CANADIAN UTILITIES LIMITED
An ATCO Company

CONSOLIDATED FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2007

PRICEWATERHOUSECOOPERS

PricewaterhouseCoopers LLP
Chartered Accountants
111 5 Avenue SW, Suite 3100
Calgary, Alberta
Canada T2P 5L3
Telephone +1 (403) 509 7500
Facsimile +1 (403) 781 1825

Auditors' Report

To the Share Owners of
Canadian Utilities Limited

We have audited the consolidated balance sheets of Canadian Utilities Limited as at December 31, 2007 and 2006 and the consolidated statements of earnings and retained earnings, cash flows and comprehensive income for each of the years in the two year period ended December 31, 2007. These consolidated 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 the company as at December 31, 2007 and 2006 and the results of its operations and its cash flows for each of the years in the two year period ended December 31, 2007 in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta

February 19, 2008

CANADIAN UTILITIES LIMITED
CONSOLIDATED STATEMENT OF EARNINGS AND RETAINED EARNINGS
(Millions of Canadian Dollars except per share data)

	Note	Three Months Ended December 31 **2007**	Three Months Ended December 31 2006	Year Ended December 31 **2007**	Year Ended December 31 2006
		(Unaudited)			
Revenues	3	**$ 657.1**	$ 671.1	**$2,404.9**	$2,430.4
Costs and expenses					
Natural gas supply		**24.8**	10.2	**42.1**	36.4
Purchased power		**13.6**	12.5	**49.9**	46.1
Operation and maintenance		**251.4**	243.5	**941.6**	950.3
Selling and administrative		**77.1**	74.9	**216.8**	207.5
Depreciation and amortization		**99.0**	95.6	**351.5**	348.5
Interest	6, 12	**55.0**	54.6	**217.4**	222.9
Franchise fees		**37.4**	42.4	**151.2**	150.4
		558.3	533.7	**1,970.5**	1,962.1
		98.8	137.4	**434.4**	468.3
Interest and other income	5	**21.3**	18.9	**64.3**	58.5
Earnings before income taxes		**120.1**	156.3	**498.7**	526.8
Income taxes	3, 6	**13.1**	47.4	**77.7**	167.1
		107.0	108.9	**421.0**	359.7
Dividends on equity preferred shares		**8.3**	8.9	**34.3**	35.8
Earnings attributable to Class A and Class B shares		**98.7**	100.0	**386.7**	323.9
Retained earnings at beginning of period as restated	7	**1,984.1**	1,741.1	**1,813.3**	1,721.9
		2,082.8	1,841.1	**2,200.0**	2,045.8
Dividends on Class A and Class B shares		**39.6**	36.3	**156.8**	176.7
Purchase of Class A shares and other direct charges to retained earnings	8	**7.2**	0.4	**7.2**	64.7
Retained earnings at end of period		**$2,036.0**	$1,804.4	**$2,036.0**	$1,804.4
Earnings per Class A and Class B share	15	**$ 0.78**	$ 0.80	**$ 3.08**	$ 2.57
Diluted earnings per Class A and Class B share	15	**$ 0.78**	$ 0.80	**$ 3.07**	$ 2.56
Dividends paid per Class A and Class B share	15	**$ 0.315**	$ 0.29	**$ 1.25**	$ 1.40

CANADIAN UTILITIES LIMITED
CONSOLIDATED BALANCE SHEET
(Millions of Canadian Dollars)

		December 31	
	Note	**2007**	2006
ASSETS			
Current assets			
Cash and short term investments	4, 18	**$ 747.2**	$ 798.8
Accounts receivable		**373.9**	362.3
Inventories		**101.8**	96.5
Regulatory assets	2	**10.2**	13.3
Derivative assets	21	**0.8**	-
Prepaid expenses		**29.8**	23.6
		1,263.7	1,294.5
Property, plant and equipment	9	**5,678.5**	5,426.1
Regulatory assets	2	**75.6**	43.2
Derivative assets	21	**73.3**	-
Other assets	10	**194.3**	229.7
		$7,285.4	$6,993.5
LIABILITIES AND SHARE OWNERS' EQUITY			
Current liabilities			
Accounts payable and accrued liabilities		**$ 375.0**	$ 338.8
Income taxes payable	3, 6	**1.2**	22.7
Future income taxes	6	**1.7**	0.3
Regulatory liabilities	2	**-**	0.5
Derivative liabilities	21	**2.6**	-
Non-recourse long term debt due within one year	12	**65.4**	59.3
		445.9	421.6
Future income taxes	3, 6	**153.8**	194.7
Regulatory liabilities	2	**146.5**	148.8
Derivative liabilities	21	**3.3**	-
Deferred credits	13	**307.9**	229.0
Long term debt	12	**2,603.2**	2,411.5
Non-recourse long term debt	12	**478.1**	626.7
Equity preferred shares	14	**625.0**	636.5
Class A and Class B share owners' equity			
Class A and Class B shares	15	**516.9**	516.0
Contributed surplus	16	**1.9**	1.2
Retained earnings		**2,036.0**	1,804.4
Accumulated other comprehensive income	22	**(33.1)**	3.1
Retained earnings and accumulated other comprehensive income		**2,002.9**	1,807.5
		2,521.7	2,324.7
		$7,285.4	$6,993.5

[Original signed by N.C. Southern]
DIRECTOR

[Original signed by J.W. Simpson]
DIRECTOR

CANADIAN UTILITIES LIMITED
CONSOLIDATED STATEMENT OF CASH FLOWS
(Millions of Canadian Dollars)

	Note	Three Months Ended December 31 **2007**	Three Months Ended December 31 2006	Year Ended December 31 **2007**	Year Ended December 31 2006
		(Unaudited)			
Operating activities					
Earnings attributable to Class A and Class B shares		**$ 98.7**	$ 100.0	**$ 386.7**	$ 323.9
Adjustments for:					
Depreciation and amortization		**99.0**	95.6	**351.5**	348.5
Future income taxes	3	**(19.5)**	11.3	**(15.7)**	(1.6)
Deferred availability incentives		**4.5**	(41.0)	**2.2**	(20.2)
TXU Europe settlement - net of income taxes	4	**(2.5)**	(3.3)	**(11.1)**	(1.6)
Other		**(0.2)**	5.8	**12.3**	8.5
Funds generated by operations		**180.0**	168.4	**725.9**	657.5
Changes in non-cash working capital	17	**(52.9)**	(48.5)	**(19.0)**	(39.6)
Cash flow from operations		**127.1**	119.9	**706.9**	617.9
Investing activities					
Purchase of property, plant and equipment		**(212.6)**	(184.0)	**(700.8)**	(567.7)
Costs on disposal of property, plant and equipment		**(14.7)**	(4.3)	**(16.2)**	(10.4)
Contributions by utility customers for extensions to plant		**25.8**	20.1	**91.2**	81.3
Non-current deferred electricity costs		**(4.5)**	(8.7)	**(9.6)**	4.5
Changes in non-cash working capital	17	**5.2**	15.4	**12.3**	(18.3)
Income tax reassessment	6	**-**	-	**-**	(12.8)
Other		**(1.1)**	0.9	**(19.0)**	(4.1)
		(201.9)	(160.6)	**(642.1)**	(527.5)
Financing activities					
Issue of long term debt		**255.0**	320.0	**255.0**	355.5
Repayment of long term debt		**(50.0)**	(175.0)	**(50.0)**	(175.0)
Repayment of non-recourse long term debt	4	**(12.3)**	(12.6)	**(122.8)**	(64.6)
Issue of equity preferred shares by subsidiary	14	**-**	-	**115.0**	-
Redemption of equity preferred shares	14	**-**	-	**(126.5)**	-
Net issue (purchase) of Class A shares		**(7.7)**	1.9	**(6.4)**	(67.5)
Dividends paid to Class A and Class B share owners		**(39.6)**	(36.3)	**(156.8)**	(176.7)
Changes in non-cash working capital	17	**-**	(0.1)	**-**	(0.1)
Other		**(3.6)**	(2.6)	**(6.3)**	(3.9)
		141.8	95.3	**(98.8)**	(132.3)
Foreign currency translation		**(2.7)**	11.6	**(17.6)**	16.3
Cash position					
Increase (decrease)		**64.3**	66.2	**(51.6)**	(25.6)
Beginning of period		**682.9**	732.6	**798.8**	824.4
End of period		**$ 747.2**	$ 798.8	**$ 747.2**	$ 798.8

CANADIAN UTILITIES LIMITED
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME
(Millions of Canadian Dollars)

		Three Months Ended December 31		Year Ended December 31	
	Note	**2007**	2006	**2007**	2006
		(Unaudited)			
Earnings attributable to Class A and Class B shares		**$98.7**	$100.0	**$386.7**	$323.9
Other comprehensive income, net of income taxes:					
Cash flow hedges	22	**0.4**	-	**2.7**	-
Foreign currency translation adjustment	22	**(7.2)**	18.1	**(31.6)**	21.3
		(6.8)	18.1	**(28.9)**	21.3
Comprehensive income		**$91.9**	$118.1	**$357.8**	$345.2

1. Summary of significant accounting policies

Financial Statement Presentation

The accompanying consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and include the accounts of Canadian Utilities Limited and its subsidiaries, including a proportionate share of joint venture investments (the "Corporation"). Principal operations are Utilities (ATCO Electric, ATCO Gas, ATCO Pipelines), Power Generation (ATCO Power, Alberta Power (2000)) and Global Enterprises (ATCO Midstream, ATCO Frontec, ATCO I-Tek). Significant joint venture investments consist principally of power generation plants; a substantial portion of Power Generation's operations are conducted through joint ventures.

Effective January 1, 2007, the Corporation adopted the Canadian Institute of Chartered Accountants ("CICA") recommendations pertaining to financial instruments, which establish standards for the recognition, measurement, disclosure and presentation of financial assets, financial liabilities and non-financial derivatives. These recommendations require that fair value be used to measure financial assets that are held for trading or available for sale, financial liabilities that are held for trading and all derivative financial instruments. Other financial assets, such as loans and receivables and investments that are held to maturity, and other financial liabilities are measured at their amortized cost. This change in accounting had the following effect on the consolidated financial statements for the three months and year ended December 31, 2007:

(a) Recognition of interest rate swaps, foreign currency forward contracts and certain natural gas purchase contracts as derivative assets and liabilities in the consolidated financial statements (see Note 21).
(b) Recognition of the fair value of a power generation revenue contract liability associated with the natural gas purchase contracts derivative asset (see Note 21).
(c) Recognition of a mark-to-market adjustment for the change in fair value of the natural gas purchase contracts derivative asset and recognition of an adjustment to the associated power generation revenue contract liability (see Note 5).
(d) Restatement of opening retained earnings at January 1, 2007 to recognize the prior years' earnings effect of the natural gas purchase contracts derivative asset and the associated power generation revenue contract liability, as well as the prior years' earnings effect of accounting for certain financial assets and financial liabilities at amortized cost using the effective interest method (see Note 7).
(e) Reclassification of deferred financing charges from other assets to long term debt and non-recourse long term debt (see Note 12).

Effective January 1, 2007, the Corporation adopted the CICA recommendations pertaining to hedges, which establish standards for the identification, designation, documentation and effectiveness of hedging relationships for the purpose of applying hedge accounting. The purpose of hedge accounting is to ensure that gains, losses, revenues and expenses from effective hedging relationships are recorded in earnings in the same period. This change in accounting had no effect on the consolidated financial statements for the three months and year ended December 31, 2007.

Effective January 1, 2007, the Corporation adopted the CICA recommendations regarding the reporting and disclosure of comprehensive income. Comprehensive income consists of changes in the equity of the Corporation from sources other than the Corporation's share owners, and includes earnings of the Corporation, the foreign currency translation adjustment relating to self-sustaining foreign operations and unrealized gains and losses on changes in fair values of available-for-sale assets and effective cash flow hedging instruments. Other comprehensive income comprises revenues, expenses, gains and losses that are recognized in comprehensive income but are excluded from earnings of the period. Comprehensive income is disclosed in a separate statement in the consolidated financial statements.

1. Summary of significant accounting policies (continued)

Effective January 1, 2007, the Corporation adopted the CICA recommendations regarding the presentation of equity and changes in equity. These recommendations require separate presentation of the components of equity, including retained earnings, accumulated other comprehensive income, contributed surplus, share capital and reserves, and the changes therein. As a result of this change in accounting, the Corporation has included a reconciliation of accumulated other comprehensive income in the notes to the consolidated financial statements (see Note 22). In accordance with the recommendations, comparative figures have been adjusted to incorporate the foreign currency translation adjustment into accumulated other comprehensive income.

Effective January 1, 2007, the Corporation adopted the CICA recommendations that prescribe the criteria for changing accounting policies, together with the accounting treatment and disclosure of changes in accounting policies, changes in accounting estimates and corrections of errors. Adoption of these recommendations had no effect on the consolidated financial statements for the three months and year ended December 31, 2007, except for the disclosure of accounting changes that have been issued by the CICA but have not yet been adopted by the Corporation because they are not effective until a future date (see Future Accounting Changes below).

Certain comparative figures have been reclassified to conform to the current presentation.

Rate Regulation

ATCO Electric and its subsidiaries, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical, the ATCO Gas and ATCO Pipelines divisions of ATCO Gas and Pipelines Ltd. and the Battle River and Sheerness generating plants of Alberta Power (2000), all of which are wholly owned subsidiaries of Canadian Utilities Limited's wholly owned subsidiary, CU Inc., are collectively referred to in these consolidated financial statements as the "regulated operations". Accounting for rate regulated operations is described in Note 2.

Use of Estimates

The preparation of the Corporation's consolidated financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the year. On an on-going basis, management reviews its estimates, particularly those related to depreciation and amortization methods, useful lives and impairment of long-lived assets, amortization of deferred availability incentives, asset retirement obligations, employee future benefits and the fair values of financial instruments, using currently available information. Changes in facts and circumstances may result in revised estimates, and actual results could differ from those estimates.

Revenue Recognition

For regulated operations, revenues are recognized in a manner that is consistent with the underlying rate design as mandated by the regulator.

Revenues from ATCO Gas' regulated distribution of natural gas include variable charges, which are recognized on the basis of meter readings upon delivery of natural gas to customers and include an estimate of usage not yet billed, and fixed charges, based on the provision of the distribution service during the period

Revenues from ATCO Electric's regulated distribution of electricity include variable charges, which are recognized on the basis of meter readings upon delivery of electricity to customers and include an estimate of usage not yet billed, and fixed charges, based on the provision of the distribution service during the period. Revenues for the use of ATCO Electric's regulated transmission facilities are based on an annual tariff and are recognized evenly throughout the year.

Revenues from ATCO Pipelines' regulated transmission of natural gas are recognized on the basis of contractual arrangements. For certain services, revenues are recognized on the basis of meter readings upon delivery of natural gas to customers and include an estimate of usage not yet billed.

1. Summary of significant accounting policies (continued)

Revenues from regulated sales and distribution of natural gas and electricity by other regulated operations, excluding Alberta Power (2000), are recognized upon delivery, primarily on the basis of meter readings, and include an estimate of usage not yet billed.

Revenues from generating plants are recognized upon delivery of output or upon availability of delivery as prescribed by contractual arrangements. Incentives and penalties associated with Alberta Power (2000)'s Power Purchase Arrangements ("PPA") are recognized as described under the accounting policy for deferred availability incentives.

Revenues from ATCO Midstream's natural gas storage and processing capacity are recognized on the basis of contractual arrangements, and revenues from the sale of natural gas liquids are recognized upon delivery.

Revenues from the supply of contracted services are recorded by the percentage of completion method; full provision is made for any anticipated loss. Other revenues are recognized when products are delivered or services are provided.

Natural Gas Supply

Natural gas supply expense for regulated operations, which consists of natural gas volumes purchased for sales to customers, is based on actual costs incurred.

Natural gas supply expense for ATCO Midstream, which consists of natural gas volumes purchased for natural gas liquids extraction and sales to third parties, is based on actual costs incurred.

Purchased Power

Purchased power expense for regulated operations in the Yukon Territory and the Northwest Territories is based on the actual cost of electricity purchased. The amount included in customer rates in the Yukon Territory is based on actual costs and in the Northwest Territories is based on forecast cost. Revenues are adjusted for variances from forecast cost, and the variances are deferred until such time as approval from the regulator is obtained for refund to or collection from customers.

Income Taxes

The regulated operations follow the method of accounting for income taxes that is consistent with the method of determining the income tax component of their rates. When future income taxes are not provided in the income tax component of current rates, such future income taxes are not recognized to the extent that it is expected that they will be recovered from customers through inclusion in future rates.

Other subsidiaries follow the liability method of accounting for income taxes. Under this method, future tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. Future tax liabilities and assets are measured using enacted and substantively enacted tax rates. The effect on future tax liabilities and assets of a change in tax rates is recognized in income in the period that the change occurs.

Cash and Short Term Investments

Short term investments consist of certificates of deposit and bankers' acceptances with maturities generally of 90 days or less at purchase.

Inventories

Inventories are valued at the lower of average cost or net realizable value.

1. **Summary of significant accounting policies** (continued)

Property, Plant and Equipment

Property, plant and equipment are recorded at cost less accumulated depreciation and unamortized contributions by utility customers for extensions to plant.

Regulated operations include in property, plant and equipment an allowance for funds used during construction at rates approved by the Alberta Utilities Commission ("AUC") for debt and equity capital. Property, plant and equipment in the other subsidiaries include capitalized interest incurred during construction.

Certain regulated additions are made with the assistance of non-refundable cash contributions from customers when the estimated revenue is less than the cost of providing service or where special equipment is needed to supply the customers' specific requirements. These contributions are amortized on the same basis as, and offset the depreciation charge of, the assets to which they relate.

Depreciation is provided on assets on a straight-line basis over their estimated useful lives. Depreciation rates for regulated assets, excluding Alberta Power (2000)'s generating plants, are approved by the AUC and include a provision for future removal costs and site restoration costs (see the accounting policy for asset retirement obligations below). On retirement of these depreciable regulated assets, the accumulated depreciation is charged with the cost of the retired unit, net disposal costs and site restoration costs.

Property, plant and equipment and intangible assets with finite lives are tested for recoverability whenever events or changes in circumstances indicate a possible impairment. An impairment of property, plant and equipment and intangible assets with finite lives is recognized in earnings when the asset's carrying value exceeds the total cash flows expected from its use and eventual disposition. The impairment loss is then calculated as the difference between the asset's carrying value and its fair value, which is determined using present value techniques.

Deferred Financing Charges

Issue costs of long term debt are amortized over the life of the debt using the effective interest method. Issue costs of preferred shares relating to regulated operations are amortized over the expected life of the issue and issue costs of preferred shares relating to other subsidiaries are charged to retained earnings. Unamortized premiums and issue costs of redeemed long term debt and preferred shares relating to regulated operations are amortized over the life of the issue funding the redemption. The Corporation's deferred financing charges pertaining to long term debt have been reclassified from other assets to long term debt and non-recourse long term debt in accordance with the CICA recommendations for financial instruments (see Note 12).

Deferred Availability Incentives

Under the terms of the PPA's, the Corporation is subject to an incentive/penalty regime related to generating unit availability. Incentives are paid to the Corporation by the PPA counterparties for availability in excess of predetermined targets, whereas penalties are paid by the Corporation to the PPA counterparties when the availability targets are not achieved.

Accumulated incentives in excess of accumulated penalties are deferred. For any of the individual PPA's, should accumulated incentives plus estimated future incentives exceed accumulated penalties plus estimated future penalties, the excess will be amortized to revenues on a straight-line basis over the remaining term of the PPA's. Should accumulated penalties plus estimated future penalties exceed accumulated incentives plus estimated future incentives, the shortfall will be expensed in the year the shortfall occurs.

Asset Retirement Obligations

Asset retirement obligations are legal obligations associated with the retirement of tangible long lived assets. To the extent that they can be quantified, these obligations are measured and recognized at fair value, which is determined using present value techniques.

1. Summary of significant accounting policies (continued)

An asset retirement obligation is recorded as a liability in deferred credits, with a corresponding increase to property, plant and equipment. The liability is accreted over the estimated time period until settlement of the obligation, with the accretion expense included in depreciation and amortization. The asset is depreciated over its estimated useful life.

Asset retirement obligations for regulated natural gas and electric transmission and distribution assets are not recognized as the Corporation expects to use the assets in service for an indefinite period. As such, no final removal date can be determined and, consequently, a reasonable estimate of the related retirement obligations cannot be made at this time. Asset retirement obligations have been recorded for the regulated and non-regulated electricity generating plants and the natural gas liquids extraction and processing plants.

Long Term Debt Due Within One Year

When the Corporation intends to refinance long term debt due within one year on a long term basis and there is a written undertaking from an underwriter to act on the Corporation's behalf with respect thereto, or sufficient capacity exists under long term bank loan agreements to issue commercial paper or assume bank loans, then long term debt due within one year is classified as long term.

Derivative Financial Instruments

In conducting its business, the Corporation uses various instruments, including forward contracts, swaps and options, to manage the risks arising from fluctuations in exchange rates, interest rates and commodity prices. All such instruments are used only to manage risk and not for trading purposes.

CICA recommendations require the recognition and measurement of derivative instruments embedded in host contracts that were issued, acquired or substantively modified on or after January 1, 2003. Derivative instruments embedded in host contracts that were issued, acquired or substantively modified prior to January 1, 2003 have not been identified and recognized in the consolidated financial statements as permitted by the recommendations.

The Corporation designates each derivative instrument as either a hedging instrument or a non-hedge derivative:

(a) A hedging instrument is designated as either:
   (i) a fair value hedge of a recognized asset or liability or,
   (ii) a cash flow hedge of either:
      - a specific firm commitment or anticipated transaction or,
      - the variable future cash flows arising from a recognized asset or liability.

   At inception of a hedge, the Corporation documents the relationship between the hedging instrument and the hedged item, including the method of assessing retrospective and prospective hedge effectiveness. At the end of each period, the Corporation assesses whether the hedging instrument has been highly effective in offsetting changes in fair values or cash flows of the hedged item and measures the amount of any hedge ineffectiveness. The Corporation also assesses whether the hedging instrument is expected to be highly effective in the future.

   A hedging instrument is recorded on the consolidated balance sheet at fair value. Payments or receipts on a hedging instrument that is determined to be highly effective as a hedge are recognized concurrently with, and in the same financial category as, the hedged item. Subsequent changes in the fair value of a fair value hedge are recognized in earnings concurrently with the hedged item. For a cash flow hedge, the effective portion of changes in fair value is recognized in other comprehensive income and is subsequently transferred to earnings concurrently with the hedged item, whereas the portion of the changes in fair value that is not effective at offsetting the hedged exposure is recognized in earnings.

   If a hedging instrument ceases to be highly effective as a hedge, is de-designated as a hedging instrument or is settled prior to maturity, then the Corporation ceases hedge accounting prospectively for that instrument; for a cash flow hedge, the gain or loss deferred to that date remains in accumulated other comprehensive income and is transferred to earnings concurrently with the hedged item. Subsequent changes in the fair value of that derivative instrument are recognized in earnings.

1. **Summary of significant accounting policies** (continued)

If the hedged item is sold, extinguished or matures prior to the termination of the related hedging instrument, or if it is probable that an anticipated transaction will not occur in the originally specified time frame, then the gain or loss deferred to that date for the related hedging instrument is immediately transferred from accumulated other comprehensive income to earnings.

Hedge gains or losses that were recognized in other comprehensive income are added to the initial carrying amount of a non-financial asset or non-financial liability when:
(i) an anticipated transaction for a non-financial asset or non-financial liability becomes a specific firm commitment for which fair value hedge accounting is applied or,
(ii) a cash flow hedge of an anticipated transaction subsequently results in the recognition of the non-financial asset or non-financial liability.

(b) A non-hedge derivative instrument is recorded on the consolidated balance sheet at fair value and subsequent changes in fair value are recorded in earnings.

The Corporation applies settlement date accounting to the purchases and sales of financial assets. Settlement date accounting implies the recognition of an asset on the day it is received by the Corporation and the recognition of the disposal of an asset on the day that it is delivered by the Corporation. Any gain or loss on disposal is also recognized on that day.

Transaction costs that are directly attributable to the acquisition or issue of financial assets or financial liabilities that are not held for trading are added to the fair value of such assets or liabilities at time of initial recognition.

Employee Future Benefits

The Corporation accrues for its obligations under defined benefit pension and other post employment benefit plans. Costs of these benefits are determined using the projected benefits method prorated on service and reflects management's best estimates of investment returns, wage and salary increases, age at retirement and expected health care costs.

Pension plan assets at the end of the year are reported at market value. The expected long term rate of return on plan assets is determined at the beginning of the year on the basis of the long bond yield rate at the beginning of the year plus an equity and management premium that reflects the plan asset mix. Expected return on plan assets for the year is calculated by applying the expected long term rate of return to the market related value of plan assets, which is the average of the market value of plan assets at the end of the preceding three years.

Accrued benefit obligations at the end of the year are determined using a discount rate that reflects market interest rates on high quality corporate bonds that match the timing and amount of expected benefit payments.

Experience gains and losses and the effect of changes in assumptions in excess of 10% of the greater of the accrued benefit obligations or the market value of plan assets, adjustments resulting from plan amendments and the net transitional liability or asset, which arose upon the adoption in 2000 of the current accounting standard, are amortized over the estimated average remaining service life of employees.

Pursuant to an AUC decision effective January 1, 2000, the regulated operations, excluding Alberta Power (2000), are required to expense contributions for other post employment benefit and certain other defined benefit pension plans as paid. The differences between the amounts accrued and paid are deferred in non-current regulatory assets and liabilities.

Employer contributions to the defined contribution pension plans are expensed as paid.

1. Summary of significant accounting policies (continued)

Stock Based Compensation Plans

The Corporation expenses stock options granted on and after January 1, 2002; no compensation expense is recorded for stock options granted prior to January 1, 2002 as permitted by GAAP. The Corporation determines the fair value of the options on the date of grant using an option pricing model and recognizes the fair value over the vesting period of the options granted as compensation expense and contributed surplus. Contributed surplus is reduced as the options are exercised and the amount initially recorded in contributed surplus is credited to Class A and Class B share capital.

No compensation expense is recognized when share appreciation rights are granted. Prior to vesting, compensation expense arising from an increase or decrease in the market price of the shares over the base value of the rights is accrued equally over the remaining months to the date of vesting. After that date, compensation expense arising from an increase or decrease in the market price of the shares is recognized monthly in earnings.

Foreign Currency Translation

Assets and liabilities of self-sustaining foreign operations are translated into Canadian dollars at the rate of exchange in effect at the balance sheet date and revenues and expenses are translated at the average monthly rates of exchange during the year. Gains or losses on translation of self-sustaining foreign operations are included in accumulated other comprehensive income in share owners' equity.

Monetary assets and liabilities of integrated foreign operations, as well as non-monetary assets carried at market value, are translated into Canadian dollars at the rate of exchange in effect at the balance sheet date. Other non-monetary assets and non-monetary liabilities are translated at rates of exchange in effect when the assets were acquired or liabilities incurred. Revenues and expenses are translated at the average monthly rates of exchange during the year; depreciation and amortization are translated at rates of exchange consistent with the assets to which they relate. Gains or losses on translation of integrated foreign operations are recognized in earnings.

Transactions undertaken by Canadian operations that are denominated in foreign currencies are translated into Canadian dollars at the rate of exchange in effect at the transaction date. Monetary items and non-monetary items that are carried at market value arising from a transaction denominated in a foreign currency are adjusted to reflect the rate of exchange in effect at the balance sheet date. Gains or losses on translation of such monetary and non-monetary items are recognized in earnings.

Future Accounting Changes

The CICA has issued new accounting recommendations for capital disclosures which require disclosure of both qualitative and quantitative information that enables users of financial statements to evaluate the Corporation's objectives, policies and processes for managing capital. These recommendations are effective for the Corporation beginning January 1, 2008.

The CICA has issued new accounting recommendations for disclosure and presentation of financial instruments which require disclosures of both qualitative and quantitative information that enables users of financial statements to evaluate the nature and extent of risks arising from financial instruments to which the Corporation is exposed. These recommendations are effective for the Corporation beginning January 1, 2008.

The CICA has issued new accounting recommendations for measurement and disclosure of inventories which provide guidance on the determination of cost and its subsequent recognition as an expense, including any writedown to net realizable value, and on the cost formulas that are used to assign costs to inventories. The adoption of these recommendations is not expected to have a material impact on the earnings or assets of the Corporation. These recommendations are effective for the Corporation beginning January 1, 2008.

1. Summary of significant accounting policies (continued)

The CICA has removed a temporary exemption in its accounting recommendations that permitted assets and liabilities arising from rate regulation to be recognized and measured on a basis other than in accordance with the primary sources of GAAP. The Corporation is evaluating the possibility of using standards issued by the Financial Accounting Standards Board in the United States that allow for the recognition and measurement of rate regulated assets and liabilities as another source of Canadian GAAP. The CICA has also issued new recommendations that will require the recognition of future income tax assets and liabilities as well as a separate regulatory asset or liability for the amount of future income taxes expected to be included in future rates and recovered from or paid to future customers. These recommendations are effective for the Corporation beginning January 1, 2009, and will be applied prospectively. The amount of unrecorded future income tax liabilities of the regulated operations at December 31, 2007 is $159.4 million.

In 2006, the CICA announced that accounting standards in Canada are to converge with International Financial Reporting Standards ("IFRS"). The Corporation will need to begin reporting under IFRS in the first quarter of 2011 with comparative data for the prior year. IFRS uses a conceptual framework similar to GAAP, but there could be significant differences on recognition, measurement and disclosures that will need to be addressed. The Corporation is currently assessing the impact of these standards on its financial statements.

2. Accounting for rate regulated operations

Nature and economic effects of rate regulation

ATCO Electric, ATCO Gas and ATCO Pipelines (the "utilities") are regulated primarily by the AUC, which, effective January 1, 2008, succeeded the Alberta Energy and Utilities Board as regulator for the utilities industry. The AUC administers acts and regulations covering such matters as rates, financing, accounting, construction, operation and service area.

The Battle River and Sheerness generating plants of Alberta Power (2000) were regulated by the AUC until December 31, 2000 but are now governed by legislatively mandated PPA's that were approved by the AUC. These plants are included in regulated operations primarily because the PPA's are designed to allow the owners of generating plants constructed before January 1, 1996 to recover their forecast fixed and variable costs and to earn a return at the rate specified in the PPA's. Each plant will become deregulated upon the earlier of one year after the expiry of its PPA or a decision to continue to operate the plant. For PPA's expiring prior to 2019, Alberta Power (2000) has one year after the expiry of a PPA to determine whether to decommission the generating plant in order to fully recover plant decommissioning costs or to continue to operate the plant and be responsible for the decommissioning costs. For PPA's expiring after 2018 decommissioning costs are the responsibility of the plant owner. Each PPA is to remain in effect until the earlier of the last day of the estimated life of the related generating plant or December 31, 2020.

The utilities are subject to a cost of service regulatory mechanism under which the AUC establishes the revenues required (i) to recover the forecast operating costs, including depreciation and amortization and income taxes, of providing the regulated service, and (ii) to provide a fair and reasonable return on utility investment, or rate base. Whereas actual operating conditions may vary from forecast, actual returns achieved can differ from approved returns.

Rate base for each utility is the aggregate of the AUC approved investment in property, plant and equipment, less accumulated depreciation, and unamortized contributions by utility customers for extensions to plant, plus an allowance for working capital. The utilities earn a return on rate base intended to meet the cost of the debt and preferred share components of rate base and to provide share owners with a fair return on the common equity component of rate base.

2. Accounting for rate regulated operations (continued)

The AUC approves rates of return for the debt and preferred share components of rate base based on the actual or forecast weighted average cost of each utility's debt and preferred shares and establishes the capital structure for each utility. On July 2, 2004, the AUC established a standardized approach for determining the rate of return on common equity for each utility regulated by the AUC. This rate of return will be adjusted annually by 75% of the change in long term Government of Canada bond yield as forecast in the November Consensus Forecast, adjusted for the average difference between the 10 year and 30 year Government of Canada bond yields for the month of October as reported in the National Post. The generic return on equity determined on an annual basis in accordance with the generic cost of capital decision applies to each year of the test period in the utilities' applications. If no rate applications are filed for a particular year, then there will be no adjustment to the common equity rate of return for that year. The rate of return was 8.93% for 2006, 8.51% for 2007 and has been set at 8.75% for 2008.

Under the cost of service methodology, the utilities seek approval for their revenue requirement either through submission of general rate applications to the AUC or a negotiated settlement process with interested parties. In the latter case, the AUC monitors the negotiated settlement process and any agreement that is reached is subject to AUC approval. The AUC may approve interim rates or approve the recovery of costs on a placeholder basis, subject to final determination.

Financial statement effects of rate regulation

Certain items in these consolidated financial statements are accounted for differently than they would be in the absence of rate regulation. CICA recommendations do not require that assets and liabilities arising from rate regulation be recognized and measured in accordance with the primary sources of GAAP.

Where regulatory decisions dictate, the utilities defer certain costs or revenues as assets or liabilities on the balance sheet and record them as expenses or revenues in the earnings statement as they collect or refund amounts through future customer rates. Any adjustments to these deferred amounts are recognized in earnings in the period that the AUC renders a decision concerning these adjustments.

Circumstances in which rate regulation affects the accounting for a transaction or event are described below. For these regulatory items, the expected recovery or settlement period, or likelihood of recovery or settlement, is affected by risks and uncertainties relating to the ultimate authority of the regulator in determining the item's treatment for rate setting purposes, and, unless specifically indicated, is indeterminate.

2. Accounting for rate regulated operations (continued)

The regulatory assets and liabilities comprise the following:

	2007	2006
Regulatory assets – current:		
Deferred electricity costs	**$ 1.5**	$ 1.7
Current income tax savings associated with future income tax refund to customers	**2.0**	-
Other regulatory assets [1]	**6.7**	11.6
	$ 10.2	$ 13.3
Regulatory assets – non-current:		
Regulatory other post employment benefits asset (Note 20)	**$ 32.3**	$ 27.6
Deferred electricity costs	**17.4**	7.1
Current income tax savings associated with future income tax refund to customers	**7.0**	-
Deferred hearing costs [1]	**4.0**	1.4
Reserves for injuries and damages	**1.5**	2.0
Other regulatory assets [1]	**13.4**	5.1
	$ 75.6	$ 43.2
Regulatory liabilities – current:		
Other regulatory liabilities [1]	**$ -**	$ 0.5
Regulatory liabilities – non-current:		
Regulatory pension liability (Note 20)	**$110.0**	$118.7
Deferred royalty credits	**23.1**	19.7
Deferred electricity cost recoveries	**7.0**	6.2
Deferred hearing costs [1]	**-**	0.4
Reserves for injuries and damages	**2.1**	2.8
Other regulatory liabilities [1]	**4.3**	1.0
	$146.5	$148.8

[1] *Amortization of certain regulatory assets and liabilities, which was recorded in depreciation and amortization, amounted to $7.7 million (2006 – $14.7 million).*

Employee future benefits

The Corporation accrues for its obligations under defined benefit pension and other post employment benefit plans. The regulatory asset (liability) reflects an AUC decision, effective January 1, 2000, to record costs of employee future benefits in the utilities when paid rather than accrued. The variances between the amounts paid and accrued for each of the defined benefit pension plans and the other post employment benefit plans will vary depending on the performance of plan assets and the actuarial valuations of plan obligations. These variances will be deferred until the plans are paid, settled or terminated.

GAAP requires that the variances between the amounts accrued and paid be recognized as an expense or reduction in expense in the period in which they are accrued. Consequently, defined benefit pension plan cost in 2007 would have been $7.8 million higher (2006 – $19.5 million higher), and other post employment benefit plan cost in 2007 would have been $2.9 million higher (2006 – $3.5 million higher), in the absence of rate regulation.

Upon the adoption of the current accounting standard in 2000, the utilities had recorded deferred pension assets of $23.0 million. The utilities have been earning an AUC approved rate of return on these assets through customer rates as the assets form part of the utilities' AUC approved rate base. In the absence of rate regulation, the utilities would not be able to earn a return on these assets. Consequently, revenues in 2007 would have been $1.6 million lower (2006 – $1.7 million lower). On October 11, 2006, the AUC issued a decision that approved recovery of these assets for a nine-year period commencing January 1, 2005 and permitted the utilities to continue to earn an AUC approved rate of return on the unrecovered portion of these assets over the recovery period. In 2007, the utilities amortized $2.6 million (2006 – $5.1 million) of the deferred pension asset.

2. Accounting for rate regulated operations (continued)

Deferred electricity costs (recoveries)

Variances between ATCO Electric's actual and forecast transmission access payments may arise due to changes in tariffs charged by the Alberta Power Pool. The amount included in customer rates is based on forecast cost. Revenues are adjusted for changes in tariffs, and the variances are deferred until approval from the AUC is obtained for refund to or collection from customers, which is expected to occur in the following year. GAAP requires that revenues be based on the rates approved by the AUC and not adjusted for variances between forecast and actual costs.

In Alberta, major transmission capital projects are planned by the Alberta Power Pool and directly assigned to one of the transmission facility owners in the province. Revenue requirement includes a return on forecast rate base. Whereas actual capital costs may vary from forecast capital costs, variances may arise between the return on forecast rate base and the return on actual rate base. Revenues are adjusted for these variances, and the variances are deferred until approval from the AUC is obtained for refund to or collection from the Alberta Power Pool, which is expected to occur in the following year. GAAP requires that revenues be based on the rates approved by the AUC and not adjusted for variances between the returns on forecast and actual rate base.

Variances between ATCO Electric's actual and forecast income tax provision may arise due to changes in enacted and substantively enacted tax rates. The amount included in customer rates is based on forecast tax rates. Revenues are adjusted for changes in enacted and substantively enacted tax rates, and the variances are deferred until approval from the AUC is obtained for refund to or collection from customers, which is expected to occur in the following year. GAAP requires that revenues be based on customer rates approved by the AUC and not adjusted for variances between forecast and actual tax rates.

Consequently, revenues in 2007 would have been $9.4 million lower (2006 – $1.2 million lower) in the absence of rate regulation.

Current income tax savings associated with future income tax refund to customers

The AUC has directed ATCO Electric to change its income tax methodology for federal purposes, whereby, effective January 1, 2007, ATCO Electric no longer recognizes future income taxes, and to refund to customers the future income taxes of $34.4 million collected under the previously allowed tax methodology (see Note 3). As a result of this decision, ATCO Electric recorded a reduction in future income tax liabilities of $34.4 million and a liability to customers of $49.3 million in the third quarter of 2007, offset by a regulatory asset of $14.9 million which represents current income tax savings to be realized in future periods. There was no effect on earnings as revenues and income taxes were both initially reduced by $34.4 million. There will also be no effect on earnings in future periods as the current income tax savings realized in future periods will be offset by a reduction in revenues as the regulatory asset is reversed.

In the fourth quarter of 2007, the liability to customers and the regulatory asset were reduced by $0.7 million due to a reduction in future income tax rates. Furthermore, in December 2007, ATCO Electric refunded $16.1 million of the liability to transmission customers, thereby realizing $5.2 million of current income tax savings, which further reduced revenues, and reducing the future income taxes to be refunded by $10.9 million. The total reduction in revenues and income taxes in 2007 was $39.6 million.

ATCO Electric will be refunding the remaining $32.5 million to distribution customers over a five year period commencing in 2008, of which $6.7 million is included in current liabilities and $25.8 million is included in deferred credits (see Note 13). As these amounts are refunded, ATCO Electric will realize the remaining $9.0 million of current income tax savings and eliminate the remaining $23.5 million of future income taxes to be refunded. GAAP requires that revenues not be adjusted for the current income tax savings to be realized in future periods.

Consequently, revenues for 2007 would have been $9.0 million lower in the absence of rate regulation. Assets of $2.0 million are included in current regulatory assets and $7.0 million are included in non-current regulatory assets in the balance sheet.

2. Accounting for rate regulated operations (continued)

Deferred hearing costs

The utilities incur hearing costs on an ongoing basis associated with various AUC regulatory proceedings. These costs are comprised primarily of legal and consulting expenses incurred by the utilities in addition to costs incurred by intervenor groups that have been reimbursed by the utilities as directed by the AUC. Hearing costs are deferred to the balance sheet and are expensed using AUC approved annual amounts that are collected through customer rates. Variances between the approved annual amounts and actual costs incurred are deferred until the next general rate application or until a specific application is made to the AUC requesting recovery from or refund to customers. GAAP requires that hearing costs be expensed in the period in which they are incurred. Consequently, expenses in 2007 would have been \$3.0 million higher (2006 – \$6.8 million lower) in the absence of rate regulation.

Reserves for injuries and damages

The AUC has approved the use of reserves for injuries and damages by the utilities as a means of self-insurance. The reserves for injuries and damages are established based on annual amounts approved by the AUC to be expensed by each utility and collected through customer rates. Variances between the approved annual amounts and actual costs incurred are deferred until the following general rate application or until a specific application is made to the AUC requesting recovery from or refund to customers. GAAP requires that claims be expensed in the period in which they are incurred. Consequently, expenses in 2007 would have been \$1.2 million higher (2006 – \$3.6 million lower) in the absence of rate regulation.

For Alberta Power (2000), reserves for injuries and damages are recoverable under the terms of the PPA's on a straight line basis through 2008. GAAP requires that claims be expensed in the period in which they are incurred. Consequently, expenses in 2007 would have been \$1.0 million lower (2006 – \$1.0 million lower) in the absence of rate regulation.

Deferred royalty credits

Under the terms of PPA's, the compensation for certain royalties incurred by Alberta Power (2000) for coal supply are averaged over the term of each PPA. As such, royalty costs incurred are deferred and expensed on the same average cost basis as reflected in the underlying PPA revenues. GAAP requires that royalty costs be expensed in the period in which they are incurred. Consequently, expenses in 2007 would have been \$3.4 million lower (2006 – \$1.6 million lower) in the absence of rate regulation.

Other regulatory assets and liabilities

Other regulatory assets and liabilities include the following:

a) On December 13, 2006, the AUC issued a decision approving the distribution of the proceeds from the sale of the Red Deer Operating Centre, which occurred in 2005, to ATCO Gas. GAAP requires that gains and losses related to asset dispositions be recognized in the period the disposition was made. Consequently, revenues in 2006 would have been \$1.0 million lower in the absence of rate regulation.

b) ATCO Pipelines has received AUC approval to defer the variances between actual and AUC approved forecast revenues and costs associated with the movement (receipt or delivery) of natural gas between ATCO Pipelines' system and other connected pipeline systems. ATCO Pipelines has applied for approval to recover these deferral account balances in its general rate application which was filed with the AUC on October 1, 2007. GAAP requires that actual revenues and costs be recognized in the period in which they are earned or incurred. Consequently, revenues in 2007 would have been \$0.1 million higher (2006 – \$0.9 million higher) and expenses would have been \$0.2 million lower (2006 – \$0.6 million lower) in the absence of rate regulation. Assets of \$2.5 million and \$0.2 million (2006 – \$2.7 million and \$0.2 million) are included in current regulatory assets and non-current regulatory assets, respectively, and liabilities of \$0.9 million are included in non-current regulatory liabilities (2006 – \$0.5 million in current regulatory liabilities and \$0.3 million in non-current regulatory liabilities).

2. **Accounting for rate regulated operations** (continued)

c) ATCO Pipelines has received AUC approval to establish a deferral account for the Salt Cavern Storage facility to collect (i) the revenue requirements for return on rate base and associated income taxes related to the necessary working capital for the natural gas in storage, and (ii) the gains or losses associated with the sale of natural gas in the market upon withdrawal from storage. ATCO Pipelines is required to submit an application to the AUC, either separately or in conjunction with a general rate application for that particular year, requesting recovery from or refund to customers of the deferral amount should the deferral account exceed $2.0 million at the end of the annual injection/withdrawal cycle on March 31 of a particular year. ATCO Pipelines has applied for approval to recover this deferral account balance in its general rate application which was filed with the AUC on October 1, 2007. GAAP requires that actual revenues and costs be recognized in the period in which they are earned or incurred. Consequently, revenues in 2007 would have been $2.2 million lower (2006 – $2.6 million lower) in the absence of rate regulation. Assets of $5.9 million are included in non-current regulatory assets (2006 – $3.7 million) in the balance sheet.

d) ATCO Pipelines has received AUC approval to establish deferral accounts to collect the costs and revenues arising from load balancing transactions. Load balancing requires the purchase or sale of natural gas to maintain appropriate operating pressures on ATCO Pipelines' North and South transmission pipeline systems. Should the deferral account for either North or South exceed $2.0 million, ATCO Pipelines may submit an application to the AUC requesting recovery from or refund to customers of that particular deferral amount. GAAP requires that actual revenues and costs be recognized in the period in which they are earned or incurred. Consequently, revenues in 2007 would have been $4.7 million higher (2006 – $8.9 million higher expenses) in the absence of rate regulation. Assets of $4.2 million are included in current regulatory assets in the balance sheet (2006 – $8.9 million).

e) ATCO Electric, ATCO Gas and ATCO Pipelines have provided interest free market differential loans to employees when relocating; however, ATCO Electric's revenue requirement includes a recovery from customers for imputed interest on these loans. Effective January 1, 2007, the CICA recommendations regarding the measurement of financial assets require that these loans be measured at fair value, resulting in a reduction in their carrying amount. ATCO Electric defers the variances between the fair value and face value of the loans as a regulatory asset. GAAP requires that the variances be recorded as compensation expense upon issue of the loans, with subsequent accretion according to the effective interest method over their respective terms. Consequently, revenues for 2007 would have been $1.1 million lower in the absence of rate regulation. Assets of $2.5 million are included in non-current regulatory assets.

Other items affected by rate regulation

The AUC permits an allowance for funds used ("AFU"), based on each utility's weighted average cost of capital, to be included in rate base. AFU is also included in the cost of property, plant and equipment for financial reporting purposes, and is depreciated as part of the total cost of the related asset, based on the expectation that depreciation expense, including the AFU component, will be approved for inclusion in future customer rates. Since AFU includes preferred share and common equity components, it exceeds the amount allowed to be capitalized in similar circumstances in the absence of rate regulation.

The utilities and the generating plants of Alberta Power (2000) follow the method of accounting for income taxes that is consistent with the method of determining the income tax component of its rates. When future income taxes are not included in the income tax component of current rates, such future income taxes are not recognized to the extent that they will be recovered from customers through inclusion in future rates. GAAP requires the recognition of all future income tax liabilities and future tax assets in the absence of rate regulation (see Note 6).

3. Regulatory matters

On September 22, 2007, ATCO Electric received a decision on its General Tariff Application for 2007 and 2008 which was filed with the AUC in November 2006. The decision established the amount of revenue ATCO Electric can recover through its rates for electric distribution and transmission service provided to its customers for 2007 and 2008. The effect of the decision on the earnings of ATCO Electric was not material, as higher revenues primarily resulting from increased investment in capital expenditures and previously approved interim customer rates were offset by lower allowed rate of return on common equity (8.51% in 2007 versus 8.93% in 2006) and other adjustments.

The decision also directed ATCO Electric to change its income tax methodology for federal purposes, whereby, effective January 1, 2007, ATCO Electric no longer recognizes future income taxes, and to refund to customers the future income taxes of $34.4 million collected under the previously allowed tax methodology. As a result of this decision, ATCO Electric recorded a reduction in future income tax liabilities of $34.4 million and a liability to customers of $49.3 million in the third quarter of 2007, offset by a regulatory asset of $14.9 million which represents current income tax savings to be realized in future periods. There was no effect on earnings as revenues and income taxes were both initially reduced by $34.4 million. There will also be no effect on earnings in future periods as the current income tax savings realized in future periods will be offset by a reduction in revenues as the regulatory asset is reversed.

In the fourth quarter of 2007, the liability to customers and the regulatory asset were reduced by $0.7 million due to a reduction in future income tax rates. Furthermore, in December 2007, ATCO Electric refunded $16.1 million of the liability to transmission customers, thereby realizing $5.2 million of current income tax savings, which further reduced revenues, and reducing the future income taxes to be refunded by $10.9 million. The total reduction in revenues and income taxes in 2007 was $39.6 million.

ATCO Electric will be refunding the remaining $32.5 million to distribution customers over a five year period commencing in 2008, of which $6.7 million is included in current liabilities and $25.8 million is included in deferred credits (see Note 13). As these amounts are refunded, ATCO Electric will realize the remaining $9.0 million of current income tax savings (see Note 2) and eliminate the remaining $23.5 million of future income taxes to be refunded.

In January 2006, ATCO Gas received a decision on its general rate application which was filed with the AUC in May 2005 for the 2005, 2006 and 2007 test years. The decision established the amount of revenue ATCO Gas can recover through distribution rates for natural gas distribution service to its customers over the period of 2005 to 2007. The decision also approved the return on common equity as determined by the AUC's standardized rate of return methodology. The rate of return on common equity was 8.93% in 2006 and 8.51% for 2007. The final impact of the decision is subject to the outcome of an existing process regarding the pricing of services provided by ATCO I-Tek. A benchmarking report was received on January 23, 2008, and an application is anticipated to be made to the AUC by the end of February 2008 to finalize the placeholder costs. A decision from the AUC is expected before the end of the second quarter of 2008.

In November 2007, ATCO Gas filed a general rate application with the AUC for 2008 and 2009 requesting, among other things, increased revenues to recover increased financing, depreciation, and operating costs associated with increased rate base in Alberta. ATCO Gas has filed an application requesting interim adjustable rates pending the AUC's decision on the general rate application. In December 2007, ATCO Gas received a decision from the AUC approving interim adjustable rate increases amounting to 50% of ATCO Gas' requested revenue increase. A decision from the AUC is not expected until the third quarter of 2008.

In October 2007, ATCO Pipelines filed a general rate application for 2008 and 2009 requesting, among other things, increased revenues to recover increased financing, depreciation and operating costs associated with an increased rate base in Alberta. A decision from the AUC is not expected until the fourth quarter of 2008. In November 2007, ATCO Pipelines filed an application requesting interim adjustable rates pending the AUC's decision on the general rate application. In December 2007, ATCO Pipelines received a decision from the AUC approving interim adjustable rate increases amounting to 40% of ATCO Pipelines' requested revenue increase.

The Corporation has a number of other regulatory filings and regulatory hearing submissions before the AUC for which decisions have not been received. The outcome of these matters cannot be determined at this time.

4. TXU Europe settlement

On November 19, 2002, an administration order was issued by an English Court against TXU Europe Energy Trading Limited ("TXU Europe") which had a long term "off take" agreement for 27.5% of the power produced by the 1,000 megawatt Barking generating plant in London, England, in which the Corporation, through Barking Power, has a 25.5% equity interest. Barking Power had filed a claim for damages for breach of contract related to TXU Europe's obligations to purchase 27.5% of the power produced by the Barking generating plant. Following negotiations with the administrators, an agreement was reached with respect to Barking Power's claim.

In settlement of its claim, Barking Power received distributions of £144.5 million (approximately $327 million) in 2005, of which the Corporation's share was $83.1 million, and distributions of £34.8 million (approximately $71 million) in 2006, of which the Corporation's share was $18.2 million. Income taxes of approximately $28.5 million relating to the distributions have been paid.

The Corporation's share of this settlement is being recognized in earnings in equal monthly amounts over the remaining term of the TXU Europe contract to September 30, 2010. Based on the foreign currency exchange rate in effect at December 31, 2007, earnings after income taxes of approximately $10 million per year have yet to be recognized. These earnings will be dependent upon foreign currency exchange rates in effect at the time that the earnings are recognized.

On May 31, 2007, £95.0 million of the TXU proceeds, of which the Corporation's share was $52.7 million, were applied to Barking Power's non-recourse long term debt.

5. Interest and other income

	2007	2006
Interest	**$46.4**	$39.3
Allowance for funds used by regulated operations	**9.7**	9.3
Gains on dispositions of property, plant and equipment and other investments	**3.2**	8.3
Gain on natural gas purchase contracts derivative asset (Note 21)	**13.5**	-
Loss on power generation revenue contract liability (Note 21)	**(9.4)**	-
Cash flow hedge losses	**(0.5)**	-
Other	**1.4**	1.6
	$64.3	$58.5

6. Income taxes

The income tax provision differs from that computed using the statutory tax rates for the following reasons:

	2007		2006	
Earnings before income taxes	**$498.7**	**%**	$526.8	%
Income taxes, at statutory rates	**$160.2**	**32.1**	$171.2	32.5
Part VI.1 tax benefit	**(15.6)**	**(3.1)**	-	-
Change in method of accounting for future income taxes in certain regulated operations	**(34.4)**	**(6.9)**	(4.0)	(0.8)
Unrecorded future income taxes relating to regulated operations	**(4.9)**	**(1.0)**	2.5	0.5
Change in future income taxes resulting from reduction in tax rates	**(14.9)**	**(3.0)**	(12.2)	(2.3)
Future income taxes recorded at less than current statutory rates	**(3.6)**	**(0.7)**	(1.5)	(0.3)
Foreign tax rate variance	**(3.6)**	**(0.7)**	(2.0)	(0.4)
Non-deductible interest on foreign financing	**1.4**	**0.3**	1.3	0.2
ATCO Gas tax reassessments	**(8.8)**	**(1.8)**	(1.2)	(0.2)
H.R. Milner income tax reassessment	**-**	**-**	7.4	1.4
Resource allowance	**-**	**-**	(1.6)	(0.3)
Crown royalties and other non-deductible Crown payments	**-**	**-**	0.7	0.1
Other	**1.9**	**0.4**	6.5	1.3
	77.7	**15.6**	167.1	31.7
Current income taxes	**112.6**		183.0	
Future income tax recoveries	**$ (34.9)**		$ (15.9)	

The future income tax liabilities (assets) comprise the following:

	2007	2006
Property, plant and equipment	**$185.2**	$230.6
Deferred assets and liabilities	**(33.5)**	(35.5)
Tax loss carryforwards	**(0.6)**	(0.1)
Derivative financial instruments	**3.4**	-
Other	**1.0**	-
	155.5	195.0
Less: Amounts included in current future income taxes	**1.7**	0.3
	$153.8	$194.7

At December 31, 2007, unrecorded future income tax liabilities of the regulated operations amounted to $159.4 million and unrecorded future income tax assets of other operations amounted to $0.8 million. The liabilities include $4.7 million in respect of Alberta Power (2000)'s generating plants, which will be recovered through future payments received in respect of the PPA's.

On June 15, 2007, an amendment to tax legislation pertaining to the taxation of preferred share dividends paid by corporations (Part VI.1 tax) received third reading in the House of Commons. The Canada Revenue Agency ("CRA") has been assessing corporate tax returns based on this proposed change since January 1, 2003, resulting in a reduction of taxes paid to the CRA. As this change is now considered to have been substantively enacted, the Corporation recorded a reduction to current income tax expense related to years prior to 2007 of $15.6 million. Funds generated by operations increased by $15.6 million, offset by a similar reduction in changes in non-cash working capital, leaving the Corporation's cash position unchanged.

6. Income taxes (continued)

In the fourth quarter of 2007, ATCO Gas successfully appealed previous CRA reassessments which resulted in an $8.8 million decrease in income taxes and an increase in interest income, net of income taxes, of $0.7 million for an overall increase to earnings of $9.5 million. These ATCO Gas CRA reassessments applied to the 1999 to 2006 taxation years and allowed ATCO Gas to treat previously reported capital outlays as current expenditures for income tax purposes.

In 2006, the CRA issued a reassessment for Alberta Power (2000)'s 2001 taxation year. The CRA's reassessment treats the proceeds received from the sale of the H.R. Milner generating plant to the Alberta Balancing Pool as income rather than as a sale of an asset. The Corporation has appealed the reassessment to the Tax Court of Canada. The full impact of the reassessment was a $12.4 million increase in interest and income tax expense, a $12.4 million decrease in earnings, and a $28.8 million payment associated with the tax and interest assessed. It is expected that $16.4 million of this cash payment will be recovered by reducing income taxes payable through higher capital cost allowance claims.

There are tax loss carryforwards of $0.4 million for a Canadian subsidiary corporation and $4.6 million for a foreign subsidiary corporation for which no tax benefit has been recorded. The losses for the Canadian subsidiary corporation begin to expire in 2010 and the losses for the foreign subsidiary corporation do not expire.

Income taxes paid amounted to $135.6 million (2006 — $187.0 million).

7. Retained earnings at beginning of period as restated

	January 1	
	2007	2006
Retained earnings at beginning of period as previously reported	**$1,804.4**	$1,721.9
Adjustments to retained earnings to recognize the prior years' effect of:		
(a) the fair value of the natural gas purchase contracts derivative asset (net of income taxes)	**41.6**	-
(b) the fair value of the power generation revenue contract liability associated with the natural gas purchase contracts derivative asset (net of income taxes)	**(31.6)**	-
(c) the change in method of accounting for long term debt and non-recourse long term debt at amortized cost using the effective interest method (net of income taxes)	**(0.6)**	-
(d) the fair value of receivables (net of income taxes)	**(0.5)**	-
Retained earnings at beginning of period as restated	**$1,813.3**	$1,721.9

8. Purchase of Class A shares and other direct charges to retained earnings

	2007	2006
Purchase of Class A shares	**$7.2**	$64.4
Purchase of ATCO Európa Szerkezetgyártó és Kereskedelmi Kft. (Note 19)	**-**	0.3
	$7.2	$64.7

9. Property, plant and equipment

	Composite Depreciation Rates	2007 Cost	2007 Accumulated Depreciation	2006 Cost	2006 Accumulated Depreciation
Utilities	3.7%	**$ 7,036.4**	**$2,589.7**	$6,490.4	$2,411.1
Power Generation	3.3%	**2,839.9**	**1,093.9**	2,853.7	1,026.1
Global Enterprises	7.5%	**313.3**	**148.6**	269.5	140.8
Other	4.8%	**26.7**	**8.0**	26.7	6.7
		$10,216.3	**3,840.2**	$9,640.3	3,584.7
Property, plant and equipment less accumulated depreciation			**6,376.1**		6,055.6
Unamortized contributions by utility customers for extensions to plant			**697.6**		629.5
			$5,678.5		$5,426.1

Accumulated depreciation includes amounts provided for future removal and site restoration costs, net of salvage value, of $417.0 million (2006 ─ $374.6 million).

Composite depreciation rates reflect total depreciation in the year as a percentage of mid-year cost, excluding construction work-in-progress of $142.5 million (2006 ─ $114.2 million) and non-depreciable assets of $52.9 million (2006 ─ $52.3 million).

10. Other assets

	2007	2006
Accrued pension asset (Note 20)	**$139.5**	$157.1
Security deposits for debt	**19.6**	22.8
Deferred financing charges for debt [1]	**-**	25.0
Deferred financing charges for equity preferred shares [2]	**2.7**	-
Other	**32.5**	24.8
	$194.3	$229.7

(1) *Commencing January 1, 2007, in accordance with CICA recommendations regarding the presentation of financial liabilities, long term debt and non-recourse long term debt have been reduced by their respective cumulative unamortized balance of deferred financing charges. Amortization of deferred financing charges for debt, which was recorded in interest expense, amounted to $3.5 million (2006 – $2.8 million).*

(2) *Amortization of deferred financing charges for equity preferred shares, which was recorded in interest expense, amounted to $0.2 million (2006 – nil).*

11. Lines of credit

At December 31, 2007, the Corporation has the following lines of credit that enable it to obtain financing for general business purposes:

	2007 Total	2007 Used	2007 Available	2006 Total	2006 Used	2006 Available
Long term committed	**$ 326.0**	**$48.2**	**$277.8**	$326.0	$47.4	$278.6
Short term committed	**600.0**	**10.0**	**590.0**	600.0	14.0	586.0
Uncommitted	**74.1**	**12.9**	**61.2**	69.1	7.1	62.0
	$1,000.1	**$71.1**	**$929.0**	$995.1	$68.5	$926.6

11. Lines of credit (continued)

Of the $71.1 million used at December 31, 2007, $47.0 million is included in long term debt and $24.1 million represents outstanding letters of credit.

12. Long term debt and non-recourse long term debt

The CICA recommendations regarding the measurement of financial liabilities require the financial liabilities to be measured at initial recognition, including transaction costs, minus principal repayments, plus or minus the cumulative amortization using the effective interest method of any difference between that initial amount and the maturity amount, minus any reduction for impairment. Accordingly, deferred financing charges have been recalculated using the effective interest method. Commencing January 1, 2007, in accordance with CICA recommendations regarding the presentation of financial liabilities, long term debt and non-recourse long term debt have been reduced by their respective cumulative unamortized balance of deferred financing charges.

Long term debt

	Effective Interest Rate	**2007**	2006
Canadian Utilities			
CU Inc. debentures – unsecured			
2002 4.801% due November 2007	4.913%	**$ -**	$ 50.0
2000 6.97% due June 2008	7.062%	**100.0**	100.0
1989 Series 10.20% due November 2009	10.331%	**125.0**	125.0
1990 Series 11.40% due August 2010	11.537%	**125.0**	125.0
2000 7.05% due June 2011	7.130%	**100.0**	100.0
2007 4.883% due November 2012	4.990%	**35.0**	-
2004 5.096% due November 2014	5.162%	**100.0**	100.0
2002 6.145% due November 2017	6.217%	**150.0**	150.0
2004 5.432% due January 2019	5.492%	**180.0**	180.0
1999 6.8% due August 2019	6.861%	**300.0**	300.0
1990 Second Series 11.77% due November 2020	11.903%	**100.0**	100.0
2006 4.801% due November 2021	4.854%	**160.0**	160.0
1991 Series 9.92% due April 2022	10.063%	**125.0**	125.0
1992 Series 9.40% due May 2023	9.511%	**100.0**	100.0
2004 5.896% due November 2034	5.939%	**200.0**	200.0
2005 5.183% due November 2035	5.226%	**185.0**	185.0
2006 5.032% due November 2036	5.072%	**160.0**	160.0
2007 5.556% due October 2037	5.598%	**220.0**	-
CU Inc. other long term obligation, due June 2009, unsecured	6.000%	**4.5**	4.5
Canadian Utilities Limited debentures – unsecured			
2002 6.14% due November 2012	6.228%	**100.0**	100.0
Less: Deferred financing charges		**(13.3)**	-
		2,556.2	2,364.5
ATCO Midstream Ltd. credit facility, at BA rates, due June 2012, unsecured [1]	Floating	**25.0**	25.0
ATCO Power Canada Ltd. credit facility, at BA rates, due August 2012, secured by a pledge of cash [1]	Floating	**22.0**	22.0
		$2,603.2	$2,411.5

12. Long term debt and non-recourse long term debt (continued)

Non-recourse long term debt

The CICA recommendations pertaining to financial instruments do not permit the presentation of interest rate swaps in combination with floating rate long term debt to emulate fixed rate long term debt. Consequently, any of the Corporation's floating rate non-recourse long term debt that had previously been presented in combination with interest rate swaps is now presented exclusive of the effect of the interest rate swaps (see Note 21). The comparative figures have been restated; this change in presentation had no effect on the amount of the Corporation's non-recourse long term debt.

Project Financing	Effective Interest Rate	**2007**	2006
Barking Power Limited payable in British pounds:			
Term loans, at fixed rates averaging 7.95%, due to 2010:			
(£17.9 million (2006 – £22.8 million))	7.95%	**$ 35.1**	$ 52.1
Term loan, at LIBOR, due to 2008 (1):			
(£5.2 million (2006 – £37.5 million))	Floating	**10.2**	85.5
Osborne Cogeneration Pty Ltd., payable in Australian dollars:			
Term loan, at Bank Bill rates, due to 2013 (1):			
($31.9 million AUD (2006 – $36.4 million AUD))	Floating (2)	**27.7**	33.5
ATCO Power Alberta Limited Partnership ("APALP"):			
Term loan, at LIBOR, due to 2016 (1)	Floating (2)	**77.0**	90.0
Joffre:			
Term loan, at BA rates, due to 2012 (1)	Floating (2)	**0.4**	5.6
Term facility, at Canadian Prime Advances, due to 2012 (1)	Floating (2)	**0.1**	-
Term loan, at LIBOR, due to 2012 (1)	Floating (2)	**0.8**	10.0
Notes, at fixed rate of 8.59%, due to 2020	8.845%	**32.0**	32.0
Scotford:			
Term loan, at BA rates, due to 2014 (1)	Floating (2)	**42.5**	42.5
Term facility, at Canadian Prime Advances, due to 2014 (1)	Floating (2)	**10.7**	0.3
Term loan, at LIBOR, due to 2014 (1)	Floating (2)	**-**	10.7
Notes, at fixed rate of 7.93%, due to 2022	8.302%	**25.3**	26.1
Muskeg River:			
Term loan, at BA rates, due to 2014 (1)	Floating (2)	**32.5**	32.7
Term facility, at Canadian Prime Advances, due to 2014 (1)	Floating (2)	**0.1**	-
Term loan, at LIBOR, due to 2014 (1)	Floating (2)	**8.1**	8.2
Notes, at fixed rate of 7.56%, due to 2022	7.902%	**27.6**	29.4
Brighton Beach:			
Term loan, at BA rates, due to 2020 (1)	Floating (2)	**19.2**	20.2
Term loan, at LIBOR, due to 2020 (1)	Floating (2)	**17.3**	18.1
Construction overrun facility, at BA rates, due to 2020 (1)	Floating (2)	**4.7**	4.9
Construction overrun facility, at LIBOR, due to 2020 (1)	Floating (2)	**4.3**	4.5
Notes, at fixed rate of 6.924%, due to 2024	7.025%	**104.9**	107.8

. **12. Long term debt and non-recourse long term debt** (continued)

Non-recourse long term debt *(continued)*

Project Financing	Effective Interest Rate	**2007**	2006
Cory:			
Cost overrun facility, at BA rates, due to 2011 [1]	Floating [2]	**2.4**	3.0
Notes, at fixed rate of 7.586%, due to 2025	7.872%	**35.5**	36.5
Notes, at fixed rate of 7.601%, due to 2026	7.880%	**31.5**	32.4
Less: Deferred financing charges		**(6.4)**	-
		543.5	686.0
Less: Amounts due within one year		**65.4**	59.3
		$478.1	$626.7

BA – Bankers' Acceptance
LIBOR – London Interbank Offered Rate

(1) *The above interest rates have additional margin fees at a weighted average rate of 1.2% (2006 ─ 1.1%). The margin fees are subject to escalation.*
(2) *Floating interest rates have been partially or completely hedged with interest rate swaps (see Note 21).*

The non-recourse long term debt is secured by charges on the projects' assets and by an assignment of the projects' bank accounts, outstanding contracts and agreements. The book value of the pledged assets and bank accounts at December 31, 2007 was $1,235.6 million (2006 ─ $1,415.2 million).

Guarantees

Canadian Utilities Limited has provided a number of guarantees related to ATCO Power's obligations under non-recourse loans associated with certain of its projects. These guarantees cover the following items:

a) **Construction liens** – Represents liens currently registered against project assets. Effective September 30, 2005, ATCO Power entered into an indemnity agreement with Brighton Beach Power Ltd. obligating it to cover any cash shortfalls associated with clearing the construction liens registered against the project. This agreement allowed the project to achieve financial completion under the terms of the project financing agreement. The maximum amount of the indemnity is $8.3 million. Canadian Utilities Limited issued a guarantee to Brighton Beach Power Ltd. guaranteeing the payments under the indemnity agreement. The indemnity and the guarantee are reduced as the liens are settled. At December 31, 2007, the value of the guarantee is $8.3 million.

b) **Project cash flows** ─ Represents annual payments related to maintaining base case margins for electricity prices on the merchant power component of the project, being 24 megawatts ("MW") for the Scotford project and 48 MW for the Muskeg River project. These guarantees became effective upon the commercial operation of the plants and exist until 2022, when the project debt is to be fully repaid. The amounts payable under these guarantees will vary each year depending on the pool price received for the merchant power generated. Any payments made to maintain the project base case margins will either be available for distribution to the owners or be applied to mandatory prepayment of the project debt in accordance with the terms of the project financing agreement depending upon the specific operating results of the plant. At December 31, 2007, no amounts were outstanding under the guarantee.

12. Long term debt and non-recourse long term debt (continued)

c) **Reserve amounts —** Represents amounts to be set aside for major maintenance and debt service reserves as stipulated in the project's financing agreement. These reserves are intended to be funded with project cash flows. To the extent that project cash flows are insufficient to meet reserve requirements, Canadian Utilities Limited may choose to provide guarantees in lieu of ATCO Power providing security. At December 31, 2007, the amount of the obligations under these guarantees is:

Project	Major Maintenance	Debt Service
APALP project financing	Nil [(1)]	$ 7.0
Brighton Beach project financing	Nil [(2)]	Nil
Cory project financing	Nil [(1)]	$ 3.9
Joffre project financing	Nil [(3)]	$ 1.6
Muskeg River project financing	Nil [(1)]	$ 9.0
Scotford project financing	Nil [(1)]	$12.1

[(1)] *No major maintenance reserve required for this financing.*
[(2)] *Reserve requirements of $0.2 million met with project cash flows.*
[(3)] *Reserve requirements of $0.1 million met with project cash flows.*

d) **Prepaid operating and maintenance fee —** Should ATCO Power cease to be operator of the APALP generating plants as a result of a termination of the operating agreement, Canadian Utilities Limited has guaranteed the payment of the unamortized portion of the prepaid operating and maintenance fee to APALP, the proceeds of which are to be used to repay project debt in accordance with the project financing agreements. This guarantee, which declines by $1.2 million per year, remains in effect until 2016, when the project debt is to be fully repaid. At December 31, 2007, the maximum value of the guarantee is $28.8 million.

e) **Purchase project assets —** Represents an obligation to purchase the Scotford and Muskeg River projects at a price sufficient to repay any outstanding project debt upon the occurrence of any one of the following very limited events:

(i) where all of the following events have occurred:
- the insolvency of ATCO Power;
- the failure of the project debt lenders to complete a sale of the project pursuant to their security within a fixed period of time; and
- the project purchaser of electricity and steam elects to terminate its purchase contracts due to the insolvency of ATCO Power;

(ii) where the project purchaser of electricity and steam does not remove ATCO Power as operator of the project after an event of default under the project financing agreements in circumstances where such default is either:
- a deliberate or willful breach of a project financing agreement; or
- where ATCO Power has failed to co-operate with the lenders in a sale of the project; and

(iii) where the project purchaser of electricity and steam terminates its purchase contracts for the project as a result of a default by ATCO Power's project minority joint venturers. ATCO Power has the right to cure any such default by acquiring the minority interest which is in default.

These guarantees remain in effect until the project debt is fully repaid. At December 31, 2007, no such events have occurred.

Canadian Utilities Limited has also guaranteed ATCO Power's duties to operate the Barking Power, Scotford and Muskeg River generating plants in accordance with acceptable industry operating standards under the relevant project contracts.

12. Long term debt and non-recourse long term debt (continued)

ATCO Power (80%) and ATCO Resources (20%), a wholly owned subsidiary of Canadian Utilities Limited's parent corporation, ATCO Ltd., have a joint venture in the above projects subject to guarantees, excluding Barking Power.

The foregoing guaranteed amounts represent ATCO Power's 80% interest. Canadian Utilities Limited has also guaranteed similar obligations in respect of ATCO Resources' 20% interest. ATCO Ltd. has indemnified and agreed to reimburse Canadian Utilities Limited for any amounts it may be required to pay under these guarantees in respect of ATCO Resources' 20% interest.

To date, Canadian Utilities Limited has not been required to pay any of its guaranteed obligations.

Minimum debt repayments

The minimum annual debt repayments for each of the next five years are as follows:

	Long Term Debt	Non-Recourse Long Term Debt	Total
2008	$100.0	$ 65.4	$165.4
2009	129.5	46.0	175.5
2010	125.0	50.3	175.3
2011	100.0	42.3	142.3
2012	82.0	38.8	120.8
	$536.5	$242.8	$779.3

Of the $165.4 million due in 2008, $100.0 million is to be refinanced and is, therefore, excluded from long term debt due within one year in the balance sheet.

Interest expense

Interest expense is as follows:

	2007	2006
Long term debt	**$169.1**	$161.0
Non-recourse long term debt	**43.2**	49.0
Notes payable	**-**	0.3
Bank indebtedness	**1.4**	1.5
Amortization of deferred financing charges	**3.7**	2.8
Interest on H.R. Milner income tax reassessment (Note 6)	**-**	8.3
	$217.4	$222.9

Interest paid amounted to $210.6 million (2006 — $220.8 million).

13. Deferred credits

	2007	2006
Accrued other post employment benefits liability (Note 20)	**$ 52.8**	$ 45.1
Deferred availability incentives	**41.8**	39.6
Asset retirement obligations	**73.1**	69.4
Power generation revenue contract liability (Note 21)	**54.2**	-
Liability to customers for refund of future income taxes (Note 3)	**25.8**	-
Deferred revenues (Note 4)	**26.2**	46.8
Accrued equipment repairs and maintenance	**8.6**	7.5
Other	**25.4**	20.6
	$307.9	$229.0

13. Deferred credits (continued)

Deferred availability incentives

Amortization of deferred availability incentives, which was recorded in revenues, amounted to $11.8 million (2006 – $10.6 million).

The amount to be amortized is dependent upon estimates of future generating unit availability and future electricity prices over the term of the PPA's. Each quarter, the Corporation uses these estimates to forecast the incentives to be received from, less penalties to be paid to, the PPA counterparties. These forecasts are added to the accumulated unamortized deferred availability incentives outstanding at the end of the quarter; the resulting total is divided by the remaining term of the PPA to arrive at the amortization for the quarter.

Asset retirement obligations

Changes in asset retirement obligations are summarized below:

	2007	2006
Obligations at beginning of year	**$69.4**	$62.2
Obligations incurred	**0.1**	3.7
Accretion expense	**3.6**	3.5
Obligations at end of year	**$73.1**	$69.4

The Corporation estimates the undiscounted amount of cash flow required to settle the asset retirement obligations is approximately $131 million, which will be incurred between 2008 and 2052. The discount rates used to calculate the fair value of the asset retirement obligations have a weighted average rate of 5.7%.

14. Equity preferred shares

CU Inc. equity preferred shares

Authorized and issued

Authorized: An unlimited number of Series Preferred Shares, issuable in series.

Issued:

	Stated Value	Redemption Dates	**2007**		2006	
			Shares	**Amount**	Shares	Amount
	(dollars)					
Cumulative Redeemable Preferred Shares						
4.60% Series 1	$25.00	See below	**4,600,000**	**$115.0**	-	$ -

On April 18, 2007, CU Inc., a subsidiary corporation, issued $115.0 million Cumulative Redeemable Preferred Shares Series 1 at a price of $25.00 per share for cash. The dividend rate has been fixed at 4.60%. The net proceeds of the issue were used in part to redeem $91.8 million of the outstanding Cumulative Redeemable Second Preferred Shares Series Q, R and S of ATCO Electric, ATCO Gas and ATCO Pipelines, subsidiary corporations of CU Inc., that are held by Canadian Utilities Limited.

Fair values

Fair values for preferred shares determined using quoted market prices for the same or similar issues are $94.7 million (2006 - nil).

14. Equity preferred shares (continued)

Redemption privileges

The Series 1 preferred shares are redeemable at the option of the Corporation commencing on June 1, 2012, at the stated value plus a 4% premium per share for the next 12 months plus accrued and unpaid dividends. The redemption premium declines by 1% in each succeeding twelve month period until June 1, 2016.

Canadian Utilities Limited equity preferred shares

Authorized and issued

Authorized: An unlimited number of Series Second Preferred Shares, issuable in series.

Issued:

	Stated Value (dollars)	Redemption Dates	**2007** Shares	**2007** Amount	2006 Shares	2006 Amount
Cumulative Redeemable Second Preferred Shares						
5.9% Series Q	$25.00	Open	**-**	**$ -**	2,277,675	$ 56.9
5.3% Series R	$25.00	Open	**-**	**-**	2,146,730	53.7
6.6% Series S	$25.00	Open	**-**	**-**	635,700	15.9
5.8% Series W	$25.00	See below	**6,000,000**	**150.0**	6,000,000	150.0
6.0% Series X	$25.00	See below	**6,000,000**	**150.0**	6,000,000	150.0
Perpetual Cumulative Second Preferred Shares						
4.35% Series O	$25.00	December 2, 2011	**1,600,000**	**40.0**	1,600,000	40.0
4.35% Series T	$25.00	December 2, 2011	**1,600,000**	**40.0**	1,600,000	40.0
4.35% Series U	$25.00	December 2, 2011	**800,000**	**20.0**	800,000	20.0
4.70% Series V	$25.00	October 3, 2012	**4,400,000**	**110.0**	4,400,000	110.0
				$510.0		$636.5
Total CU Inc. and Canadian Utilities Limited equity preferred shares				**$625.0**		$636.5

On May 18, 2007, Canadian Utilities Limited redeemed $126.5 million of outstanding Cumulative Redeemable Second Preferred Shares Series Q, R, and S at a price of $25.00 per share plus accrued and unpaid dividends per share.

The dividends payable on the Series O, T, U, and V preferred shares are fixed until the redemption dates specified above, at which time a new dividend rate may be established by negotiations between Canadian Utilities Limited and the owners of the shares.

On October 3, 2007, the dividend rate on the Series V preferred shares was reset from 5.25% to 4.70%.

Fair values

Fair values for preferred shares determined using quoted market prices for the same or similar issues are $517.3 million (2006 ─ $666.8 million).

Redemption privileges

The preferred shares, except for Series W and X, are redeemable on the dates specified above at the option of Canadian Utilities Limited at the stated value plus accrued and unpaid dividends.

The Series W preferred shares are redeemable commencing on March 1, 2008 at the stated value plus a 4% premium for the next 12 months plus accrued and unpaid dividends. The redemption premium declines by 1% in each succeeding 12 month period until March 1, 2012.

14. Equity preferred shares (continued)

The Series X preferred shares are redeemable commencing June 1, 2008 at the stated value plus a 4% premium for the next 12 months plus accrued and unpaid dividends. The redemption premium declines by 1% in each succeeding 12 month period until June 1, 2012.

15. Class A and Class B shares

Authorized and issued

	Class A Non-Voting		Class B Common		Total	
	Shares	Amount	Shares	Amount	Shares	Amount
Authorized:	Unlimited		Unlimited			
Issued and outstanding:						
December 31, 2005	82,876,186	$379.7	44,016,284	$139.4	126,892,470	$519.1
Purchased and cancelled	(1,832,200)	(8.4)	-	-	(1,832,200)	(8.4)
Stock options exercised	327,900	5.3	-	-	327,900	5.3
Converted: Class B to Class A	84,800	0.3	(84,800)	(0.3)	-	-
December 31, 2006	**81,456,686**	**376.9**	**43,931,484**	**139.1**	**125,388,170**	**516.0**
Purchased and cancelled	**(157,800)**	**(0.7)**	**-**	**-**	**(157,800)**	**(0.7)**
Stock options exercised	**64,300**	**1.6**	**-**	**-**	**64,300**	**1.6**
Converted: Class B to Class A	**145,800**	**0.5**	**(145,800)**	**(0.5)**	**-**	**-**
December 31, 2007	**81,508,986**	**$378.3**	**43,785,684**	**$138.6**	**125,294,670**	**$516.9**

From January 1, 2008 to February 15, 2008, 46,400 Class B common shares were converted to Class A non-voting shares.

Earnings per share

Earnings per Class A non-voting and Class B common share is calculated by dividing the earnings attributable to Class A and Class B shares by the weighted average shares outstanding. Diluted earnings per share is calculated using the treasury stock method, which reflects the potential exercise of stock options on the weighted average Class A non-voting and Class B common shares outstanding. The average number of shares used to calculate earnings per share are as follows:

	Three Months Ended December 31		Year Ended December 31	
	2007	2006	**2007**	2006
	(Unaudited)			
Weighted average shares outstanding	**125,390,562**	125,321,693	**125,409,080**	126,218,722
Effect of dilutive stock options	**564,511**	512,786	**525,057**	468,457
Weighted average diluted shares outstanding	**125,955,073**	125,834,479	**125,934,137**	126,687,179

Share owner rights

The owners of the Class A non-voting shares and the Class B common shares are entitled to share equally, on a share for share basis, in all dividends declared by Canadian Utilities Limited on either of such classes of shares as well as the remaining property of Canadian Utilities Limited upon dissolution. The owners of the Class B common shares are entitled to vote and to exchange at any time each share held for one Class A non-voting share.

If a take-over bid is made for the Class B common shares which would result in the offeror owning more than 50% of the outstanding Class B common shares and which would constitute a change in control of Canadian Utilities

15. Class A and Class B shares (continued)

Limited, owners of Class A non-voting shares are entitled, for the duration of the bid, to exchange their Class A non-voting shares for Class B common shares and to tender such Class B common shares pursuant to the terms of the take-over bid. Such right of exchange is conditional upon the completion of the take-over bid giving rise to the right of exchange, and if the take-over bid is not completed, then the right of exchange shall be deemed never to have existed. In addition, owners of the Class A non-voting shares are entitled to exchange their shares for Class B common shares of Canadian Utilities Limited if ATCO Ltd., the present controlling share owner of Canadian Utilities Limited, ceases to own or control, directly or indirectly, more than 10,000,000 of the issued and outstanding Class B common shares of Canadian Utilities Limited. In either case, each Class A non-voting share is exchangeable for one Class B common share, subject to changes in the exchange ratio for certain events such as a stock split or rights offering.

Normal course issuer bid

On May 23, 2006, Canadian Utilities Limited commenced a normal course issuer bid for the purchase of up to 5% of the outstanding Class A shares. The bid expired on May 22, 2007. Over the life of the bid, 1,679,700 shares were purchased, all of which were purchased in 2006. On May 23, 2007, Canadian Utilities commenced a new normal course issuer bid for the purchase of up to 5% of the outstanding Class A shares. The bid will expire on May 22, 2008. From May 23, 2007, to February 15, 2008, 157,800 shares have been purchased, all of which were purchased in 2007.

Special dividend

The Corporation paid a Special Dividend of $0.25 per Class A non-voting and Class B common share on September 1, 2006.

16. Stock based compensation plans

Stock option plan

Of the 6,400,000 Class A non-voting shares authorized for grant in respect of options under Canadian Utilities Limited's stock option plan, 3,122,200 Class A non-voting shares are available for issuance at December 31, 2007. Options may be granted to directors, officers and key employees of Canadian Utilities Limited and its subsidiaries at an exercise price equal to the weighted average of the trading price of the shares on the Toronto Stock Exchange for the five trading days immediately preceding the date of grant. The vesting provisions and exercise period (which cannot exceed 10 years) are determined at the time of grant.

Changes in shares under option are summarized below:

	2007		2006	
	Class A Shares	**Weighted Average Exercise Price**	Class A Shares	Weighted Average Exercise Price
Options at beginning of year	**1,208,000**	**$25.12**	1,415,500	$21.59
Granted	**163,500**	**47.82**	121,000	43.45
Exercised	**(64,300)**	**22.91**	(327,900)	16.62
Cancelled	**(3,000)**	**47.84**	(600)	24.52
Options at end of year	**1,304,200**	**$28.02**	1,208,000	$25.12

16. Stock based compensation plans (continued)

Information about stock options outstanding at December 31, 2007 is summarized below:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Class A Shares	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Class A Shares	Weighted Average Exercise Price
$17.23 - $18.87	331,300	1.9	$17.86	331,300	$17.86
$20.65 - $28.65	487,400	2.3	23.54	473,000	23.47
$30.25 - $47.84	485,500	7.9	39.46	105,800	33.47
$17.23 - $47.84	1,304,200	4.3	$28.02	910,100	$22.59

In 2007, Canadian Utilities Limited granted 163,500 options to purchase Class A non-voting shares at a weighted average exercise price of $47.82 per share. The options have a term of ten years and vest over the first five years.

Changes in contributed surplus are summarized below:

	2007	2006
Contributed surplus at beginning of year	**$1.2**	$ 0.7
Stock option expense	**0.7**	0.5
Contributed surplus at end of year	**$1.9**	$ 1.2

The Corporation uses the Black-Scholes option pricing model, which estimated the weighted average fair value of the options granted during 2007 at $7.23 per option (2006 ─ $6.24 per option) using the following weighted average assumptions:

	2007	2006
Risk free interest rate	**4.0%**	4.0%
Expected holding period prior to exercise	**6.2 years**	6.2 years
Share price volatility	**12.5%**	11.9%
Estimated annual Class A share dividend	**2.5%**	2.5%

Share appreciation rights

Directors, officers and key employees of the Corporation may be granted share appreciation rights that are based on Class A non-voting shares of Canadian Utilities Limited or Class I Non-Voting Shares of ATCO Ltd. The vesting provisions and exercise period (which cannot exceed 10 years) are determined at the time of grant. The base value of the share appreciation rights is equal to the weighted average of the trading price of the Class A non-voting shares and the Class I Non-Voting Shares, respectively, on the Toronto Stock Exchange for the five trading days immediately preceding the date of grant. The holder is entitled on exercise to receive a cash payment equal to any increase in the market price of the Class A non-voting shares and Class I Non-Voting Shares, respectively, over the base value of the share appreciation rights exercised.

Share appreciation rights expense amounted to $0.7 million (2006 ─ $2.4 million).

17. Changes in non-cash working capital

	2007	2006
Operating activities, changes related to:		
Accounts receivable	**$(15.8)**	$(25.6)
Inventories	**(3.8)**	0.5
Regulatory assets	**5.1**	(10.6)
Prepaid expenses	**(5.2)**	(3.0)
Accounts payable and accrued liabilities	**21.5**	1.7
Income taxes	**(20.3)**	6.4
Future income taxes	**-**	(3.8)
Regulatory liabilities	**(0.5)**	(5.2)
	$(19.0)	$(39.6)
Investing activities, changes related to:		
Inventories	**$ (2.9)**	$ (8.1)
Prepaid expenses	**(1.1)**	(0.3)
Accounts payable and accrued liabilities	**16.3**	(6.2)
Income taxes	**-**	(3.7)
	$ 12.3	$(18.3)
Financing activities, changes related to:		
Accounts receivable	**$ -**	$ (0.1)

18. Joint ventures

The Corporation's interest in joint ventures is summarized below:

	2007	2006
Statement of earnings		
Revenues	**$ 484.9**	$ 533.0
Operating expenses	**291.0**	328.1
Depreciation and amortization	**42.1**	40.4
Interest	**36.1**	41.2
	115.7	123.3
Interest and other income	**13.3**	8.9
Earnings from joint ventures before income taxes	**$ 129.0**	$ 132.2
Balance sheet		
Current assets	**$ 165.7**	$ 266.9
Current liabilities	**(142.6)**	(174.0)
Property, plant and equipment	**871.7**	933.2
Deferred items – net	**(50.1)**	(93.1)
Non-recourse long term debt	**(350.4)**	(465.2)
Investment in joint ventures	**$ 494.3**	$ 467.8

18. Joint ventures (continued)

	2007	2006
Statement of cash flows		
Operating activities	**$ 143.6**	$ 180.8
Investing activities	**(17.7)**	(19.1)
Financing activities	**(208.0)**	(131.0)
Foreign currency translation	**(10.7)**	14.1
Increase (decrease) in cash position	**$ (92.8)**	$ 44.8

Current assets include cash of $65.2 million (2006 ─ $160.9 million) which is only available for use within the joint ventures.

19. Related party transactions

In transactions with ATCO Ltd. and its wholly owned subsidiary corporations, the Corporation sold fuel in the amount of $2.0 million (2006 ─ $2.2 million), provided computer operations and systems development services totaling $6.7 million (2006 – $2.4 million), recovered administrative expenses totaling $1.6 million (2006 ─ $2.4 million) and incurred administrative expenses and corporate signature rights totaling $8.3 million (2006 ─ $8.6 million). The Corporation also incurred capital expenditures of $9.4 million (2006 ─ nil) that were recorded in property, plant and equipment.

In transactions with entities related through common control, the Corporation provided security services and recovered administrative expenses totaling $0.3 million (2006 – $0.2 million) and incurred advertising, promotion and administrative expenses totaling $1.5 million (2006 ─ $1.7 million).

At December 31, 2007, accounts receivable due from related parties amounted to $0.8 million (2006 – $4.9 million) and accounts payable due to related parties amounted to $8.3 million (2006 – $3.2 million).

These transactions are in the normal course of business and under normal commercial terms.

On October 1, 2006, the Corporation purchased the common shares of ATCO Európa Szerkezetgyártó és Kereskedelmi Kft. from an affiliate corporation for $0.5 million cash, partially offset by the forgiveness of $0.4 million of debt owed by the Corporation to the affiliate corporation. This purchase was recorded at carrying value, resulting in a charge to retained earnings of $0.3 million.

20. Employee future benefits

The Corporation maintains registered defined benefit and defined contribution pension plans for most of its employees and provides other post employment benefits, principally health, dental and life insurance, for retirees and their dependants. The defined benefit pension plans provide for pensions based on employees' length of service and final average earnings. As of 1997, new employees automatically participate in the defined contribution pension plan and employees participating in the defined benefit pension plans may transfer to the defined contribution pension plan at any time. Upon transfer, further accumulation of benefits under the defined benefit pension plans ceases. The Corporation also maintains non-registered, non-funded defined benefit pension plans for certain officers and key employees.

20. Employee future benefits (continued)

Information about the Corporation's benefit plans, in aggregate, is as follows:

	2007		2006	
	Pension Benefit Plans	**Other Post Employment Benefit Plans**	Pension Benefit Plans	Other Post Employment Benefit Plans
Benefit plan assets, obligations and funded status				
Market value of plan assets:				
Beginning of year	**$1,704.1**	**$ -**	$1,561.1	$ -
Actual return on plan assets	**30.7**	**-**	187.3	-
Employee contributions	**3.8**	**-**	3.7	-
Employer contributions	**0.7**	**-**	-	-
Benefit payments	**(41.2)**	**-**	(39.8)	-
Payments to defined contribution plans [1]	**(9.5)**	**-**	(8.2)	-
End of year	**$1,688.6**	**$ -**	$1,704.1	$ -
Accrued benefit obligations:				
Beginning of year	**$1,642.0**	**$ 83.5**	$1,485.0	$ 80.3
Current service cost	**39.8**	**2.6**	38.0	3.0
Interest cost	**86.3**	**4.2**	80.8	4.2
Employee contributions	**3.8**	**-**	3.7	-
Benefit payments from plan assets [2]	**(41.2)**	**-**	(39.8)	-
Benefit payments by employer	**(4.3)**	**(2.0)**	(4.3)	(1.8)
Experience losses (gains) [3]	**(75.7)**	**(8.9)**	78.6	(2.2)
End of year [4]	**$1,650.7**	**$ 79.4**	$1,642.0	$ 83.5
Funded status:				
Excess (deficiency) of assets over obligations [4]	**$ 37.9**	**$(79.4)**	$ 62.1	$(83.5)
Amounts not yet recognized in financial statements:				
Unrecognized net cumulative experience losses on plan assets and accrued benefit obligations	**289.1**	**8.2**	316.0	17.7
Unrecognized net transitional liability (asset)	**(187.5)**	**18.4**	(221.0)	20.7
Accrued asset (liability) (Notes 10, 13)	**$ 139.5**	**$(52.8)**	$ 157.1	$(45.1)
Regulatory asset (liability) [5] (Note 2)	**$ (110.0)**	**$ 32.3**	$ (118.7)	$ 27.6

(1) *Employer contributions for certain of the Corporation's defined contribution pension plans are paid from the assets of the defined benefit pension plans.*

(2) *Pension plan benefit payments are indexed to increases in the Canadian Consumer Price Index to a maximum increase of 3% per annum.*

(3) *A change in the liability discount rate at December 31 assumption resulted in experience gains in 2007 of approximately $99 million, whereas a change in the average compensation rate increase assumption for the year resulted in experience losses in 2007 of approximately $29 million for the pension benefit plans. Changes in assumptions regarding the average compensation rate increase for the year and age at retirement resulted in experience losses in 2006 of approximately $66 million for the pension benefit plans.*

(4) *The non-registered, non-funded defined benefit pension plans had accrued benefit obligations of $84.0 million at December 31, 2007 (2006 – $84.2 million). Apart from these obligations, the excess of assets over obligations for the registered defined benefit pension plans at December 31, 2007 was $121.9 million (2006 – $146.3 million)*.

(5) *The regulatory asset (liability) reflects an AUC decision to record costs of employee future benefits in the regulated operations, excluding Alberta Power (2000), when paid rather than accrued.*

20. Employee future benefits (continued)

	2007		2006	
	Pension Benefit Plans	**Other Post Employment Benefit Plans**	Pension Benefit Plans	Other Post Employment Benefit Plans
Benefit plan cost				
Components of benefit plan cost:				
Current service cost	**$ 39.8**	**$ 2.6**	$ 38.0	$ 3.0
Interest cost	**86.3**	**4.2**	80.8	4.2
Actual return on plan assets	**(30.7)**	**-**	(187.3)	-
Experience losses (gains) on accrued benefit obligations	**(75.7)**	**(8.9)**	78.6	(2.2)
	19.7	**(2.1)**	10.1	5.0
Adjustments to recognize long term nature of employee future benefits:				
Unrecognized portion of actual return on plan assets	**(64.4)**	**-**	107.6	-
Unrecognized portion of experience gains (losses) on accrued benefit obligations	**75.7**	**8.9**	(78.6)	2.2
Amortization of net cumulative experience losses on plan assets and accrued benefit obligations	**15.6**	**0.6**	24.5	2.0
Amortization of net transitional liability (asset)	**(33.5)**	**2.3**	(32.4)	2.3
	(6.6)	**11.8**	21.1	6.5
Defined benefit plans cost	**13.1**	**9.7**	31.2	11.5
Defined contribution plans cost	**11.0**	**-**	9.7	-
Total cost	**24.1**	**9.7**	40.9	11.5
Less: Capitalized	**2.1**	**2.5**	1.9	2.7
Less: Unrecognized defined benefit plans cost (income) (1) (2)	**7.8**	**2.9**	19.5	3.5
Net cost recognized (2)	**$ 14.2**	**$ 4.3**	$ 19.5	$ 5.3

(1) The unrecognized defined benefit plans cost (income) reflects an AUC decision to record costs of employee future benefits in the regulated operations, excluding Alberta Power (2000), when paid rather than accrued.

(2) Net cost recognized for pension benefit plans in 2007 includes the amortization of $2.6 million (2006 – $5.1 million) of the deferred pension assets recorded by the Corporation upon the adoption of the current accounting standard in 2000. On October 11, 2006, the AUC approved recovery of these assets for a nine-year period commencing January 1, 2005 (Note 2).

In the unaudited three months ended December 31, 2007, net cost of $3.0 million (2006 – $7.8 million) was recognized for pension benefit plans and net cost of $1.0 million (2006 – $1.6 million) was recognized for other post employment benefit plans.

20. **Employee future benefits** (continued)

Weighted average assumptions

	2007		2006	
	Pension Benefit Plans	**Other Post Employment Benefit Plans**	Pension Benefit Plans	Other Post Employment Benefit Plans
Assumptions regarding benefit plan cost:				
Expected long term rate of return on plan assets for the year	**6.6%**	**-**	6.1%	-
Liability discount rate for the year	**5.1%**	**5.1%**	5.1%	5.1%
Average compensation increase for the year	**(1)**	**-**	3.5%	-
Assumptions regarding accrued benefit obligations:				
Liability discount rate at December 31	**5.5%**	**5.5%**	5.1%	5.1%
Long term inflation rate	**2.5%**	**(2)**	2.5%	(2)

(1) The assumed average compensation increases are 4.0% for five years (2007-2011) and 3.5% thereafter.

(2) The assumed annual health care cost trend rate increases used in measuring the accumulated post employment benefit obligation are as follows: for drug costs, 7.8% for 2007 grading down over 6 years to 4.5% (2006 – 8.5% for 2006 grading down over 7 years to 4.5%), and, for other medical and dental costs, 4.0% for 2007 and thereafter (2006 – 4.0% for 2006 and thereafter).

The sensitivities of key assumptions used in measuring accrued benefit obligations and benefit plan cost for 2007 are outlined in the following table. The sensitivities of each key assumption have been calculated independently of changes in other key assumptions. Actual experience may result in changes in a number of assumptions simultaneously.

	2007 Pension Benefit Plans		2007 Other Post Employment Benefit Plans	
	Accrued Benefit Obligation	Benefit Plan Cost	Accrued Benefit Obligation	Benefit Plan Cost
Expected long term rate of return on plan assets				
1% increase (1)	-	$ (4.0)	-	-
1% decrease (1)	-	$ 4.0	-	-
Liability discount rate				
1% increase (1)	$ (82.3)	$(5.6)	$(3.7)	$(0.3)
1% decrease (1)	$104.9	$ 8.4	$ 4.6	$ 0.4
Future compensation rate				
1% increase (1)	$ 21.9	$ 3.0	-	-
1% decrease (1)	$(20.1)	$(2.8)	-	-
Long term inflation rate				
1% increase (1) (2) (3)	$ 36.5	$ 4.5	$ 3.9	$ 0.6
1% decrease (1) (3)	$(63.8)	$(7.7)	$(3.1)	$(0.4)

(1) Sensitivities are net of the associated regulatory asset (liability) and unrecognized defined benefit plans cost, which reflect an AUC decision to record costs of employee future benefits in the regulated operations, excluding Alberta Power (2000), when paid rather than accrued.

(2) The long term inflation rate for pension plans reflects the fact that pension plan benefit payments are indexed to increases in the Canadian Consumer Price Index to a maximum increase of 3.0% per annum.

(3) The long term inflation rate for other post employment benefit plans is the assumed annual health care cost trend rate described in the weighted average assumptions.

20. Employee future benefits (continued)

Pension benefit plan assets

	2007		2006	
	Amount	**%**	Amount	%
Plan asset mix:				
Equity securities [(1)]	**$1,000.4**	**59.3**	$1,028.7	60.4
Fixed income securities [(2)]	**621.7**	**36.8**	605.6	35.5
Real estate [(3)]	**37.2**	**2.2**	32.7	1.9
Cash and other assets [(4)]	**29.3**	**1.7**	37.1	2.2
	$1,688.6	**100.0**	$1,704.1	100.0

(1) *Equity securities consist of investments in domestic and foreign preferred and common shares. At December 31, 2007, the market values of investments in United States' securities and international equities, denominated in a number of different currencies, are $114.9 million and $308.1 million, respectively (2006 – $236.7 million and $238.2 million, respectively).*

(2) *Fixed income securities consist of investments in federal and provincial government and corporate bonds and debentures.*

(3) *Real estate consists of investments in closed-end real estate funds.*

(4) *Cash and other assets consist of cash, short term notes and money market funds.*

At December 31, 2007, plan assets include long term debt of CU Inc. having a market value of $12.2 million (2006 – $8.7 million), Class A non-voting and Class B common shares of Canadian Utilities Limited having a market value of $18.5 million (2006 – $19.1 million) and Class I Non-Voting Shares of ATCO Ltd. having a market value of $20.0 million (2006 – $18.2 million).

Funding

Employees are required to contribute a percentage of their salary to the registered defined benefit pension plans. The Corporation is required to provide the balance of the funding, based on triennial actuarial valuations, necessary to ensure that benefits will be fully provided for at retirement. Based on the most recent actuarial valuation for funding purposes as of December 31, 2006 the Corporation is continuing a contribution holiday that began on April 1, 1996 for all but one of the registered pension plans; commencing in 2007, the Corporation is required to make annual contributions of approximately $0.7 million to cover the unfunded liability of that plan. The next actuarial valuation for funding purposes is required as of December 31, 2009.

21. Risk management and financial instruments

The Corporation is exposed to changes in interest rates, commodity prices and foreign currency exchange rates. The Power Generation segment is affected by the cost of natural gas and the price of electricity in the Province of Alberta and the United Kingdom and the Global Enterprises segment is affected by the cost of natural gas and the price of natural gas liquids. In conducting its business, the Corporation may use various instruments, including forward contracts, swaps and options, to manage the risks arising from fluctuations in exchange rates, interest rates and commodity prices. All such instruments are used only to manage risk and not for trading purposes.

At December 31, 2007, the following derivative instruments were outstanding: interest rate swaps that hedge interest rate risk on the variable future cash flows associated with a portion of non-recourse long term debt, foreign currency forward contracts that hedge foreign currency risk on the future cash flows associated with specific firm commitments or anticipated transactions and certain natural gas purchase contracts.

21. **Risk management and financial instruments** (continued)

The derivative assets and liabilities comprise the following:

	2007
Derivative assets – current:	
Interest rate swap agreements	**$ 0.2**
Foreign currency forward contracts	**0.6**
	$ 0.8
Derivative assets – non-current:	
Natural gas purchase contracts	**$72.5**
Interest rate swap agreements	**0.8**
	$73.3
Derivative liabilities – current:	
Interest rate swap agreements	**$ 1.5**
Foreign currency forward contracts	**1.1**
	$ 2.6
Derivative liabilities – non-current:	
Interest rate swap agreements	**$ 3.3**

Interest rate risk

The Corporation has converted variable rate non-recourse long term debt to fixed rate debt through the following interest rate swap agreements:

Project Financing	Swap Fixed Interest Rate [1]	Variable Debt Interest Rate	Maturity Date	Notional Principal **2007**	Notional Principal 2006
Osborne: ($30.3 million AUD (2006 – $34.6 million AUD))	7.333%	Bank Bill Rate in Australia	December 2013	**$ 26.3**	$ 31.8
APALP:	7.790%	90 day BA	November 2008	**1.3**	2.6
	7.567%	90 day BA	December 2008	**1.8**	3.6
	7.750%	6 month LIBOR	December 2011	**73.7**	83.8
Joffre:	7.286%	90 day BA	September 2012	**19.8**	24.0
Scotford:	5.332%	90 day BA	September 2008	**51.4**	54.2
Muskeg River:	5.287%	90 day BA	December 2007	**-**	40.8
	5.515%	90 day BA	December 2012	**32.6**	-
	5.615%	3 month LIBOR	December 2012	**8.2**	-
Brighton Beach:	5.837%	30 day BA	June 2009	**8.5**	8.9
	6.575%	90 day BA	March 2019	**34.2**	36.1
Cory:	6.586%	90 day BA	June 2011	**2.1**	2.7
				$259.9	$288.5

BA − Bankers' Acceptance
LIBOR – London Interbank Offered Rate

[1] *The above swap fixed interest rates include any long term debt margin fees; the margin fees are subject to escalation (Note 12).*

The Corporation has fixed interest rates, either directly or through interest rate swap agreements, on 98% (2006 — 96%) of total long term debt and non-recourse long term debt.

21. Risk management and financial instruments (continued)

Foreign exchange rate risk

The Corporation has exposure to changes in the carrying values of its foreign operations, including assets and liabilities, as a result of changes in exchange rates. Gains or losses on translation of self-sustaining foreign operations are included in the foreign currency translation adjustment account in accumulated other comprehensive income. Gains or losses on translation of integrated foreign operations are recognized in earnings.

The Corporation has entered into foreign currency forward contracts in order to fix the exchange rate on certain service contracts, planned equipment expenditures and operational cash flows denominated in U.K. pounds sterling ("£"), U.S. dollars and Euros. At December 31, 2007, the contracts consist of purchases of £0.7 million, $3.1 million U.S. and 7.0 million Euros, and sales of 33.0 million Euros (2006 – purchases of $0.2 million U.S. and sales of 3.0 million Euros).

Natural gas purchase contracts and associated power generation revenue contract liability

The Corporation has long term contracts for the supply of natural gas for certain of its power generation projects. Under the terms of certain of these contracts, the volume of natural gas that the Corporation is entitled to take is in excess of the natural gas required to generate power. As the excess volume of natural gas can be sold, the Corporation is required to designate these entire contracts as derivative instruments. The Corporation recognized a non-current derivative asset of $59.0 million on January 1, 2007; thereafter, the Corporation will record mark-to-market adjustments through earnings as the fair values of these contracts change with changes in future natural gas prices. These natural gas purchase contracts mature in November 2014.

As all but the excess volume of natural gas is committed to the Corporation's power generation obligations, the Corporation could not recognize the entire fair values of these natural gas purchase contracts in its revenues. Consequently, on January 1, 2007, the Corporation recognized a provision for a power generation revenue contract in the amount of $44.8 million; thereafter, the Corporation will record adjustments to the power generation revenue contract liability concurrently with the mark-to-market adjustments for the natural gas purchase contracts derivative asset. This power generation revenue contract liability is included in deferred credits in the consolidated balance sheet.

The mark-to-market adjustment increased the derivative asset by $14.1 million and $13.5 million, respectively, for the unaudited_three months and year ended December 31, 2007; the associated power generation revenue contract liability increased by $10.2 million and $9.4 million, respectively, for the unaudited_three months and year ended December 31, 2007. At December 31, 2007, the natural gas purchase contracts derivative asset is $72.5 million and the power generation revenue contract liability is $54.2 million. The mark-to-market adjustment for the derivative asset and the corresponding adjustment for the associated power generation revenue contract liability increased earnings by $2.8 million, net of income taxes, for the unaudited three months ended December 31, 2007 and increased earnings by $2.9 million, net of income taxes, for the year ended December 31, 2007.

Credit risk

For cash and short term investments and accounts receivable, credit risk represents the carrying amount on the consolidated balance sheet. Accounts receivable credit risk is reduced by a large and diversified customer base, requirement of letters of credit, and, for regulated operations other than Alberta Power (2000), the ability to recover an estimate for doubtful accounts through approved customer rates.

Derivative credit risk arises from the possibility that a counterparty to a contract fails to perform according to the terms and conditions of that contract. Derivative credit risk is minimized by dealing with large, credit-worthy counterparties in accordance with established credit approval policies.

21. Risk management and financial instruments (continued)

Fair value of non-derivative financial instruments

The carrying values and fair values of the Corporation's non-derivative financial instruments are as follows:

	2007		2006	
	Carrying Value	**Fair Value**	Carrying Value	Fair Value
Assets				
Cash and short term investments [1]	**$ 747.2**	**$ 747.2**	$ 798.8	$ 798.8
Accounts receivable [1]	**373.9**	**373.9**	362.3	362.3
Liabilities				
Accounts payable and accrued liabilities [2]	**375.0**	**375.0**	338.8	338.8
Liability to customers for refund of future income taxes (Note 13) [3]	**25.8**	**25.8**	-	-
Long term debt [3]	**2,603.2**	**2,907.5**	2,411.5	2,788.4
Non-recourse long term debt [3]	**543.5**	**578.0**	686.0	718.1

(1) *Recorded at cost. Fair value approximates the carrying amounts due to the short term nature of the financial instruments and negligible credit losses.*

(2) *Recorded at cost. Fair value approximates the carrying amounts due to the short term nature of the financial instruments.*

(3) *Recorded at amortized cost. Fair values are determined using quoted market prices for the same or similar issues. Where the market prices are not available, fair values are estimated using discounted cash flow analysis based on the Corporation's current borrowing rate for similar borrowing arrangements.*

Fair value of derivative financial instruments

The fair values of the Corporation's derivative financial instruments are as follows:

	2007			2006		
	Notional Principal [1]	**Fair Value Receivable (Payable) [3]**	**Maturity**	Notional Principal [1]	Fair Value Receivable (Payable) [3]	Maturity
Interest rate swaps	**$259.9**	**$(3.8)**	**2008-2019**	$288.5	$(7.3)	2007-2019
Foreign currency Forward contracts	**$ 62.6**	**$(0.5)**	**2008**	$ 4.6	$ 0.3	2007
Natural gas purchase contracts	**N/A [2]**	**$72.5**	**2014**	N/A [4]	N/A [4]	N/A [4]

(1) *The notional principal is not recorded in the consolidated financial statements as it does not represent amounts that are exchanged by the counterparties.*

(2) *The notional amount for the natural gas purchase contracts is the maximum volumes that can be purchased over the terms of the contracts.*

(3) *Fair values for the interest rate swaps and the foreign currency forward contracts have been estimated using period-end market rates, and fair values for the natural gas purchase contracts have been estimated using period-end forward market prices for natural gas. These fair values approximate the amount that the Corporation would either pay or receive to settle the contract at December 31.*

(4) *In accordance with the CICA recommendations for financial instruments, disclosures not required in financial statements for periods prior to January 1, 2007 need not be provided on a comparative basis.*

22. Other comprehensive income

Other comprehensive income ("OCI") of the Corporation is comprised of three components: the unrealized gains and losses on effective cash flow hedging instruments, the unrealized gains and losses on financial assets that are available for sale, and the foreign currency translation adjustment relating to self-sustaining foreign operations.

Changes in the components of accumulated OCI are summarized below:

	Three Months Ended December 31		Year Ended December 31	
	2007	2006	**2007**	2006
Accumulated OCI at beginning of period:				
Cash flow hedge losses [(1)]	**$ (5.1)**	$ -	**$ -**	$ -
Financial assets available for sale [(2)]	**0.1**	-	**-**	-
Foreign currency translation adjustment	**(21.3)**	(15.0)	**3.1**	(18.2)
	(26.3)	(15.0)	**3.1**	(18.2)
Adjustment to accumulated OCI at beginning of period due to change in method of accounting for:				
Cash flow hedge losses [(3)]	**-**	-	**(7.4)**	-
Financial assets available for sale [(2)]	**-**	-	**0.1**	-
	-	-	**(7.3)**	-
OCI for the period:				
Changes in fair values of cash flow hedges [(4)]	**0.5**	-	**2.7**	-
Transfers of cash flow hedge losses to earnings [(2)]	**-**	-	**0.1**	-
Transfer of gain on financial assets available for sale to earnings [(2)]	**(0.1)**	-	**(0.1)**	-
	0.4	-	**2.7**	-
Foreign currency translation adjustment	**(7.2)**	18.1	**(31.6)**	21.3
	(6.8)	18.1	**(28.9)**	21.3
Accumulated OCI at end of period:				
Cash flow hedge losses [(5)]	**(4.6)**	-	**(4.6)**	-
Financial assets available for sale	**-**	-	**-**	-
Foreign currency translation adjustment	**(28.5)**	3.1	**(28.5)**	3.1
	$(33.1)	$ 3.1	**$(33.1)**	$ 3.1

(1) *Net of income taxes of $2.2 million.*
(2) *Net of income taxes of nil.*
(3) *Net of income taxes of $3.2 million.*
(4) *Net of income taxes of $(0.3) million and $(1.3) million, respectively.*
(5) *Net of income taxes of $1.9 million and $1.9 million, respectively.*

23. Commitments and contingencies

Commitments

The Corporation has contractual obligations in the normal course of business; future minimum payments are as follows:

	2008	2009	2010	2011	2012	Total of All Subsequent Years
Operating leases [1]	$ 16.3	$ 10.4	$ 9.7	$ 7.2	$ 4.5	$ 13.6
Purchase obligations:						
Coal purchase contracts [2]	49.3	50.4	51.3	52.9	54.4	296.3
Natural gas purchase contracts [3]	50.3	50.4	48.8	20.1	11.1	6.3
Operating and maintenance agreements [4]	19.4	16.6	17.8	17.9	13.9	68.9
Other	3.9	2.0	0.3	0.3	0.3	0.2
	$139.2	$129.8	$127.9	$98.4	$84.2	$385.3

(1) Operating leases are comprised primarily of long term leases for office premises and equipment.

(2) Alberta Power (2000) has fixed price long term contracts to purchase coal for its coal-fired generating plants.

(3) Natural gas purchase contracts consist primarily of ATCO Power contracts to purchase natural gas for certain of its natural gas-fired generating plants.

(4) ATCO Power and Alberta Power (2000) have long term service agreements with suppliers to provide operating and maintenance services at certain of their generating plants.

Contingencies

Measurement inaccuracies occur from time to time with respect to ATCO Electric's, ATCO Gas' and ATCO Pipelines' metering facilities. Measurement adjustments are settled between the parties based on the requirements of the Electricity and Gas Inspections Act (Canada) and applicable regulations issued pursuant thereto. There is a risk of disallowance of the recovery of a measurement adjustment if controls and timely follow-up are found to be inadequate by the AUC.

The Corporation is party to a number of other disputes and lawsuits in the normal course of business. The Corporation believes that the ultimate liability arising from these matters will have no material impact on the consolidated financial statements.

As a result of decisions of the Supreme Court of Canada in Garland vs. Consumers' Gas Co., the imposition of late payment penalties on utility bills has been called into question. The Corporation is unable to determine at this time the impact, if any, that these decisions will have on the Corporation.

In 2004, ATCO Gas and ATCO Electric transferred their retail energy supply businesses to Direct Energy Marketing Limited and one of its affiliates (collectively "DEML"), a subsidiary of Centrica plc. ATCO Gas and ATCO Electric continue to own and operate the natural gas and electricity distribution systems used to deliver energy.

Although ATCO Gas and ATCO Electric transferred to DEML certain retail functions, including the supply of natural gas and electricity to customers and billing and customer care functions, the legal obligations of ATCO Gas and ATCO Electric remain if DEML fails to perform. In certain events (including where DEML fails to supply natural gas and/or electricity and ATCO Gas and/or ATCO Electric are ordered by the AUC to do so), the functions will revert to ATCO Gas and/or ATCO Electric with no refund of the transfer proceeds to DEML by ATCO Gas and/or ATCO Electric.

23. Commitments and contingencies (continued)

Centrica plc, DEML's parent, has provided a $300 million guarantee, supported by a $235 million letter of credit in respect of DEML's obligations to ATCO Gas, ATCO Electric and ATCO I-Tek in respect of the ongoing relationships contemplated under the transaction agreements. However, there can be no assurance that the coverage under these agreements will be adequate to cover all of the costs that could arise in the event of a reversion of such functions.

Canadian Utilities Limited has provided a guarantee of ATCO Gas', ATCO Electric's and ATCO I-Tek's payment and indemnity obligations to DEML contemplated under the transaction agreements.

24. Segmented information

Description of segments

The Corporation operates in the following business segments:

The **Utilities** Business Group includes the regulated distribution of natural gas by ATCO Gas, the regulated transmission and distribution of water by CU Water, the regulated transmission of natural gas by ATCO Pipelines, the regulated distribution and transmission of electric energy by ATCO Electric and its subsidiaries, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical, and the provision of non-regulated complementary projects by ATCO Energy Solutions (formerly ATCO Utility Services).

The **Power Generation** Business Group includes the non-regulated supply of electricity and cogeneration steam by ATCO Power, the regulated supply of electricity by Alberta Power (2000), and the sale of fly ash and other combustion byproducts produced in coal fired electrical generating plants by ASHCOR Technologies.

The **Global Enterprises** Business Group includes the non-regulated gathering, processing, storage, purchase and sale of natural gas by ATCO Midstream, the provision of project management and technical services for customers in the industrial, defence and transportation sectors by ATCO Frontec, the development, operation and support of information systems and technologies and the provision of billing services, payment processing, credit, collection and call centre services by ATCO I-Tek and the sale of travel services to both business and consumer sectors by ATCO Travel. The Corporation sold its 50% interest in Genics, a manufacturer of wood preservation products, effective August 1, 2006.

The Corporate and Other segment includes commercial real estate owned by the Corporation in Alberta.

Segmented results – Three months ended December 31

2007 2006	Utilities	Power Generation	Global Enterprises	Corporate and Other	Intersegment Eliminations	Consolidated
(Unaudited)						
Revenues – external	**$306.8** $308.4	**$193.9** $226.7	**$155.8** $135.6	**$ 0.6** $ 0.4	**$ -** $ -	**$657.1** $671.1
Revenues – intersegment [(1)]	**6.5** 6.3	**-** -	**42.4** 38.3	**2.9** 2.9	**(51.8)** (47.5)	**-** -
Revenues	**$313.3** $314.7	**$193.9** $226.7	**$198.2** $173.9	**$ 3.5** $ 3.3	**$(51.8)** $(47.5)	**$657.1** $671.1
Earnings attributable to Class A and Class B shares	**$ 48.0** $ 43.7	**$ 25.5** $ 36.9	**$ 27.7** $ 27.3	**$(4.1)** $(6.5)	**$ 1.6** $ (1.4)	**$ 98.7** $100.0

(1) *Intersegment revenues are recognized on the basis of prevailing market or regulated prices.*

24. **Segmented information** (continued)

Segmented results – Year ended December 31

2007 2006	Utilities	Power Generation	Global Enterprises	Corporate and Other	Intersegment Eliminations	Consolidated
Revenues – external	**$1,091.4**	**$ 773.0**	**$538.6**	**$ 1.9**	**$ -**	**$2,404.9**
	$1,086.2	$ 799.5	$543.3	$ 1.4	$ -	$2,430.4
Revenues – intersegment [1]	**25.1**	**-**	**134.0**	**11.7**	**(170.8)**	**-**
	24.6	-	123.9	11.3	(159.8)	-
Revenues	**1,116.5**	**773.0**	**672.6**	**13.6**	**(170.8)**	**2,404.9**
	1,110.8	799.5	667.2	12.7	(159.8)	2,430.4
Operating expenses	**640.6**	**422.6**	**486.1**	**18.6**	**(166.3)**	**1,401.6**
	601.4	431.3	490.5	18.7	(151.2)	1,390.7
Depreciation and amortization	**223.7**	**97.2**	**29.1**	**1.5**	**-**	**351.5**
	220.2	95.4	31.5	1.4	-	348.5
Interest expense	**140.6**	**79.0**	**2.9**	**171.9**	**(177.0)**	**217.4**
	132.5	92.2	2.2	162.4	(166.4)	222.9
Interest and other income	**(16.6)**	**(20.6)**	**(2.7)**	**(201.4)**	**177.0**	**(64.3)**
	(20.3)	(11.9)	(4.1)	(188.6)	166.4	(58.5)
Earnings before income taxes	**128.2**	**194.8**	**157.2**	**23.0**	**(4.5)**	**498.7**
	177.0	192.5	147.1	18.8	(8.6)	526.8
Income taxes	**(22.2)**	**57.6**	**47.2**	**(1.2)**	**(3.7)**	**77.7**
	45.4	69.7	46.1	8.7	(2.8)	167.1
	150.4	**137.2**	**110.0**	**24.2**	**(0.8)**	**421.0**
	131.6	122.8	101.0	10.1	(5.8)	359.7
Dividends on equity preferred shares	**10.7**	**2.5**	**-**	**21.1**	**-**	**34.3**
	10.4	3.6	-	21.8	-	35.8
Earnings attributable to Class A and Class B shares	**$ 139.7**	**$ 134.7**	**$110.0**	**$ 3.1**	**$ (0.8)**	**$ 386.7**
	$ 121.2	$ 119.2	$101.0	$ (11.7)	$ (5.8)	$ 323.9
Total assets	**$4,103.0**	**$2,187.4**	**$345.2**	**$562.5**	**$ 87.3**	**$7,285.4**
	$3,799.0	$2,240.0	$278.1	$576.2	$100.2	$6,993.5
Purchase of property, plant and equipment	**$ 588.9**	**$ 49.2**	**$ 62.7**	**$ -**	**$ -**	**$ 700.8**
	$ 505.0	$ 48.1	$ 14.2	$ 0.4	$ -	$ 567.7

[1] *Intersegment revenues are recognized on the basis of prevailing market or regulated prices.*

Geographic segments

	Domestic		Foreign		Consolidated	
	2007	2006	**2007**	2006	**2007**	2006
Revenues	**$2,143.8**	$2,130.6	**$261.1**	$299.8	**$2,404.9**	$2,430.4
Property, plant and equipment	**$5,369.5**	$5,099.5	**$309.0**	$326.6	**$5,678.5**	$5,426.1