Management discussion and analysis

This management's discussion and analysis (MD&A) dated March 28, 2006 should be read in conjunction with the audited consolidated financial statements of EPCOR Utilities Inc. (the Company or EPCOR) for the years ended December 31, 2005 and 2004. 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", "expect" or similar words suggest future outcomes. By their nature, certain future events 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 provides energy, water and energy related services, including electricity generation, distribution, transmission and marketing to end-use customers, natural gas marketing, and water purification, water distribution and wastewater services in Alberta, British Columbia, Ontario and the U.S. Pacific Northwest. Through its investment in EPCOR Power L.P. (Power LP), EPCOR also has electricity generation operations in Colorado and New York. This strategy is delivered through an integrated structure with a balanced portfolio of regulated and competitive businesses. EPCOR continues to look for opportunities for growth consistent with its balanced portfolio of businesses. By maintaining a strong base in regulated wires and water businesses and growing its commercial electricity and water operations, EPCOR intends to increase shareholder value as a leading North American supplier of energy and water services.

KEY PERFORMANCE INDICATORS

Performance of EPCOR in meeting the goals of its 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 EPCOR, its shared service units and its business units operating within each business segment.

Within each category, there are specific measures established for each shared service unit and business unit that are important to the results of the respective unit. 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. Environment and safety performance are measured based on both 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 a customer satisfaction survey.

For 2005, EPCOR's results were ahead of targets for both its internal non-financial and financial performance measures.

CONSOLIDATED FINANCIAL INFORMATION

($ millions)	2005	2004 (restated)[2]	2003 (restated)[1] [2]
Revenues	$ 2,698.8	$ 2,594.6	$ 2,535.7
Preferred dividends, including dividend taxes, paid by subsidiary companies	21.5	21.5	21.0
Net income from continuing operations	158.7	182.7	147.8
Net income from discontinued operations	28.4	15.3	291.2
Net income	187.1	198.0	439.0
Total assets	5,658.8	4,202.0	4,354.6
Long-term debt	2,081.0	1,610.3	1,700.6
Common share dividends	122.7	120.5	110.5

(1) Restated on 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 from continuing operations

Net income from continuing operations for the year ended December 31, 2003	**$**	**147.8**
2004 adjustment for increased estimates of deferred availability incentives for plants operating under PPAs		29.7
Lower electricity load, settlement and billing adjustments		21.6
Lower bad debts expenses and revenue reconciliation project costs		13.5
Higher Ontario electricity margins		7.4
2004 loss on disposal of Frederickson plant		(10.9)
Lower income from the Rossdale generation plant		(14.0)
Lower Alberta electricity margins		(17.0)
Other		4.6
Net income from continuing operations for the year ended December 31, 2004		**182.7**
Genesee Phase 3 results of operations from March 1, 2005 commencement		37.4
Gains on the sale of Alberta mid-market electricity and natural gas contracts and settlement of litigation		13.3
2004 loss on disposal of interest in Frederickson generation plant		10.9
Lower general and administration expenses		10.9
Decreased financing expenses excluding impact of Genesee Phase 3 financing, PILOT settlement and investment in and consolidation of Power LP		13.9
Lower acquired PPA results		(12.6)
Non-recurrence of 2004 increased estimates of deferred availability incentives for plants operating under PPAs		(22.1)
Lower Alberta electricity margins		(26.5)
2005 PILOT settlement		(39.8)
Other		(9.4)
Net income from continuing operations for the year ended December 31, 2005	**$**	**158.7**

Net income from continuing operations for the year ended December 31, 2005 was $158.7 million compared to $182.7 million for 2004. Net income from continuing operations decreased by $24.0 million for the year ended December 31, 2005 compared to the previous year while net income from continuing operations for the year ended December 31, 2004 increased by $34.9 million compared to the previous year for the reasons discussed below.

- EPCOR's 50 per cent interest in the sale of electricity generated by the Genesee Phase 3 generation unit, which commenced commercial operations on March 1, 2005, increased net income from continuing operations in 2005 compared to 2004 by $37.4 million after financing expenses and income taxes.
- In the third quarter of 2005, EPCOR recorded a gain of $13.3 million on the sale of Alberta mid-market electricity contracts and settlement of litigation.
- In the second quarter of 2004, EPCOR received cash proceeds of $104.9 million on the disposal of a 49.85 per cent interest in its Frederickson generation plant located in the State of Washington. A loss of $10.9 million after income taxes, including foreign exchange losses of $7.0 million, was recorded on the transaction. There was no similar loss in 2005.
- EPCOR recorded decreased general and administration expenses of $10.9 million in 2005 compared to 2004 consisting of lower costs associated with customer service and administration activities. These reductions resulted primarily from the disposal of mid- and mass-market contracts in both years and lower bad debts expense.
- Financing expenses, excluding the impact of Genesee Phase 3 financing, the PILOT

settlement and the investment in and consolidation of Power LP, decreased in 2005 compared to 2004 due to lower debt levels.

- EPCOR, with its syndicate partners, holds the Power Purchase Arrangements (PPAs) for two independently owned power plants in Alberta. In 2005, the margins on sales of electricity generated by these plants were lower than 2004 since higher wholesale prices of electricity in 2005 impacted PPA costs, including the costs of replacement energy when the plants were undergoing maintenance, by more than the associated increase in electricity revenues.
- In the first quarter of 2004, EPCOR increased its estimates of retained availability incentives on its generation units operating under PPAs thus increasing net income from continuing operations by $22.1 million for the year ended December 31, 2004. There was no similar adjustment of estimates impacting net income from continuing operations in 2005.
- For the year ended December 31, 2005, net income from continuing operations decreased by $26.5 million compared to 2004 as the margins on new and renewed Alberta electricity contracts for larger customers decreased from previous contract margins. As expected, margins have declined over the past two years as higher margin contracts expired and were replaced with contracts reflecting current market prices at lower margins.
- In 2005, EPCOR recorded a charge of $38.1 million to amounts in lieu of income taxes plus interest of $1.7 million resulting from the Company's settlement with Alberta Revenue, Tax and Administration (Alberta Revenue), as agent for Alberta's Balancing Pool with respect to the value of goodwill for purposes of the Payment in Lieu of Income Taxes (PILOT) Regulation.

The change to net income from continuing operations due to EPCOR's investment in Power LP from the acquisition date of September 1, 2005 was not significant.

Net income and net income from discontinued operations

Net income for the year ended December 31, 2003	**$**	**439.0**
Increases in net income from continuing operations – see previous table		34.9
Non-recurrence of 2003 gain on disposal of Union Energy		(291.1)
Increased income from Clover Bar operations		6.9
2004 adjustment for increased estimates of deferred availability incentives for Clover Bar plant		3.9
Other		4.4
Net income for the year ended December 31, 2004		**198.0**
Decreases in net income from continuing operations – see previous table		(24.0)
2005 Clover Bar PPA termination payment received		82.7
2005 impairment of Clover Bar generation plant and other termination costs		(64.4)
Non-recurrence of 2004 increased estimates of deferred availability incentives for Clover Bar plant		(3.9)
Other		(1.3)
Net income for the year ended December 31, 2005	**$**	**187.1**

Net income for the year ended December 31, 2005 was $187.1 million compared to $198.0 million for 2004. Net income decreased by $10.9 million for the year ended December 31, 2005 compared to the previous year while net income for the year ended December 31, 2004 decreased by $241.0 million compared to the previous year due to the changes in net income from continuing operations as previously discussed and the impact of discontinued operations as discussed below.

- In the fourth quarter of 2003, EPCOR disposed of its investment in its subsidiaries, Union Energy Inc. and EPCOR Energy Securitizations Inc. (collectively Union Energy), thereby exiting the water heater rental and related financing businesses that it acquired in 2001. The proceeds on disposal (net of underwriters' fees) were $793.3 million, resulting in a gain of $291.1 million.
- In the third quarter of 2005, EPCOR received a termination payment of $82.7 million from Alberta's Balancing Pool on termination of the Clover Bar PPA. This was offset by the write-down of the Clover Bar generation plant and other termination costs of $64.4 million incurred as a result of EPCOR's decision to decommission the generation units.
- Net income from discontinued operations also includes the results from conventional operations of the Clover Bar generation plant for each period presented including the increased availability incentives recognized in 2004 which did not recur in 2005.

Revenues

Revenues for the year ended December 31, 2003	**$**	**2,535.7**
Energy sales		40.6
Commercial and other sales		18.3
Revenues for the year ended December 31, 2004		**2,594.6**
Energy sales		(61.2)
Commercial and other sales		61.0
Consolidation of Power LP revenues		104.4
Revenues for the year ended December 31, 2005	**$**	**2,698.8**

Revenues from energy sales decreased in 2005 due to lower retail and wholesale electricity and natural gas sales resulting from the 2004 disposal of Alberta mass-market contracts and the 2005 third quarter disposal of Alberta mid-market contracts. These decreases were partly offset by the incremental impact of EPCOR's 50 per cent share of sales of electricity generated by Genesee Phase 3 which commenced operations on March 1, 2005. Other revenues have increased due to higher ancillary service activity and more commercial contract-based services such as the Britannia Mine, B.C. and Sooke, B.C. projects. Incremental revenues in 2005 compared to 2004 resulting from the consolidation of Power LP were $104.4 million.

Capital spending and investment

($ millions)	2005	2004	2003
Generation	$ 118.2	$ 102.3	$ 151.2
Distribution and Transmission	64.5	47.6	39.9
Energy Services	7.9	14.6	21.1
Water Services	47.5	46.7	30.4
Corporate – other	5.8	9.2	9.2
	243.9	220.4	251.8
Investment in Power LP	534.4	-	-
	$ 778.3	$ 220.4	$ 251.8

Capital expenditures for property, plant and equipment increased in 2005 compared to 2004 due primarily to capital costs of $63.2 million relating to construction of the Kingsbridge wind-powered generation facility in Ontario. Construction on Genesee Phase 3 was completed in 2005 with commercial operation commencing on March 1, 2005. Capital expenditures on Genesee Phase 3 were $15.3 million compared to $73.3 million in the previous year. As discussed in the following Significant Events section, EPCOR's interest in Power LP was acquired for a total purchase price of $534.4 million including acquisition costs.

SIGNIFICANT EVENTS

Acquisition of Interest in Limited Partnership

On September 1, 2005, EPCOR closed its transaction with TransCanada Corporation (TransCanada) for the acquisition of TransCanada's interest in TransCanada Power, L.P. EPCOR acquired approximately 14.5 million units of Power LP (approximately 30.6 per cent), 100 per cent ownership of the General Partner of Power LP, and all of TransCanada's interests in the management and operations agreements governing the ongoing operation of Power LP's power generation assets. The total consideration paid was $529.0 million plus acquisition costs of $5.4 million. On close of the transaction, Power LP was renamed EPCOR Power L.P. Power LP owns a portfolio of 11 power generation assets in Canada and the United States, with a total net generating capacity of 744 megawatts. The generation plants include natural gas, waste heat, small-scale hydro, and bio-mass facilities.

The acquisition has been accounted as a business combination with full consolidation of the financial position and results of Power LP from the date of acquisition.

Clover Bar generation plant

On April 1, 2005, Alberta's Balancing Pool, as PPA holder, advised EPCOR of its decision to terminate the Clover Bar PPA, effective September 30, 2005. In accordance with the terms of the PPA, EPCOR received a termination payment of $82.7 million on September 30, 2005. In light of the announced termination of the PPA, EPCOR studied a variety of alternatives to redeploy the Clover Bar generation plant after the termination date. None of the alternatives provided economically feasible operation of the plant and therefore EPCOR chose to decommission the existing generation units commencing on termination of the PPA. Decommissioning is expected to take two years or more. EPCOR recorded a charge of $64.4 million, before income taxes, consisting of a write-down of the generation plant and related assets plus other costs associated with curtailing the operation of the plant.

PILOT settlement

On January 1, 2001, the PILOT Regulation under the *Electric Utilities Act* (Alberta) came into effect requiring certain of EPCOR's operations, which are exempt from taxation, to pay amounts in lieu of income taxes in substantially the same manner as if they were taxable under federal and provincial tax laws. Accordingly, under the PILOT Regulation, on January 1, 2001, these operations were deemed to have disposed of and re-acquired their assets at fair market value. EPCOR determined that the resulting tax bases of these assets were greater than their book values giving rise to a future tax benefit associated with the additional deductions available for amounts in lieu of income tax purposes. Under generally accepted accounting principles, the future tax benefit associated with the additional tax deductions available was recognized as a future tax asset in the balance sheet. Since the initial recognition of the future tax was the result of imposed legislation, the corresponding adjustment was recorded as an adjustment to retained earnings in 2001.

Alberta Revenue, as agent for Alberta's Balancing Pool, is responsible for assessing EPCOR's amounts in lieu of income tax returns filed under the PILOT Regulation. In July 2003, Alberta Revenue notified EPCOR that it was their view that the value of goodwill for amounts in lieu of income tax purposes for the Company's generation assets operating under PPAs, as determined by EPCOR at the date that the Company first became subject to the PILOT Regulation, was overstated. A value of goodwill for PILOT Regulation purposes lower than the amount established by EPCOR on January 1, 2001 results in decreased deductions available in determining amounts in lieu of income taxes. All else being equal, this creates additional amounts in lieu of income taxes payable from 2001 to date and lower future amounts in lieu of income tax assets associated with such deductions. At January 1, 2001, EPCOR estimated the balance of future amounts in lieu of income tax assets associated with the goodwill to be $112.9 million, based on an estimated fair market value of goodwill of $400.0 million. The value of goodwill was settled during the year between EPCOR and Alberta Revenue for PILOT Regulation purposes at $250.0 million. This resulted in an increase in current amounts in lieu of income taxes payable including related interest of $11.5 million and a decrease in future amounts in lieu of income tax asset of $28.3 million resulting in a one-time charge of $39.8 million to amounts in lieu of income taxes expense and interest expense.

Sale of mid-market electricity contracts

Effective September 30, 2005, EPCOR sold approximately 635 Alberta mid-market commercial, industrial and institutional electricity contracts. This disposal of contracts decreased the customer base for electricity sales in the fourth quarter of 2005 and in future periods.

SEGMENT RESULTS

Generation

Generation earns income from generation units operating under PPAs and from commercial power generation units. EPCOR's 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, EPCOR receives formula-based fixed capacity and variable payments which are intended to provide the Company 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 per cent over the rate of long-term Canada bonds. In addition, EPCOR receives incentives and pays penalties when the output available from the generation unit exceeds or falls below target availability levels as set out in the PPAs. The target availability levels in the PPAs 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 of generation units operating under PPAs is managing their costs and ensuring that the units are able to meet or exceed the target availability levels set out in the PPAs.

The Clover Bar PPA was terminated effective September 30, 2005 at which time decommissioning of the plant commenced. Clover Bar PPA availability incentives of $6.3 million after income taxes were recognized in income in 2005.

The Rossdale PPA expired on December 31, 2003 and the plant was operated as a commercial generation unit throughout 2004. PPA availability incentives of $3.4 million (after income taxes) for Rossdale since 2001 were recognized in income in 2003. An ancillary services contract with the Alberta Electric System Operator (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.

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. EPCOR’s general objective is to contract the majority of its 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.

		2005	2004[1]
Generation results			
(including intersegment transactions, $ millions)			
Revenues		$ 637.4	$ 467.7
Expenses	Operating	329.1	220.7
	Depreciation, amortization and asset retirement accretion	92.6	60.3
	Financing	146.2	117.7
	Income taxes	66.7	33.5
	Non-controlling interests	17.1	-
		651.7	432.2
Net income (loss) from continuing operations		**(14.3)**	**35.5**
Discontinued operations		28.4	17.9
Net income		**$ 14.1**	**$ 53.4**

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

Generation net income from continuing operations

Net income from continuing operations for the year ended December 31, 2004[2]	**$**	**35.5**
Genesee Phase 3 results of operations from March 1, 2005 commencement		20.0
Non-recurrence of 2004 loss on disposal of interest in Frederickson generation plant		10.9
Mark-to-market losses		(10.1)
Non-recurrence of 2004 increased estimates of deferred availability incentives for plants operating under PPAs		(22.1)
2005 PILOT settlement		(39.8)
Other		(8.7)
Net (loss) from continuing operations for the year ended December 31, 2005	**$**	**(14.3)**

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

For the year ended December 31, 2005, Generation net income from continuing operations decreased by $49.8 million from the prior year primarily due to the PILOT settlement as discussed under Significant Events.

- Generation's 50 per cent interest in the sale of electricity generated by the Genesee Phase 3 generation unit, which commenced commercial operations on March 1, 2005, increased net income from continuing operations in 2005 compared to 2004 by $20.0 million after financing expenses and income taxes.

- In 2004, Generation recorded a loss of $10.9 million after income taxes including foreign exchange losses of $7.0 million, on the disposal of a 49.85 per cent interest in its Frederickson generation plant. There was no similar loss in 2005.

- In 2005, Generation incurred larger mark-to-market losses on its Joffre electricity contract-for-differences due to the impact of increases in natural gas prices.

- In the first quarter of 2004, Generation increased its estimates of retained availability incentives on its generation units operating under PPAs, thus increasing net income from continuing operations by $22.1 million for the year ended December 31, 2004. There was no similar adjustment of estimates impacting net income from continuing operations in 2005.

Generation net income and net income from discontinued operations

Net income for the year ended December 31, 2004	**$**	**53.4**
Decreases in net income from continuing operations – see previous table		(49.8)
2005 Clover Bar PPA termination payment received		82.7
2005 impairment of Clover Bar generation plant and other termination costs		(64.4)
Non-recurrence of 2004 increased estimates of deferred availability incentives for Clover Bar plant		(3.9)
Other		(3.9)
Net income for the year ended December 31, 2005	**$**	**14.1**

For the year ended December 31, 2005, Generation net income decreased by $39.3 million due to the changes in net income from continuing operations discussed above plus the net impact of the transactions discussed below.

- In the third quarter of 2005, Generation received a termination payment of $82.7 million from Alberta's Balancing Pool on termination of the Clover Bar PPA. This was partly offset by the write-down of the Clover Bar generation plant and other termination costs of $64.4 million incurred as a result of EPCOR's decision to decommission the generation units.

- Net income from discontinued operations also includes the results of operations from conventional operations of the Clover Bar generation plant for each period presented including the increased availability incentives recognized in 2004 which did not recur in 2005.

Generation revenues

Electricity generation (000s of megawatt-hours)	2005	2004
Generation units owned by EPCOR		
Coal generation units	7,805	6,279
Natural gas generation units	740	1,068
Hydro and wind generation units	144	120
Total	**8,689**	**7,467**
Generation units owned by Power LP[3]		
Natural gas and/or waste heat units	390	
Wood waste and/or waste heat units	246	
Hydro generation units	197	
Total	**833**	

(3) EPCOR acquired a 30.6 per cent interest in the Power LP plants effective September 1, 2005. The electricity generation volumes presented above reflect the generation of the Power LP generation units for the four months ended December 31, 2005.

Revenues for the year ended December 31, 2004[4]	**$**	**467.7**
Power LP revenues from September 1, 2005 acquisition		104.4
Genesee Phase 3 revenues from March 1, 2005 commencement of operations		84.7
Non-recurrence of 2004 increased estimates of deferred availability incentives for plants operating under PPAs		(33.4)
Other		14.0
Revenues for the year ended December 31, 2005	**$**	**637.4**

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

For the year ended December 31, 2005, Generation revenues increased by $169.7 million from the prior year primarily due to Power LP's revenues which are fully consolidated in EPCOR's results from the date of acquisition of September 1, 2005 and the incremental revenues resulting from electricity sales for the period from the date of commencement of operations at Genesee Phase 3 on March 1, 2005.

Generation expenses

Expenses for the year ended December 31, 2004[5]	**$**	**432.2**
Power LP expenses from September 1, 2005 acquisition		90.0
Genesee Phase 3 expenses from March 1, 2005 commencement of operations		64.7
PILOT settlement		39.8
Non-controlling interest in Power LP results from September 1, 2005 acquisition		17.1
Mark-to-market losses		10.1
Non-recurrence of 2004 loss on disposal of interest in Frederickson generation plant		(10.9)
Other		8.7
Expenses for the year ended December 31, 2005	**$**	**651.7**

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

For the year ended December 31, 2005, Generation expenses increased by $219.5 million from the prior year primarily due to Power LP's expenses which are fully consolidated in EPCOR's results from the date of acquisition of September 1, 2005 and the PILOT settlement. Incremental expenses related to electricity sales were incurred for the period from the date of commencement of operations at Genesee Phase 3 on March 1, 2005. The non-controlling interest in Power LP's results from the date of acquisition is included in expenses of the Generation segment.

Distribution and Transmission

Distribution and Transmission principally earns income by transmitting high voltage electricity from generation plants to points of distribution and, from there, distributing low voltage electricity to retailers' end-use customers. EPCOR's distribution and transmission assets are located in and around The City of Edmonton. Under the *Electric Utilities Act* (Alberta), regulation of Distribution transferred from Edmonton City Council to the Alberta Energy and Utilities Board (AEUB) effective January 1, 2004. EPCOR earns provincially regulated distribution and transmission tariffs intended to allow the Company to recover its prudent costs and earn a fair rate of return on its distribution and transmission infrastructure. EPCOR 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 and The Town of Ponoka.

In addition to providing electricity transmission and distribution services, Distribution and Transmission earns income through competitive contract-based commercial services related to maintaining and repairing streetlighting, traffic signals, light rail transit and trolley facilities.

		2005	2004
Distribution and Transmission results			
(including intersegment transactions, $ millions)			
Revenues	Distribution	$ 168.0	$ 158.2
	Transmission	32.8	32.9
	Commercial and other	46.9	40.5
		247.7	231.6
Expenses	Operating	182.3	165.5
	Depreciation, amortization and asset retirement accretion	25.7	23.6
	Financing	21.4	19.4
		229.4	208.5
Net income		**$ 18.3**	**$ 23.1**

Distribution and Transmission net income

Net income for the year ended December 31, 2004	**$ 23.1**
Financing expenses	(2.0)
Depreciation and amortization	(2.1)
Other	(0.7)
Net income for the year ended December 31, 2005	**$ 18.3**

For the year ended December 31, 2005, Distribution and Transmission net income decreased by $4.8 million from the prior year primarily due to increased financing expenses due to higher capital expenditures and lower cash inflows from operating activities. Financing expenses also increased due to the conversion of lower rate short-term debt to higher rate long-term debt. Depreciation and amortization expenses increased due to increased depreciable property, plant and equipment balances.

Distribution and Transmission revenues

	2005	2004
Electricity distribution (000s megawatt-hours)	6,988	6,693

Revenues for the year ended December 31, 2004	**$ 231.6**
Distribution revenues	9.8
Commercial and other revenues	6.4
Other	(0.1)
Revenues for the year ended December 31, 2005	**$ 247.7**

For the year ended December 31, 2005, Distribution and Transmission revenues increased by $16.1 million from the prior year mainly due to increased distribution tariff revenues on increased distribution volumes and increased access service revenues caused by increased volumes and higher electricity wholesale market prices. The increase in commercial and other revenues reflected an increased volume of contract-based commercial services work.

Distribution and Transmission expenses

Expenses for the year ended December 31, 2004	**$**	**208.5**
Energy purchase costs related to distribution activity		5.3
Commercial and other activity expenses		10.6
Depreciation and amortization		2.1
Financing expenses		2.0
Other		0.9
Expenses for the year ended December 31, 2005	**$**	**229.4**

For the year ended December 31, 2005, Distribution and Transmission expenses increased by $20.9 million from the prior year due to increased energy purchase and other costs resulting from increased distribution volumes and higher electricity wholesale market prices. The increase in commercial and other activity costs reflected increased volume of contract-based commercial services work.

Energy Services

Energy Services earns income through the provision of electricity and 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 at rates that are intended to cover the costs of supplying natural gas (including the commodity cost and costs related to transportation, credit risk, and natural gas price and volume risks) and provide a competitive margin.

Energy Services also manages EPCOR's overall electricity and natural gas portfolio aggregating the generation and the electricity and natural gas required to serve estimated customer demands in all markets in which the Company operates. 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 within limits established under prudent risk management policies. In 2000, EPCOR and its syndicate partners purchased the PPAs associated with TransAlta's Sundance generation plant (units 5 and 6) and Alberta Power (2000) Ltd.'s (ATCO) Battle River generation plant. The electricity provided under these PPAs, in addition to that produced from EPCOR's commercial plants, is used to help balance 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.

			2005	2004
Energy Services results				
(including intersegment transactions, $ millions)				
Revenues	Energy sales		$ 1,853.5	$ 1,932.1
	Commercial and other		53.0	34.2
			1,906.5	1,966.3
Expenses	Operating		1,736.6	1,817.0
	Depreciation, amortization and asset retirement accretion		39.4	42.7
	Financing		48.1	50.0
	Income taxes		24.1	20.6
			1,848.2	1,930.3
Net income from continuing operations			**58.3**	**36.0**
Loss from discontinued operations			-	(0.6)
Net income			**$ 58.3**	**$ 35.4**

Energy Services net income from continuing operations

Net income from continuing operations for the year ended December 31, 2004	**$ 36.0**
Merchant margins on electricity generated by Genesee Phase 3	17.4
Gains on the sale of Alberta mid-market electricity and natural gas contracts and settlement of litigation	13.3
Mark-to-market accounting adjustments	11.5
General and administration expenses	10.9
Merchant margins on electricity generated by Frederickson	6.2
Lower acquired PPA results	(12.7)
Lower Alberta electricity margins	(26.5)
Other	2.2
Net income from continuing operations for the year ended December 31, 2005	**$ 58.3**

For the year ended December 31, 2005, Energy Services net income from continuing operations increased by $22.3 million from the prior year for the reasons discussed below.

- Energy Services net income from continuing operations increased by $17.4 million from the prior year due to the incremental sales of electricity generated by Genesee Phase 3 (under contract with the Generation segment) from the March 1, 2005 commencement of plant operations.
- In the third quarter of 2005, Energy Services recorded a gain of $13.3 million on the sale of Alberta mid-market electricity contracts and settlement of litigation.
- Net income from continuing operations increased by $11.5 million after income taxes primarily due to the recognition of unrealized increases in the fair values of energy supply contracts that were previously deferred under hedge accounting. During the year, the Company sold Ontario mid- and mass-market sales contracts. As a result, the underlying energy supply contracts were no longer eligible for hedge accounting and the resulting fair value adjustments (mark-to-market gains) were recorded in income.
- Energy Services recorded decreased general and administration expenses of $10.9 million in 2005 compared to 2004 consisting of lower costs associated with customer service and administration activities. These reductions resulted primarily from the disposal of mid- and mass-market contracts in both years and lower bad debts

expense.

- Merchant margins also increased due to the reduction of expenses related to the sale of electricity generated by the Frederickson plant.
- Energy Services, with its syndicate partners, holds the Power Purchase Arrangements (PPAs) for two independently owned power plants in Alberta. In 2005, the margins on sales of electricity generated by these plants were lower than 2004 since higher wholesale prices of electricity in 2005 impacted PPA costs, including the costs of replacement energy when the plants were undergoing maintenance, by more than the associated increase in electricity revenues.
- For the year ended December 31, 2005, net income from continuing operations decreased by $26.5 million compared to 2004 as the margins on new and renewed Alberta electricity contracts for larger customers decreased from previous contract margins. As expected, margins have declined over the past two years as higher margin contracts expired and were replaced with contracts reflecting current market prices at lower margins.

Energy Services net income and net income from discontinued operations

Net income for the year ended December 31, 2004	**$**	**35.4**
Increase in net income from continuing operations – see previous table		22.3
Discontinued operations		0.6
Other		-
Net income for the year ended December 31, 2005	**$**	**58.3**

For the year ended December 31, 2005, Energy Services net income increased by $22.9 million from the prior year due to an increase in net income from continuing operations and losses on the disposal of discontinued operations recorded in 2004.

Energy Services revenues

	2005	2004
Retail consumption		
Electricity (000s of megawatt-hours)	13,135	14,925
Natural gas (000s of gigajoules)	3,634	11,288

Revenues for the year ended December 31, 2004	**$**	**1,966.3**
Energy sales		(78.6)
Commercial and other revenues		18.8
Revenues for the year ended December 31, 2005	**$**	**1,906.5**

For the year ended December 31, 2005, Energy Services revenues decreased by $59.8 million from the prior year primarily due to lower electricity and natural gas sales due to the 2004 disposal of Alberta mass-market contracts and the 2005 third quarter disposal of Alberta mid-market contracts. These decreases were partly offset by the impact of higher electricity prices in 2005 compared to 2004. Commercial and other revenues increased in 2005 compared to 2004 due to higher ancillary services activity. Ancillary services consist of system support services and generation reserve products provided by Energy Services and utilized by AESO as the system controller to maintain stability of the Alberta electricity grid and to balance generation supply and demand.

Energy Services expenses

Expenses for the year ended December 31, 2004	**$**	**1,930.3**
Energy purchase costs		(67.4)
General and administration expenses		(10.9)
Other		(3.8)
Expenses for the year ended December 31, 2005	**$**	**1,848.2**

For the year ended December 31, 2005, Energy Services expenses decreased by $82.1 million from the prior year primarily due primarily to lower energy purchase costs caused by the 2004 disposal of Alberta mass-market contracts and the 2005 third quarter disposal of Alberta mid-market contracts.

Water Services

Water Services earns income primarily from the treatment, distribution and sale of drinking 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 also 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 also earns incremental income through providing 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.

In April 2005, Water Services received approval from the B.C. Comptroller of Water Rights to acquire White Rock Utilities Limited, a water utility serving approximately 18,000 people in the community of White Rock, B.C. Water Services assumed control of these operations on May 1, 2005.

			2005		2004
Water Services results					
(including intersegment transactions, $ millions)					
Revenues	Water sales	$	111.9	$	107.5
	Commercial and other		63.0		29.6
			174.9		137.1
Expenses	Operating		121.0		80.7
	Depreciation, amortization and asset retirement accretion		14.0		13.0
	Financing		21.1		19.1
	Income taxes		(0.5)		-
			155.6		112.8
Net income		**$**	**19.3**	**$**	**24.3**

Water Services net income

Net income for the year ended December 31, 2004	**$**	**24.3**
Water sales less related franchise fees		3.1
Water treatment expenses		(3.8)
Administration expenses		(2.0)
Financing expenses		(2.0)
Other		(0.3)
Net income for the year ended December 31, 2005	**$**	**19.3**

For the year ended December 31, 2005, Water Services net income decreased by $5.0 million from the prior year primarily due to higher water treatment costs resulting from poor water quality conditions in the spring of 2005. Increased administration expenses consisted primarily of higher employee wages and benefits. Increased financing expenses were due to the conversion of lower rate short-term debt to higher rate long-term debt. These decreases were partly offset by increased water sales due to increased volumes as a result of customer growth and a rate increase in the second quarter of 2005.

Water Services revenues

	2005	2004
Water sales (megalitres)	121,083	120,070

Revenues for the year ended December 31, 2004	**$**	**137.1**
Competitive contract based water and wastewater project revenues		33.4
Water sales		4.4
Revenues for the year ended December 31, 2005	**$**	**174.9**

For the year ended December 31, 2005, Water Services revenues increased by $37.8 million from the prior year primarily due to increased commercial services activity including the Britannia Mine, B.C., Sooke, B.C. and Okotoks, Alberta projects. Water sales experienced a modest increase due to a combination of increased volumes due to customer growth and a rate increase in the second quarter of 2005.

Water Services expenses

Expenses for the year ended December 31, 2004	**$**	**112.8**
Expenses of competitive contract-based water and wastewater projects		32.3
Expenses of water sales operations		8.5
Financing expenses		2.0
Expenses for the year ended December 31, 2005	**$**	**155.6**

For the year ended December 31, 2005, Water Services expenses increased by $42.8 million from the prior year primarily due to the costs associated with increased commercial services activity. Expenses of water sales operations increased due to increased water treatment costs resulting from poor water quality conditions in spring 2005 and other increased costs consistent with increased water sales. Financing expenses increased due to the conversion of lower rate short-term debt to higher-rate long-term debt in 2005.

CONSOLIDATED BALANCE SHEETS

Significant changes in consolidated assets are outlined below:

$millions	December 31, 2005	December 31, 2004	Increase due to Power LP net assets acquired	Other increase (decrease)
Cash and cash equivalents	$ 90.0	$ 455.7	$ 17.9	$ (383.6)
	Refer to cash flows summary below.			
Accounts receivable	588.8	424.0	29.6	135.2
	Reflects increased electricity prices.			
Derivative financial instruments asset (current)(1)	57.9	3.7	4.4	49.8
	Reflects increased prices and volumes of unhedged positions that are marked-to-market and recorded in the balance sheet.			
Other current assets	57.0	52.6	16.0	(11.6)
	Reflects the other current assets acquired on the investment in Power LP.			
Property, plant and equipment	3,698.3	2,744.7	844.2	109.4
	Reflects the property, plant and equipment acquired on the investment in Power LP and capital expenditures in excess of depreciation and amortization expense.			
Power purchase arrangements	632.8	167.3	495.4	(29.9)
	Reflects the power purchase arrangement acquired on the investment in Power LP and amortization of PPAs.			
Contract and customer rights and other intangible assets	196.4	67.5	137.0	(8.1)
	Reflects the contract rights acquired on the investment in Power LP and the amortization of customer rights.			
Derivative financial instruments asset (non-current) (1)	39.9	17.3	-	22.6
	Reflects increased prices and volumes of unhedged positions that are marked-to-market and recorded in the balance sheet.			
Future income tax asset (non-current)	87.7	175.3	-	(87.6)
	Reflects the PILOT settlement with Alberta Revenue.			
Goodwill	148.5	-	145.7	2.8
	Reflects the goodwill recorded on the investment in Power LP.			
Other assets	61.5	93.9	-	(32.4)
	Reflects the change in non-current assets of the Clover Bar discontinued operations that were written down in the third quarter of 2005.			

Significant changes in consolidated liabilities and equity are outlined below:

$millions	December 31, 2005	December 31, 2004	Increase due to Power LP net assets acquired	Other increase (decrease)
Short-term debt	$ 28.5	$ -	$	$ 28.5
	Reflects increase in commercial paper issued to finance the investment in the Power LP.			
Derivative financial instruments liability (current) [1]	59.1	7.4	-	51.7
	Reflects increased prices and volumes of unhedged positions that are marked-to-market and recorded in the balance sheet.			
Other current liabilities	553.9	384.4	46.3	123.2
	Reflects increased accounts payable due to increased electricity prices.			
Long-term debt (including current portion)	2,081.0	1,610.3	448.5	22.2
	Reflects long-term debt recorded on the investment in Power LP and the issue of a $200.0 million 30-year medium term note in November 2005 partly offset by a scheduled repayment of a medium term note due in January 2005 and other ongoing, scheduled debt repayments.			
Derivative financial instruments liability (non-current) [1]	45.2	21.0	-	24.2
	Reflects increased prices and volumes of unhedged positions that are marked-to-market and recorded in the balance sheet.			
Future income tax liability	98.6	0.4	97.3	0.9
	Reflects the future income tax liability associated with the net assets acquired on purchase of the Power LP.			
Other non-current liabilities	147.9	139.8	18.6	(10.5)
	Reflects other non-current liabilities assumed on the investment in Power LP.			
Non-controlling interests	887.2	345.7	545.1	(3.6)
	Reflects the non-controlling interests in Power LP which result from consolidation of the Power LP.			
Shareholder’s equity	1,757.4	1,693.0	-	64.4
	Reflects net income offset by common share dividends.			

[1] EPCOR uses various open-market derivative financial instruments with arms’-length parties, including contracts-for-differences, to manage its electricity price risk. When those financial instruments do not meet all the required conditions for hedge accounting, they are recorded at fair value or “marked-to-market”. As a result of sales of end-use customer contracts during the year and as part of electricity portfolio management, physical contracts were replaced with financial contracts. The financial contracts did not meet all the conditions for hedge accounting resulting in an increase in the amount of unhedged derivative financial instrument assets and liabilities. The increase in derivative financial instrument assets and liabilities was also due to higher electricity prices and to forward foreign exchange contracts which are marked-to-market.

CONSOLIDATED STATEMENTS OF CASH FLOWS

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

	$millions					
	Year ended December 31					
	2005	2004	Change	2004	2003	Change
Operating	$ 466.2	$ 438.4	$ 27.8	$ 438.4	$ 557.6	$ (119.2)
Investing	(751.4)	(46.8)	(704.6)	(46.8)	375.5	(422.3)
Financing	(80.5)	(350.4)	269.9	(350.4)	(533.2)	182.8
Opening cash balance[(1)]	455.7	414.5	41.2	414.5	14.6	399.9
Closing cash balance[(1)]	$ 90.0	$ 455.7	$ (365.7)	$ 455.7	$ 414.5	$ 41.2

(1) Cash balance includes cash and cash equivalents.

Operating changes:

The 2004 to 2005 increase in cash inflows reflects the receipt of the Clover Bar PPA termination payment and changes in non-cash operating working capital due to the timing of receipts and payments.

Investing changes:

The 2004 to 2005 increase in cash outflows reflects the investment in the Power LP and the 2004 proceeds on disposal of a 49.85 per cent interest in the Frederickson plant, units of UE Waterheater Income Fund and competitive mass-market energy contracts.

Financing changes:

The 2004 to 2005 decrease in cash outflows reflects the cash received on a $200.0 million medium term note issued in November 2005 offset by the 2004 decreased short-term U.S. financing.

LIQUIDITY AND CAPITAL RESOURCES

($ millions)	2005	2004	2003
Cash flow from operations[1][2]	$ 519.9	$ 385.2	$ 323.0
Long-term borrowings during the year	200.0	-	-
Medium term notes redeemed or purchased during the year	-	-	(221.0)
Cash and cash equivalents, at end of year	90.0	455.7	414.5
Short-term debt, at end of year	(28.5)	-	(116.7)
Ratios[1]			
Debt to equity[3]	44:56	44:56	48:52
Interest coverage on long-term debt:			
Income before interest and taxes[4]	3.4 X	2.8 X	2.4 X
Income from continuing operations before interest and taxes [5]	3.0 X	2.6 X	2.4 X
Income before interest, taxes, depreciation and amortization[6]	5.1 X	4.0 X	3.6 X
Income from continuing operations before interest, taxes, depreciation and amortization[7]	4.3 X	3.7 X	3.7 X
Cash flow to interest bearing debt (per cent)[8]	24.5	24.0	17.8
Credit ratings[9]			
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 and 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.

(2) Refer to the following section, Non-GAAP Financial Measures for a reconciliation of cash flow from operations to cash flow from operating activities.

(3) 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 short-term debt plus long-term debt (including the current portion). Equity is equal to non-controlling interests and shareholder's equity. Total capital is equal to short-term debt, long-term debt (including the current portion), non-controlling interests and shareholder's equity.

(4) Income before interest and taxes is equal to operating income before financing expenses divided by interest on long-term debt.

(5) Income from continuing operations before interest and taxes is equal to operating income before financing expenses divided by interest on long-term debt for continuing operations.

(6) Income before interest, taxes, depreciation, amortization and asset retirement accretion is equal to operating income before financing expenses adding back depreciation and amortization, divided by interest on long-term debt.

(7) Income from continuing operations before interest, taxes, depreciation, amortization and asset retirement accretion is equal to operating income before financing expenses adding back depreciation and amortization, divided by interest on long-term debt for continuing operations.

(8) 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).

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

EPCOR used its existing cash balances and debt facilities to fund the $529.0 million purchase price for TransCanada's interest in the Power LP and fund the Company's ongoing capital expenditures.

On October 2, 2005, EPCOR filed a short-form base shelf prospectus that qualifies the Company to offer to the public in Canada, from time to time, Medium Term Note Debentures at prices and on terms determined at the time of issue, in an aggregate amount not to exceed $800.0 million. The prospectus is valid for a period of twenty five months from the aforementioned prospectus date. On November 17, 2005, EPCOR completed a public offering of senior unsecured medium term notes in the aggregate principal amount of $200.0 million. The notes have a coupon rate of 5.65 per cent and mature on November 16, 2035. The net proceeds of the offering were used to repay EPCOR's commercial paper indebtedness and for general corporate purposes.

Cash flow from operations, which is defined as net income adjusted for non-cash items, increased in 2005 to $519.9 million from $385.2 million in 2004 while cash flow from operating activities increased to $466.2 million from $438.4 million. The increase in cash flow from operations consisted of the receipt of the Clover Bar PPA termination payment partly offset by the decrease in net income from continuing operations. The increase in cash flow from operating activities consisted primarily of the receipt of the Clover Bar PPA termination payment partly offset by changes in non-cash operating working capital balances due to timing of receipts and payments.

At December 31, 2005, EPCOR maintained bank lines of credit of $1,110.0 million of which $1,060.0 million are committed term lines for the purpose of providing short-term capital and letters of credit. The lines of credit are $200.0 million committed until August 2006; $50.0 million committed under an extendable, term operating loan until August 2007; $300.0 million committed under a two-year extendable term loan until December 2007; $300.0 million committed under a three-year extendable term loan until December 2008; $210.0 million committed under a five-year term loan until November 2009; and $50.0 million uncommitted. At December 31, 2005, EPCOR had $98.3 million (US$84.5 million) of loans and $153.9 million of letters of credit outstanding under these credit facilities. The letters of credit were issued to meet the credit requirements of energy market participants, to meet conditions of certain debt and service agreements, and to satisfy legislated reclamation requirements. The committed bank lines also back EPCOR's commercial paper program, which has an authorized capacity of $500.0 million. At December 31, 2005, commercial paper of $28.5 million (2004-$nil) was issued and outstanding. Effective February 15, 2006, the one-year, two-year and three-year committed syndicated bank credit facilities were replaced by a single $800.0 million extendable syndicated bank credit facility consisting of a three-year $400.0 million facility and a five-year $400.0 million facility.

In 2005, EPCOR acquired a 30.6 per cent interest in Power LP for a total cost of $534.4 million. The purchase was financed by cash and issuance of commercial paper.

Working capital requirements for 2006 are expected to be substantially the same as 2005.

EPCOR's dividend policy with respect to the common shares owned by The City of Edmonton has remained unchanged since 2000. Under the policy, the current annual dividend is set at the greater of the previous year's dividend adjusted for the forecasted change in the consumer price index or 60 per cent of earnings available to common shares of

EPCOR in the applicable year. The dividend policy is subject to amendment in the event of 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 forecasted earnings. In accordance with EPCOR's dividend policy, the annual dividends were $122.7 million and $120.5 million, respectively for 2005 and 2004. Dividends for 2006 are set at $125.1 million.

EPCOR paid dividends on preferred shares issued by its subsidiaries, EPCOR Finance Corporation and EPCOR Preferred Equity Inc., totaling $19.6 million (2004 - $19.6 million). EPCOR also incurred income taxes of $1.9 million (2004 - $1.9 million) on these preferred share dividends.

EPCOR is committed to fund various capital projects. The total amount of committed capital funding at December 31, 2005 was $300.0 million for the years from 2006 to 2008 (2004 - $33.8 million committed for 2005). Although not committed, EPCOR has budgeted average annual capital requirements of approximately $120.0 million for infrastructure maintenance (distribution, transmission, water and generation operating under PPAs).

In 2006, EPCOR has principal repayment obligations on its long-term debt totalling $54.0 million (2005 - $131.0 million). Base capital expenditures are projected to be consistent with 2005 expenditures. Cash on hand and operating cash flows are expected to be the source of funds from which debt repayment obligations and capital programs will be funded in 2006.

In 2005, 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). The state of the electricity markets in general continues to be characterized by excess generating capacity in some North American regional markets, relatively high natural gas prices and environmental uncertainties. Specific risks cited for Canadian utility companies include declining allowed regulated returns on equity for rate-regulated operations and the financing and execution of major development projects. The credit issues facing North American utility companies have improved and at least one credit rating agency has characterized the Canadian and U.S. electric utilities as relatively stable. A rating change for EPCOR would likely impact interest costs and the availability of sources of investment capital.

NON-GAAP FINANCIAL MEASURES

EPCOR uses cash flow from operations as a measure of the Company's ability to generate funds from current operations. A reconciliation of cash flow from operations to cash flow from operating activities is as follows:

Year ended December 31	2005	2004	2003
Cash flow from operations	**$ 519.9**	**$ 385.2**	**$ 323.0**
Collection of deferred amounts receivable	-	21.7	191.8
Change in other non-current assets and liabilities	(40.4)	(42.0)	(18.0)
(Decrease) increase in non-cash operating working capital	(13.3)	73.5	60.8
Cash flow from operating activities	**$ 466.2**	**$ 438.4**	**$ 557.6**

NEW ACCOUNTING STANDARDS IN 2005

Consistent with the future accounting changes described in EPCOR's 2004 annual MD&A

and additional changes since the previous year-end, EPCOR has adopted accounting policies in accordance with the following new accounting standards:

Consolidation of variable interest entities

EPCOR has identified and evaluated its interests which potentially would be subject to the provisions of the new accounting standard for the consolidation of variable interest entities. EPCOR has concluded that the impact of this new standard is not material to the consolidated financial statements.

Determining whether an arrangement contains a lease

In December 2004, the Emerging Issues Committee of the Canadian Institute of Chartered Accountants (CICA) reached a consensus that is intended to clarify the requirements for identifying whether a commercial arrangement should be accounted for as a lease at its inception. This consensus applies to arrangements agreed to, modified or acquired in business combinations on or after January 1, 2005. As of January 1, 2005, EPCOR entered into a new agreement for the operation of its Rossdale generation plant with AESO. This agreement provides ongoing system reliability for The City of Edmonton and back-up generation for the Province of Alberta until December 31, 2008 unless the agreement is terminated earlier by AESO. The agreement with AESO has been accounted for as a lease in accordance with the CICA consensus.

This consensus also applies to arrangements acquired in business combinations initiated on or after January 1, 2005. The terms of Power LP's Castleton, Manchief, Mamquam, Queen Charlotte and Williams Lake PPAs are such that the related property, plant and equipment are accounted for as assets under operating leases in EPCOR's consolidated financial statements.

Disclosures by entities subject to rate regulation

Effective for its 2005 annual financial statements, EPCOR has complied with the requirements of Accounting Guideline 19 – Disclosures by Entities Subject to Rate Regulation as issued by the CICA in May 2005. This guideline specifies information about rate-regulated entities that is required to be disclosed in an entity's financial statements. EPCOR's rate-regulated entities include most of Distribution and Transmission's operations and certain operations within Energy Services and Water Services.

FUTURE ACCOUNTING CHANGES

Financial instruments, hedges, comprehensive income and equity

In 2005, the CICA issued three new Accounting Handbook Sections as follows: Section 3855, Financial Instruments, - Recognition and Measurement, Section 3865, Hedges and Section 1530, Comprehensive Income. Section 3855 prescribes when to recognize a financial instrument on the balance sheet and at what amount and how to present financial instrument gains and losses. Section 3865 provides alternative treatments to Section 3855 guidance when qualifying transactions are designated as hedges for accounting purposes. Section 1530 introduces the new concept of comprehensive income which is defined as the change in equity (net assets) of an enterprise during a period from transactions and other events and circumstances from non-owner sources. A statement of comprehensive income will present net income and each component to be recognized in other comprehensive income. These components would include, for example, exchange gains and losses arising on translation of the financial statements of self-sustaining foreign operations, which are currently included in a separate component of shareholders' equity. These new sections apply to annual and interim periods beginning on or after October 1, 2006. These changes in accounting standards are not expected to have a material impact to consolidated net income of EPCOR.

Non-monetary transactions

In 2005, the CICA issued new Accounting Handbook Section 3831 - Non-monetary Transactions. This new section requires all non-monetary transactions to be measured at fair value unless certain exceptions are met. Commercial substance replaces culmination of the earnings process as the test for fair value measurement. A transaction is deemed to have commercial substance if it causes an identifiable, measurable change in the economic circumstances of the entity. Commercial substance is a function of the cash flows expected by the reporting entity. It applies to non-monetary transactions initiated in periods beginning on or after January 1, 2006. EPCOR does not expect application of this new standard to have a material effect on its consolidated financial statements.

Accounting and financial reporting standards

In January 2005, the CICA Accounting Standards Board (AcSB) announced that it had ratified a new strategic plan whereby the AcSB will move to a single set of globally accepted high level standards over an expected five-year period. For public companies, Canadian GAAP will be replaced by International Financial Reporting Standards (IFRS). As they currently exist, Canadian GAAP and IFRS overlap to a great extent but there are some differences that may be significant. The impact to EPCOR cannot be determined until detailed convergence plans and recommendations are in place.

DISCLOSURE CONTROLS AND PROCEDURES

In conformance with the Canadian Securities Administrators' Multilateral Instrument 52-109, EPCOR has filed certificates signed by the Chief Executive Officer and the Chief Financial Officer that, among other matters, comment on disclosure controls and procedures.

Management has evaluated the design and effectiveness of EPCOR's disclosure controls and procedures as of December 31, 2005. Based on this evaluation, management has concluded that these controls and procedures are appropriately designed and operating effectively.

The evaluation considered EPCOR's Corporate 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.

SIGNIFICANT ACCOUNTING POLICIES

Revenue recognition under PPAs

EPCOR records the electricity revenue from its generation units operating under PPAs at the long-term price of power embedded in the PPAs, including estimated penalties and incentives for operating above or below specified availability targets set out in the PPA. Under this approach, EPCOR defers incentives, on a plant-by-plant basis in the current period, that are not expected to be sustained over the full term of the PPA. The degree to which incentives are recognized or deferred for each plant will change due to revisions to the long-term outlook of plant performance based on historical data, planned maintenance, reliability and plant availability and due to revisions in the estimated long-term price embedded in the PPA.

Financial commodity contracts

EPCOR uses contracts-for-differences for risk management purposes. Such contracts 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.

Amounts in lieu of income taxes

EPCOR accounts for amounts in lieu of income taxes in the same manner as federally and provincially legislated income taxes, on the basis that the amounts are a form of income tax and their determination is similar to the determination of income taxes.

Consolidation of Power LP

While EPCOR owns only 30.6 per cent 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, EPCOR 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 known challenges within the Alberta and Ontario electric systems and the statutory delays in final load settlement determinations and information, adjustments to previous estimates could be material.

Fair values

For determining the valuation of financial instruments that do not meet hedge accounting standards, the potential impairments of long-lived assets, the amount of asset retirement obligation liabilities and certain disclosures, EPCOR is 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, EPCOR uses appropriate price modeling to estimate fair value. Estimates of fair value used for potential asset impairments are mainly based on discounted cash flow techniques employing estimated future cash flows based on a number of assumptions and using an appropriate discount rate. Estimates will include forecasts of future wholesale electricity and natural gas prices. The fair value of asset retirement obligations depends on the total undiscounted amount of the estimated cash flows required to settle the obligations and the appropriate credit-adjusted risk-free discount rate.

Allowance for doubtful accounts

EPCOR continually reviews its aged accounts receivable and assesses 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. As the assessment of allowances is an estimate, actual bad debts experience will vary from the estimate.

Useful lives of assets

Depreciation and amortization is an estimate to allocate the cost of an asset over its estimated useful life on a systematic and rational basis. Depreciation and amortization also includes amounts for future decommissioning costs and, commencing in 2004, 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 EPCOR's 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.

CONTRACTUAL OBLIGATIONS

$millions	Payments due by period					
	2006	2007	2008	2009	2010 and thereafter	Total
Acquired PPA obligations[1]	$ 225.0	$ 196.0	$ 244.6	$ 247.3	$ 2,689.3	$ 3,602.2
Capital projects	83.8	210.0	45.0	-	-	338.8
Long-term debt	54.0	47.5	335.9	241.2	1,406.5	2,085.1
Natural gas purchase contracts[2]	34.5	38.6	43.8	45.9	345.8	508.6
Natural gas transportation contracts[3]	12.5	13.2	14.0	14.9	125.3	179.9
Operating leases	2.2	1.9	2.1	2.0	3.3	11.5
Waste heat contracts[4]	0.8	0.8	0.8	0.9	6.3	9.6
Other purchase obligations	42.7	22.1	16.2	7.7	1.7	90.4
Total contractual obligations	$ 455.5	$ 530.1	$ 702.4	$ 559.9	$ 4,578.2	$ 6,826.1

(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) 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.

(3) 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.

(4) 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 AES, effective February 1, 2005, EPCOR has guaranteed AES's prudential obligations with AESO and Alberta's wire service providers and gas distributors to a maximum of $40.0 million based on December 31, 2005 electricity and natural gas prices and the maximum volumes under the energy supply agreements. 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, 2005 and it is uncertain what, if any, additional amounts may be incurred in the future. There were no other material guarantee obligations outstanding in respect of third parties at December 31, 2005.

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.

EPCOR recorded interest expense of $62.8 million in 2005 compared with $73.5 million in 2004 on its 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 2005 corresponds to the decrease in the obligation. The outstanding balance of the obligation to The City of Edmonton was $381.9 million at December 31, 2005, a decrease of $77.5 million from the amount of $459.4 million outstanding at the end of the previous year.

Sales from EPCOR to The City of Edmonton included electricity and water, maintenance, repair and construction services, and customer care services totalling $65.7 million in 2005 compared with $68.7 million in 2004. EPCOR paid franchise fees to The City of Edmonton, determined on the basis of distribution volumes and water revenues, and property taxes of $44.6 million in 2005 and $42.9 million in 2004. The City of Edmonton provided miscellaneous services to EPCOR totalling $6.5 million in 2005 and $9.5 million in 2004.

RISK MANAGEMENT

EPCOR's 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 EPCOR's Risk Oversight Council, a senior executive group including the vice president of risk management. Second, EPCOR's vice president of risk management is generally responsible for monitoring compliance with risk management policies. His responsibility includes oversight of enterprise wide risks and management of EPCOR's commodity risk management (or middle office) function. The third level of risk management occurs in operations. The operational business units and shared service units are generally responsible for carrying out the risk management and mitigation activities associated with the risks in their respective operations. These risk management activities are generally integral aspects of the business units' and shared service units' operations. In summary, EPCOR believes that risk management is a key component of the Company's culture and has put into place cost-effective risk management practices. At the same time, EPCOR views risk management as an ongoing process and continually reviews its risks and looks for ways to enhance its risk management processes.

Electricity price and volume risk

EPCOR buys and sells electricity in the wholesale markets of Alberta, Ontario, the U.S. Pacific Northwest and several states in the eastern United States. Such exchanges are settled at the hourly spot market prices of the respective markets. EPCOR currently uses purchase and sale arrangements including contracts-for-differences and firm price physical contracts for periods of varying duration to manage its exposure to spot price variability within specified risk limits. Due to the reduced market liquidity (limited product) 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. EPCOR balances its electricity book within the limits of its policies. EPCOR generally trades in electricity to reduce its exposure to changes in electricity prices or to match physical or financial obligations.

When aggregate customer electricity consumption (load shape) changes unexpectedly, EPCOR is exposed to price risk. Load shape refers to the different pattern of consumption between peak hours and off-peak hours. Consumption is highest during peak hours, which are generally the hours of the day when people and organizations are active. Conversely, consumption is lower during off-peak hours. EPCOR purchases 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, EPCOR relies on historical aggregate consumption data (load shape) provided by load settlement agents and local distribution companies to anticipate what aggregate customer consumption will be during peak hours. When consumption varies from historical consumption patterns and the volume of electricity purchased for any given peak hour period, EPCOR is exposed to the prevailing market prices to either buy the electricity if it is short or sell the electricity if it is long. Exposures can be exacerbated by system events like unexpected generation plant outages and unusual weather patterns.

Electricity sales associated with EPCOR’s generation units that are subject to PPAs are governed by the terms of the 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.

Electricity price and volume risks for Power LP have been minimized by the execution of fixed-price, long-term power sales contracts with five investment-grade power buyers – Ontario Electricity Financial Corporation, British Columbia Hydro and Power Authority, TransCanada Corporation, Niagara Mohawk Power Corporation and Public Service Company of Colorado.

Natural gas price and volume risk

Price risk associated with natural gas purchased for EPCOR’s natural gas-fired generation plants operating under PPAs is mitigated by the provisions of the PPA which require the PPA holder 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. At the Frederickson generation plant, the gas supply, for EPCOR’s 50.15 per cent interest in the plant, is provided by the customers under tolling agreements. 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.

For its retail natural gas business, EPCOR balances its exposure by purchasing natural gas back-to-back with its sales contracts to the fullest extent possible. That is, EPCOR normally only purchases 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 EPCOR's risk management policies. For its Tunis, Ontario plant, the Power LP is exposed to commodity price risk on its natural gas purchases beginning in 2010 when its natural gas supply contract ends prior to the expiry of the PPA in 2014.

The initial term of a block of natural gas contracts that EPCOR acquired in 2000 expired in late 2004. The customers under these contracts had an option to renew at the original contracted price and approximately 50 per cent 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 $11.0 million over the next four years, depending on future natural gas prices.

Operational risk

EPCOR's 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 EPCOR's and the acquired PPA plant owners' operating and maintenance practices that minimize the likelihood of prolonged unplanned down time. EPCOR has a very strong record of availability, as measured against its peers by the Canadian Electricity Association. In addition, the penalty provisions within the PPAs provide appropriate incentives to owners to keep the plants operational. The terms of the PPAs also provide force majeure protection for high-impact, low probability events including major equipment failures. EPCOR's 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, EPCOR has 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 Generation, Distribution and Transmission, and Water Services is 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.

EPCOR's fuel expense for the Genesee plants is predominately comprised of coal supply. Coal is supplied under long-term agreements with the Genesee Coal Mine joint venture, of which EPCOR holds a 50 per cent 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.

EPCOR employs several key computer application systems to support its various operations such as electricity and water distribution network control systems, electricity and water plant control systems and electricity settlement and billing systems. EPCOR takes measures to reduce the risk of failure of these systems or the hardware and network infrastructure on which they operate.

EPCOR has established 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

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. Both EPCOR and certain load settlement agents have experienced challenges since 2001 to provide quality customer consumption data for timely and accurate billings to some customers. Although EPCOR began working with load settlement agents in early 2002 to resolve issues related to settlement and the accuracy of customer consumption data, adjustments to bills continued throughout 2005 and 2004, albeit at a reduced frequency. Under an amendment to the *Alberta Regulated Default Supply Regulation* which came into effect in June 2003, regulated rate providers may not collect from customers an amount undercharged due to a billing error if the error occurred more than twelve months before the date of the revised billing.

Rates for energy charges to RRT customers were determined according to the 2004 to 2005 energy price setting plan which was approved by the AEUB in 2003. 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 are expected to be set by the AEUB in 2006. The 2005 revenues have been recorded at the approved interim rates for 2005; the impact of adjustments to 2005 rates will be recorded when the rate decisions are received. This 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 and a fair margin on energy sold to RRT customers. EPCOR's ability to recover the actual costs of providing service and to earn a fair return on investment and a fair energy margin is dependent on achieving the forecasts established in the rate-setting process.

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 has 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, 2005, EPCOR had approximately $18.0 million due from the Ontario government with respect to this rebate.

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 will replace the current Regulated Rate Tariff after its expiry on June 30, 2006 as 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 will be set using a combination of long-term and monthly forward hedges, with an increasing percentage of monthly forward hedges required 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. This electricity pricing model change may impact EPCOR's volume of electricity sales, as well as electricity margins, to its customers. EPCOR currently provides approximately 55 per cent of the Regulated Retail Tariff load within the Province of Alberta. The future financial impact to EPCOR cannot be determined at this time.

Supply risk of acquired PPAs

EPCOR holds acquired PPAs, which entitle the Company to the electricity produced from specific generating units up to their committed capacity. In most cases where plant capability falls below committed capacity, EPCOR is entitled to receive 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 purchaser from fulfilling its obligation under the PPAs, could have a material negative impact on the ability of EPCOR to generate revenue. In such circumstances, EPCOR would be required to replace electricity that it is short of, 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 energy purchases to EPCOR.

Credit risk

Credit risk is associated with the ability of counterparties to satisfy their contractual obligations to EPCOR, including payment and performance. Credit risk is managed by making appropriate credit assessments of counterparties, dealing with creditworthy counterparties, and where appropriate, requiring the counterparty to provide appropriate security. Credit exposures and practices are governed by specific credit limits set out in EPCOR's credit policy. During 2002 and 2003, there was a general reduction in the number of creditworthy counterparties in the wholesale electricity marketplace. This has made management of risk more difficult for EPCOR as it reduced market liquidity and could impede the Company's ability to quickly and cost effectively react to changes in electricity long or short positions. Liquidity in the markets in which EPCOR operates has been slowly improving since 2003 as more creditworthy counterparties have emerged in the marketplace.

Environmental risk

EPCOR complies, in all material respects, with federal, provincial and local environmental legislation and guidelines with respect to its electricity and water operations. As EPCOR's generation business is a significant emitter of carbon dioxide, a greenhouse gas, it must comply with existing and emerging federal and provincial requirements including a program to offset emissions. The greenhouse gas reduction targets embedded in the Kyoto protocol will result in increased future costs to EPCOR, but the amounts are uncertain as they will depend on yet to be established policies on how the targets and associated remediation costs are ultimately allocated to industry sectors, emitters and consumers.

EPCOR's water 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.

EPCOR's power plants also produce nitrous oxide (NOx), sulphur oxide (SOx), and mercury. EPCOR must comply with existing and emerging federal and provincial requirements to limit the emission of these chemicals. EPCOR participates in the Clean Air Strategic Alliance which has recommended a framework on NOx, SOx, mercury and particulate emissions to the Alberta government for both natural gas- and coal-fired generation plants. It has also recommended that mercury emission standards be implemented for coal-fired generation plants. At this point in time, there is no legislated obligation that EPCOR is required to assume for capital costs to fulfill potential mercury control requirements.

EPCOR continues to work with governments of all levels to ensure that the legislated targets can be met.

Project risk

The construction and development of generation and water treatment facilities and acquisition activities are subject to various engineering, construction and environmental risks relating to performance, delays and cost overruns. EPCOR attempts 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 provided where and when available.

Weather risk

Weather can have a significant impact on EPCOR's operations. Temperature levels, seasonality and precipitation, both 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 the Company's hydro-generating units and also impacts the cooling pond reservoir level at the Battle River generation plant which in turn can impact the performance of the Battle River acquired PPA. The level and quality of spring run-off in the North Saskatchewan River affects the quality of water entering EPCOR's water purification systems and the resulting costs of purification. Seasonal weather patterns are a factor in the volume and extent of water main breaks. Weather variability and seasonality also impact the demand and supply of water.

Weather related financial instruments are available in the financial markets but the Company has not pursued them due to their limited coverage and relatively high cost.

Foreign exchange risk

Fluctuations in the exchange rate between the U.S. dollar or the Euro and the Canadian dollar affect some of EPCOR's revenues, capital and operating costs and cash flows and could adversely impact EPCOR's financial performance and condition.

EPCOR's 50.15 per cent interest in the Frederickson generation plant, located in the State of Washington, is accounted for as a self-sustaining foreign operation utilizing the current-rate method of foreign currency translation. EPCOR manages its exposure to foreign exchange risk on these operations by offsetting its investment with a U.S. dollar denominated loan. The net impact of the unrealized gains or losses of the investment and the offsetting loan are accumulated and reported as “foreign currency translation adjustment” in shareholder’s equity. The accumulated foreign currency translation adjustment mainly reflects an unrealized exchange loss incurred in the first quarter of 2003 before U.S. dollar financing was put in place.

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, 2005, US$93.5 million or approximately one-half of these future cash flows were hedged for 2006 to 2011 at a weighted average exchange rate of 1.296.

In situations where EPCOR contracts to purchase large value parts for Generation, Distribution and Transmission operations from suppliers outside of Canada, the Company generally fixes the purchase price in Canadian dollars by contracting in Canadian dollars or using forward foreign exchange contracts. Forward foreign exchange contracts for 98.8 million Euros, matching EPCOR’s future Euro exposure for wind turbines expected to be purchased under contract for the Kingsbridge Wind Power Project in Ontario, were in place at the end of 2005.

Conflicts of interest

Certain conflicts of interest could arise as a result of EPCOR’s relationship with the City of Edmonton. The City of Edmonton may have a conflict arise as a shareholder of EPCOR and the administrator of the budget for the citizens of Edmonton. The City of Edmonton has the authority to establish the dividend policy in respect of the common shares of the Company held by it.

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. EPCOR Power Services Ltd. (GP), a wholly owned subsidiary of the Company, is the general partner of Power LP and EPCOR manages the assets and operations of Power LP. 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 a total of 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, risks of a widespread influenza or other pandemic illness, EPCOR’s ability to generate sufficient cash flow from operations to meet its current and future 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 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. EPCOR's ability to mitigate these risks is dependent on management's ability to anticipate such risks and, where possible, to develop appropriate mitigation plans.

EPCOR's operations are subject to the risks of a widespread influenza outbreak or other pandemic illness. EPCOR is 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.

EPCOR and approximately 450 other employers, participating in certain Alberta public pension plans including the Local Authorities Pension Plan, have been named in a $1.25 billion class action lawsuit regarding pension benefits. EPCOR's opinion is that this lawsuit is without merit. The outcome of this matter is not determinable at this time, and EPCOR's potential loss, if any, cannot be estimated.

In July 2004, NAL Resources Limited (NAL) and Devon Canada Corporation (Devon) commenced actions against Power LP claiming the gas supply contracts under which NAL and Devon sell gas to Power LP for its Tunis power plant have been frustrated as of January 1, 2003 due to an alleged inability to determine the commodity charge for gas under such agreements. NAL and Devon additionally seek monetary damages based on referenced spot gas prices should the courts uphold their claims. Power LP has filed statements of defense and will vigorously defend the actions. The final outcome is not determinable at this time and, accordingly, no amount has been accrued in the financial statements.

While EPCOR believes it employs prudent risk management controls and procedures as outlined above, there can be no assurance that risk management steps taken will avoid future loss due to the occurrence of the above risks or unforeseen risks.

DERIVATIVE FINANCIAL INSTRUMENTS

EPCOR uses various open-market derivative financial instruments with arm's-length parties, including contracts-for-differences, to manage its exposure to electricity and natural gas price, foreign exchange rates and interest rate risks. These derivative financial instruments are recorded at fair value (that is, marked-to-market) in the balance sheet unless they are designated as hedges which are effective. The fair value of the contracts-for-differences represents the net amount that would have been received on the termination of the contracts with the counterparties at the balance sheet date.

Derivative financial instruments assets and liabilities recorded in the consolidated balance sheet include both deferred unrealized gains and losses on derivative financial instruments recorded upon termination of a hedging relationship and unrealized gains and losses on derivative financial instruments which did not satisfy the conditions for hedge accounting. The deferred gains and losses are amortized and recognized into income on a straight-line basis over the remaining terms of the respective financial instruments.

Those derivative financial instruments that are designated as effective hedges are not recorded on 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)		2005			2004		
			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	$ (130.0)	10.9	MWh	$ 12.2	12.0	MWh
Electricity purchases contracts-for-differences	Hedge	35.5	3.6	MWh	13.4	8.2	MWh
Forward foreign exchange contracts	Hedge	-	-		(0.2)	17.3	Euros

MWh – megawatt-hours

EPCOR does not have any other material off-balance sheet arrangements.

OUTLOOK

In 2005, EPCOR increased its pace of growth with the acquisition of Power LP. On a go-forward basis, continuing operations will reflect the impact of a full year's contribution of Power LP earnings, contributions from the Kingsbridge I wind farm and a full year's production from EPCOR's 50 per cent share of Genesee Phase 3 offset by continued margin compression on retail and wholesale contracts.

Electricity deregulation has slowed in most markets in North America but the generation overbuild of the past couple of years is closing as demand catches up with supply. Spark spreads are improving as power prices rise but are still relatively low, with high natural gas prices continuing to reduce the amount of time that commercial natural gas-fired plants can economically run. There is interest, particularly in Alberta and the U.S., for clean coal technologies to take advantage of the abundant supply and help move toward energy self-reliance.

Opportunities for water or wastewater contracts continue to develop, albeit at a slower pace. EPCOR has capitalized on opportunities and will continue to work with governments to show the value of the Company's expertise to manage and operate water and wastewater systems.

EPCOR's key performance drivers include achieving net income targets, good operational performance and development of EPCOR power and water facilities.

Subsequent to year-end, EPCOR announced that it reorganized certain subsidiaries within its Generation segment to better align its legal structure with its operating structure to realize efficiencies. As a result of the restructuring, EPCOR Generation Inc. (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 the PILOT regulation. 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 will have additional deductions available for income tax purposes. As a result of these additional deductions and adjustments to current and future income tax assets recorded in the balance sheet, it is expected that consolidated net income for 2006 will increase by $110.0 million to $140.0 million.

A significant portion of contracted sales to customers by EPCOR during the period from 2000 to 2002 were at market prices and margins that were significantly higher than market prices and margins on current contracts. With the expiration of most of the remaining higher margin contracts over the next year, there is no assurance that the Company will be able to renew these contracts, or that the new contract values and related margins will not be lower than those on expiring contracts. Capital expenditures may rise in 2006 depending on the outcome of various business development opportunities. Planned capital projects for 2006 include the E.L. Smith water treatment plan expansion and the Kingsbridge II wind farm. Base capital spending for infrastructure is projected to remain stable in 2006 in the range of that incurred in 2005. Cash flow from operating activities is expected to remain in the range that it was in 2005 excluding the Clover Bar termination payment.

On March 14, 2006, EPCOR and TransAlta Corporation announced that they have signed a development agreement to jointly pursue TransAlta's Keephills 3 power project which is a proposed 450 megawatt generation unit adjacent to TransAlta's existing Keephills facility.

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, 2005	$ 888.6	$ 45.8	$ (8.4)	$ 37.4
September 30, 2005	595.8	63.3	22.0	85.3
June 30, 2005	587.8	46.4	9.7	56.1
March 31, 2005	626.6	3.2	5.1	8.3
December 31, 2004	662.8	50.3	3.1	53.4
September 30, 2004	632.5	36.3	4.2	40.5
June 30, 2004	603.2	35.9	2.0	37.9
March 31, 2004	696.1	60.2	6.0	66.2

For the quarter ended December 31, 2005, net income from continuing operations decreased by $4.5 million from the same quarter in the prior year primarily due to the negative impact of reduced margins on Alberta electricity sales contracts and higher electricity pool prices on acquired PPA results. These decreases were partly offset by the positive impact of the incremental Genesee Phase 3 operations.

Net income for the fourth quarter of 2005 decreased by $16.0 million over net income for the same quarter in 2004 primarily due to the changes in net income from continuing operations plus the absence of earnings from the Clover Bar generation plant which was shut down for decommissioning effective September 30, 2005.

Segment results for the fourth quarter included lower earnings in Generation with a net loss of $11.2 million in the fourth quarter of 2005 compared to net income of $8.4 million for the corresponding period in 2004. Generation's fourth quarter results include the negative impact of the curtailment of operations of its Clover Bar generation plant which thus reduced income contributions. Energy Services quarterly net income was flat at $14.5 million in the last fiscal quarter of 2005 compared to $14.6 million in the fourth quarter of 2004. Distribution and Transmission net income fell to $2.3 million in the fourth quarter of 2005 from $6.9 million in the fourth quarter of 2004. This was primarily due to lower income from commercial services as margins on third-party construction jobs decreased. Water Services experienced a modest decrease in net income in the fourth quarter of 2005 compared to 2004 to $4.4 million from $4.8 million due to lower water sales volumes.

Events for 2005 and 2004 quarters that have significantly impacted net income from continuing operations and net income and the comparability between quarters are:

- 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 mid-market electricity contracts and

settlement of litigation.

- June 30, 2005 second quarter results include the unrealized mark-to-market gains 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 include a full quarter's results of operations for the Genesee Phase 3 generation unit from its start-up date of March 1, 2005 of approximately $7.0 million after financing expenses and income taxes.
- June 30, 2005 second quarter 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.
- December 31, 2004 fourth quarter results include the gain on the sale of Alberta competitive mass-market electricity and natural gas contracts of approximately $6.0 million after income taxes.
- June 30, 2004 second quarter results include the loss on disposal of a 49.85 per cent interest in the Frederickson generation plant of $10.9 million after income taxes.
- March 31, 2004 first quarter results include the income increase due to the revised estimates for availability incentive income of $26.0 million after income taxes.

ADDITIONAL INFORMATION

Additional information relating to EPCOR including the Company's 2005 Annual Information Form (AIF) is available on SEDAR at www.sedar.com.