.7
			1,852.4		1,750.5
Operating income before corporate charges			110.4		155.8
Corporate charges			21.6		22.9
Operating income		**$**	**88.8**	**$**	**132.9**

Operating income for the year ended December 31, 2005	**$**	**132.9**
Higher Alberta electricity margins		21.4
Lower depreciation expense		11.3
2005/2006 regulatory rate decision for RRT non-energy charges		5.3
2005 gain on sale of Alberta competitive electricity contracts and favourable settlement of litigation		(20.5)
Lower Ontario electricity margins		(30.5)
Unrealized fair value changes in derivative financial instruments		(43.0)
Other		11.9
Decrease in operating income		(44.1)
Operating income for the year ended December 31, 2006	**$**	**88.8**

For the year ended December 31, 2006, Energy Services operating income decreased by $44.1 million from the prior year due to the net impact of the following.

- Alberta electricity margins were higher due to higher pool prices and additional generation from Genesee 3, which commenced operations in March 2005 and the Calpine short-term tolling arrangement, which did not exist in 2005. Lower natural gas prices and maintenance costs, and higher ancillary services revenues all contributed to higher operating income from the Joffre generation facility. In addition, transmission costs on all the Alberta generation facilities were lower due to the new *Transmission Regulation* effective January 1, 2006. Revenues for RRT non-energy charges were also higher due to higher rates for certain customer groups and more customers.

  Alberta electricity revenues and expenses decreased primarily due to the Battle River PSA and Sundance PSA sale transactions, and the sale of competitive contracts in September 2005. Revenues were also lower due to lower realized settlements on financial sells as a result of higher Alberta pool prices. These decreases in energy revenues and expenses were partly offset by increased generation from Genesee 3 and Calpine facilities, higher Alberta pool prices, and favourable cost variances on Joffre as described above.

- Depreciation expense was lower due to the write-down of assets that were associated with the competitive contracts sold in 2005, and a portion of customer rights that were fully depreciated in 2005.

- Ontario electricity margins were lower due to the termination of the Ontario government rebates program in March 2006, lower Ontario market prices and lower income from financial transmission rights. Ontario energy revenues and energy expenses increased $6.2 million and $36.7 million, respectively, compared to 2005. The increases were primarily due to higher favourable settlements on financial sells and unfavourable settlements on derivative financial instruments to buy power forward ("financial buys") resulting from lower Ontario pool prices. Increases in energy revenues were partly offset by lower revenues from the rebate program.
- Unrealized fair value decreases in derivative financial instruments were primarily due to increasing forward Alberta pool prices in 2006 compared to 2005 on financial sell contracts which were not designated as hedges for accounting purposes. These financial sells hedge, on an economic basis, anticipated energy revenues.

  Unrealized fair value changes on derivative financial instruments increased energy revenues by $97.3 million from 2005 to 2006 due to decreasing forward Ontario pool prices on financial sells which were partly offset by increasing forward Alberta pool prices on financial sells. Unrealized fair value changes on financial buys increased energy purchases by $140.3 million due to decreasing forward Ontario pool prices from 2005 to 2006. Unrealized fair value changes in derivative financial instruments recorded for accounting purposes are not necessarily representative of the economic value of these instruments when considered in conjunction with any related economically hedged item such as future power supply. (See Derivative Financial Instruments).

	2006	2005[1]
Retail sales		
Electricity (000s of megawatt-hours)		
RRT	5,710	5,520
Default	872	904
Competitive	3,582	6,671
	10,164	13,095
Natural gas (000s of gigajoules)	2,044	3,634

(1) Restated for final load settlement results received in 2006 for 2005.

	2006	2005
Energy supply (MWh)		
Battle River PPA generation	2,253	3,107
Sundance PPA generation	2,828	3,352
	5,081	6,459
Calpine short-term tolling arrangement	715	-
	5,796	6,459

In 2006, our core Energy Services business performed well. The short-term Calpine tolling arrangements that were put in place for nine months of 2006 contributed positively to earnings and our ability to manage our energy position. Overall customer sales volumes declined in 2006 from 2005 due to the sale of certain competitive contracts in 2005. Power retail sales volumes for RRT, default and large industrial customers remained consistent from 2005 to 2006.

In 2006, we began re-positioning our power portfolio by selling interests in our Battle River and Sundance PPAs. The sale of additional interests in Battle River from 2007 to 2010 will further reduce our power supply volumes which will be replaced over time with new production from the Clover Bar and Keephills 3 facilities when they come on line.

Energy Services will continue to play a key role in EPCOR's growth as it continues to pursue opportunities with large commercial and industrial customers and manage EPCOR's electricity and natural gas portfolios. As new generation assets are added to EPCOR's fleet, Energy Services will contract with Generation for the capacity of the new assets and optimize the value of those investments by selling the electricity to the market or end-use customers. Energy Services is also working to add value to existing operations by identifying opportunities for marketing electricity in each region. In January 2007, Energy Services reorganized certain subsidiaries. As a result, a future income tax asset of approximately $11.9 million and a reduction of income tax expense, will be recorded in the first quarter of 2007.

Water Services

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

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

Water Services operating income

		2006	2005
Water Services results			
(including intersegment transactions, $ millions)			
Revenues	Water sales	$ 119.1	$ 111.9
	Commercial and other	85.6	101.9
		204.7	213.8
Expenses	Operations, maintenance, administration and foreign exchange	125.2	136.6
	Franchise fees and taxes other than income taxes	8.1	7.7
	Depreciation, amortization and asset retirement accretion	16.5	15.3
		149.8	159.6
Operating income before corporate charges		54.9	54.2
Corporate charges		10.6	8.8
Operating income		**$ 44.3**	**$ 45.4**

Operating income for the year ended December 31, 2005	**$**	**45.4**
Higher water sales		7.2
Higher depreciation expense		(1.2)
Write-down of venture capital investment		(2.0)
Higher operations, maintenance administration and other		(5.1)
Decrease in operating income		(1.1)
Operating income for the year ended December 31, 2006	**$**	**44.3**

Water sales were higher in 2006 compared to 2005 primarily due to a rate increase in the second quarter of 2006. Maintenance costs were higher in 2006 than in 2005 due to an increase in water main breaks. Depreciation expense also increased year over year due to an increase in the depreciable asset base. In addition, a water venture investment was written down to reflect a permanent decline in value.

For the year ended December 31, 2006, Water Services revenues and expenses decreased by $9.1 million and $8.0 million, respectively, from the prior year primarily due to decreased commercial construction services as a number of construction projects were completed in 2005. Water Services generates revenue and incurs expenses to construct water treatment facilities for municipal and provincial customers. Wastewater treatment plants for the District of Sooke in British Columbia and for the Britannia Mine site north of Vancouver, British Columbia were substantially completed in 2005 and the wastewater collection system for the District of Sooke was completed in March, 2006.

	2006	2005
Water volumes for the City of Edmonton and surrounding region		
Water sales (megalitres)	125,106	121,083

EPCOR owns four and operates thirteen water treatment and distribution facilities as well as operating sixteen waste water and distribution facilities in Alberta and British Columbia. Our core market is stable as we are the sole supplier of water within Edmonton. In 2006, we saw a slight increase in water volumes, primarily due to population growth in the Edmonton region. Operationally, the facilities we own and/or manage performed well in both 2005 and 2006.

The most significant upcoming change that will impact Water Services is the completion of the EL Smith water treatment plant expansion, which will provide water capacity necessary to meet the anticipated growth in the City of Edmonton. This asset will be added to Water's rate base upon completion and will be reflected in PBR rates resulting in additional cash flow and earnings to EPCOR. That expansion is scheduled for completion in 2009.

CONSOLIDATED BALANCE SHEETS

Significant changes in consolidated assets are outlined below:

	December 31, 2006	December 31, 2005	Increase (decrease) $ millions	Explanation
Cash and cash equivalents	$ 260.3	$ 90.0	$ 170.3	Refer to cash flows summary below.
Accounts receivable (including income taxes recoverable)	643.9	593.8	50.1	Reflects increase in receivables for the PPAs, Genesee 3 due to timing of receipts and the acquisition of PEV.
Derivative financial instruments asset (current)	25.9	57.9	(32.0)	Reflects decreased Ontario forward prices on positions offset by de-designation of Power LP's foreign exchange derivatives which are recognized at fair value in the balance sheet.
Other current assets	72.3	57.0	15.3	Reflects increases in inventory for planned maintenance and repairs and acquisition of PEV.
Property, plant and equipment	3,906.1	3,698.3	207.8	Reflects the PEV acquisition and capital expenditures in excess of depreciation and amortization expense.
Power purchase arrangements	757.5	632.8	124.7	Reflects the acquisition of interests in Battle River PPA (Sundance swap) and the PEV acquisition, offset by amortization.
Contract and customer rights and other intangible assets	201.8	196.4	5.4	Reflects the PEV acquisition, offset by amortization.
Derivative financial instrument asset (non-current)	20.2	39.9	(19.7)	Reflects decreased Ontario forward prices on positions offset by de-designation of Power LP's foreign exchange derivatives which are recognized at fair value in the balance sheet.
Future income tax asset (non-current)	126.9	87.7	39.2	Reflects additional deductions available for income tax purposes resulting from the Generation reorganization.
Goodwill	182.7	148.5	34.2	Reflects goodwill from the acquisition of PEV.
Other assets	185.7	61.5	124.2	Reflects long-term note receivables issued to PPA syndicate members on sale of interest in the Sundance PSA and the PEV acquisition.

Significant changes in consolidated liabilities and shareholder's equity are outlined below:				
	December 31, 2006	**December 31, 2005**	**Increase (decrease) $ millions**	**Explanation**
Short-term debt	$ 216.3	$ 28.5	$ 187.8	Reflects Power LP's new borrowing under its bridge acquisition credit facility, offset by repayment of commercial paper.
Derivative financial instruments liability (current)	24.2	59.1	(34.9)	Reflects decreased Ontario forward prices partly offset by increased Alberta forward prices on positions which are recognized at fair value in the balance sheet.
Accounts payable and accrued liabilities	603.2	507.3	95.9	Reflects acquisition of PEV and timing of payments to AESO and wire service providers.
Other current liabilities	128.4	51.2	77.2	Reflects increase in future income taxes for the gain on the Battle River PSA and related transactions.
Long-term debt (including current portion)	2,178.6	2,082.7	95.9	Reflects new borrowings under Power LP's credit facilities for the acquisition of PEV, offset by ongoing scheduled debt repayments and repayment of US long-term financing.
Derivative financial instruments liability (non-current)	26.8	45.2	(18.4)	Reflects decreased Ontario forward prices and favourable impact of forward prices on the Joffre CfD, offset by the deferral of foreign exchange derivatives upon de-designation for accounting purposes and higher forward Alberta pool prices on positions which are recognized at fair value in the balance sheet.
Future income tax liability (non-current)	80.5	98.6	(18.1)	Reflects the acquisition of PEV.
Other non-current liabilities	132.1	146.6	(14.5)	Reflects decreased deferred incentives on generation units operating under PPAs and a reduced asset retirement obligation for the Clover Bar generation facility.
Non-controlling interests	750.6	887.2	(136.6)	Reflects redemption of $150 million of preferred shares and Power LP distributions to non-controlling interests, offset by non-controlling interests' share of Power LP earnings and issue of partnership units.
Shareholder's equity	2,242.6	1,757.4	485.2	Reflects net income offset by common share dividends.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Cash inflows (outflows) and cash position are summarized below:

	$millions					
	Year ended December 31					
	2006	**2005**	**Change**	**2005**	**2004**	**Change**
Operating	$ 581.2	$ 466.2	$ 115.0	$ 466.2	$ 438.4	$ 27.8
Investing	(294.2)	(751.4)	457.2	(751.4)	(46.8)	(704.6)
Financing	(116.7)	(80.5)	(36.2)	(80.5)	(350.4)	269.9
Opening cash and cash equivalents	90.0	455.7	(365.7)	455.7	414.5	41.2
Closing cash and cash equivalents	$ 260.3	$ 90.0	$ 170.3	$ 90.0	$ 455.7	$ (365.7)

Operating changes:

The 2005 to 2006 increase in cash inflows reflects the full year impact of Power LP ownership and changes in non-cash working capital due to the timing of receipts and payments, offset by receipt of the Clover Bar PPA termination payment in 2005.

Investing changes:

The 2005 to 2006 decrease in investing activities reflects the investment in Power LP in 2005 compared with the lower investments in 2006, including the Power LP's purchase of PEV, net of proceeds on sale of a partial interest in the Battle River PPA.

Financing changes:

The 2005 to 2006 increase in financing outflows reflects redemption of preferred shares and higher distributions to non-controlling interest in Power LP in 2006, and higher long-term debt issues in 2005. These increases were partly offset by higher short-term borrowings and the issue of Power LP partnership units to non-controlling interests in 2006.

LIQUIDITY AND CAPITAL RESOURCES

($millions)	2006	2005	2004
Cash flow from operations[1]	$ 556.7	$ 519.9	$ 385.2
Long-term borrowings during the year	405.7	200.0	-
Cash and cash equivalents, at end of year	260.3	90.0	455.7
Short-term debt, at end of year	(216.3)	(28.5)	-
Ratios[1]			
Debt to equity[2]	45:55	44:56	44:56
Interest coverage (excluding gain on sale of PPA and related transactions) on long-term debt:			
Income before financing and taxes[3]	3.0 X	3.4 X	2.8 X
Income from continuing operations before financing and taxes [4]	2.9 X	3.0 X	2.6 X
Income before financing, taxes, depreciation and amortization[5]	4.4 X	5.1 X	4.0 X
Income from continuing operations before financing, taxes, depreciation and amortization[6]	4.3 X	4.3 X	3.7 X
Cash flow to interest bearing debt (%)[7]	23.2	24.5	24.0
Credit ratings[8]			
Standard & Poor's			
Long-term debt	BBB+	BBB+	BBB+
Preferred shares of subsidiary companies	P-2 (Low)	P-2 (Low)	P-2 (Low)
Dominion Bond Rating Service			
Short-term debt	R-1 (low)	R-1 (low)	R-1 (low)
Long-term debt	A (low)	A (low)	A (low)
Preferred shares of subsidiary companies	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)

(1) Cash flow from operations and ratios in this table are non-GAAP financial measures, do not have any standardized meaning prescribed by GAAP and are unlikely to be comparable to similar statistics published by other companies. They are presented since they are commonly referred to by debt holders and other interested parties in evaluating the Company's financial position and in assessing its credit worthiness. Refer to the section, Non-GAAP Financial Measures for a reconciliation of cash flow from operations to cash flow from operating activities.

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

(3) Revenue less operating expenses, for continuing and discontinued operations, divided by interest on long-term debt and capital lease obligation for continuing and discontinued operations.

(4) Revenue less operating expenses, for continuing operations, divided by interest on long-term debt and capital lease obligation for continuing operations.

(5) Revenue less operating expenses excluding depreciation, amortization and asset retirement accretion, for continuing and discontinued operations, divided by interest on long-term debt and capital lease obligation for continuing and discontinued operations.

(6) Revenue less operating expenses excluding depreciation, amortization and asset retirement accretion, for continuing operations divided by interest on long-term debt and capital lease obligation for continuing operations.

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

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

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

Acquisition financing

On April 27, 2006, Power LP issued subscription receipts to provide part of the funding for its acquisition of the Frederickson power facility from EPCOR. On August 1, 2006, the date of the sale, the subscription receipts were converted to limited partnership units of Power LP for net proceeds of $79.9 million. EPCOR retained its 30.6% interest in Power LP by acquiring 30.6% of the subscription receipts issue. The balance of the purchase price for the facility was financed by $32.0 million (US $27.5 million) committed lines of credit and cash on hand.

Coincident with the sale of the Frederickson facility on August 1, 2006, EPCOR repaid $87.4 million (US $77.0.million) outstanding under its three-year extendible credit facility, which had been drawn to hedge its investment in this US operation.

On each of September 22, 2006 and October 2, 2006 Power LP secured a $100.0 million, three-year revolving extendible bank credit facility. In anticipation of the PEV acquisition, Power LP entered into two single-purpose non-revolving bridge credit facilities, one for a one-year term and one for a three-year term. Power LP's acquisition of PEV on November 1, 2006 for $370.4 million (US $329.9 million) was financed by $257.8 million (US $229.6 million) drawn under the bridge credit facilities, $112.3 million (US $100.0 million) drawn under the two revolving credit facilities and the balance in cash.

Other financing

On February 14, 2006 EPCOR replaced its one-year $200.0 million, two-year $300.0 million and three-year $300.0 million syndicated bank credit facilities with a single $800.0 million extendible syndicated bank credit facility consisting of a three-year $400.0 million tranche and a five-year $400.0 million tranche. On April 13, 2006 the Company entered into an additional $100.0 million, two-year revolving, extendible bank credit facility. On May 18, 2006, the Company entered into three more $100.0 million two-year revolving extendible bank credit facilities.

On June 23, 2006, Power LP issued senior unsecured medium term notes for a principal amount of $210.0 million. The notes have a coupon rate of 5.95% and mature in June, 2036. The net proceeds of the offering were used to repay Power LP's $210.0 million credit facility.

At December 31, 2006 the Company's bank lines of credit were as follows.

($ millions) December 31,	2006	2005	2006	2005
	EPCOR		Power LP	
Bank lines of credit – committed	$ 1,200.0	$ 800.0	$ 467.6	$ 260.0
Bank lines of credit – uncommitted	25.0	50.0	20.0	-
	1,225.0	850.0	487.6	260.0
Outstanding loans	-	(98.3)	(420.4)	(210.0)
Letter of credit outstanding	(236.2)	(153.9)	(11.6)	-
Bank lines of credit available	$ 988.8	$ 597.8	$ 55.6	$ 50.0

Committed bank lines are used principally for the purpose of providing capital and letters of credit. Letters of credit are issued to meet conditions of certain debt and service agreements, and to satisfy legislated reclamation requirements. The committed bank lines also back the Company's commercial paper program which has an authorized capacity of $500.0 million, although no commercial paper was outstanding at December 31, 2006 (2005 - $28.5 million).

EPCOR's dividend policy for the common shares owned by the City of Edmonton has remained unchanged since 2000. Under the policy, the annual dividend is set at the greater of the previous year's dividend adjusted for the forecast change in the consumer price index, and 60% of the current year's earnings available to the common shareholder. This policy is subject to amendment in the event of a significant change in EPCOR's business or financial condition. Dividends for the year are generally established in the fall of the previous year based on forecast earnings. In accordance with the policy, the annual dividends for 2006 were $125.1 million (2005 - $122.7).

Power LP paid $85.1 million (2005 - $20.7 million, from the date of acquisition) of distributions to the non-controlling unit holders.

EPCOR paid preferred share dividends and related income taxes of $17.0 million (2005 - $21.5 million). The decrease from 2005 was due to the redemption of six million preferred shares at their stated redemption price for $150.0 million cash on June 30, 2006.

Operating activities

Cash flow from operating activities, which includes changes in non-cash working capital, increased to $581.2 million in 2006 from $466.2 million in 2005. The increase consisted of full year earnings of the Power LP and changes in working capital partly offset by the receipt of the Clover Bar PPA termination payment in 2005. Working capital requirements for 2007 are expected to be substantially the same as in 2006.

2007 cash requirements

In 2007, cash requirements will include operating expenditures, capital maintenance, new capital projects and investments, preferred and common share dividends, Power LP distributions and debt repayments.

In December 2006, the Company announced that the EUB had approved our proposal to construct three natural gas fired peaking power generation units for an aggregate gross generating capacity of 240 MW at our Clover Bar site in northeast Edmonton. EPCOR expects construction to be complete by 2010 for an estimated cost of $245.0 million.

Total capital expenditures in 2007 are expected to be in the $800.0 million to $900.0 million range, which can vary materially depending on project schedules and scope changes, new opportunities that emerge and material and labour cost escalation. Key new projects include Clover Bar, Keephills 3, E.L. Smith and a high voltage transmission line in the City of Edmonton. Scheduled debt repayments for 2007 are anticipated to be approximately $58.6 million of long-term debt and $216.3 million of short-term debt and common and preferred share dividends are expected to be $127.6 million and $11.9 million, respectively. Power LP’s 2007 cash distributions will be as determined by the Board of Directors of the general partner. If total cash requirements remain as planned, the sources of capital will be from cash on hand, operating cash flows, existing credit facilities, public equity markets (Power LP) and new public debt borrowings.

In December 2006, we announced that we were re-examining the project design and schedule of the Kingsbridge II project. The original project commitment estimate of $300 million is currently under review and will likely be at least $350.0 million based on current rates for construction costs.

On February 26, 2007, EPCOR and TransAlta announced the decision to proceed with the building of Keephills 3, a 450 MW supercritical coal plant at TransAlta’s Keephills Site, about 70 kilometers west of Edmonton. EPCOR and TransAlta will be equal partners in the ownership of Keephills 3. The project is estimated to be completed in 2011 with a total capital cost of $1.6 billion. We estimate our commitment for 2007 at approximately $200.0 million.

Credit ratings

In 2006, Standard & Poor’s reaffirmed EPCOR’s credit rating for long-term debt at BBB+. Dominion Bond Rating Service’s recent rating remained unchanged at A(low). A rating change for EPCOR would likely impact interest costs on new borrowings and the availability of sources of investment capital.

CONTRACTUAL OBLIGATIONS

$millions	Payments due by period					
	2007	2008	2009	2010	2011 and thereafter	Total
Acquired PPA obligations[1]	$ 141.1	$ 124.5	$ 106.0	$ 81.3	$ 973.4	$ 1,426.3
Capital projects[2]	95.7	34.5	-	-	-	130.2
Natural gas purchase contracts[3]	40.6	45.8	47.9	46.7	300.7	481.7
Loan commitments	13.4	-	-	-	6.1	19.5
Natural gas transportation contracts[4]	13.2	14.0	14.9	15.0	110.3	167.4
Long-term debt	58.6	237.6	218.8	225.8	1,437.8	2,178.6
Interest on long-term debt	193.5	184.0	152.1	133.5	1,042.7	1,705.8
Short-term debt	216.3					216.3
Capital leases	11.5	11.1	11.2	12.2	67.4	113.4
Operating leases	2.5	2.9	2.7	2.5	0.4	11.0
Waste heat contracts[5]	0.8	0.8	0.8	0.9	5.4	8.7
Other purchase obligations	10.6	6.0	5.2	1.9	0.8	24.5
Total contractual obligations	$ 797.8	$ 661.2	$ 559.6	$ 519.8	$ 3,945.0	$ 6,483.5

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

(2) EPCOR's obligation to construct the Kingsbridge II wind-power generation facility is not included as the project design and schedule are being re-examined. In 2005, when the contract with the Ontario Power Authority was entered into, the estimated commitment was $300.0 million.

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

(4) The natural gas transportation contracts are based on estimates subject to changes in regulated rates for transportation and have expiry dates ranging from 2010 to 2016.

(5) Waste heat contracts continue while the Power LP plants in Ontario are in operation. Prices are escalated yearly by the prior year's Consumer Price Index.

In the normal course of business, EPCOR provides financial support and performance assurances, including guarantees, letters of credit and surety bonds, to third parties in respect of its subsidiaries. The liabilities associated with these underlying subsidiary obligations are included in the consolidated balance sheet. In connection with the sale of Alberta mass-market competitive contracts to Alberta Energy Savings L.P. ("AESLP"), effective February 1, 2005, EPCOR made arrangements to provide AESLP's prudential obligations with AESO and Alberta's wire service providers and gas distributors. On December 31, 2006, prudential posted under this arrangement was $35.6 million (2005 - $40.0 million). EPCOR has also agreed to indemnify certain liabilities of UE Waterheater Income Fund ("the Fund") until 2010 primarily consisting of potential tax and other liabilities that could arise relating to operations of the water heater rental business prior to the 2003 sale by EPCOR to the Fund. Any known liabilities associated with this indemnification have been recorded at December 31, 2006 and it is uncertain what, if any, additional amounts may be incurred in the future.

In connection with the Keephills 3 project announced on February 26, 2007, EPCOR is committed for 50% of the capital costs of the project and expects to incur about $200.0 million of those costs in 2007. EPCOR and TransAlta have indemnified each other during the construction period for up to $115.0 million each in the event that either party makes payments to the turbine supplier on behalf of the other party.

We have also committed to constructing a high voltage transmission line and substation over the next two years at an estimated cost of $82.4 million.

As part of the agreement for the Sundance Swap, we committed to providing interest-free notes of approximately $19.5 million to the counterparties to fund the income tax liabilities that they incur on the disposition of their interests in the Battle River PSA. We expect to advance approximately $13.4 million in the first quarter 2007, to be repaid in annual instalments to 2020. The amount and timing of any additional advances under this commitment are not known.

There were no other material guarantee obligations outstanding in respect of third parties and no significant liquidity risks with respect to the Company's financial instruments at December 31, 2006.

OUTLOOK

In 2006, we executed on our growth strategy by announcing the new Clover Bar power development and acquiring Primary Energy Ventures through Power LP. In February 2007, we announced, with TransAlta, our decision to jointly build Keephills 3. These initiatives provide additional diversification to both our investment portfolio and geographic footprint. The focus for 2007 will be on operational excellence, execution of development projects and integration of PEV.

The North American power industry requires investment in new generation to address shrinking reserve capacity, and in transmission to compensate for the past decade's under-investment and to fulfill new requirements to connect remote renewable generation. However, actual development of new generation has been challenged by concerns regarding fuel choices because of the volatility in natural gas prices and legislative uncertainty with respect to air emissions. Although growth is therefore expected in wind, solar, biomass and geothermal energy production, the majority of new generation in North America is expected to come from natural gas and coal in the near term.

Environmental policy development and discussion is increasing across North America and around the world. These debates are important for EPCOR and our challenge is to ensure that we help satisfy the growing demand for energy in an environmentally responsible way. We expect that new stringent emission standards will evolve and could have a material impact on

EPCOR's operations.

Across North America, we expect a continuation of the mix of deregulated and regulated markets. Opportunities continue to emerge in the form of government request for proposals, contracting opportunities with regulated utilities in the U.S. and sales of isolated generation assets.

Water is another topic of increasing public interest although the water market is lagging those discussions. In Canada, the general public has been slow to support significant public private partnerships. However, EPCOR has been successful in working with municipalities who recognize our strong capabilities in managing water systems. Long term water availability and increasing water quality standards will continue to increase third party participation as municipalities face pressure to upgrade their infrastructures.

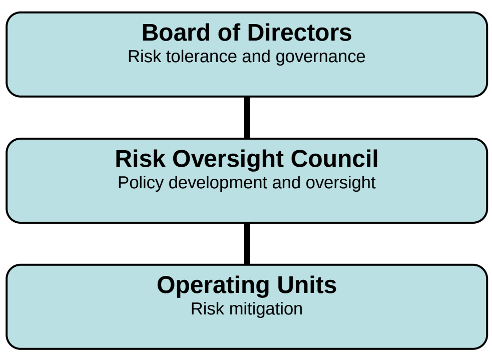
Our strategy of developing new power generation with varied fuels and improving our existing power and water operations remains.

In 2007, our earnings are expected to be lower as they will not benefit from large gains similar to the sale of the 55% interest in the Battle River PPA or the tax benefit of the generation reorganization in 2006. Other factors that will impact 2007 include:

- The full year of earnings from PEV and the Kingsbridge I wind power project.
- Planned outages at the Genesee site required by the AESO to accommodate generator transformer upgrades.
- Recognition of future income tax assets associated with an internal reorganization on January 1, 2007 that made a previously tax exempt subsidiary taxable.
- Contract termination costs associated with Kingsbridge II.

RISK MANAGEMENT

Approach to risk management



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

Electricity price and volume risk

We buy and sell electricity in the wholesale markets of Alberta, Ontario, and the United States. Such exchanges are settled at the spot market prices of the respective markets. We currently use purchase and sale arrangements including contracts-for-differences and firm price physical contracts for periods of varying duration to manage our exposure to spot price variability within specified risk limits. Due to limited market liquidity and the varying shape of electricity consumption during peak usage hours compared with off-peak usage hours, it is not possible to hedge all positions every hour. We balance our electricity position within the limits of our policies and generally trade in electricity to reduce the Company's exposure to changes in electricity prices or to match physical or financial obligations. A limited portion of our trading is directed at optimizing our electricity position.

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

Electricity sales associated with EPCOR's Genesee 1 and Genesee 2 units are governed by the terms of the associated PPAs. These sales are accounted for as long-term, fixed margin contracts, which generally limit the impact of swings in wholesale spot electricity prices, unless plant availability drops significantly below the PPA target availability for an extended period. Our other plants, such as Brown Lake, Miller Creek, and Kingsbridge 1 operate under long-term commercial contracts with credit worthy counterparties. Our 40% interest in the Joffre cogeneration facility is governed by a long-term contract but its operations are subject to market price variability since there are provisions in the commercial contract that require the facility to run to provide steam to the host facility, irrespective of market prices. Our 50% interest in Genesee 3 is not covered by a long-term commercial contract; however, as a base-loaded coal fired generating unit, with a relatively low variable cost, it will generally run when it is available. It is subject to spot price exposure when those prices are below its price for corresponding variable costs or the unit suffers an unplanned outage. Since its commissioning, the occasions when Alberta electricity prices have been below Genesee 3's variable cost have been very limited and the plant has operated above our expectations.

Electricity price and volume risks for Power LP, including the PEV plants acquired in November 2006, are lower than they would be in a merchant environment since each of the facilities operates under long-term power sales contracts with investment-grade power buyers, including Ontario Electricity Financial Corporation, British Columbia Hydro and Power Authority, Public Service Company of Colorado, San Diego Gas and Electric Company, the U.S. Navy, and Carolina Power & Light Company.

Although commercial contracts provide better electricity price and volume protection than if the plant operations were completely subject to spot market risk, the contract provisions must be met and the Company can incur charges in the event of unplanned outages or variations from the contract performance benchmarks.

Natural gas price and volume risk

Price risk associated with natural gas purchased for our natural gas-fired generation plants operating under commercial contracts is mitigated by the provisions of the contracts which generally require the contract power buyer to pay the generator a market indexed price or buy the gas outright on behalf of the plant. Natural gas price risk associated with the Joffre cogeneration plant is partially flowed through to its electricity sale prices which partially depend on the natural gas price. For Power LP's natural gas-fired plants, the natural gas price risks have been minimized by executing fixed-price long-term contracts for a significant portion of the supply of natural gas or through the use of tolling agreements. However, certain Power LP plants are at risk for the fuel supply beyond the fixed price contract term if it expires before the termination of the power purchase arrangement. For example, for its Tunis Plant, Power LP is exposed to commodity prices risk on its natural gas purchases commencing with the expiry of its natural gas contract in 2010 and until the expiry of the PPA in 2014. Similar exposures exist for shorter periods at other Power LP plants. We will attempt to bridge these gaps by securing new natural gas contracts when the existing contracts expire.

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

The initial term of a block of natural gas contracts that we acquired in 2000 expired in late 2004. The customers under these contracts had an option to renew at the original contracted price and approximately 56% did so. Due to the relatively low embedded contract price, EPCOR will experience losses on servicing these contracts which are estimated to be up to

$8.0 million over the remaining three years, depending on future natural gas prices. As we are no longer active in the retail natural gas market we will continue to seek opportunities to exit from these contracts.

Commodity risk measures and limits

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

We use Value-at-Risk ("VaR") to measure the risk in our energy commodity portfolio. VaR is the maximum expected loss over a given period of time at a given level of confidence. Our VaR is calculated at a 95% statistical confidence level over a holding period of 20 business days. In other words, at the time it is measured, there is a one in 20 chance that the fair value of our commodity portfolio could change by an amount in excess of the VaR amount, over a 20 day period commencing from the point in time that it is measured. The VaR calculation incorporates price volatilities, correlations and forward prices as major input variables. As VaR is not a perfect measure of risk, we apply a factor to the calculated VaR amount to attempt to capture unaccounted for exposures. The resulting measure is referred to as the "Total Exposure" of the portfolio. EPCOR's one year total electricity and natural gas exposure, excluding contracted operations such as those of Power LP, as at December 31, 2006 was $19.8 million (2005 - $16.7 million).

To supplement the Total Exposure estimates, we use stress-testing and scenario analysis on the electricity and natural gas portfolios by applying plausible but unlikely adverse market conditions and movements. This testing is used to determine the resulting financial effects on the portfolios in relation to the Company's Total Exposure limits. We have also adopted a series of operational limits for our energy trading operations, including position limits, transaction limits and stop loss limits. Key risk measures in relation to the applicable limits are reported daily to Risk Oversight Council and quarterly to the Board of Directors.

Operational risk

The ability of EPCOR's power plants to generate the expected amount of electricity that will be sold under contract or to the applicable market has a significant impact on the revenues of the Company. If a power plant delivers less than the required quantities of electricity in a given month, revenue may be insufficient to cover contractual or financial obligations.

Our plant operations are susceptible to outages due to equipment failure, which could make plants unavailable to provide service. This is also true for the generation units associated with the acquired PPAs. Such risks are partially mitigated by our, and the acquired PPA plant owners' operating and maintenance practices that are intended to minimize the likelihood of prolonged unplanned down time. We have a very strong record of availability, as measured against our peers by the Canadian Electricity Association. In addition, the penalty provisions within the PPAs provide appropriate incentives to owners to keep the plants well maintained and operational. The terms of the PPAs also provide force majeure protection for high-impact, low probability events including major equipment failures. Our maintenance practices are augmented by the maintenance of an inventory of strategic spare parts, which can reduce down time considerably in the event of failure. Finally, we have secured appropriate business interruption insurance to reduce the impact of prolonged outages at Genesee, Sundance, Battle River, Frederickson and the Power LP plants caused by insured events.

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

Fuel expense for the Genesee plants is predominantly comprised of coal supply. Coal is supplied under long-term agreements with the Genesee Coal Mine joint venture, of which we hold a 50% interest. The price of coal is based on a cost-of-service model with annual updates to inflation, interest rate and capital budget parameters and is, therefore, not subject to coal market price volatility. EPCOR and the Genesee Coal Mine joint venture maintain coal inventories which are available as fuel supply in the event that the coal mine equipment and operations suffer significant disruption. Power LP's coal-fired power plants (Roxboro and Southport) purchase coal and coal-based fuel from local suppliers in the southeast U.S. The coal and coal-based fuel is transported to the power plants by rail service. Any disruption in rail service due to unforeseen circumstances could impair the operations of the coal-fired power plants if alternative transportation cannot be arranged in a timely manner.

The level of waste heat fuel at the Power LP Ontario plants provided by TransCanada Corporation's adjacent compressor stations is dependent upon the amount of natural gas throughput on the pipeline and the output of the compressor stations. In addition, the availability of waste heat gases is dependent upon the compressor stations remaining in use and their ability to supply the waste heat gases.

Performance of our hydroelectric facilities is dependent upon the availability of water. Variances in water flows are caused by uncontrollable weather-related factors affecting precipitation and could result in volatility of hydroelectric plant revenues. In addition, the hydroelectric facilities are exposed to potential dam failure, which could affect water flows and have an impact on revenues from the associated plants.

We manage the wood waste fuel risk at Power LP's biomass and wood waste plants through contracts with a number of wood waste suppliers. Two wood suppliers ceased operations in 2006 due to a mill closure and a fire, but we are actively pursuing additional long-term replacements for the displaced supply.

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

We maintain an Accounting and Auditing Complaints policy which provides for confidential disclosure of any wrong-doing relating to accounting, reporting and auditing matters.

Government and regulatory risk

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

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

In March 2005, EPCOR filed regulatory tariff applications with the AEUB for the years 2005 and 2006 for its Distribution and Transmission operations and for its RRT non-energy charges. Final rates for 2005 and 2006 were set by the AEUB in 2006. EPCOR will file its next set of tariff applications in 2007 for its 2007 – 2009 tariffs. The application process has risks customarily associated with rate-regulated tariff filings. The AEUB sets rates intended to permit regulated entities to recover estimated costs of providing service and a fair rate of return on investment in distribution and transmission and RRT assets. Our ability to recover the actual costs of providing service and to earn a fair return on investment is dependent on achieving the forecasts established in the rate-setting process.

On June 8, 2005, the Government of Alberta announced a new 5-year Regulated Rate Option ("RRO") for residential, farm and small commercial Alberta electricity consumers. The new RRO replaced the prior Regulated Rate Tariff which expired on June 30, 2006 and regulates our charges to these customers for energy. The RRO became the default option for consumers in the aforementioned customer segments who have not entered into contracts with an electricity retailer. Starting on July 1, 2006, the new RRO was implemented, which uses a combination of long-term and monthly forward hedges, with an increasing percentage of monthly forward hedges over the five-year transition period. At the end of the transition period in 2010, the new RRO is intended to be similar to the design of the current natural gas default rate, which is based on monthly forward prices. As this electricity pricing model results in increasing volatility in prices to our customers over the transition period, it may impact our volume of electricity sales, as well as electricity margins. However, it is too early in the transition process to determine the future financial impact to EPCOR. We currently provide approximately 55% of the Regulated Retail Tariff load within the province of Alberta.

On December 9, 2004, the Minister of Energy for the Province of Ontario introduced new regulations in respect of the rebate mechanism to electricity consumers which effectively fixes the prices for electricity. The impact to retailers who had existing fixed price contracts in place with customers was to prospectively reduce the rebate due to the retailer. Notwithstanding this change, the Ontario government pledged to compensate retailers for any shortfall between the rebate mechanism in place prior to December 9, 2004 and the replacement rebate mechanism for those fixed price contracts in place at that time. At December 31, 2006, we had recorded approximately $12.4 million due from the Ontario government with respect to this rebate and expect to receive full settlement by April 30, 2007.

Proposed tax changes

On October 31, 2006, the Minister of Finance (Canada) ("Finance") announced the “Tax Fairness Plan” which proposed changes (the “2006 Proposed Rules”) to the manner in which certain publicly traded trusts and partnerships (“SIFTs”) are taxed. On December 21, 2006, Finance released draft amendments to the *Income Tax Act* (Canada) (the "Tax Act") to implement the 2006 Proposed Rules. The 2006 Proposed Rules generally operate to apply a tax at the limited partnership level on certain income of SIFTs, such as Power LP, at rates of tax comparable to the combined federal and provincial corporate tax and to re-characterize that income as taxable dividends in the hands of SIFT unit holders.

The 2006 Proposed Rules indicate that they will apply to SIFTs, the units of which were publicly-traded before November 1, 2006, beginning with the 2011 taxation year of the SIFT. However, Finance indicated in their announcement of the 2006 Proposed Rules that while there was no intention to prevent existing SIFTs from pursuing normal growth prior to 2011; any "undue expansion" could result in an acceleration of the effective date for that SIFT. On December 15, 2006, Finance issued Guidelines on the meaning of "undue expansion" and "normal growth". The Guidelines indicate that no change will be recommended to the 2011 date in respect of any SIFT whose equity capital grows as a result of issuances of new equity before 2011, by an amount that does not exceed an objective "safe harbour" amount based on a percentage of the SIFT's market capitalization as of the end of trading on October 31, 2006. EPCOR is currently considering the possible impact of the Proposed Rules on Power LP and appropriate mitigation strategies, however, the Power LP expects that it can issue up to $1,878.0 million of new equity before 2011 without accelerating the date that it becomes subject to the Proposed Rules assuming they are enacted in their current form.

The Proposed Rules were not substantively enacted at December 31, 2006, but substantive enactment of the Proposed Rules will require recognition of future income tax amounts based on estimated net taxable temporary differences that will reverse after 2010 and for which no tax has been recorded in the consolidated statements. Accordingly, future income tax expense and a net future income tax liability are expected to be recognized at the date the Proposed Rules become substantively enacted but they are not expected to be material.

The 2006 Proposed Rules may have an adverse impact on Power LP, its unit holders and the value of the units.

On March 19, 2007, Finance tabled its 2007 federal budget, which included proposals for additional changes to the Tax Act, including restrictions on the deductibility of interest expense related to investments in foreign affiliates and revised capital cost allowance rates for certain asset categories. We are examining the proposed changes but given the limited amount of time since the budget was tabled, we are currently unable to provide an assessment of their potential impact on EPCOR.

Supply risk of Alberta PPAs

EPCOR holds interests in acquired PPAs, which entitle the Company to its proportionate interest in the electricity produced from specific generating units up to their committed capacity. In most cases where plant capability falls below committed capacity, we are entitled to receive our relative portion of the availability payments from the plant owners based on the 30-day rolling average power pool prices and target availability. The occurrence of an event which disrupts the ability of the power plants to produce or sell power or thermal energy for an extended period under the PPAs, including events which preclude the subsequent purchasers from fulfilling their obligation under the PPAs, could have a material negative impact on our ability to generate revenue. In such circumstances, we would be required to replace electricity that became unavailable at market rates prevailing at that time, while being relieved of the obligation to pay the unit capacity fee. Depending on market liquidity, the prices could be significantly higher than the prices inherent in the PPA, thus increasing the cost of our energy purchases.

Credit risk

Credit risk is the possible financial loss associated with the ability of counterparties to satisfy their contractual obligations to EPCOR, including payment and performance. We manage credit risk and limit exposures through our credit policies and procedures which include an established credit review process, specific terms and limits, credit diversification, daily monitoring of wholesale exposures against credit limits, appropriate allowance provisioning and the use of credit mitigation strategies, including collateral arrangements.

For wholesale energy counterparties, credit risk is measured by estimating the costs (or proceeds) of replacing the commodity position, represented by physical or derivative contracts, adjusting for settlement amounts due to or due from the counterparty and netting amounts, if permitted under legally enforceable set-off rights.

For residential and commercial customers under regulated or default power rates, credit exposures are generally restricted to amounts owed from the customers.

The distribution of wholesale and end-use credit risk for EPCOR is summarized below:

December 31 ($millions)	2006	2005
Wholesale (includes industrial end-use customers, trading and position management counterparties)		
Investment grade[1]	$ 116	$ 272
Below investment grade[1]	14	82
Unrated regulated residential, small commercial and default supply customers[2]	151	118
Total	$ 281	$ 472

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

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

Due to the volatility of the wholesale prices of electricity and natural gas, the market value of individual credit exposures could exceed the credit limits granted to those wholesale counterparties. If the counterparty were to fail to perform its obligations, such as delivering electricity, EPCOR could incur a material loss including the cost of replacing the obligation, any loss on amounts owed from the counterparty or any losses incurred on liability settlements.

For RRT and commercial customers operating under default rates, the portfolio is reasonably well diversified with no significant credit concentrations. Historically, credit losses in these customer segments have not been significant and depend in large measure, on the strength of the economy and the ability of the customers to effectively manage their operations through economic cycles and competitive pressures. Should economic conditions or market pressures decline in the regions in which we operate, we may experience additional credit losses in these segments.

The year over year decrease in the credit exposure of investment grade counterparties was due primarily to the shorter remaining terms of wholesale purchase contracts. The reduction in exposure in the below investment grade category is due to reduced term and expiry of retail contracts in the Alberta market combined with increased forward prices. In the regulated and default group, the higher exposures are driven largely by higher receivable balances than in the prior year.

Environmental risk

EPCOR's generation business is a significant emitter of carbon dioxide (a greenhouse gas), nitrogen oxides ("NO_x") and sulphur dioxide ("SO_2 "). EPCOR complies, in all material respects, with federal, provincial, state and local environmental legislation and guidelines with respect to its electricity operations. Compliance with future environmental legislation may require significant capital and operating expenditures and failure to comply could result in fines and penalties or the regulator could force the curtailment of operations.

Canada

The greenhouse gas ("GHG") reduction targets embedded in the Kyoto protocol will result in increased operating costs to EPCOR, but the amounts are uncertain as they will depend on yet to be established policies about how the targets and associated remediation costs are ultimately allocated to industry sectors, emitters and consumers. In October 2006, the federal government announced its intent to pass a Clean Air Act (“CAA”) including requirements to reduce GHG emissions. If the federal government’s proposed CAA is passed, it will likely result in a review of its 2003 National Guidelines for NO_x, SO_2 and particulate matter emissions from new generating stations. While the requirements for the electricity sector under the proposed CAA are not yet known, it is expected that a significant reduction of GHG emissions will be required.

We participate in the Clean Air Strategic Alliance (“CASA”) which has recommended to the Alberta government a framework on NO_x, SO_2, mercury and particulate emissions, for both natural gas-fired and coal-fired generation plants. It has also recommended that mercury emission standards be implemented for coal-fired generation plants. Currently there is no legislated obligation that EPCOR is required to assume for capital costs to fulfill potential mercury control requirements in Canada, however, we are developing compliance plans in anticipation of legislation.

In September 2006, EPCOR, in collaboration with the Canadian Clean Power Coalition and the Alberta Energy Research Institute, announced its participation in a $33.0 million research project to undertake a front-end engineering design study of a 400MW clean coal project. Our contribution is $11.0 million and use of the Genesee site for the study. The study is expected to be completed in 2015.

On March 8, 2007 the Government of Alberta introduced legislation that would require that all companies that emit more than 100,000 tonnes of GHGs per year must reduce their emissions intensity by 12% by July 1, 2007. Emissions intensity is a measure of emissions per unit of production. In the case of electricity generation it would be the amount of emissions per MWh. Under the proposed regulation, entities that cannot meet the reduction target may either contribute cash to a technology fund at the rate of $15 per tonne in excess of the 12% reduction, or invest in Alberta based projects that reduce or offset emissions on their behalf. EPCOR is currently assessing the impact of the proposed legislation on its operations and its current licenses and permits, which could be material.

Our water operations comply in all material respects with federal, provincial, and local environmental legislation and guidelines. These operations are controlled through stringent water treatment standards and controls covering the quality of treated water and the number, frequency and form of water quality testing, as well as mandatory improvements to the water treatment process. We are actively involved in a watershed management program, which involves the protection and management of our Edmonton water source from impurities such as soil particles, excess nutrients, fertilizers, microbiological contaminants and organic materials. Activities undertaken include river water quality monitoring, forming stakeholder partnerships to work on watershed issues, and acting as a resource and leader on quality issues of the North Saskatchewan River Basin.

United States

We continually assess the potential impact on Power LP assets of future legislation and regulatory requirements for certain air emissions under the United States’ Clean Air Act

(“US CAA”). The US CAA Clean Air Interstate Rule (“CAIR”) and Clean Air Mercury Rule (“CAMR”) will affect the Roxboro and Southport facilities in North Carolina beginning in 2009. Potential CAIR and CAMR compliance strategies are being developed and are expected to be completed by the end of 2007. The bankruptcy and shut-down of Roxboro’s steam host in 2006 could impact the future availability of SO_2 allocations needed to offset future excess emission credit purchase costs.

The Kenilworth facility in New Jersey is potentially affected by the Regional Greenhouse Gas Initiative applicable in seven New England states. The regulations are implemented on a state-by-state basis and we are monitoring New Jersey’s proposals and evaluating their impact on Power LP operations.

California has recently enacted stringent limits on greenhouse gases and is currently developing regulations to implement the program. We are monitoring the state’s progress and the features of the program to assess the financial and operational implications on Power LP’s California plants.

Compliance with future environmental legislation may require material capital and operating expenditures and failure to comply could result in fines and penalties or the regulator could force the curtailment of operations. There are significant uncertainties associated with the current legislative proposals including implementation details, their impact on current licenses and permits, and how compliance costs might be recovered through prices or shared among emitters, customers and stakeholders. Accordingly, it is not possible to provide meaningful estimates of the costs of complying with the proposed legislation or the net financial impact on EPCOR.

Project risk

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

Availability of people

Our ability to continuously operate and grow the business is dependent upon retaining and developing sufficient labor and management resources. As with most organizations, we are facing the demographic shift as large numbers of employees are expected to commence retirement over the next few years. In addition, the competition for labour and management, particularly in Alberta and British Columbia, is extremely competitive. We employ good human resource practices and have been named a top 100 employer in Canada for 7 consecutive years. We must continue to develop our human resource strategies to ensure an adequate supply of labour and management.

Weather risk

Weather can have a significant impact on our operations. Temperature levels, seasonality and precipitation, within EPCOR's markets and adjacent geographies, can affect the level of demand for electricity and natural gas, thus resulting in electricity and natural gas, price and volume volatility. In addition, the level of precipitation affects the availability of our hydro generating units and impacts the cooling pond reservoir level at the Battle River generation plant, which in turn can impact the performance of our interest in the Battle River acquired PPA.

The level and quality of spring run-off in the North Saskatchewan River affect the quality of water entering our water purification systems and the resulting costs of purification. Weather variability and seasonality also impact the demand and supply of water.

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

Weather related financial instruments are available in the financial markets but we have not pursued them due to their limited coverage and relatively high cost. Financial exposures associated with extreme weather are managed through our insurance programs.

Foreign exchange risk

Fluctuations in the exchange rate between the U.S. dollar or the Euro, and the Canadian dollar affect some of our revenues, capital costs, operating costs and cash flows, and could have an adverse impact our financial performance and condition.

The foreign exchange risk of anticipated U.S. dollar denominated cash flows from Power LP's U.S. plants is managed through the use of forward foreign exchange contracts for periods of up to seven years. At December 31, 2006, US $331.0 million or approximately 70% of these future cash flows were economically hedged for 2007 to 2013 at a weighted average exchange rate of 1.14. Power LP also entered into U.S. dollar forward foreign exchange contracts in anticipation of an issuance of a Canadian equity financing. At December 31, 2006, forward foreign exchange purchase contracts amounted to approximately $140.4 million at a weighted average exchange rate of 1.13.

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

Conflicts of interest

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

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

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

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

General economic conditions, business environment and other risks

Fluctuations in interest rates, product supply and demand, market competition, risks associated with technology, EPCOR's ability to generate sufficient cash flow from operations to meet its current and future economic and business conditions, EPCOR's ability to access external sources of debt and equity capital, general economic and business conditions, EPCOR's ability to make capital investments and the amounts of capital investments, risks associated with existing and potential future lawsuits and other regulations, assessments and audits (including income tax) against EPCOR and its subsidiaries, political and economic conditions in the geographic regions in which EPCOR and its subsidiaries operate, difficulty in obtaining necessary regulatory approvals, a significant decline in EPCOR's reputation and such other risks and uncertainties described from time to time in EPCOR's reports and filings with the Canadian Securities authorities could materially adversely impact EPCOR's business, prospects, financial condition, results of operations or cash flows. Our ability to mitigate these risks is dependent upon management's ability to anticipate such risks and, where possible, to develop appropriate mitigation plans.

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

In 2005, the Company reported that it was named, along with 450 other employers, in a $1.25 billion class action lawsuit against the Local Authorities Pension Plan. The Company reported that the lawsuit was in its opinion without merit and in 2006 the Company was dropped from the lawsuit.

The following table outlines our estimated sensitivity to specific risk factors as at December 31, 2006. Each sensitivity factor provides a range of outcomes assuming all other factors are held constant and current risk management strategies, including hedges, are in place. Under normal circumstances, such sensitivity factors will not be held constant but rather, will change at the same time as other factors are changing. In addition, these sensitivities are presented at December 31, 2006 and the degree of sensitivity to each factor will change as the Company's mix of assets and operations subject to these factors changes or the degree of commodity hedge coverage changes.

Factor ($ millions)	Change	Annual Cash Flow	Annual Net Income
Wholesale price of electricity – Alberta[1]	+ $5/MWh	2.0	2.0
Wholesale price of natural gas[1]	+ $1/Gj	(1.0)	(1.0)
US exchange rate	+ $0.01 (CDN to US dollar)	nominal	2.2
Short term interest rates	+1.0%	0.8	0.8
Increase in water consumption – Alberta	+3.0%	2.8	2.8
Canadian federal and provincial income tax rates	-1.0%	1.4	3.1

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

CONTROLS AND PROCEDURES

As of December 31, 2006, management conducted an evaluation of the design and effectiveness of the Company's disclosure controls and procedures. The evaluation took into consideration the Company's Disclosure Policy, the sub-certification process that has been implemented, and the functioning of its Disclosure Committee. In addition, the evaluation covered the Company's processes, systems and capabilities relating to public disclosures, and the identification and communication of material information. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that the disclosure controls and procedures are appropriately designed and are effective.

Also as of December 31, 2006, management conducted an evaluation of the design of internal controls over financial reporting to provide reasonable assurance regarding the reliability of financial reporting. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that the internal controls over financial reporting are appropriately designed with the exception of those controls that pertain to the PEV business that was acquired in late 2006. Documentation of the design of internal control over financial reporting for the PEV business will be finalized in 2007.

These evaluations were conducted in reference to the standards of the Committee of Sponsoring Organizations ("COSO"), a recognized control model, and the requirements of Multilateral Instrument 52-109 of the Canadian Securities Administrators.

There were no changes in the Company's internal controls over financial reporting that occurred since September 30, 2006, other than those that result from the acquisition of the PEV business, that have materially affected, or are reasonably likely to materially affect the Company's internal control over financial reporting.

NEW ACCOUNTING STANDARDS IN 2006

Non-monetary transactions

The Canadian Institute of Chartered Accountants ("CICA") issued a new accounting standard, Non-monetary Transactions, which applies to non-monetary transactions initiated in periods beginning on or after January 1, 2006. This new standard requires all non-monetary transactions to be measured at fair value unless certain exceptions are met. As part of the sale of the Battle River PPA and related transactions, we exchanged a portion of our interest in the Sundance PSA for a 30% interest in the Battle River PSA. The exchange was measured in accordance with this new accounting standard at the fair value of the Sundance Swap plus cash consideration. We did not have any other material non-monetary transactions in 2006.

FUTURE ACCOUNTING CHANGES

Financial instruments, hedges, and comprehensive income

The CICA issued four new related accounting standards: Financial Instruments, - Recognition and Measurement, Financial Instruments – Disclosure and Presentation, Hedges and Comprehensive Income. These standards apply to EPCOR commencing January 1, 2007 and based on our analysis to date, the significant impacts of the new standards on the Company are expected to include the following.

- A new statement entitled "Consolidated Statement of Comprehensive Income" will be added to our consolidated financial statements. This statement will include net income and the components of other comprehensive income such as unrealized foreign exchange gains or losses arising from the translation of any self-sustaining foreign operations, the effective portion of the changes in the fair value of derivative instruments used in cash flow hedges of electricity sales and purchases and the effective portion of the changes in the fair value of foreign currency cash flow hedges. Each component of the statement of comprehensive income will be recorded net of income taxes.
- These other comprehensive income items will be reclassified to the income statement in the period that the corresponding foreign exchange gain or loss is realized or the corresponding hedged item of the cash flow hedge affects net income. The cumulative amount of these other comprehensive income components will be called "accumulated other comprehensive income" and included as a new category in shareholder's equity.
- We enter into both non-financial and financial contracts to manage our energy portfolio. All derivatives will be measured at fair value and shown on the balance sheet as derivative financial assets and derivative financial liabilities. Changes in the fair value of the financial derivatives that do not qualify for hedge accounting or are not designated as contracts used for the purpose of receipt of or delivery of a non-financial item in accordance with our expected purchase, sale or usage requirements, will be recorded in income. This is similar to how such items have been treated in the past. A more significant change is that the effective portion of changes in the fair value of financial derivatives that qualify under hedge accounting will be reported in

other comprehensive income while the ineffective portion will be reported in net income.

- Non-financial derivatives that are designated as contracts for the purpose of receipt of or delivery of a non-financial item in accordance with our expected purchase, sale or usage requirements are excluded from the requirements of the new standards. Such contracts will include physical power and gas purchase and sale contracts. Accordingly, revenues and expenses incurred on these contracts will be recorded in the income statement at the contract settlement date. Loans, receivables and debt will be recorded at amortized cost and amortized using the effective interest rate method.
- The changes in the carrying values of financial derivatives as a result of adopting these new standards will be recognized as adjustments to accumulated other comprehensive income or retained earnings, as appropriate, as at January 1, 2007. The previously deferred unrealized gains and losses on derivative financial instruments recorded upon termination of a hedging relationship will be reclassified from the balance sheet to other comprehensive income as at January 1, 2007. In addition, the cumulative effect of changing the method of amortization of deferred debt issue costs, premiums and discounts to the effective interest rate method will be recorded in retained earnings as at January 1, 2007. Prior periods' financial statements will not be restated.

These changes in accounting standards may result in significant variability in other comprehensive income and net income. We continue to analyze the impact of adopting these new standards.

Financial instrument disclosure and presentation and capital disclosures

In December, 2006 the CICA issued three new accounting standards that will apply to EPCOR commencing January 1, 2008. They are Financial Instruments – Disclosures, Financial Instruments – Presentation and Capital Disclosures. These standards require increased disclosures with increased emphasis on risks associated with financial instruments. We will review these standards over the next twelve months with a view to adopting them in our financial reporting commencing in 2008.

International financial reporting standards

The CICA plans to move financial reporting for Canadian public companies to International Financial Reporting Standards ("IFRS") over a transition period from 2006 to 2011. The impact on EPCOR's financial statements of transitioning to IFRS cannot yet be determined until detailed convergence plans and recommendations are in place.

SIGNIFICANT ACCOUNTING POLICIES

Revenue recognition under PPAs

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

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

Revenues from the Company's power generation plants located outside of Alberta are recognized upon delivery of output or upon availability of delivery as prescribed by contractual arrangements. These contractual arrangements are also commonly referred to as PPAs. Revenues under the Curtis Palmer PPA are recognized at the lower of (1) the cumulative billable contract price per megawatt hour (MWh) and (2) an amount determined by the MWhs made available during the period, multiplied by the average price per MWh over the term of the contract. Any excess of the contract price over the average price is recorded as deferred revenue.

Financial commodity contracts

EPCOR uses contracts-for-differences (or fixed-for-floating swaps) for risk management purposes. Such contracts designated as hedges are matched to an underlying commodity sale or purchase to fix the price and are used solely to reduce risk. The settled amounts under these contracts are recorded as adjustments to revenues or energy purchases in the period settled. Any financial contracts that do not meet hedge effectiveness tests are accounted for at their fair values.

Consolidation of Power LP

While EPCOR owns only 30.6% of the outstanding units of Power LP, EPCOR has determined that it controls Power LP under generally accepted accounting principles. Accordingly, the acquisition of EPCOR's interest in Power LP was accounted as a business combination with full consolidation of the financial position and results of Power LP in the financial statements of EPCOR from the date of acquisition.

CRITICAL ACCOUNTING ESTIMATES

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

Electricity revenues, costs and unbilled consumption

Due to the imprecision in customer consumption data received from load settlement agents, the lag between billing dates and meter reading dates and the lag between billing dates and financial reporting dates, we must use estimates for determining the amount of energy consumed but not yet billed. These estimates affect accrued revenues and accrued energy costs of the Energy Services segment. There are a number of variables in the computation of these estimates, and the underlying energy settlement processes within EPCOR and the Alberta and Ontario electric systems are complex. Owing to the factors above and the statutory delays in final load settlement determinations and information, adjustments to previous estimates could be material. Estimates for unbilled consumption average about $85.0 million at the end of each month and these estimates vary from $60.0 million to $100.0 million. Adjustments from estimate to actual, in the full cycle of billing for a calendar month, are less than $5.0 million.

Fair values

For determining the valuation of financial instruments that do not meet hedge accounting standards, asset impairments, asset retirement obligations and purchase price allocations for business combinations, and for determining certain disclosures, we are required to estimate the fair value of certain assets or obligations.

Fair values of financial instruments are based on quoted market prices when these instruments are traded in active markets. In illiquid or inactive markets, we use appropriate price modeling to estimate fair value. For our energy positions that do not qualify for hedge accounting we use forward electricity and natural gas prices to estimate fair value. These adjustments are recorded in energy sales and purchases, and derivative assets and liabilities.

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

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

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

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

PPA availability incentives

Electricity revenue from the Genesee 1 and 2 units operating under PPAs includes an estimate of availability incentives as described above under Significant Accounting Policies. Availability incentive payments received are deferred in non-current liabilities and recognized in energy sales when they are expected to be sustained over the full term of the PPA. Accordingly the amount deferred can vary from no amount to the full amount of availability incentive payments received. At December 31, 2006, $2.5 million was deferred in the balance sheet and $26.3 million was recognized in energy sales during the year.

Allowance for doubtful accounts

We continually review our aged accounts receivable and assess the underlying credit quality of the customers or counterparties. The allowance for doubtful accounts reflects an estimate of the accounts receivable that are ultimately expected to be uncollectible. It is based on a number of factors including the aging of receivables, historical write-offs within customer groups, assessments of the collectibility of amounts from individual customers and general economic conditions. EPCOR’s allowance account averaged $6.0 million and reported bad debts were $3.2 million in 2006. The estimate affects accounts receivable and all segments’ operations, maintenance and administration expenses.

Useful lives of assets

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

Income taxes and amounts in lieu of income taxes

EPCOR follows the asset and liability method of accounting for income taxes and amounts in lieu of income taxes. Income taxes and amounts in lieu of income taxes are determined based on estimates of our current income taxes and estimates of future income taxes resulting from temporary differences between the carrying values of assets and liabilities in the financial statements and their tax values. Future income tax assets are assessed to determine the likelihood that they will be recovered from future taxable income. To the extent recovery is not considered likely, a valuation allowance is recorded and charged against income in the period that the allowance is created or revised. Estimates of the provision for income taxes and amounts in lieu of income taxes, future income tax assets and liabilities and any related valuation allowance might vary from actual amounts incurred.

Fair values and useful lives are used in determining potential impairments for each long lived asset, which will vary with each asset and market conditions at the particular time. Similarly, income taxes and amounts in lieu of income taxes will vary with taxable income and, under certain conditions, with fair values of assets and liabilities. Accordingly, it is not possible to provide a reasonable quantification of the range of these estimates that would be meaningful to readers.

NON-GAAP FINANCIAL MEASURES

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

Year ended December 31	2006	2005	2004
Cash flow from operations	**$ 556.7**	**$ 519.9**	**$ 385.2**
Collection of deferred amounts receivable	-	-	21.7
Change in other non-current assets and Liabilities	(14.6)	(40.4)	(42.0)
Change in non-cash operating working capital	39.1	(13.3)	73.5
Cash flow from operating activities	**$ 581.2**	**$ 466.2**	**$ 438.4**

DERIVATIVE FINANCIAL INSTRUMENTS

We use various open-market derivative financial instruments with arm's-length parties, including contracts-for-differences, to manage our exposure to electricity and natural gas price, foreign exchange rates and interest rate risks. These derivative financial instruments are recorded at fair value in the balance sheet unless they are designated as hedges which are effective. Realized gains and losses and unrealized changes in fair value on derivatives that either do not qualify or we elect not to apply for hedge accounting treatment under CICA Accounting Guideline 13, are recognized in net income. The corresponding unrealized changes in the fair value of the respective hedged exposures are not recognized in income. Derivative financial instruments that are fair valued can produce volatility in net income as a result of fluctuating forward commodity prices, exchange rates and interest rates which are not offset by the unrealized fair value changes of the exposure being hedged. As a result, the recording of gains on losses for changes in fair values of derivative financial instruments for accounting purposes does not necessarily represent the underlying economics of the hedging transaction.

For example, we have more physical supply of power in Alberta from our generating stations and power purchased under PPAs than we have contracted to physically sell. We utilize financial sells to reduce our exposure to changes in the price of power in Alberta. Economically, we benefit from higher Alberta pool prices due to our net long position, where our expected physical supply is in excess of our physical and financial sells. However, financial sells that are not hedged for accounting purposes are fair valued at each balance sheet date whereas the offsetting anticipated future physical supply (or hedged item) is not. Accordingly, an increase in forward Alberta power prices can result in fair value losses for accounting purposes whereas on an economic basis these losses are offset by unrecognized economic gains on the physical supply. This economic gain will be recognized in later periods when power is produced and sold. The opposite is true for forward price decreases in Alberta power prices.

The gains and losses on derivatives used in managing exposures related to commodity price risk and foreign exchange rate risk on cash flows generated on foreign currency denominated revenues are recognized in energy revenues or energy purchases as the related sales or purchases occur. Unrealized changes in fair value are recorded in energy revenues or energy purchases, as appropriate, at the end of each reporting period.

Those derivative financial instruments that are designated as effective hedges are not recorded in the balance sheet since the gains and losses relating to the derivative financial instruments are deferred and recognized in the same period and financial statement category as the corresponding hedged transactions. They are summarized below:

December 31 ($ millions)		2006			2005		
			Notional quantity or principal amount			Notional quantity or principal amount	
		Fair value asset (liability)	Amount in millions	Measure	Fair value asset (liability)	Amount in millions	Measure
Electricity sales contracts-for-differences	Hedge	$ (150.6)	8.5	MWh	$ (130.0)	10.9	MWh
Electricity purchases contracts-for-differences	Hedge	90.6	7.8	MWh	35.5	3.6	MWh
MWh – megawatt-hours							

We do not have any other material off-balance sheet arrangements.

RELATED PARTY TRANSACTIONS

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

We recorded financing expenses of $58.1 million in 2006 ($62.8 million - 2005) on EPCOR's debt obligation to The City of Edmonton. This debt obligation relates to debt capital raised by The City of Edmonton prior to 1996 when EPCOR commenced raising capital directly. The decrease in interest expense in 2006 corresponds to the decrease in the obligation. The outstanding balance of the obligation to The City of Edmonton was $309.0 million at December 31, 2006 (2005 - $381.9 million).

Sales from EPCOR to The City of Edmonton included electricity and water, maintenance, repair and construction services, and customer care services totaling $69.0 million in 2006 (2005 - $65.7 million). We paid franchise fees and property taxes to the City of Edmonton of $45.9 million (2005 - $44.6 million). The City of Edmonton provided miscellaneous services to EPCOR totaling $7.6 million (2005 - $6.5 million).

Included in the Company's revenues is $0.6 million for the provision of management services by Power LP to PERC under a long-term management agreement. At December 31, 2006, accounts receivable included $0.3 million due from PERC.

FOURTH QUARTER REVIEW AND QUARTERLY RESULTS

Quarter ended	Revenues	Net income from continuing operations	Net income (loss) from discontinued operations	Net income
		(Unaudited, in $ millions)		
December 31, 2006	$728.1	$16.5	$1.0	$17.5
September 30, 2006	701.5	46.9	8.6	55.5
June 30, 2006	688.7	383.5	-	383.5
March 31, 2006	812.5	185.6	-	185.6
December 31, 2005	865.8	45.8	(8.4)	37.4
September 30, 2005	582.4	63.3	22.0	85.3
June 30, 2005	575.8	46.4	9.7	56.1
March 31, 2005	615.6	3.2	5.1	8.3

For the quarter ended December 31, 2006, net income from continuing operations decreased by $29.3 million from the same quarter in the prior year primarily due to unrealized fair value decreases in derivative financial instruments which were not designated as hedges for accounting purposes, resulting from higher forward market prices. In addition, income from Power LP operations was lower primarily due to unrealized foreign exchange losses on the translation of US dollar debt in 2006. These decreases were partly offset by increased generation from the Calpine short-term tolling arrangement, higher generation incentive income and realized gains on foreign exchange forward contracts in the fourth quarter of 2006.

Net income for the fourth quarter of 2006 decreased by $19.9 million from net income for the same quarter in 2005 primarily due to the reductions in net income from continuing operations described above, partly offset by the absence of inventory write-downs and gas contract termination costs for Cloverbar, which occurred in 2005.

Segment results for the fourth quarter included lower operating income in Energy Services with an operating loss of $6.7 million compared to operating income of $33.1 million for the corresponding period in 2005. Energy Services fourth quarter results included unrealized fair value decreases due to higher forward market prices on merchant and wholesale positions in Alberta, partly offset by increased generation from the Calpine short-term tolling arrangement.

Generation's operating income decreased to $52.4 million in the fourth quarter of 2006 from $61.7 million in the fourth quarter of 2005 primarily due to lower income from Power LP, higher maintenance costs for a major outage at the Genesee 2 plant, the write-down of Kingsbridge II project assets and the write-down of some Frederickson development costs in 2006. These decreases were partly offset by an unrealized fair value increase in the Joffre CfD which was not designated as a hedge for accounting purposes.

Distribution and Transmission's operating income decreased to $6.3 million in the fourth quarter of 2006 from $9.2 million in the fourth quarter of 2005, primarily due to a decrease in volume of contract-based commercial services work.

Water Services' operating income decreased to $8.3 million in the fourth quarter of 2006 compared to $11.7 million in the fourth quarter of 2005, primarily due to the write down of a venture capital investment.

Events for 2006 and 2005 quarters that have significantly impacted net income from continuing operations and net income and the comparability between quarters are:

- September 30, 2006 third quarter results include a net income increase from discontinued operations of $10.0 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.
- June 30, 2006 second quarter results include the sale of a 55% interest in the Battle River PPA and related transactions which contributed $327.3 million to net income. The regulatory decisions for the 2005/2006 distribution and transmission tariffs and the RRT non-energy charge were received in the second quarter of 2006 resulting in a $9.8 million increase in net income. Future income tax assets and liabilities were adjusted to reflect the corporate income tax rate reductions that were enacted by the governments of Alberta and Canada in the quarter. These tax adjustments reduced net income by $16.1 million.
- March 31, 2006 first quarter results include the tax impact of the Generation reorganization whereby a Generation subsidiary became subject to federal and provincial income taxes rather than the PILOT Regulation. As a result, additional deductions are available for income tax purposes and the net tax effect was recognized as non-current future income tax assets in the balance sheet with a corresponding increase in net income of $117.1 million. In addition, unrealized fair value changes in derivative financial instruments increased net income by $13.9 million.
- December 31, 2005 fourth quarter results include the impact of reduced Alberta electricity margins as margins on new and renewed electricity contracts decreased.
- September 30, 2005 third quarter results include the net income pick-up of approximately $17.0 million consisting of the Clover Bar PPA termination payment partly offset by the write-down of the Clover Bar assets. The third quarter results also include gains of $13.3 million after income taxes on the sale of Alberta competitive electricity contracts and settlement of litigation.
- June 30, 2005 second quarter results include the unrealized fair value increases on energy supply contracts associated with Ontario electricity sales contracts that were sold during the quarter. These gains had previously been deferred in accordance with hedge accounting and were approximately $8.0 million after income taxes. June 30, 2005 second quarter results also include a full quarter's results of operations for the Genesee 3 generation unit from its start-up date of March 1, 2005 of approximately $7.0 million after financing expenses and income taxes. As well, this quarter's results include decreased Alberta electricity margins of approximately $8.0 million after income taxes.

- March 31, 2005 first quarter results include the adjustment of amounts in lieu of income taxes and interest as a result of the revised goodwill value for PILOT Regulation purposes of $39.8 million.

ADDITIONAL INFORMATION

Additional information relating to EPCOR including the Company's 2006 Annual Information Form is available on SEDAR at www.sedar.com.