Consolidated Financial Statements of

EPCOR UTILITIES INC.

Years ended December 31, 2008 and 2007

Management's responsibility for financial reporting

The preparation and presentation of the accompanying consolidated financial statements of EPCOR Utilities Inc. are the responsibility of management and the consolidated financial statements have been approved by the Board of Directors. In management's opinion, the consolidated financial statements have been prepared within reasonable limits of materiality in accordance with Canadian generally accepted accounting principles. The preparation of financial statements necessarily requires judgment and estimation when events affecting the current year depend on determinations to be made in the future. Management has exercised careful judgment where estimates were required, and these consolidated financial statements reflect all information available to March 13, 2009. Financial information presented elsewhere in this annual report is consistent with that in the consolidated financial statements.

To discharge its responsibility for financial reporting, management maintains systems of internal controls designed to provide reasonable assurance that the Company's assets are safeguarded, that transactions are properly authorized and that reliable financial information is relevant, accurate and available on a timely basis. The internal control systems are monitored by management, and evaluated by an internal audit function that regularly reports its findings to management and the Audit Committee of the Board of Directors.

The consolidated financial statements have been examined by KPMG LLP, the Company's external auditors. The external auditors are responsible for examining the consolidated financial statements and expressing their opinion on the fairness of the financial statements in accordance with Canadian generally accepted accounting principles. The auditors' report outlines the scope of their audit examination and states their opinion.

The Board of Directors, through the Audit Committee, is responsible for ensuring management fulfils its responsibilities for financial reporting and internal controls. The Audit Committee, which is comprised of independent directors, meets regularly with management, the internal auditors and the external auditors to satisfy itself that each group is discharging its responsibilities with respect to internal controls and financial reporting. The Audit Committee reviews the consolidated financial statements and annual report and recommends their approval to the Board of Directors. The external auditors have full and open access to the Audit Committee, with and without the presence of management. The Audit Committee is also responsible for reviewing and recommending the annual appointment of the external auditors and approving the annual external audit plan.

On behalf of management,

Don Lowry
President and Chief Executive Officer

Mark Wiltzen
Senior Vice President and
Chief Financial Officer

March 13, 2009

EPCOR UTILITIES INC.
Consolidated Financial Statements

Years ended December 31, 2008 and 2007

KPMG

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Chartered Accountants
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Canada

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AUDITORS' REPORT TO THE SHAREHOLDER OF EPCOR UTILITIES INC.

We have audited the consolidated balance sheets of EPCOR Utilities Inc. as at December 31, 2008 and 2007 and the consolidated statements of income, comprehensive income, changes in shareholder's equity and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of EPCOR Utilities Inc. as at December 31, 2008 and 2007 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants

Edmonton, Canada

March 13, 2009

EPCOR UTILITIES INC.

Consolidated Statements of Income
(In millions of dollars)

Years ended December 31, 2008 and 2007

	2008	2007
Revenues	$ 3,442	$ 3,663
Operating expenses (income):		
Energy purchases and fuel	2,139	2,306
Operations, maintenance and administration	670	517
Franchise fee, property taxes and other taxes	68	66
Depreciation, amortization and asset retirement accretion (note 6)	258	245
Foreign exchange losses (gains)	9	(37)
Gain on sale of power syndicate agreement (note 4)	(34)	(34)
Impairments (notes 9 and 10)	52	13
Net financing expenses (note 19)	177	171
	3,339	3,247
Net income before income taxes and non-controlling interests	103	416
Income taxes (reductions) (note 20)	(21)	112
Net income before non-controlling interests	124	304
Non-controlling interests (note 15)	(51)	27
Net income	$ 175	$ 277

See accompanying notes to consolidated financial statements.

EPCOR UTILITIES INC.

Consolidated Balance Sheets
(In millions of dollars)

December 31, 2008 and 2007

	2008	2007
Assets		
Current assets:		
Cash and cash equivalents (notes 26 and 30)	$ 111	$ 79
Accounts receivable	502	581
Income taxes recoverable	7	10
Inventories (note 5)	84	62
Prepaid expenses	9	9
Derivative instruments assets (note 22)	130	104
Future income tax assets (note 20)	3	3
	846	848
Property, plant and equipment (note 6)	4,728	4,216
Power purchase arrangements (note 7)	593	679
Contract and customer rights and other intangible assets (note 8)	207	192
Derivative instruments assets (note 22)	75	116
Future income tax assets (note 20)	103	103
Goodwill (note 9)	161	185
Other assets (note 10)	235	223
	$ 6,948	$ 6,562

Approved on behalf of the Board:

Hugh J. Bolton
Director and Chairman of the Board

Wesley R. Twiss
Director and Chairman of the Audit Committee

		2008		2007

Liabilities and Shareholder's Equity

Current liabilities:				
Short-term debt (note 11)	$	140	$	138
Accounts payable and accrued liabilities		587		615
Income taxes payable		4		44
Derivative instruments liabilities (note 22)		131		136
Other current liabilities		20		15
Future income tax liabilities (note 20)		34		39
Current portion of long-term debt (note 12)		26		388
		942		1,375
Long-term debt (note 12)		2,702		1,751
Derivative instruments liabilities (note 22)		110		78
Other non-current liabilities (note 13)		125		125
Future income tax liabilities (note 20)		100		126
		3,979		3,455
Non-controlling interests (note 15)		540		740
Shareholder's equity:				
Share capital (note 16)				
Retained earnings		2,476		2,430
Accumulated other comprehensive loss (note 17)		(47)		(63)
		2,429		2,367
Contingencies and commitments (note 29)				
Subsequent events (notes 10, 21 and 32)				
	$	6,948	$	6,562

See accompanying notes to consolidated financial statements.

EPCOR UTILITIES INC.

Consolidated Statements of Changes in Shareholder's Equity
(In millions of dollars)

Years ended December 31, 2008 and 2007

	2008	2007
Retained earnings:		
Balance, beginning of year	$ 2,430	$ 2,245
Adjustment for changes in accounting policies	-	12
Net income	175	277
Common share dividends paid	(130)	(128)
Refundable taxes	1	24
Balance, end of year	2,476	2,430
Accumulated other comprehensive loss:		
Balance, beginning of year	(63)	(2)
Adjustment for changes in accounting policies	-	(41)
Other comprehensive income (loss)	16	(20)
Balance, end of year (note 17)	(47)	(63)
Total shareholder's equity, end of year	$ 2,429	$ 2,367

See accompanying notes to consolidated financial statements.

EPCOR UTILITIES INC.

Consolidated Statements of Comprehensive Income
(In millions of dollars)

Years ended December 31, 2008 and 2007

	2008	2007
Net income	$ 175	$ 277
Other comprehensive income (loss), net of income taxes:		
Unrealized gains (losses) on derivative instruments designated as cash flow hedges (1)	26	(72)
Reclassification of losses on derivative instruments designated as cash flow hedges to net income (2)	7	46
Unrealized gains on financial instruments designated as available for sale(3)	7	3
Reclassification of gains on financial instruments designated as available for sale to net income (4)	(10)	-
Unrealized loss in self-sustaining foreign operations (5)	(62)	-
Non-controlling interests (5) (note 15)	48	3
	16	(20)
Comprehensive income	$ 191	$ 257

(1) For the years ended December 31, 2008 and 2007, net of income tax expense of $13 and income tax recovery of $29, respectively.

(2) For the years ended December 31, 2008 and 2007, net of reclassification of income tax recoveries of $3 and $20, respectively.

(3) For the years ended December 31, 2008 and 2007, net of income tax expense of $2 and $1, respectively.

(4) For the year ended December 31, 2008 net of reclassification of income tax expense of $3.

(5) For the years ended December 31, 2008 and 2007, net of income tax expense of nil.

See accompanying notes to consolidated financial statements.

EPCOR UTILITIES INC.

Consolidated Statements of Cash Flows
(In millions of dollars)

Years ended December 31, 2008 and 2007

	2008	2007
Operating activities:		
Net income	$ 175	$ 277
Adjustments to reconcile net income to funds from operating activities:		
Depreciation, amortization and asset retirement accretion (note 6)	258	245
Impairments (notes 9 and 10)	52	13
Gain on sale of power syndicate agreement (note 4)	(34)	(34)
Non-controlling interests in Power LP (note 15)	(58)	19
Fair value changes on derivative instruments	98	(16)
Unrealized foreign exchange losses (gains)	21	(70)
Other	(16)	7
Future income taxes	(12)	76
	484	517
Change in non-cash operating working capital (note 18)	(81)	24
	403	541
Investing activities:		
Property, plant and equipment and other assets	(658)	(499)
Change in non-cash working capital	28	50
Acquisition of Morris Cogeneration LLC (note 3)	(89)	-
Non-bank sponsored asset backed commercial paper (note 10)	-	(71)
Proceeds on sale of power syndicate agreement (note 4)	53	59
Proceeds on sale of portfolio investments	16	-
Other	7	(8)
	(643)	(469)
Financing activities:		
Net proceeds from issue of short-term debt	2	138
Repayment of short-term debt	-	(200)
Proceeds from issue of long-term debt	910	395
Repayment of long-term debt	(411)	(347)
Issue of subsidiary preferred shares (note 15)	-	121
Redemption of subsidiary preferred shares (note 15)	-	(200)
Distributions to non-controlling interests	(94)	(91)
Issue of limited partnership units of Power LP to non-controlling interests (note 15)	-	69
Common share dividends paid	(130)	(128)
Debt issue costs	(14)	-
	263	(243)
Foreign exchange gain (loss) on cash held in a foreign currency	9	(10)
Increase (decrease) in cash and cash equivalents	32	(181)
Cash and cash equivalents, beginning of year	79	260
Cash and cash equivalents, end of year	$ 111	$ 79

	2008	2007
Supplementary cash flow information:		
Interest paid net of interest received	$ 154	$ 161
Income taxes paid net of income taxes recovered	65	29

See accompanying notes to consolidated financial statements.

1. Description of business:

(a) Nature of operations:

EPCOR Utilities Inc. (the Company or EPCOR) builds, owns and operates power plants, electrical transmission and distribution networks, water and wastewater treatment facilities and infrastructure, and provides energy and water services and products to its residential and commercial customers. The Company operates in Canada and the United States (U.S.), with its head office located in Edmonton, Alberta.

The common shares of EPCOR are owned by The City of Edmonton (the COE). The Company was established by City Council under City Bylaw 11071.

(b) Rate regulation:

EPCOR provides rate-regulated electric distribution and transmission services to customers within the City of Edmonton and surrounding areas, and supplies electricity under Regulated Rate Tariffs (RRT) to customers in Alberta. EPCOR's electric distribution and transmission operations and its RRT operations are regulated by the Alberta Utilities Commission (AUC), pursuant to the *Electric Utilities Act* (Alberta), the *Public Utilities Board Act* (Alberta) and the *Hydro and Electric Energy Act* (Alberta). The AUC administers these acts and regulations regarding tariffs, rates, construction, financing, operations, accounting and service area. The distribution and transmission and RRT businesses operate under cost-of-service regulation, whereby the AUC issues rate orders establishing the revenue requirements of these businesses, which are those revenues required to recover approved operating costs and to provide a rate of return on a deemed capital structure applied to approved rate base assets. The approved 2008 returns on equity (ROE) for the distribution and transmission and RRT businesses were 8.75% (2007 – 8.51%) and 8.86% (2007 – 8.51%) respectively. The approved ROE for the approval period is adjusted annually by formula for forecast changes in long-term Government of Canada bond yields.

The RRT business is required to file rate applications with the AUC for the approval of both RRT energy billing rates and RRT non-energy billing rates. After a process of public consultation is completed, the AUC approves the rates for the specified period. On April 28, 2006, an Energy Price Setting Plan was approved for the period July 1, 2006 to June 30, 2011 which determines the energy margin, the procurement methodology and energy rates for the Company's RRT customers. The Company applies for non-energy rates based on estimated costs of service. Once the rates are approved, they are not adjusted as a result of actual costs of service being different from those which were estimated other than for certain prescribed costs that are eligible for deferral account treatment. The AUC approved non-energy rates for the RRT business, for the years 2007 through 2009, on April 30, 2008.

1. Description of business, continued:

(b) Rate regulation, continued:

EPCOR's water treatment and distribution services to customers within the COE are rate regulated by the COE Council pursuant to a performance-based rates (PBR) bylaw. Rates approved pursuant to this bylaw are intended to allow the Company to recover its operating costs and earn a ROE of 11.25% (2007 – 11.25%), while also providing an incentive to manage costs below inflation. If performance targets outlined in the bylaw are achieved, water rates are increased by the change in the rate of inflation less an efficiency factor of 25 basis points.

The current PBR bylaw has been approved by the COE Council for a five-year period through to March 31, 2012.

The regulator for water services provided within Edmonton, the COE, is a related party as it is the Company's shareholder.

Water sales to regional water commissions that supply water to communities surrounding Edmonton are rate regulated by the AUC on a complaints-only basis, whereby such communities may apply to the AUC to resolve disputes in connection with rates, tolls or charges determined by EPCOR. EPCOR sets the rates charged to the regional water commissions to recover related operating and capital costs plus a ROE.

2. Summary of significant accounting policies:

(a) Basis of presentation:

These consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles (GAAP).

These consolidated financial statements include the accounts of EPCOR, its subsidiaries, and its proportionate share of assets, liabilities, revenues and expenses of joint ventures. They include the accounts of the Company's approximate 30.6% interest in EPCOR Power L.P. (Power LP). Under GAAP, EPCOR controls Power LP which therefore is a subsidiary of EPCOR.

All significant intercompany balances and transactions have been eliminated on consolidation.

(b) Changes in significant accounting policies:

Commencing January 1, 2008, the Company adopted new accounting standards as issued by the Canadian Institute of Chartered Accountants (CICA) for Capital Disclosures, Financial Instruments – Disclosures and Presentation and Inventories. The new accounting standards have been applied retrospectively and the comparative financial statements have not been restated.

2. Summary of significant accounting policies, continued:

(b) Changes in significant accounting policies, continued:

Financial instruments – disclosures and presentation

The new standards establish requirements for the reporting and presentation of quantitative and qualitative information that is intended to provide users of the financial statements with additional insight into the Company's risks associated with financial instruments and how these risks are managed. These risks include credit, liquidity and market risks. The disclosures required under these new standards have been incorporated into these consolidated financial statements and discussed in note 21 – Fair value and classification of financial assets and liabilities, note 22 – Derivative instruments and hedge accounting and note 23 – Risk management.

Capital Disclosure

The new standard requires qualitative information about the Company's objectives, policies and processes for managing capital and quantitative data related to the Company's capital, as discussed in note 24 – Capital management.

Inventories

The new standard requires the Company's inventories to be measured at the lower of cost and net realizable value except for natural gas inventories held in storage for trading purposes which are measured at fair value less costs to sell. The Company's adoption of the standard did not have a material impact on these consolidated financial statements. The additional disclosures required under the new standard are provided in note 5 - Inventories.

Future accounting changes

In December 2007, the CICA amended Handbook Sections 1100 - Generally Accepted Accounting Principles and 3465 - Income Taxes, and made consequential amendments to Accounting Guideline 19 - Disclosures by Entities Subject to Rate Regulation. The amendments removed the temporary exemption from the requirement to apply Section 1100 to the recognition and measurement of assets and liabilities arising from rate regulation. As permitted by Canadian GAAP, the Company will use standards issued by the Financial Accounting Standards Board in the U.S. as another source of Canadian GAAP. The U.S. Statement of Financial Accounting Standards No. 71 – Accounting for the Effects of Certain Types of Regulation (FAS 71) allows for the recognition and measurement of rate regulated assets and liabilities. The Company has assessed its accounting for rate-regulated operations in relation to these amendments, while giving consideration to FAS 71, and does not expect the impact to be material. These amendments are effective January 1, 2009, and will be adopted by the Company as of that date.

2. Summary of significant accounting policies, continued:

(b) Changes in significant accounting policies, continued:

Future accounting changes, continued

In February 2008, the CICA issued Handbook Section 3064 – Goodwill and Intangible Assets and consequential amendments to Section 1000 – Financial Statement Concepts. The new section establishes standards for the recognition, measurement and disclosure of goodwill and intangible assets. The provisions relating to the definition and initial recognition of intangible assets, including internally generated intangible assets, are equivalent to the corresponding provisions in International Financial Reporting Standards (IFRS). The Company has reviewed its capitalization policies and practices for compliance with the new standard and expects to reclassify approximately $89 million of net assets from property, plant and equipment to contract and customer rights and other intangible assets. The Company does not expect the other impacts of this standard to be material. These amendments are effective January 1, 2009, and will be adopted by the Company as of that date.

On January 20, 2009 the Emerging Issues Committee of the CICA issued EIC-173, Credit Risk and the Fair value of Financial Assets and Financial Liabilities, which clarifies that an entity's own credit risk and the credit risk of the counterparty should be taken into account in determining the fair value of financial assets and liabilities, including derivative instruments. EIC-173 is to be applied retrospectively without restatement of prior periods in interim and annual financial statements for periods ending on or after the date of issuance of EIC-173. EPCOR will adopt this recommendation in its fair value determinations as at March 31, 2009 and is currently assessing the impact of this change on its consolidated financial statements.

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

(c) Regulatory accounting:

The Company accounts for certain transactions in accordance with applicable rate regulation (regulatory accounting). Under regulatory accounting, the timing of the Company's recognition of certain assets, liabilities, revenues and expenses may differ from that otherwise expected under Canadian GAAP for non-rate-regulated enterprises.

Certain separate assets and liabilities have been recognized solely as a result of the effects of rate regulation. At December 31, 2008 and 2007, these assets and liabilities are not material.

2. Summary of significant accounting policies, continued:

(c) Regulatory accounting, continued:

For the Company's rate-regulated enterprises, the following accounting principles apply:

(i) *Asset disposals and retirements* - For rate-regulated transmission, distribution and RRT businesses, when an asset other than land or buildings is retired or disposed of, any proceeds are recorded as a reduction to the cost of the replacement asset, no gain or loss is reflected in income, and the related cost and accumulated depreciation are not removed until the end of the originally estimated useful life. Where there is no replacement asset, the proceeds are recorded as a reduction of the next most similar asset capitalized. On disposals of land and buildings, any difference between the proceeds and cost are recognized in income, the cost and accumulated depreciation are removed, and the accumulated depreciation on buildings is recorded in a deferral account to be returned to the rate payer in a future tariff application.

For rate-regulated water services businesses, any proceeds or salvage value is recorded in accumulated depreciation, with no gain or loss reflected in income at the time of retirement or disposition. The results of the disposal or retirement are then recognized in future depreciation rates and depreciation charges. Cost and accumulated depreciation balances of retired assets are removed. In the case where an entire asset class ceases to exist, net proceeds in excess of accumulated depreciation are recorded as a gain on sale.

Non-rate-regulated entities include gains or losses on disposal of property, plant and equipment in net income at the time of retirement or disposition and the original cost and accumulated depreciation are removed.

(ii) *Asset removal costs* - For rate-regulated transmission, distribution and RRT businesses, costs to remove an asset are included in the cost of the replacement asset. For rate-regulated water services businesses, future costs for decommissioning of assets are provided for based on estimated removal and site restoration costs, net of salvage value, as approved by the regulator. These amounts are recorded as a provision for plant decommissioning on the balance sheet with a corresponding increase in the cost of the related asset. Upon the retirement of water utility assets, the removal and site restoration costs, net of salvage value, are charged to the provision for plant decommissioning. The removal and site restoration costs for these assets are based on independent studies of plant decommissioning and site restoration commissioned by the Company and, where applicable, as directed by the regulator. Asset retirement obligations for non-regulated entities are recognized in the period in which they are incurred as described in note 2(r).

2. Summary of significant accounting policies, continued:

(c) Regulatory accounting, continued:

(iii) *Allowance for funds used during construction (AFUDC)* - The Company capitalizes AFUDC to provide for the cost of capital invested in rate-regulated construction activities. AFUDC is applied during construction at the weighted average cost of capital of the particular rate-regulated operations, as approved by the regulator. Since AFUDC includes not only an interest component, but also a cost-of-equity component, it exceeds the amount allowed to be capitalized under GAAP in similar circumstances in the absence of rate regulation.

(iv) *Intercompany profit on sales to rate-regulated affiliates* – The Company does not eliminate intercompany profits arising from sales within the consolidated group of EPCOR companies and included in assets remaining within its rate-regulated businesses, as the intercompany profit is deemed to have been realized to the extent that the sales price is recognized for rate-making purposes by the regulator. Intercompany profits included in assets remaining with a non-rate-regulated entity within the consolidated group are unrealized and are eliminated upon consolidation.

(d) Measurement uncertainty:

The preparation of the Company's financial statements, in accordance with Canadian GAAP, requires management to make estimates that affect the reported amounts of revenues, expenses, assets and liabilities as well as the disclosure of contingent assets and liabilities at the financial statement date.

By regulation, wire service providers in Alberta are not required to submit final load settlement data on customer electricity usage until eight months after the month in which such electricity was consumed. The data and associated processes and systems used by the Company to estimate electricity revenues and costs, including unbilled consumption, are complex. The Company's estimation procedures will not necessarily detect errors in underlying data provided by industry participants including wire service providers and load settlement agents.

The degree to which revenues are recognized or deferred under the Power Purchase Arrangement (PPA) described in note 2(q) depends upon long-term outlooks of generation unit performance. Such outlooks of performance are estimated based on the generation units' historical performance, planned maintenance, reliability and generation availability, and revisions in the estimated long-term price embedded in the PPA.

The amount of revenues and related profit recognized under the percentage of completion method for certain plant construction and other project upgrades described in note 2(e) depends on accuracy of cost, schedule and performance estimates and estimates related to the ability to recover additional contract costs through change orders or claims to the customer or contractors.

2. Summary of significant accounting policies, continued:

(d) Measurement uncertainty, continued:

For certain accounting measures such as determining asset impairments, purchase price allocations for business combinations, recording financial assets and liabilities, recording certain non-financial derivatives and for certain disclosures, the Company is required to estimate the fair value of certain assets or obligations. Estimates of fair value may be based on readily determinable market values or on depreciable replacement cost or discounted cash flow techniques employing estimated future cash flows based on a number of assumptions and using an appropriate discount rate.

Measurement of the Company's asset retirement obligations and the related accretion expense requires the use of estimates with respect to the amount and timing of asset retirements, the extent of site remediation required and related future cash flows.

Measurement of certain of the Company's pension costs and plan assets and obligations requires the use of estimates with respect to expected plan investment performance, salary escalation, retirement ages of employees, timing of related future cash flows and appropriate discount rates for use in discounted cash flow and actuarial techniques.

Depreciation and amortization is an estimate to allocate the cost of an asset over its estimated useful life on a systematic and rational basis. Estimating the appropriate useful lives of assets requires significant judgment and is generally based on estimates of common life characteristics of common assets.

Income taxes are determined based upon estimates of the Company's current income taxes and estimates of future income taxes resulting from temporary tax differences. Future income tax assets are assessed to determine the likelihood that they will be realized from future taxable income. To the extent that realization is not considered likely, a valuation allowance is recorded and charged against income in the period that the allowance is created or revised.

Certain estimates are necessary since the regulatory environment that the Company operates in often requires amounts to be recorded at estimated values until finalization and adjustment pursuant to subsequent regulatory decisions, or other regulatory proceedings.

Adjustments to previous estimates, which may be material, will be recorded in the period they become known.

(e) Revenue recognition:

Revenues from the sales of electricity, natural gas and water are recognized upon delivery or availability for delivery under take-or-pay contracts. These revenues include an estimate of the value of electricity, natural gas and water consumed by customers, but billed subsequent to year-end.

Revenues from the sale of goods are recognized when the products have been delivered. Revenues from services are recognized when the service has been performed or delivered.

2. Summary of significant accounting policies, continued:

(e) Revenue recognition, continued:

The Company recognizes revenue from its Alberta generation units operating under a PPA as described in note 2(q). PPAs are a form of long-term sales arrangements between the owner of a generation unit and the buyer of the PPA.

Revenues from the Company's power generation plants located outside of Alberta are recognized upon delivery of output or upon availability of delivery as prescribed by contractual arrangements. These contractual arrangements are also commonly referred to as PPAs. Revenue from certain long-term contracts with fixed payments is recognized at the lower of (1) the megawatt hours (MWhs) made available during the period multiplied by the billable contract price per MWh and (2) an amount determined by the MWhs made available during the period, multiplied by the average price per MWh over the term of the contract from the date of acquisition. Any excess of the current period contract price over the average price is recorded as deferred revenue.

Certain Water Services contracts constitute multiple-deliverable arrangements. Certain deliverables of these arrangements are separately accounted for, provided the delivered elements have stand-alone value to the customer, the fair value of any undelivered elements can be objectively and reliably determined and there is no general right of return. These identifiable deliverables may include, but are not limited to, plant construction and project upgrades and expansions, financing or leasing of upgrades and facilities operations. For arrangements which include multiple deliverables and for which the criteria for recognition as a multiple-deliverable arrangement are met, the total contract value is allocated to each element based on its relative fair value and the Company's relevant revenue recognition policies are applied to each element. When the stated contract consideration associated with an undelivered item is contingent upon delivery, revenue related to each deliverable with contingent revenues is recognized based on the lesser of the relative fair value and the non-contingent revenues.

Revenue from plant construction and other project upgrades and expansions provided to customers is recognized on the percentage of completion basis. Percentage of completion is estimated based on an assessment of progress towards the completion of contract tasks or milestones. These estimates result in the recognition of unbilled receivables as the revenue is earned prior to billing customers. Provisions for estimated losses on uncompleted contracts are made for the full amount of the projected loss in the period in which the losses are identified. Revenues and costs related to change orders are included in total estimated contract revenue and expenses when approval is reasonably assured. Revenue from the financing of the upgrades and expansions is recognized over the term of each contract using the effective interest method based on the fair-value of the loan calculated at the inception of each contract.

2. Summary of significant accounting policies, continued:

(e) Revenue recognition, continued:

Finance income earned from arrangements accounted for as direct financing leases is accounted for as described in note 2(s).

(f) Financial instruments:

Financial assets are identified and classified as either available for sale, held for trading, held to maturity, or loans and receivables. Financial liabilities are classified as either held for trading or other liabilities. Initially, all financial assets and financial liabilities are recorded on the balance sheet at fair value with subsequent measurement determined by the classification of each financial asset and liability.

Financial assets and financial liabilities held for trading are measured at fair value with the changes in fair value reported in net income. Financial assets held to maturity, loans and receivables and financial liabilities other than those held for trading are measured at amortized cost. Available-for-sale financial assets are measured at fair value with changes in fair value reported in other comprehensive income until the financial asset is disposed of or becomes impaired. Investments in equity instruments classified as available for sale that do not have quoted market prices in an active market are measured at cost.

Upon initial recognition, the Company may designate financial instruments as held for trading when such financial instruments have a reliably determinable fair value and where doing so eliminates or significantly reduces a measurement or recognition inconsistency that would otherwise arise from measuring assets and liabilities or recognizing gains and losses on them on a different basis. The Company has designated its cash and cash equivalents and investment in non-bank sponsored asset backed commercial paper as held for trading. All other non-derivative financial assets not meeting the Company's criteria for designating as held for trading are classified as available for sale, loans and receivables or held to maturity.

Financial assets purchased or sold, where the contract requires the asset to be delivered within an established timeframe, are recognized on a settlement date basis.

Transaction costs on financial assets and liabilities classified as other than held for trading are capitalized and amortized over the expected life of the instrument, based on contractual cash flows, utilizing the effective interest method. The effective interest method calculates the amortized cost of a financial asset or liability and allocates the interest income or expense over the term of the financial asset or liability using an effective interest rate.

2. Summary of significant accounting policies, continued:

(g) Derivative instruments and hedging activities:

To reduce its exposure to movements in energy commodity prices, interest rate changes, and foreign currency exchange rates, the Company uses various risk management techniques including the use of derivative instruments. Derivative instruments may include forward contracts, fixed-for-floating swaps, and option contracts. Such instruments may be used to establish a fixed price for an energy commodity, an interest-bearing obligation or an obligation denominated in a foreign currency. All derivative instruments, including embedded derivatives, are recorded at fair value on the balance sheet as derivative instruments assets or derivative instruments liabilities except for embedded derivatives instruments that are clearly and closely linked to their host contract and the combined instrument is not measured at fair value. Any contract to buy or sell a non-financial item is not treated as a non-financial derivative if that contract was entered into and continues to be held for the purpose of the receipt or delivery of a non-financial item in accordance with the Company's expected purchase, sale or usage requirements. All changes in the fair value of derivatives are recorded in net income unless cash flow hedge accounting is used, in which case changes in fair value of the effective portion of the derivatives are recorded in other comprehensive income. On the adoption of the current accounting standards for derivatives in 2007, the Company chose a transition date of January 1, 2003 for embedded derivatives and therefore is only required to account separately for those embedded derivatives in any hybrid instruments issued, acquired or substantively modified after that date. The Company does not account for foreign currency derivatives embedded in non-financial instrument host contracts when the currency that is commonly used in contracts to purchase or sell non-financial items in the economic environment is that currency in which the transaction takes place.

The Company uses financial contracts-for-differences (or fixed-for-floating swaps) to hedge the Company's exposure to fluctuations in electricity prices. Under these instruments, the Company agrees to exchange, with creditworthy or adequately secured counterparties, the difference between the variable or indexed price and the fixed price on a notional quantity of the underlying commodity for a specified timeframe.

The Company uses non-financial forward delivery derivatives to manage the Company's exposure to fluctuations in natural gas prices related to its remaining natural gas customer contracts and obligations arising from its natural gas fired generation facilities. Under these instruments, the entity agrees to sell or purchase natural gas at a fixed price for delivery of a pre-determined quantity under a specified timeframe.

2. Summary of significant accounting policies, continued:

(g) Derivative instruments and hedging activities, continued:

Foreign exchange forward contracts are used by the Company to manage foreign exchange exposures, consisting mainly of U.S dollar exposures, resulting from anticipated transactions denominated in foreign currencies. For transactions involving the development or acquisition of property, plant and equipment, when the anticipated transaction subsequently results in the recognition of a financial asset, the associated gains or losses on hedging derivatives recognized in other comprehensive income are included in the initial carrying amount of the asset acquired in the same period or periods during which the asset acquired affects net income.

The Company may use forward interest rate or swap agreements and option agreements to manage the impact of fluctuating interest rates on existing debt.

The Company may use hedge accounting when there is a high degree of correlation between the risk in the item designated as being hedged (the hedged item) and the derivative instrument designated as a hedge (the hedging instrument). The Company documents all relationships between hedging instruments and hedged items at the hedge's inception, including its risk management objectives and its assessment of the effectiveness of the hedging relationship on a retroactive and prospective basis. The Company uses cash flow hedges for certain of its anticipated transactions to reduce exposure to fluctuations in changes in commodity prices. In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is recognized in other comprehensive income, while the ineffective portion is recognized in net income. The amounts recognized in accumulated other comprehensive income are reclassified into net income in the same period or periods in which the hedged item occurs and is recorded in net income or when the hedged item becomes probable of not occurring. The Company has not designated any fair value hedges at the balance sheet date.

A hedging relationship is discontinued if the hedge relationship ceases to be effective, if the hedged item is an anticipated transaction and it is probable that the transaction will not occur by the end of the originally specified time period, if the entity terminates its designation of the hedging relationship, or if either the hedged or hedging instrument ceases to exist as a result of its maturity, expiry, sale, termination or cancellation and is not replaced as part of the Company's hedging strategy.

2. Summary of significant accounting policies, continued:

(g) Derivative instruments and hedging activities, continued:

If a cash flow hedging relationship is discontinued or ceases to be effective, any cumulative gains or losses arising prior to such time are deferred in accumulated other comprehensive income and recognized in net income in the same period as the hedged item, and subsequent changes in the fair value of the derivative instrument are reflected in net income. If the hedged or hedging item matures, expires, or is sold, extinguished or terminated and the hedging item is not replaced, any gains or losses associated with the hedging item that were previously recognized in other comprehensive income are recognized in net income in the same period as the corresponding gains or losses on the hedged item. When it is no longer probable that an anticipated transaction will occur within the originally determined period and the associated cash flow hedge has been discontinued, any gains or losses associated with the hedging item that were previously recognized in other comprehensive income are recognized in net income in the period.

When the conditions for hedge accounting cannot be applied, the changes in fair value of the derivative instruments are recognized as described above. The fair value of derivative financial instruments reflects changes in the commodity market prices, interest rates and foreign exchange rates. Fair value is determined based on exchange or over-the-counter price quotations by reference to bid or asking price as appropriate, in active markets. In illiquid or inactive markets, the Company uses appropriate valuation and price modeling techniques commonly used by market participants to estimate fair value. Fair values determined using valuation models require the use of assumptions concerning the amounts and timing of future cash flows. Fair value amounts reflect management's best estimates using external readily observable market data such as future prices, interest rate yield curves, foreign exchange rates, discount rates for time value, and volatility where available. The Company has applied price modeling to the non-bank sponsored asset backed commercial paper classified as held for trading as described in notes 10 and 21. It is possible that the assumptions used in establishing fair value amounts will differ from future outcomes and the impact of such variations could be material.

(h) Income taxes:

Under the Income Tax Act (Canada) (ITA), a municipally owned corporation is subject to income tax on its taxable income if the income from activities for any relevant period that was earned outside the geographical boundaries of the municipality exceeds 10% of the corporation's total income for that period. As a result of these and other provisions, certain Canadian subsidiaries of the Company are taxable under the ITA and provincial income tax acts. The Company's U.S. subsidiaries are subject to income tax pursuant to U.S. federal and state tax laws.

2. Summary of significant accounting policies, continued:

(h) Income taxes, continued:

The Company follows the asset and liability method of accounting for income taxes. Under this method, current income taxes are recognized for the estimated income taxes payable or recoverable for the current year. Future income tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Future income tax assets and liabilities are measured using enacted or substantively enacted rates of tax expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on future tax assets and liabilities is recognized in income in the period that includes the date of enactment or substantive enactment.

(i) Cash and cash equivalents:

Cash and cash equivalents include cash or highly liquid, investment-grade, short-term investments and are recorded at fair market value.

(j) Inventories:

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

(k) Property, plant and equipment:

Property, plant and equipment are recorded at cost and include contracted services, materials, interest, direct and indirect labour, overhead costs, asset retirement costs, and net revenues during the pre-operating period. Certain assets may be acquired or constructed with financial assistance in the form of contributions from developers or customers and non-repayable government grants. Contributions received for financing the costs of assets are recorded as a reduction of the related asset cost.

Depreciation on property, plant and equipment is provided on the straight-line basis over their estimated useful lives. The regulator approves depreciation rates for rate-regulated assets. No depreciation is provided on construction work in progress.

2. Summary of significant accounting policies, continued:

(k) Property, plant and equipment, continued:

The Company capitalizes interest during construction for non-rate-regulated operations to provide for the costs of borrowing on construction activities. Interest is applied during construction using the average cost of debt associated with the specific project. The Company's rate-regulated operations capitalize AFUDC.

(l) Power purchase arrangements:

Acquired PPAs are reflected on the consolidated balance sheets as power purchase arrangements and are recorded at cost and are amortized over their terms on a straight-line basis.

Alberta PPAs, which are comprised of the Sundance PPA and a portion of the Battle River PPA, reflect the cost to acquire the rights to the committed generating capacity of five regulated Alberta generation units auctioned by the Government of Alberta in the year 2000 as part of provincial electricity deregulation. The cost of the Alberta PPAs also reflects the sale over a four-year period, ending in 2010, of the Company's interest in the Battle River PPA and related transactions, including the current and prior period sales of the Battle River Power Syndicate Agreement (Battle River PSA) described in note 4. Under the terms of the Alberta PPAs, the Company is obligated to make fixed and variable payments to the owners of the underlying generation units over their respective terms. Such amounts are recorded as operating expenses as incurred. At December 31, 2008, the remaining term of the 20-year Sundance PPA is 12 years. The Company is also obligated to make fixed and variable payments to the buyer of the Battle River PPA, in proportion to its effective ownership interest, until the sale of the Company's remaining interest in the Battle River PSA is completed in 2010.

The Company purchased the Alberta PPAs with an equity syndicate under syndication agreements. Under the terms of the agreements, the syndicate members receive their proportionate share of the committed generating capacity in exchange for their proportionate share of the price paid for the Alberta PPAs and all payments to the generation unit owners.

The Company's investment in the Alberta PPAs and its revenues and expenses there under are recorded on a proportionate basis, after deducting the equity syndicate's share.

The Power LP PPAs reflect the cost to acquire long-term sales contracts under which revenue is earned by Power LP's generation units. The Power LP PPAs are amortized over their contract terms, which range from one to 20 years.

(m) Contract and customer rights and other intangible assets:

Contract rights include acquired management and operations agreements. Costs assigned to contract rights are amortized on a straight-line basis, from the dates of acquisition, over the contract terms which range from one to 70 years.

2. Summary of significant accounting policies, continued:

(m) Contract and customer rights and other intangible assets, continued:

Customer rights represent the costs to acquire the rights to provide electricity services to particular customer groups. The costs are amortized on a straight-line basis over terms ranging from five to 30 years depending on the expectation of benefit from the underlying customer group.

Water rights associated with acquired hydroelectric power generation plants are recorded at cost and are amortized over the remaining useful lives of the associated property, plant and equipment.

Other rights include the cost to acquire land lease agreements for use in wind power projects in Ontario and coal supply access rights relating to the Keephills 3 Project (note 29(b)). The lease rights are amortized on a straight-line basis over the estimated useful lives of the related wind power assets, commencing when those assets are constructed and commissioned for service. The access rights will be amortized over the life of the coal supply agreement and amortization will commence when the Keephills 3 plant is commissioned for service.

(n) Goodwill:

Goodwill is the cost of an acquisition less the fair value of the net assets of an acquired business. Goodwill is not amortized, but rather is tested for impairment at least annually or more frequently if events and circumstances indicate that a possible impairment may exist. To test for impairment, the fair value of the reporting unit to which the goodwill relates is compared to the carrying amount, including goodwill, of the reporting unit. If the carrying amount of the reporting unit exceeds its fair value, the fair value of the reporting unit's goodwill is compared with its carrying amount to measure the impairment loss, if any. The Company determines the fair value of a reporting unit using discounted cash flow techniques and estimated future cash flows.

(o) Other assets:

Non-bank sponsored asset backed commercial paper is recorded at fair value and is classified as a non-current asset due to the expected timing of repayment of the restructured term floating-rate notes described in note 10.

Investments in which the Company exercises significant influence are accounted for using the equity method. Other investments are classified as available for sale and are recorded at fair value unless the investments do not have a quoted market price in an active market in which case the investments are recorded at cost. Investments recorded at cost for which there is a decline in fair value below cost that is other than temporary are written down and the loss is recognized in net income.

2. Summary of significant accounting policies, continued:

(o) Other assets, continued:

Loans and other long-term receivables are comprised of promissory notes receivable and amounts due from customers more than one year from the balance sheet date and will be repaid between 2009 and 2025.

(p) Impairment of long-lived assets:

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

(q) Deferred availability incentives:

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

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

(r) Asset retirement obligations:

The Company recognizes asset retirement obligations in the period in which they are incurred, unless the fair value cannot be reasonably determined. A corresponding asset retirement cost is added to the carrying amount of the associated long-lived asset, and is depreciated over the estimated useful life of the asset. Accretion of the liability due to the passage of time is an operating expense, and is recorded over the estimated time period until settlement of the obligation.

2. Summary of significant accounting policies, continued:

(r) Asset retirement obligations, continued:

The Company has recorded asset retirement obligations for its power generation plants and Genesee coal mine as it is legally required to remove the facilities at the end of their useful lives and restore the plant and mine sites to their original condition. Asset retirement obligations for the coal mine are incurred over time as new areas are mined, and a portion of the liability is settled over time as areas are reclaimed prior to final pit reclamation.

The Company is legally required to remove its rate-regulated distribution, transmission and water long-lived assets at the end of their useful lives and restore to original condition their associated sites. However, as the lives of these assets are indeterminate, the Company has not recorded asset retirement obligations since the estimated fair value of the obligations are not reasonably determinable. While the asset retirement obligations cannot be reasonably determined, the Company records a provision for decommissioning on its rate-regulated water assets as approved by its regulator.

(s) Leases or arrangements containing a lease:

Leases or other arrangements entered into for use of property, plant and equipment are classified as either capital or operating leases. Leases or other arrangements that transfer substantially all of the benefits and risks of ownership of property to the Company are classified as capital leases. Equipment acquired under capital leases is depreciated over the term of the lease. Rental payments under operating leases are expensed as incurred.

Finance income related to leases or arrangements accounted for as either direct financing leases or as sales-type leases, is recognized in a manner that produces a constant rate of return on the net investment in the lease. The net investment in both direct financing leases and sales-type leases is composed of net minimum lease payments and unearned finance income. Unearned finance income on direct financing leases is the difference between the total minimum lease payments and the carrying amount of the leased property. Unearned finance income on sales-type leases is the difference between the total minimum lease payments and the aggregate present values of the minimum lease payments. Unearned finance income for both direct financing leases and sales-type leases is deferred and recognized in net income over the lease term.

(t) Contract liabilities:

The Company's contract liabilities, primarily related to acquired PPAs, are being amortized over the terms of the contracts which range from three to eight years.

2. Summary of significant accounting policies, continued:

(u) Foreign currency translation:

The Company's self-sustaining foreign operations are translated into Canadian dollars using the current rate method. Assets and liabilities are translated at the exchange rate in effect at the balance sheet date. Revenues and expenses are translated at average exchange rates prevailing during the period. The resulting translation gains and losses are deferred and included in accumulated other comprehensive income until there is a reduction in the Company's net investment in the foreign operations.

Foreign currency transactions and financial statements of integrated foreign operations are translated to Canadian dollars using the temporal method. Transactions denominated in foreign currencies are translated at exchange rates in effect at the transaction date. Monetary assets and liabilities denominated in foreign currencies are translated at the exchange rate in effect on the balance sheet date. The resulting foreign exchange gains and losses are included in the consolidated statements of income.

During the fourth quarter of 2008, changes in economic circumstances caused the Company to re-evaluate the functional currency of the Power LP's indirectly-owned U.S. subsidiaries. As a result, the functional currency of these U.S. subsidiaries was determined to be U.S. dollars. Accordingly, these operations are being translated prospectively using the current rate method.

(v) Employee future benefits:

The employees of the Company are either members of the Local Authorities Pension Plan (LAPP) or other defined contribution or defined benefit plans.

The LAPP is a multiemployer defined benefit pension plan. The Trustee of the plan is the Treasurer of Alberta and the plan is administered by a Board of Trustees. The Company and its employees make contributions to the plan at rates prescribed by the Board of Trustees to cover costs under the plan. Since the plan is a multiemployer plan, it is accounted for as a defined contribution plan. Accordingly, the Company does not recognize its share of any plan surplus or deficit.

The Company maintains additional defined contribution and defined benefit pension plans to provide pension benefits to those employees (comprising less than 20% of total employees) who are not otherwise served by LAPP, including employees of new or acquired operations.

2. Summary of significant accounting policies, continued:

(v) Employee future benefits, continued:

The Company accrues its obligations for its defined benefit pension plans net of plan assets. The cost of pension benefits earned by employees is actuarially determined using the projected benefit method pro-rated on services and management's best estimate of expected plan investment performance, salary escalation and retirement ages of employees. For the purpose of calculating the expected return on plan assets, those assets are valued at quoted market value. The discount rate used to calculate the interest cost on the accrued benefit obligation is determined by reference to market interest rates at the balance sheet date on high-quality debt instruments with cash flows that match the timing and amount of expected benefit payments. Past service costs from plan amendments are amortized on a straight-line basis over the estimated average remaining service of employees active at the date of amendment. The excess of the net cumulative unamortized actuarial gain or loss over 10% of the greater of the accrued benefit obligation and the market value of plan assets is amortized over the estimated average remaining service period of the active employees.

(w) Offsetting of financial assets and financial liabilities:

Financial assets and financial liabilities are presented on a net basis when the Company has a legally enforceable right to set-off the recognized amounts and intends to settle on a net basis or to realize the asset and settle the liability simultaneously.

(x) Long-term debt discounts, premiums and issue expenses:

Debenture discounts, premiums and issue expenses with respect to long-term debt are amortized over the term of the related debt using the effective interest rate method.

3. Acquisition of Morris Cogeneration LLC:

On October 31, 2008, the Company, through its Power LP subsidiary, acquired 100% of the equity interest in Morris Cogeneration LLC (Morris), a combined heat and power facility in Illinois. The total purchase price was $89 million (US$74 million) in cash.

The financial results of Morris are included in the Company's consolidated statement of income from the date of acquisition.

(Tabular amounts in millions of dollars)

3. Acquisition of Morris Cogeneration LLC, continued:

The purchase price for the acquisition of Morris was allocated to the assets acquired and liabilities assumed based on their estimated fair values as follows:

Current assets excluding cash and cash equivalents and derivative instruments assets	$	10
Derivative instruments assets – current		1
Derivative instruments assets – non-current		3
Property, plant and equipment		83
Power purchase arrangements		4
Other assets		2
Current liabilities		(7)
Other non-current liabilities		(7)
Fair value of net assets acquired	$	89

Due to the short time frame between closing of the Morris transaction and release of the financial statements, the fair value estimates of certain assets and liabilities are preliminary and are anticipated to be finalized in the first quarter of 2009. Finalization of the fair value estimates could result in material adjustments to the fair value purchase price allocation in subsequent periods.

4. Sale of power syndicate agreement:

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

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

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

The timing of the remaining future sales include the sale of a 10% interest closing on January 15, 2009, followed by the sale of the final 15% interest on January 15, 2010.

5. Inventories:

		2008		2007
Small parts and other consumables	$	58	$	52
Coal		14		10
Natural gas held in storage for trading purposes		12		-
	$	84	$	62

(Tabular amounts in millions of dollars)

5. Inventories, continued:

Inventories expensed upon usage during the year ended December 31, 2008 of $66 million (2007 - $56 million) were charged to energy purchases and fuel and operations, maintenance and administration. An inventory write-down of $1 million was recognized in the year ended December 31, 2008 (2007 – nil). No reversals of previous write-downs were recorded in the years ended December 31, 2008 or 2007. At December 31, 2008 and 2007, no inventories were pledged as security for liabilities.

6. Property, plant and equipment:

				2008
	Composite depreciation rates	Cost	Accumulated depreciation	Net book value
Generation plants and equipment	4.0%	$ 3,438	$ 883	$ 2,555
Water treatment and distribution	1.9%	1,394	321	1,073
Electricity transmission and distribution	3.2%	1,124	373	751
Retail systems and equipment	11.6%	107	54	53
Corporate information systems and equipment	9.4%	127	66	61
		6,190	1,697	4,493
Contributions:				
Generation plants and equipment	10.5%	(22)	(3)	(19)
Water treatment and distribution	1.3%	(461)	(86)	(375)
Electricity transmission and distribution	2.6%	(114)	(40)	(74)
		(597)	(129)	(468)
Assets under capital lease	16.4%	2	1	1
Land	None	98	-	98
Construction work in progress	None	604	-	604
		$ 6,297	$ 1,569	$ 4,728

(Tabular amounts in millions of dollars)

6. Property, plant and equipment, continued:

				2007
	Composite depreciation rates	Cost	Accumulated depreciation	Net book value
Generation plants and equipment	3.4%	$ 3,268	$ 779	$ 2,489
Water treatment and distribution	2.0%	1,291	303	988
Electricity transmission and distribution	3.2%	962	345	617
Retail systems and equipment	11.4%	109	50	59
Corporate information systems and equipment	9.1%	135	77	58
		5,765	1,554	4,211
Contributions:				
Generation plants and equipment	13.3%	(9)	(2)	(7)
Water treatment and distribution	1.4%	(438)	(80)	(358)
Electricity transmission and distribution	2.8%	(104)	(38)	(66)
		(551)	(120)	(431)
Assets under capital lease	2.0%	2	1	1
Land	None	94	-	94
Construction work in progress	None	341	-	341
		$ 5,651	$ 1,435	$ 4,216

Depreciation, amortization and asset retirement accretion expense is comprised of:

	2008	2007
Depreciation on assets in service	$ 206	$ 189
Accretion on asset retirement obligations (note 14)	5	5
Gain on disposal of assets	(5)	(7)
Amortization of contributions	(11)	(10)
Amortization of PPAs	53	57
Amortization of contract and customer rights and other intangible assets	10	11
	$ 258	$ 245

Interest and AFUDC capitalized to property, plant and equipment for 2008 is $23 million (2007 - $14 million).

(Tabular amounts in millions of dollars)

7. Power purchase arrangements:

			2008			2007
	Cost	Accumulated amortization	Net book value	Cost	Accumulated amortization	Net book value
Alberta PPAs	$ 197	$ 85	$ 112	$ 219	$ 78	$ 141
Power LP PPAs	613	132	481	633	95	538
	$ 810	$ 217	$ 593	$ 852	$ 173	$ 679

8. Contract and customer rights and other intangible assets:

			2008			2007
	Cost	Accumulated amortization	Net book value	Cost	Accumulated amortization	Net book value
Contract rights	$ 123	$ 13	$ 110	$ 120	$ 9	$ 111
Customer rights	106	65	41	106	61	45
Other rights	37	-	37	19	-	19
Water rights	15	1	14	15	1	14
Emission credits	9	4	5	5	2	3
	$ 290	$ 83	$ 207	$ 265	$ 73	$ 192

9. Goodwill

The changes in the carrying amount of goodwill are as follows:

	2008	2007
Balance, beginning of year	$ 185	$ 183
Impairment	(28)	-
Foreign exchange translation adjustment	4	-
Adjustments to purchase price allocations	-	2
	$ 161	$ 185

The Company completed its annual goodwill impairment testing in the fourth quarter of 2008. The future cash flows of the underlying business are reasonably stable, since they relate to largely contracted power generation operations. However, interest rate spreads have risen significantly in the fourth quarter of 2008 which increased the underlying rate used to discount the future cash flows. This higher discount rate resulted in the estimated fair value of goodwill related to the Power LP being lower than its carrying value. The resulting impairment of $28 million is recorded in net income.

(Tabular amounts in millions of dollars)

10. Other assets:

		2008		2007
Carrying amount				
Loans and other long-term receivables	$	102	$	70
Net investments in leases		52		29
Non-bank sponsored asset backed commercial paper		42		60
Investment in Primary Energy Recycling Holdings LLC (PERH)		19		50
Portfolio investments		6		13
Other		16		3
		237		225
Accumulated amortization				
Other		2		2
	$	235	$	223

Net investments in leases

The PPA under which the Company's power generation facility located in Oxnard, California operates is considered to be a direct financing lease for accounting. The PPA expires in 2020. The current portion of the net investment in lease of $2 million (2007 - $1 million) is included in accounts receivable. Financing income for the year ended December 31, 2008 of $3 million (2007 - $3 million) is included in revenues.

The Company's agreement with a third party to design, build, own and operate a potable water and wastewater treatment plant for the third party, as described in note 29(c), is considered to be a sales-type lease for accounting. The current portion of the net investment in lease for the year ended December 31, 2008 is nil (2007 – nil). The recognition of financing income will begin upon the completion of the design-build phase and the commencement of the lease payments.

Investment in PERH

The Company, through its Power LP subsidiary, holds 17.0% of the common share interests and 14.2% of the preferred share interests in PERH. The Class B Common interest is accounted for using the equity method. The Class B Preferred interest is recorded on the cost basis. For the year ended December 31, 2008, equity losses of $6 million (2007 - $4 million) included in operations, maintenance and administration expense, and $3 million (2007 - $3 million) in dividends have been recorded against the common share investment in PERH. Upon acquisition in 2006, the excess of the Company's share of the book value of PERH net assets over the carrying amount of the Class B Common interest was $19 million.

10. Other assets, continued:

Investment in PERH, continued

The Company, through its Power LP subsidiary, monitors its investment in PERH for impairment by considering current economic factors and records an impairment charge when it believes the investment has experienced a decline that is other than temporary. The Company estimates the fair value of its investment in PERH using discounted cash flow techniques and estimated future cash flows and considers other factors such as the quoted market price of the securities issued by Primary Energy Recycling Corporation, which owns the remaining interests in PERH not held by Power LP, and the market yield of comparable preferred shares. As a result, the Company recorded a $24 million pre-tax and pre-non-controlling interest impairment charge during the year to write down the investment based on its fair value.

Non-bank sponsored asset backed commercial paper

At December 31, 2008, the Company held $42 million (2007 - $60 million) in Canadian non-bank sponsored asset backed commercial paper (ABCP), all of which was purchased in 2007 at an original cost of $71 million. The Company's ABCP is part of the broader ABCP market that was disrupted by the significant lack of liquidity that emerged in August 2007 and as a result, all of the Company's ABCP matured with no payment of principal, accrued interest or roll over. At the time, all of the conduits in which the Company's ABCP investments were held were rated R-1 (high) by DBRS Limited (DBRS), which is their highest rating for commercial paper. DBRS placed these conduits "Under Review with Developing Implications" following an announcement on August 16, 2007 that a consortium representing banks, asset providers and major investors, represented by the Pan-Canadian Investors Committee (Investors Committee), had agreed in principle to a long-term proposal and interim arrangements regarding the ABCP (the Montreal Accord).

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

(Tabular amounts in millions of dollars)

10. Other assets, continued:

Non-bank sponsored asset backed commercial paper, continued

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

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

Pool	Series	Rating	Face amount	
MAV2	Class A-1	A	$ 47	67%
	Class A-2	A	9	13%
	Class B	Unrated	2	2%
	Class C	Unrated	2	2%
MAV3	IA Tracking	Unrated	11	16%
			$ 71	100%

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

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

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

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

The Company will record the exchange of ABCP for new notes at the estimated fair value of the new notes. The exchange is not expected to have a material impact on EPCOR's net income, since the ABCP was recorded at estimated fair value at each reporting date, based on the characteristics of the new notes. As a held-for-trading financial asset, the new notes, will be subject to ongoing fair value adjustments at each reporting date.

11. Short-term debt:

	2008	2007
Commercial paper and bankers' acceptances	$ 140	$ 138

(Tabular amounts in millions of dollars)

11. Short-term debt, continued:

Bank lines of credit are unsecured and are available to the Company up to an amount of $2,259 million, comprised of committed amounts of $2,190 million as described in note 12 and uncommitted amounts of $69 million. Letters of credit totaling $253 million have been issued under these facilities as described in note 30. Amounts borrowed, and letters of credit issued, if any, under these facilities which are not payable within one year, are classified as long-term debt.

The Company's commercial paper program is authorized to $500 million and is backed by the committed bank lines of credit.

In December 2008, the Company obtained an unsecured 364-day $600 million liquidity credit facility. At December 31, 2008 the company had nil outstanding under this facility.

12. Long-term debt:

	Effective Interest Rate	2008	2007
Obligation to the City of Edmonton, net of sinking fund (note 25):			
Due in 1-5 years at 9.93%[1] (2007 - 10.50%[1])	10.27%	$ 103	$ 110
Due in 6-10 years at 8.50%[1] (2007 - 8.86%[1])	10.17%	61	40
Due in 11-15 years at 7.01%[1] (2007 - 8.37%[1])	7.01%	25	91
Due in 16-20 years (2007 - 5.75%[1])		-	2
		189	243
Debentures, at 6.20%, due in 2008	6.40%	-	200
Debentures, at 6.95%, due in 2010	7.12%	200	200
Debentures, at 6.60%, due in 2011	6.88%	200	200
Debentures, at 6.75%, due in 2016	6.94%	130	130
Debentures, at 5.80%, due in 2018	6.03%	400	-
Debentures, at 6.80%, due in 2029	7.05%	150	150
Debentures, at 5.65%, due in 2035	5.88%	200	200
Debentures, at 6.65%, due in 2038	6.83%	200	-
Power LP unsecured senior notes (US$190), at 5.90%, due in 2014	6.16%	233	191
Power LP unsecured senior notes, at 5.95%, due in 2036	6.12%	210	210
Power LP unsecured senior notes (US$150), at 5.87%, due in 2017	6.01%	183	149
Power LP unsecured senior notes (US$75), at 5.97%, due in 2019	6.11%	91	74
Power LP secured term loan, at 11.25%, due in 2010	11.57%	2	4
Non-recourse financing:			
Brown Lake Project, at 8.70%, due in 2016	8.69%	7	7
Joffre Cogeneration Project, at fixed and floating rates, due in 2020	8.82%	41	41
Revolving extendible credit facilities, at floating rates (2007 – 4.86%)	1.81%	224	155
Power LP revolving extendible credit facilities, at floating rates	1.09%	87	-
Obligations under capital leases		-	1
		2,747	2,155
Less: Current portion		26	388
Deferred debt issue costs		19	16
		$ 2,702	$ 1,751

[1] Weighted average coupon rate on gross principal balance outstanding

12. Long-term debt, continued:

Obligation to the City of Edmonton

Debentures were issued, on behalf of the Company, pursuant to the City of Edmonton (COE) Bylaw authorization. The outstanding debentures are a direct, unconditional obligation of the COE. The Company's obligation to the COE matches the COE's obligation pursuant to the debentures. The portion of the 8.50% debentures, maturing in the year 2018 and totaling $61 million, rank as subordinated debt. In the event of default on other interest obligations, the coupon and sinking fund payments on the subordinated debt may be deferred for a period of up to five years, not exceeding the maturity date. If still in default at the end of five years, all unpaid payments plus accrued interest thereon may be repaid by issuing common shares to the COE. Except for the subordinated debt, the obligation to the COE will rank at least equal to all future debt that may be issued by the Company.

The Company makes annual contributions into the Sinking Fund of the COE pertaining to certain debenture issues. These payments constitute effective settlement of the respective debt as the sinking fund accumulates to satisfy the underlying debenture maturity. For any specific COE debenture with sinking fund requirements, the payment obligation ceases on maturity of the debenture.

Debentures

The Debentures are unsecured direct obligations of the Company and, subject to statutory preferred exemptions, rank equally with all other unsecured and unsubordinated indebtedness of the Company. The debentures are redeemable by the Company prior to maturity at the greater of par and a price specified under the terms of the debenture.

Power LP unsecured senior notes

The unsecured senior notes mature in July 2014 and are fully and unconditionally guaranteed by Power LP as to payment of principal, premium, if any, and interest on a senior unsecured basis. Interest is payable semi-annually.

The unsecured senior medium term notes of $210 million are due in June 2036 with interest payable semi-annually.

The unsecured senior medium term notes of $274 million (US$225 million) were issued in two tranches. The $183 million (US$150 million) and $91 million (US$75 million) issued during 2007 are due in July of 2017 and 2019 respectively with interest payable semi-annually.

Power LP secured term loan

The term loan is secured by a first fixed and specific mortgage over the Queen Charlotte plant which has a carrying amount of $14 million (2007 - $15 million) and matures on July 15, 2010.

12. Long-term debt, continued:

Non-recourse financing

Joffre Cogeneration Project financing represents the Company's share, through its subsidiary, EPCOR Power Development Corporation, of syndicated loans for the project. A $40 million portion of the debt bears a fixed interest rate of 8.59% payable quarterly until September 2020. The remaining debt bears interest at the prevailing bankers' acceptance rate plus a spread of 1.50% (2007 - 1.50%) which escalates to 1.875% over the term of the loan. The debt is secured by a charge against project assets which have a carrying amount of $114 million (2007 - $110 million). Brown Lake Project financing is secured by a charge against project assets which have a carrying amount of $12 million (2007 - $12 million).

Revolving extendible credit facilities

An $800 million extendible syndicated bank revolving credit facility, consisting of three-year and five-year tranches of $400 million each, committed to 2011 and 2013, is available to the Company. At December 31, 2008, the Company had $224 million outstanding under this facility, which is extendible beyond 2009 (2007 – $155 million).

Unsecured two-year credit facilities, including one of $90 million and four of $100 million each, for a total of $490 million, committed to 2009 and 2010, are available to the Company. At December 31, 2008, the Company had $27 million outstanding under the two-year extendible credit facilities (2007 – nil). The amounts outstanding under this facility are all drawn on the facility expiring in 2009, are drawn by way of bankers' acceptances and are included in short-term debt (note 11).

Unsecured three-year credit facilities of $100 million each for a total of $300 million, committed to June 2010, September 2010, and October 2011, respectively, are available to the Company through it's Power LP subsidiary. At December 31, 2008, the Company had $23 million in bankers' acceptances and $64 million (US$52 million) in U.S. LIBOR loans outstanding under this facility (2007 - nil).

Under the terms of the $1,590 million of extendible facilities, the Company may obtain advances by way of prime loans, U.S. base rate loans, U.S. LIBOR loans and bankers' acceptances. Depending on the facility, amounts drawn by way of prime loans bear interest at the prevailing Canadian prime rate or the average one month bankers' acceptance rate, plus a spread of 0.75%. Amounts drawn by way of U.S. base rate loans bear interest at a bank determined variable commercial lending rate or the prevailing Federal Funds Rate as published by the U.S. Federal Reserve Board, plus a spread of 0.75%. Amounts drawn by way of U.S. LIBOR loans bear interest at the prevailing LIBOR rate plus a spread ranging from 0.40% to 0.50% which varies by facility. Amounts drawn by way of bankers' acceptances bear interest at the prevailing bankers' acceptance rate plus a spread ranging from 0.40% to 0.50% which varies by facility.

Capital lease obligations

On August 24, 2007, the Company paid off its capital lease obligations for the Naval Station, North Island and Naval Training Centers for $72 million (US$68 million).

(Tabular amounts in millions of dollars)

13. Other non-current liabilities:

	2008	2007
Asset retirement obligations (note 14)	$ 95	$ 92
Employee future benefit liabilities	21	20
Other	9	13
	$ 125	$ 125

14. Asset retirement obligations:

	2008	2007
Balance, beginning of year	$ 100	$ 99
Liabilities incurred	15	8
Liabilities settled	(8)	(12)
Asset retirement accretion expense	5	5
	112	100
Less: current portion in accounts payable and accrued liabilities	17	8
	$ 95	$ 92

The Company estimates the undiscounted amount of cash flow required to settle its asset retirement obligations is approximately $ 411 million, calculated using inflation rates ranging from 2% to 3%. The expected timing for settlement of the obligations is between 2009 and 2090. The majority of the payments to settle the obligations are expected to occur between 2023 and 2064 for the power generation plants, and between 2009 and 2013 for sections of the Genesee coal mine. Discount rates ranging from 4.1% to 8.7 % were used to calculate the carrying amount of the asset retirement obligations. No assets have been legally restricted for settlement of these liabilities.

15. Non-controlling interests:

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

	2008	2007
Non-controlling interests in Power LP	$ (58)	$ 19
Preferred share dividends paid by subsidiary companies	7	12
Preferred share issue costs recognized on redemption of preferred shares	-	3
Recovery of preferred share dividend taxes recognized in prior periods	-	(7)
	$ (51)	$ 27

(Tabular amounts in millions of dollars)

15. Non-controlling interests, continued:

Non-controlling interests reflected on the consolidated balance sheets are comprised of:

	2008	2007
Non-controlling interests in Power LP, beginning of year	$ 618	$ 554
Partnership units issued to non-controlling interests	-	69
Net (loss) income attributable to non-controlling interests	(58)	19
Other comprehensive loss attributable to non-controlling interests	(48)	(3)
Opening accumulated other comprehensive income adjustments attributable to non-controlling interests	-	4
Opening retained earnings adjustments attributable to non-controlling interests	-	67
Distributions to non-controlling interests	(94)	(92)
Non-controlling interests in Power LP, end of year	418	618
Preferred shares issued by subsidiary companies, beginning of year	122	197
Issue of preferred shares	-	122
Redemption of preferred shares	-	(197)
Preferred shares issued by subsidiary companies, end of year	122	122
	$ 540	$ 740

The non-controlling interests in Power LP represents the approximately 69.4% interest in Power LP not owned by EPCOR.

Preferred shares issued by subsidiary companies

On October 1, 2007, EPCOR Preferred Equity Inc., a subsidiary of the Company, completed the redemption of 8 million Cumulative Redeemable Perpetual First Preferred Shares, Series I (Series I Preferred Shares) at par for $200 million, funded from cash balances and debt.

The carrying amount of the Series I Preferred Shares prior to their redemption by the Company was $197 million, reflecting $200 million less issue costs of $3 million which were incurred when the preferred shares were issued in 2002. The $3 million difference between the redemption price and the carrying amount was charged to non-controlling interests in the consolidated statements of income.

(Tabular amounts in millions of dollars)

15. Non-controlling interests, continued:

Preferred shares issued by subsidiary companies, continued

During 2007, EPCOR Power Equity Ltd. (EPEL), a subsidiary of Power LP issued 5 million of 4.85% cumulative, redeemable First Preference Shares, Series 1 priced at $25.00 per share with dividends payable on a quarterly basis at the annual rate of $1.2125 per share. Proceeds of $121 million, net of issue costs of $4 million, were used to repay amounts outstanding under a Power LP bridge acquisition credit facility. Future income tax assets of $1 million related to the share issue costs are recorded in the preferred share balance. On or after June 30, 2012, the shares are redeemable by EPEL at $26.00 per share, declining by $0.25 each year to $25.00 per share after June 30, 2016. The shares are not retractable by the holders. The Company will not make any distributions on the Power LP units if the declaration or payment of dividends on the preferred shares is in arrears. Dividends will not be paid on the preferred shares if the Power LP unsecured senior notes are in default.

16. Share capital:

Authorized:

Unlimited number of voting common shares without nominal or par value.

Issued:

Three common shares for nominal value to the COE.

17. Accumulated other comprehensive loss

The components of accumulated other comprehensive loss at December 31, 2008 and December 31, 2007 respectively are summarized as follows:

	2008	2007
Unrealized losses on derivative instruments designated as cash flow hedges[1]	$ (29)	$ (62)
Unrealized gains on financial instruments designated as available for sale[2]	-	3
Unrealized loss in self-sustaining foreign operations[3]	(65)	(3)
Non-controlling interests[3]	47	(1)
	$ (47)	$ (63)

[1] Net of income tax recovery of $11 million (2007 – income tax recovery of $27 million).

[2] Net of income tax expense of nil (2007 – income tax expense of $1 million).

[3] Net of income tax expense of nil (2007 – nil).

(Tabular amounts in millions of dollars)

18. Change in non-cash operating working capital:

	2008	2007
Accounts receivable	$ 75	$ 71
Income taxes recoverable	2	(9)
Inventories	(16)	(7)
Prepaid expenses	-	3
Accounts payable and accrued liabilities	(73)	(44)
Income taxes	(75)	9
Other current liabilities	6	1
	$ (81)	$ 24

19. Net financing expenses:

	2008	2007
Interest on long-term debt	$ 180	$ 167
Interest on short-term debt and other financing costs	6	8
Fair value changes on financial instruments	18	12
Capitalized interest and AFUDC	(23)	(14)
Interest and dividend income	(6)	(10)
Other	2	8
	$ 177	$ 171

20. Income taxes:

	2008	2007
Current income taxes	$ 32	$ 84
Future income taxes (reductions)	(53)	28
	$ (21)	$ 112

Income taxes differ from the amounts that would be computed by applying the federal and provincial income tax rates as follows:

	2008	2007
Net income before income taxes and non-controlling interests	$ 103	$ 416
Statutory income tax rates	29.50%	32.12%
Income taxes at statutory rates	30	134
Increase (decrease) resulting from:		
Income exempt from income taxes at statutory rates	(46)	(28)
Unrecognized future income tax assets	45	(2)
Non-taxable portion of capital items	(42)	(12)
Non-taxable amounts	(8)	(28)
Effective SIFT tax	(6)	48
Adjustment for enacted changes in income tax laws and rates and other tax rate differences	2	13
Future income taxes due to change in tax status	-	(10)
Other	4	(3)
	$ (21)	$ 112

(Tabular amounts in millions of dollars)

20. Income taxes, continued:

The tax effects of temporary differences that give rise to significant portions of the future income tax assets and future income tax liabilities are presented below:

	2008	2007
Future income tax assets:		
Losses carried forward	$ 104	$ 70
Cumulative eligible capital	71	71
Property, plant and equipment – differences in net book value and undepreciated capital cost	42	35
Asset retirement obligations	22	13
Investment in partnership	20	23
Contract and customer rights and other intangible assets	16	8
Other	7	12
	282	232
Future income tax liabilities:		
Investment in partnership	191	173
Deferred income from partnership	51	56
Property, plant and equipment – differences in net book value and undepreciated capital cost	28	26
Asset retirement obligation assets	16	7
Contract and customer rights and other intangible assets	10	1
Power purchase arrangements	8	13
Long-term debt	-	8
Other	6	7
	310	291
Net future tax liabilities	$ (28)	$ (59)

	2008	2007
Presented on the balance sheet as follows:		
Current assets	$ 3	$ 3
Non-current assets	103	103
Current liabilities	(34)	(39)
Non-current liabilities	(100)	(126)
	$ (28)	$ (59)

At December 31, 2008, the Company has non-capital losses carried forward of approximately $362 million (2007 - $254 million), of which $119 million (2007 - $49 million) relate to certain U.S. subsidiaries. These losses expire between 2014 and 2028. The Company also has taxable capital losses of approximately $156 million (2007 - $16 million) and restricted limited partnership losses of approximately $22 million (2007 - $8 million) which carry forward indefinitely. There are non-capital losses available to be carried forward of $46 million (2007 - $35 million), capital losses available to be carried forward of $156 million (2007 - $4 million) and other deductible temporary differences of $229 million (2007 - $144 million) for which no tax benefit has been recognized.

Refundable taxes of $11 million (2007 - $13 million) recorded in retained earnings include $6 million (2007 - $7 million) arising from the sale of the Battle River PSA as described in note 4.

20. Income taxes, continued:

Tax on flow-through entities

Currently, the taxable income of Power LP is to be taxed in the hands of its unit holders. Canadian tax legislation related to specified investment flow-through entities (SIFT Legislation) included in Bill C-52 was enacted in 2007 and will result in changes to how certain publicly traded trusts and partnerships, including Power LP, are taxed. The SIFT Legislation applies a tax at the specified investment flow-through entity level on certain income and at tax rates comparable to the combined federal and provincial corporate tax rates, and then re-characterizes that income net of tax payable as taxable dividends in the hands of unit holders. The SIFT Legislation will apply to Power LP starting the earlier of January 1, 2011 or January 1 of the year following the date at which the Power LP exceeds the normal growth guidelines issued by the Department of Finance (Canada) on December 15, 2006. EPCOR does not expect the Power LP to be subject to the new rules prior to the January 1, 2011 date.

Enactment of the SIFT Legislation resulted in the recognition of future income taxes expense and net future tax liabilities of $48 million in 2007, based on estimated net taxable temporary differences which are expected to reverse after 2010 and for which no tax has previously been recorded at the partnership level. The Company previously recognized its 30.6% share of these future income taxes, commencing upon acquisition of Power LP, and the resulting additional future income taxes expense relates entirely to the non-controlling interests in Power LP.

Corporate restructuring within the Energy Services segment

On January 1, 2007, the Company reorganized certain subsidiaries within its Energy Services segment. As a result of the reorganization, the Company recognized future income tax assets of $10 million and a corresponding increase in consolidated net income in 2007. The resulting future income tax assets will be reduced over time, as the underlying income tax deductions are utilized to reduce taxable income.

21. Fair value and classification of financial assets and liabilities:

The Company classifies its cash and cash equivalents and current and non-current derivative instruments assets and liabilities as held for trading and measures them at fair value. Accounts receivable are classified as loans and receivables; short-term debt, accounts payable and accrued liabilities, and other current liabilities are classified as other financial liabilities: all of which are measured at amortized cost and their fair values are not materially different from their carrying amounts due to their short-term nature. The Company's beneficial interest in the Sinking Fund related to the COE debentures is classified as available for sale.

(Tabular amounts in millions of dollars)

21. Fair value and classification of financial assets and liabilities, continued:

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

		2008		2007	
Financial asset or liability	Classification	Carrying amount	Fair value	Carrying amount	Fair value
Other assets					
Non-bank sponsored asset-backed commercial paper (ABCP)	Designated as held for trading	$ 42	$ 42	$ 60	$ 60
Investment in preferred shares of Primary Energy Recycling Holdings LLC (PERH)	Available for sale	16	16	15	15
Loans and other long-term receivables	Loans and receivables	102	92	70	70
Net investments in leases	Loans and receivables	52	50	29	28
Portfolio investments	Available for sale	6	6	13	16
Long-term debt (including current portion)	Other financial liabilities	2,728	2,471	2,139	2,226

Non-bank sponsored asset-backed commercial paper

There are no observable market prices for ABCP as at the balance sheet date. Accordingly, EPCOR has estimated the fair value using a probability-weighted discounted cash flow approach based on the assumed credit ratings and potential ratings actions on the applicable new notes under the ABCP restructuring, observable interest rates and credit spreads for estimating future interest payments and applicable discount rates, the cost of margin call facilities, the cost of the restructuring, estimated recovery periods based on the estimated lives of the underlying assets associated with the new notes and ranges of recoverability based on publicly available default statistics for credit-rated entities. In estimating future cash flows from the new notes the Company assumed that it will earn interest at rates ranging from 1.00% to 12.50% (weighted average rate of 2.82%) depending on the note series, taking into account restructuring costs and margin funding. The future cash flows were discounted at rates ranging from 7.93% to 46.70% (weighted average rate of 15.20%), depending on the note series, over 8.1 to 26.0 years (weighted average amortization period of 9.2 years), taking into account the assumed credit spreads and mortality rates. In estimating the future cash flows from the new notes the Company assumed that cash flows from MAV2 Class B and Class C notes would be nil due to their subordination to the MAV2 Class A notes.

The estimated fair value of ABCP decreased by $18 million in the year (2007 - $11 million) primarily due to lower interest rates, higher observed and estimated credit spreads over the yields of long-term Government of Canada bonds and longer expected note lives underlying the new notes. Decreases in the fair value of ABCP are recorded in net financing expenses.

(Tabular amounts in millions of dollars)

21. Fair value and classification of financial assets and liabilities, continued:

Non-bank sponsored asset-backed commercial paper, continued

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

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

Refer to note 10 for additional disclosure on the Company's ABCP.

Net investments in leases

The fair values of the Company's net investments in leases are based on the estimated interest rates implicit in comparable lease arrangements or loans plus an estimated credit spread based on the counterparty risk as at December 31, 2008 and December 31, 2007.

Long-term debt and Sinking Fund

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

(Tabular amounts in millions of dollars)

21. Fair value and classification of financial assets and liabilities, continued:

Other financial instruments

Fair values on the remaining financial instruments are determined by reference to quoted bid or ask prices, as appropriate, in active markets at period-end dates.

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

22. Derivative instruments and hedge accounting:

Derivative financial and non-financial instruments are held for the purpose of energy purchases, merchant trading or financial risk management.

The derivative instruments assets and liabilities used for risk management purposes as described in note 23 consist of the following:

	2008			
	Energy		Foreign exchange	
	Cash flow hedges	Non-hedges	Non-hedges	Total
Derivative instruments assets:				
Current	$ 10	$ 108	$ 12	$ 130
Non-current	9	62	4	75
Derivative instruments liabilities:				
Current	(31)	(88)	(12)	(131)
Non-current	(29)	(43)	(38)	(110)
Net fair value	$ (41)	$ 39	$ (34)	$ (36)
Net notional buys (sells):				
Megawatt hours of electricity (millions)	(2)	(2)		
Gigajoules of natural gas (millions)	-	65		
Foreign currency (U.S. dollars)			$ (398)	
Range of contract terms in years	0.1 to 8.0	0.1 to 8.0	0.1 to 6.0	

(Tabular amounts in millions of dollars)

22. Derivative instruments and hedge accounting, continued:

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

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

(Tabular amounts in millions of dollars)

22. Derivative instruments and hedge accounting, continued:

The extent to which fair values of derivative instruments are based on observable market data is determined by the extent to which the market for the underlying commodity is judged to be active. With respect to natural gas, the Company has determined the market is active within five years. As the natural gas supply contracts extend beyond the active period of the market, fair value is determined by reference in part to published price quotations where there is observable market data and in part by relying on price forecasts prepared by an independent third party where there are limited observable natural gas prices. While external market forecasts outside the active period of the market reasonably reflect all factors that market participants would consider in setting a price, these expectations are not currently supportable by active forward market quotes. The fair values of these contracts could change significantly if the assumptions were changed to reasonably possible alternatives. The natural gas price forecasts for the period, where limited observable natural gas prices are available, range from $6.67 to $8.01 per gigajoule. The Company has determined that a reasonably possible increase or decrease of $1.00 per gigajoule in the natural gas price forecast would have a $65 million impact on the fair value estimate of these contracts. Included in this sensitivity is a $17 million impact for contract periods beyond the next five years where prices are not based on observable natural gas prices. This valuation technique resulted in unrealized pre-tax fair value losses of $5 million recognized in energy purchases and fuel for the year ended December 31, 2008 (2007 - $19 million of unrealized pre-tax fair value gains).

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

	2008		2007	
	Unrealized gains (losses)	Realized gains (losses)	Unrealized gains (losses)	Realized gains (losses)
Energy cash flow hedges	$ 52	$ (10)	$ (33)	$ (66)
Energy non-hedges	(41)	1	2	(6)
Foreign exchange non-hedges	(57)	7	16	(15)
Interest rate non-hedges	-	-	(1)	(3)

Realized gains and losses disclosed above relate only to financial derivative instruments. Realized gains and losses on non-financial derivative instruments are recorded in energy revenues or energy purchases and fuel, as appropriate.

22. Derivative instruments and hedge accounting, continued:

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

The Company has elected to apply hedge accounting on certain derivatives it uses to manage commodity price risk relating to electricity prices. For 2008, the change in the fair value of the ineffective portion of hedging derivatives required to be recognized in the income statement was nil (2007 - nil). Of the $29 million (2007 - $62 million) of net losses related to derivative instruments designated as cash-flow hedges included in accumulated other comprehensive loss at December 31, 2008, net losses of $15 million (2007 - $45 million), net of income taxes of $7 million (2007 - $20 million) are expected to settle and be reclassified to net income over the next twelve months. The Company's cash flow hedges extend up to 2016.

23. Risk management:

Risk management overview

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

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

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

23. Risk management, continued:

Risk management overview, continued

Market risk

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

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

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

Commodity price risk

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

- The Company reduces its exposure to the volatility of commodity prices related to electricity sales by entering into offsetting contracts such as contracts-for-differences and firm price physical contracts for periods of varying duration.

23. Risk management, continued:

Market risk, continued

Commodity price risk, continued

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

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

The fair value of the Company's energy related derivatives at December 31, 2008 that are required to be measured at fair value with the respective changes in fair value recognized in net income are disclosed in note 22.

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

23. Risk management, continued:

Market risk, continued

Commodity price risk, continued

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

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

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

The Company's estimation of TE takes into account positions from all wholly owned subsidiaries and subsidiaries in which the Company has a controlling interest, and reflects the Company's aggregate commodity positions from its trading and asset portfolios. The Company's Board of Directors has established an aggregate TE limit, under the Company's risk management policy, which is monitored and reported to the ROC and other senior management on a daily basis. The portfolios are stress tested regularly to observe the effects of plausible scenarios taking into account historical maximum volatilities and maximum observed price movements. Based on the commodity portfolio as at December 31, 2008, there is a higher than 95% probability that unfavorable daily market variations would not reduce the 12 month portfolio by more than $22 million.

Foreign exchange risk

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

23. Risk management, continued:

Market risk, continued

Foreign exchange risk, continued

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

The Company primarily uses foreign currency forward contracts to fix the functional currency of its non-functional currency cash flows thereby reducing its anticipated U.S. dollar denominated transactional exposure. The Company looks to limit foreign currency exposures as a percentage of estimated future cash flows. The percentage amount to be fixed will generally be higher, the shorter the period into the future that the cash flows relate to. At December 31, 2008, US$457 million or approximately 96% of expected future net cash flows from Power LP's U.S. plants had been economically hedged for 2009 to 2014 at a weighted average exchange rate of $1.12 per U.S. dollar. At December 31, 2008, US$59 million or approximately 95% of expected future net cash flows from the Company's capital expenditure commitments, denominated in U.S. dollars, had been economically hedged for 2009 to 2010 at a weighted average exchange rate of $1.15 per U.S. dollar.

As at December 31, 2008, holding all other variables constant, a $0.10 strengthening or weakening of the Canadian dollar against the U.S. dollar would increase or decrease net income by approximately $1 million. There would be no impact to other comprehensive income.

This sensitivity analysis excludes translation risk associated with the application of the current rate and temporal translation methods, financial instruments that are non-monetary items, and financial instruments denominated in the functional currency in which they are transacted and measured.

23. Risk management, continued:

Market risk, continued

Interest rate risk

The Company is exposed to changes in interest rates on its cash and cash equivalents, and floating rate short-term and long-term loans and obligations. The Company is exposed to interest rate risk from the possibility that changes in the interest rates will affect future cash flows or the fair values of its financial instruments. In some circumstances, floating rate funding may be used for short-term borrowings and other liquidity requirements. At December 31, 2008, the proportion of fixed rate debt was approximately 84% (2007 - 87%) of total long-term debt outstanding. The Company may also use derivative instruments to manage interest rate risk. At December 31, 2008 and December 31, 2007, the Company did not hold any interest rate derivative instruments.

Assuming that the amount and mix of fixed and floating rate loans and net debt remains unchanged from that held at December 31, 2008, a 100 basis point increase or decrease to interest rates would decrease or increase full year net income by $2 million and would have no direct impact on other comprehensive income.

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

Credit risk

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

(Tabular amounts in millions of dollars)

23. Risk management, continued:

Credit risk, continued

Maximum credit risk exposure

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

	2008	2007
Cash and cash equivalents	$ 111	$ 79
Accounts receivable[1]	502	581
Derivative instruments assets[1]	205	220
ABCP	42	60
Loans and other long-term receivables	102	70
Net investments in leases	52	29
Financial guarantees to third parties	31	27
Loan commitments to third parties	6	6
	$ 1,051	$ 1,072

[1] The Companies maximum exposures related to accounts receivable and derivative instruments assets by major credit concentration are comprised of maximum exposures of $195 for generation, $240 for wholesale and $272 for rate regulated companies.

This table does not take into account collateral held. At December 31, 2008, the Company held cash deposits of $57 million (2007 - $36 million) as security for certain counterparty accounts receivable and derivative contracts. The Company is not permitted to sell or re-pledge this collateral in the absence of default of the counterparties providing the collateral. At December 31, 2008, the Company also held other forms of credit enhancement in the form of letters of credit of $18 million (2007 - $1 million) and parental guarantees of $738 million (2007 - $669 million).

Credit quality and concentrations

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

(Tabular amounts in millions of dollars)

23. Risk management, continued:

Credit risk, continued

Credit quality and concentrations, continued

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

	December 31, 2008		
	Investment grade[1] or secured[4]	Non-investment grade[1]	Unrated
Accounts receivable and financial derivative instruments			
Generation	100%	-	-
Wholesale[2]	90%	10%	-
Rate-regulated customers[3]	-	-	100%
Cash and cash equivalents	100%	-	-
Loans and other long-term receivables	100%	-	-
ABCP[5]	80%	-	20%

[1] Credit ratings are based on the Company's internal criteria and analyses, which take into account, among other factors, the investment grade ratings of external credit rating agencies when available.

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

[3] Rate-regulated customer trade receivables include distribution and transmission, water sales, rate-regulated, and default power supply receivables. Under the Alberta Electric and Utilities Act, the Company provides electricity supply in its service area to residential, irrigation and small commercial customers at regulated rates, and those commercial and industrial customers who have not chosen a competitive offer and consume electricity under default supply arrangements.

[4] Certain accounts receivable and other financial assets are considered to have low credit risk as they are either secured by the underlying assets, secured by other forms of credit enhancements, or the counterparties are local or provincial governments.

[5] Based on ABCP restructuring.

23. Risk management, continued:

Credit risk, continued

Generation credit risk

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

Wholesale and merchant credit risk

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

Rate-regulated customer credit risk

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

(Tabular amounts in millions of dollars)

23. Risk management, continued:

Credit risk, continued

Accounts receivable and allowance for doubtful-accounts

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

The aging of accounts receivable was:

	December 31, 2008		
	Gross accounts receivable	Allowance for doubtful accounts	Net accounts receivable
Current[2]	$ 455	$ -	$ 455
Outstanding 30 to 60 days[2]	11	-	11
Outstanding 61 to 90 days[2]	4	-	4
Outstanding more than 90 days[1 and 2]	38	6	32
Total	$ 508	$ 6	$ 502

1 Includes $24 million which is subject to regulatory approval prior to collection but has low associated credit risk.

2 Current amounts represent accounts receivable outstanding zero to 30 days. Amounts outstanding more than 30 days are considered past due.

Bad debt expense, exclusive of recoveries, of $6 million recognized in the year ended December 31, 2008 relates to customer amounts that the Company determined would not be fully collectable. Allowances for doubtful accounts are determined by each business unit, within each operating segment, considering the unique factors of the business unit's accounts receivable. Allowances and write-offs are determined by each business unit, either by applying specific risk factors to customer groups' aged balances in accounts receivable or by reviewing material accounts on a case-by-case basis. Reductions in accounts receivable and the related allowance for doubtful accounts are recorded when the Company has determined that recovery is not possible.

(Tabular amounts in millions of dollars)

23. Risk management, continued:

Credit risk, continued

Accounts receivable and allowance for doubtful-accounts, continued

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

	2008	2007
Balance, beginning of year	$ 6	$ 6
Allowance of receivables	6	5
Receivables written off	(8)	(7)
Recovery of receivables	2	2
Balance, end of year	$ 6	$ 6

At December 31, 2008, the Company held $20 million of customer deposits for the purpose of mitigating the credit risk associated with accounts receivable from residential and business customers.

At December 31, 2008, there was no provision for credit losses associated with accounts receivable from treasury, trading and energy procurement counterparties as all balances are considered to be fully collectable.

Liquidity risk

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

As at December 31, 2008, the Company had undrawn and committed bank credit facilities, including operating lines of credit, of $1,668 million, of which $562 million is committed for at least 2 years. The Company has a long-term debt rating of BBB+ and A (low), assigned by Standard and Poor's (S&P) and DBRS Limited (DBRS), respectively. Power LP also has a long-term debt rating of BBB+ and BBB(high), assigned by S&P and DBRS respectively.

In addition, the Company has in place a Canadian shelf prospectus, which expires in November 2009, under which it may raise up to $1 billion of debt, with maturities of not less than one year. As at December 31, 2008, the available amount remaining under the Canadian shelf prospectus was $400 million. Power LP has in place a Canadian universal shelf prospectus, which expires in August 2010, under which Power LP may raise up to $1 billion in partnership units or debt, of which a maximum of $600 million can be debt. As at December 31, 2008, the Power LP has not drawn on the Power LP shelf prospectus.

(Tabular amounts in millions of dollars)

23. Risk management, continued:

Liquidity risk, continued

The following are the undiscounted cash flow requirements and contractual maturities of the Company's financial liabilities, including interest payments, as at December 31, 2008:

	Due within 1 year	Due between 1 and 2 years	2 and 3 years	3 and 4 years	4 and 5 years	Due after more than 5 years	Total contractual cash flows
Non-derivative financial liabilities:							
Short-term debt	$ 140	$ -	$ -	$ -	$ -	$ -	$ 140
Long-term debt	26	308	215	52	231	1,914	2,746
Interest payments on long-term debt	209	185	164	140	124	1,266	2,088
Accounts payable and accrued liabilities [1]	539	-	-	-	-	-	539
Other current liabilities	20	-	-	-	-	-	20
Loan commitments	6	-	-	-	-	-	6
Derivative financial liabilities:							
Net forward foreign exchange contracts	15	9	8	10	6	7	55
Net commodity contracts-for-differences	94	50	10	2	1	1	158
Total	$ 1,049	$ 552	$ 397	$ 204	$ 362	$ 3,188	$ 5,752

[1] Excluding accrued interest on long-term debt of $48 million.

24. Capital management:

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

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

(Tabular amounts in millions of dollars)

24. Capital management, continued:

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

	2008	2007
Short-term debt (note 11)	$ 140	$ 138
Long-term debt (including current portion) (note 12)	2,728	2,139
Cash and cash equivalents	(111)	(79)
Net debt	2,757	2,198
Non-controlling interests (note 15)	540	740
Shareholder's equity	2,429	2,367
Total equity	2,969	3,107
Total capital	$ 5,726	$ 5,305

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

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

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

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

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

For the year ended December 31, 2008, the Company and Power LP complied with all externally imposed capital restrictions.

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

(Tabular amounts in millions of dollars)

25. Related party balances and transactions:

The related party transactions described below 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.

The following summarizes the Company's related party balances and transactions with the COE.

			2008		2007
Balance sheet:					
Accounts receivable	(a)	$	10	$	32
Property, plant and equipment	(b)		3		14
Long-term debt (note 12)			189		243
Income statement:					
Revenues: - energy and water sales		$	26	$	25
- other	(c)		72		52
Operations, maintenance and administration	(d)		8		7
Franchise fee, property taxes and other taxes	(e)		51		49
Net financing expenses	(f)		44		54

(a) The accounts receivable balance due from the COE includes nil (2007 - $29 million) in respect of the negotiated sharing of the earnings of the COE Sinking Fund. During the year, the Company received $29 million (2007 - nil) of these balances.

(b) Costs of capital construction for water distribution mains and infrastructure.

(c) Revenues from the provision of maintenance, repair and construction services of $64 million (2007 - $45 million) and $8 million for customer billing services (2007 - $7 million).

(d) Includes certain costs of printing services and supplies, mobile equipment services, public works and various other services pursuant to service agreements.

(e) Franchise fee of $41 million (2007 - $39 million) at 0.438 cents per kilowatt-hour (2007 - 0.426 cents per kilowatt hour) for EPCOR Distribution Inc. and at 7.6% (2007 - 7.6%) of qualifying revenues of EPCOR Water Services Inc. Property taxes of $10 million (2007 - $10 million) on property owned within the COE municipal boundaries.

(f) Interest expense on the obligation to the COE.

Included in the Company's revenues is $4 million (2007 - $3 million) for the provision of management services by Power LP to PERC under a long-term management agreement. At December 31, 2008, accounts receivable includes nil due from PERC (2007 - $1 million).

(Tabular amounts in millions of dollars)

26. Joint ventures:

The Company and the coal mine operator at the Genesee plant site each have a 50% interest in the Genesee Coal Mine Joint Venture. The joint venture partner operates the coal mine. Under agreements governing this joint venture, all coal mined is to be supplied to the Company's Genesee generation plant.

The Company holds 50% interests in the Genesee 3 Project, the Keephills 3 Project and the Taylor's Coulee Chute Hydro Project, and holds a 40% interest in the Joffre Cogeneration Project. The Company, through its Power LP subsidiary, also holds a 50.15% interest in the Frederickson power plant.

A financial summary of the Company's investments in joint ventures is as follows:

	2008	2007
Current assets	$ 44	$ 38
Long-term assets	986	728
Current liabilities	68	56
Long-term liabilities	42	42
Revenues[1]	74	67
Expenses[2]	100	78
Net loss	(26)	(11)
Cash flows from operating activities	13	17
Cash flows used in investing activities	(267)	(140)
Cash flows from financing activities	245	106

[1]Excludes all revenues from Genesee 3, which are recorded as revenues by the Company but are not subject to the terms of the joint venture agreement.

[2]Excludes all costs of operating the Genesee Coal Mine Joint Venture, which are recorded as fuel expenses by the Company.

Included in the Company's cash and cash equivalents is its proportionate share of cash and cash equivalents which are restricted to use within joint ventures of $24 million (2007 - $14 million).

Under the terms of the Company's interests in the Frederickson power plant, the Genesee 3 Project and the Keephills 3 Project, the Company and its respective partners have guaranteed financial and performance obligations under the joint venture agreements limited to $40 million, $50 million and $50 million respectively.

27. Employee future benefits:

Multiemployer defined benefit pension plan and defined contribution pension plan

Over 90% of the Company's employees are either members of the Local Authority Pension Plan or its registered defined contribution plan. Accordingly, the majority of the Company's pension costs and obligations are accounted for as defined contribution plans.

(Tabular amounts in millions of dollars)

27. Employee future benefits, continued:

Defined benefit plans

The effective date for the latest actuarial valuations of both the Company's registered and supplemental pension plans was December 31, 2007. The effective date of the next valuation for funding purposes is no later than December 31, 2010 for both plans. The date used to measure the plan assets and the accrued benefit obligation was December 31, 2008. The supplemental pension plan is a non-contributory plan that is unfunded at December 31, 2008.

As part of the Company's acquisition of its interest in Power LP, employees who transferred to EPCOR on September 1, 2005 became members of the Company's registered pension plan. The plan provides pension benefits based on an employee's years of service and their highest earnings over three consecutive years of employment. Retirement pensions will be increased annually by a portion of the increase in the Consumer Price Index. Under terms of the Power LP purchase and sale agreement, the previous plan sponsor will transfer the pension liabilities for the Canadian employees and associated assets based on an actuarial valuation. As at December 31, 2008, the actual transfer of assets has not yet occurred as regulatory approval required for transfer of the assets and obligations is still outstanding.

Pension plan benefit costs, assets and obligations

	2008	2007
Costs recognized for the years ended December 31:		
Service cost	$ 3	$ 3
Interest on benefit obligation	1	1
Actuarial gains	(3)	(1)
Difference between actuarial gain recognized and actual gain on accrued benefit obligation	3	1
Defined benefit plans cost	4	4
Defined contribution plans cost	19	16
Net expense	$ 23	$ 20

	2008	2007
Funded status as at December 31:		
Market value of plan assets	$ 9	$ 9
Accrued benefit obligation	23	23
Funded status – plan deficit	(14)	(14)
Amounts not yet recognized in financial statements:		
Unamortized net losses	1	3
Accrued benefit liability recognized in financial statements	$ (13)	$ (11)
Expected average remaining service life in years – registered pension plan	11	11
Expected average remaining service life in years – supplemental pension plan	10	12

(Tabular amounts in millions of dollars)

27. Employee future benefits, continued:

Plan benefit costs, assets and obligations, continued

The accrued benefit liability is included in other non-current liabilities along with other employee future benefit liabilities. Other employee future benefit liabilities consist mainly of obligations for benefits provided to employees on long-term disability leaves.

		2008		2007
Reconciliation of accrued benefit obligation:				
Accrued benefit obligation, beginning of year	$	23	$	21
Service cost		3		3
Interest cost		1		1
Actual benefits paid		(1)		(1)
Actuarial gain		(3)		(1)
Accrued benefit obligation, end of year	$	23	$	23

		2008		2007
Plan assets:				
Market value of assets, beginning of year	$	9	$	8
Contributions		1		1
Actual return of plan assets (net of expenses)		(1)		-
Market value of assets, end of year	$	9	$	9

Total cash payments for pension benefits in 2008, consisting of cash contributed by the Company to the LAPP, other defined contribution and benefit plans and cash payments directly to beneficiaries for its unfunded pension plan, were $21 million (2007 - $16 million).

Assumptions:

The significant actuarial assumptions adopted in measuring the corporation's accrued benefit obligations were as follows:

	2008	2007
Accrued benefit obligation as at December 31		
Discount rate	6.25%	5.25%
Rate of compensation increase	4.00%	4.00%
Benefit cost for year ended December 31		
Discount rate	5.25%	5.00%
Rate of compensation increase	4.00%	4.00%
Expected rate of return on plan assets	7.00%	7.00%

(Tabular amounts in millions of dollars)

27. Employee future benefits, continued:

Information concerning the Company's registered pension plan's target asset allocation and actual asset allocation is as follows:

	2008		2007	
	Target asset allocation	Asset allocation	Target asset allocation	Asset allocation
Fixed income securities	35%	38%	35%	33%
Equity securities	60%	59%	60%	56%
Other assets	5%	3%	5%	11%
Total	100%	100%	100%	100%

28. Plants under operating leases:

Certain power generation plants operate under PPAs that convey the right to the holder of the agreement to use the related property, plant and equipment. Consequently, these power generation plants, comprised of the Castleton, Manchief, Mamquam, Queen Charlotte, Southport, Roxboro, Kenilworth, Greeley and Williams Lake plants, are accounted for as assets under operating leases. As at December 31, 2008, the carrying amount of such property, plant and equipment was $477 million (2007 - $470 million), less accumulated depreciation of $63 million (2007 - $52 million). The Company's revenue pursuant to the arrangements for the year ended December 31, 2008 was $193 million (2007 - $200 million).

29. Contingencies and commitments:

(a) The Company has committed to purchase new high efficiency gas-fired electric generating units at an estimated total cost of $284 million (2007 - $284 million), of which $186 million has been incurred as at December 31, 2008 (2007 - $67 million).

(b) On February 26, 2007, EPCOR and TransAlta Corporation (Transalta) announced their decision to build Keephills 3, a 495 megawatt (MW) supercritical coal-fired generation plant at TransAlta's Keephills site. The construction is expected to be completed in 2011. EPCOR's 50% estimated committed share of the total capital cost is $903 million (2007 - $820 million), of which $424 million has been incurred as at December 31, 2008 (2007 - $165 million). As part of contractual arrangements, EPCOR and TransAlta have indemnified each other for up to $115 million during construction in the event that either party makes payments to the turbine supplier on behalf of the other party.

(c) In May 2008, the Company entered into an agreement with a third party to design, build, own and operate a potable water and wastewater treatment plant for the third party over a 20 year term, in return for payments totaling approximately $99 million commencing upon completion of the design-build phase in 2009. The project will require a capital outlay of approximately $31 million, of which $16 million has been incurred as at December 31, 2008.

(Tabular amounts in millions of dollars)

29. Contingencies and commitments, continued:

(d) The Power LP has committed up to $119 million (US$98 million) for the enhancement of the Southport, Roxboro and North Island facilities, to be spent through 2009, of which $18 million (US$15 million) has been incurred as at December 31, 2008.

(e) Under the terms of the acquired Alberta PPAs, the Company is obligated to make monthly payments for fixed and variable costs. The estimated annual total of these payments for 2009 is $135 million. The actual amounts for 2009 and future years may vary from estimates depending on generation volume and scheduled outages. It is expected that the annual payments over the terms of the Alberta PPAs, as described in note 2(l), will range from $93 million to $159 million, adjusted for inflation, other than in the event of a forced outage.

(f) The Company has entered into a number of long-term energy purchase and transportation contracts and operating and maintenance contracts in the normal course of operations. The energy purchase and transportation contracts are measured at their fair value and recorded on the consolidated balance sheet as derivative instruments assets and liabilities as appropriate. The energy purchase and transportation contract amounts disclosed below are based on gross settlement amounts.

Approximate future payments under these contracts and under operating leases for premises are as follows:

	Energy purchase and transportation contracts	Operating and maintenance contracts	Operating leases
2009	$ 156	$ 27	$ 3
2010	122	28	3
2011	93	29	3
2012	77	30	1
2013	58	31	1
Thereafter	198	141	4
Total	$ 704	$ 286	$ 15

(g) The Company has committed to issue non-interest bearing notes receivable to the non-EPCOR syndicate members involved in the Sundance Swap transaction entered into in 2006. The commitment relates to funding potential income tax liabilities incurred by the non-EPCOR syndicate members in relation to the transaction. The total estimated loan commitment is $19 million, with annual payments of principal commencing from the date the commitment is called by the non-EPCOR syndicate members through to December 2012. At December 31, 2008, the Company has extended $13 million (2007 - $13 million) under such notes and their carrying amount of $9 million (2007 - $9 million), after fair value adjustments recorded at inception, is included in other assets.

(Tabular amounts in millions of dollars)

29. Contingencies and commitments, continued:

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

(i) On December 6, 2007 the Company entered into a long-term leasing agreement to lease head office commercial space in a new office tower being constructed in Edmonton. The agreement, with an effective date of January 1, 2012, extends for 20 years and provides the Company with three successive five-year renewal options. Under terms of the lease the Company has committed to make annual payments of $10 million for the period of January 1, 2012 through December 31, 2021 and $11 million for the period of January 1, 2022 through December 31, 2031.

(j) On December 4, 2008 the Power LP signed a definitive agreement to sell its Castleton facility, located in the state of New York, to Castleton Energy Center, LLC (CEC) for approximately US$10 million, subject to closing adjustments. The sale is expected to close in the first quarter of 2009, subject to certain closing adjustments and regulatory approvals. The related assets and liabilities of the Castleton power plant, before giving effect to the non-controlling interest in such assets and liabilities, are:

	2008	2007
Current assets		
Accounts receivable	$ 1	$ 4
Inventories and prepaid expenses	1	2
	$ 2	$ 6
Non-current assets		
Property, plant and equipment	$ 11	$ 12
Future income tax assets	1	-
	$ 12	$ 12
Current liabilities		
Accounts payable and accrued liabilities	$ 1	$ 4
Non-current liabilities		
Asset retirement obligations	$ 2	$ 2
Future income tax liabilities	2	1
	$ 4	$ 3

Net loss, before giving effect to the non-controlling interest, from the Castleton power plant for the year ended December 31, 2008 was $1 million (2007 – nil).

29. Contingencies and commitments, continued:

(k) The Company has committed to various distribution and transmission projects through 2009 and 2010, as directed by the Alberta Electric System Operator (AESO). The total estimated projects costs are $47 million (2007 - $12 million). The Company has incurred costs of $11 million (2007 - $2 million).

(l) The Company and its subsidiaries are subject to various legal claims that arise in the normal course of business. Management believes that the aggregate contingent liability of the Company arising from these claims is immaterial and therefore no provision has been made.

30. Guarantees:

The Company has issued letters of credit for $253 million (2007 - $357 million) to meet the credit requirements of energy market participants, to meet conditions of certain service agreements, and to satisfy legislated reclamation requirements.

Such letters of credit include $16 million related to prudential support provided by the Company on behalf of the purchaser of certain competitive mass-market contracts in 2004, in addition to $15 million of guarantees issued by the Company for total prudential support at December 31, 2008 of $31 million. The prudential support will be provided until 2009, unless conditions for early termination are met. The prudential support is required by (AESO) and by Alberta gas and electricity distribution service providers in order for the purchaser to participate in the Power Pool of Alberta (Power Pool) and retail energy market. The Power Pool is the market through which all physical electricity exchanges and related financial settlements in Alberta are conducted. AESO is an independent system operator which administers operation of the Power Pool as well as the transmission of all electrical energy through the interconnected electric system in the province of Alberta. The Company's maximum exposure under the prudential support, based on 2008 peak usage and electricity and gas prices and based on maximum volumes under the energy supply agreements, is estimated at approximately $46 million (2007 - $39 million). The estimated maximum exposure under the prudential support agreement will vary proportionately with changes in electricity and gas prices. In return, the Company has retained a security interest in the competitive energy contracts sold, as collateral in the event of default of the various sales transaction agreements. Under the terms of the security interest arrangement, the Company has established separate bank accounts under its control through which billings collected from the contracts and payments of related costs are processed. The Company's use of this cash is restricted to these purposes. At December 31, 2008, $37 million (2007 - $22 million) of the Company's cash resides in these bank accounts. There are no known material liabilities under the prudential support agreement as at December 31, 2008.

30. Guarantees, continued:

Under terms of the 2003 disposal of its water heater rental business, the Company has agreed to indemnify the UE Waterheater Operating Trust and/or its subsidiaries for: i) net tax liabilities of Union Energy Inc, prior to closing; ii) any large corporation taxes payable by the Fund from closing to December 31, 2007 up to $13 million; and, iii) any future net tax liability resulting from facts, circumstances and practices in effect on or prior to closing. The indemnity in items i) and ii) expires 90 days following the statutory period for tax reassessment and the indemnity in item iii) expires in 2010. Any known liabilities have been reflected on the consolidated balance sheet.

In the normal course of business, the Company 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 the underlying subsidiary obligations are included on the consolidated balance sheet.

The Company has no other material guarantee obligations outstanding in respect of third parties at December 31, 2008.

31. Segment disclosures:

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

Generation

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

Distribution and Transmission

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

Energy Services

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

Water Services

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

Corporate

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

(Tabular amounts in millions of dollars)

31. Segment disclosures, continued:

Year ended December 31, 2008

	Generation	Distribution and Transmission	Energy Services	Water Services	Corporate	Intersegment Eliminations	Consolidated
Revenues – external	$ 812	$ 134	$ 2,185	$ 311	$ -	$ -	$ 3,442
Intersegment revenues	120	127	22	5	-	(274)	-
Total revenues	932	261	2,207	316	-	(274)	3,442
Energy purchases and fuel	347	69	1,965	-	-	(242)	2,139
Operations, maintenance, administration and foreign exchange gain	300	62	71	206	72	(32)	679
Franchise fee, property taxes and other taxes	17	41	-	10	-	-	68
Depreciation, amortization and asset retirement accretion	168	30	28	20	12	-	258
Operating expenses	832	202	2,064	236	84	(274)	3,144
Operating income (loss) before corporate charges	100	59	143	80	(84)	-	298
Corporate charges	22	16	30	16	(84)	-	-
Operating income	$ 78	$ 43	$ 113	$ 64	$ -	$ -	$ 298
Gain on sale of power syndicate agreement							34
Impairments							(52)
Net financing expenses							(177)
Income before income taxes and non-controlling interests							$ 103
Total assets	$ 4,444	$ 772	$ 744	$ 849	$ 164	$ (25)	$ 6,948
Capital additions	$ 436	$ 120	$ 10	$ 74	$ 18	$ -	$ 658
Goodwill	$ 159	$ -	$ -	$ 2	$ -	$ -	$ 161

(Tabular amounts in millions of dollars)

31. Segment disclosures, continued:

Year ended December 31, 2007

	Generation	Distribution and Transmission	Energy Services	Water Services	Corporate	Intersegment Eliminations	Consolidated
Revenues – external	$ 905	$ 122	$ 2,395	$ 240	$ 1	$ -	$ 3,663
Intersegment revenues	111	125	22	24	-	(282)	-
Total revenues	1,016	247	2,417	264	1	(282)	3,663
Energy purchases and fuel	312	72	2,149	-	-	(227)	2,306
Operations, maintenance, administration and foreign exchange gain	148	56	80	163	87	(54)	480
Franchise fee, property taxes and other taxes	17	39	-	10	-	-	66
Depreciation, amortization and asset retirement accretion	159	27	30	18	11	-	245
Operating expenses	636	194	2,259	191	98	(281)	3,097
Operating income (loss) before corporate charges	380	53	158	73	(97)	(1)	566
Corporate charges	45	14	26	14	(99)	-	-
Operating income	$ 335	$ 39	$ 132	$ 59	$ 2	$ (1)	$ 566
Gain on sale of power syndicate agreement							34
Impairments							(13)
Net financing expenses							(171)
Income before income taxes and non-controlling interests							$ 416
Total assets	$ 4,220	$ 676	$ 786	$ 761	$ 153	$ (34)	$ 6,562
Capital additions	$ 240	$ 105	$ 12	$ 122	$ 20	$ -	$ 499
Goodwill	$ 183	$ -	$ -	$ 2	$ -	$ -	$ 185

(Tabular amounts in millions of dollars)

31. Segment disclosures, continued:

Geographic information:

	2008				2007			
	Canada	U.S.	Intersegment Eliminations	Total	Canada	U.S.	Intersegment Eliminations	Total
Revenues - external	$ 2,958	$ 484	$ -	$ 3,442	$ 3,215	$ 448	$ -	$ 3,663
Intersegment revenues	54	10	(64)	-	33	22	(55)	-
Total revenues	$ 3,012	$ 494	$ (64)	$ 3,442	$ 3,248	$ 470	$ (55)	$ 3,663
Property, plant and equipment	$ 4,208	$ 520	$ -	$ 4,728	$ 3,770	$ 446	$ -	$ 4,216
Goodwill	$ 123	$ 38	$ -	$ 161	$ 151	$ 34	$ -	$ 185

Intersegment transactions occur in the normal course of operations and are recorded at exchange values which are generally at normal commercial rates. All other accounting policies of the segments are the same as those disclosed in note 2.

32. Subsequent events:

On January 21, 2009 the Edmonton City Council approved a motion to transfer the Gold Bar Wastewater Treatment Plant (Gold Bar) assets and associated long-term debt to EPCOR. Gold Bar handles wastewater requirements for 700,000 residents of the COE and has a current treatment capacity of 310 megalitres per day.

The transaction is to be completed no later than March 31, 2009, for a transfer fee of $75 million payable in annual installments as follows:

2009	$ 17
2010	15
2011	14
2012	12
2013	10
2014	6
2015	1
Total	$ 75

As at December 31, 2008 the book value of the Gold Bar plant assets is estimated at $266 million which includes $38 million of restricted contributed assets on which EPCOR can not earn a return. EPCOR will also assume the offsetting capital contributions associated with the $38 million of restricted assets. Under the proposed agreement EPCOR will assume approximately $110 million of the COE’s debt, bearing a weighted average interest rate of approximately 5.25%. The remainder of the purchase price will be funded via an equity contribution from the COE.

33. Comparative figures:

Certain of the comparative figures have been reclassified to conform with the current year’s presentation.