



CANADIAN UTILITIES LIMITED
An **ATCO** Company

CONSOLIDATED FINANCIAL STATEMENTS

**FOR THE YEAR ENDED
DECEMBER 31, 2005**

February 10, 2006

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, 2005 and 2004 and the consolidated statements of earnings and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Corporation'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 Corporation as at December 31, 2005 and 2004 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants

Calgary, Alberta

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

	Note	Three Months Ended December 31		Year Ended December 31	
		2005	2004	2005	2004
<i>(Unaudited)</i>					
Revenues	3	\$ 680.3	\$ 637.0	\$2,515.8	\$3,011.4
Costs and expenses					
Natural gas supply	3	18.3	39.7	162.2	847.8
Purchased power	3	12.2	15.4	45.4	95.8
Operation and maintenance		261.7	235.2	1,003.6	872.3
Selling and administrative		57.3	43.5	190.4	158.2
Depreciation and amortization		84.5	81.2	311.5	291.5
Interest	11	51.4	52.9	210.0	203.7
Franchise fees		49.5	37.5	152.3	133.4
		534.9	505.4	2,075.4	2,602.7
		145.4	131.6	440.4	408.7
Gain on transfer of retail energy supply businesses	3	-	-	-	63.3
Interest and other income	6	10.6	10.4	36.6	30.8
Earnings before income taxes		156.0	142.0	477.0	502.8
Income taxes	7	58.0	42.8	175.6	158.0
		98.0	99.2	301.4	344.8
Dividends on equity preferred shares		8.9	8.9	35.8	35.8
Earnings attributable to Class A and Class B shares	3	89.1	90.3	265.6	309.0
Retained earnings at beginning of period		1,670.4	1,548.3	1,603.4	1,435.4
		1,759.5	1,638.6	1,869.0	1,744.4
Dividends on Class A and Class B shares		34.9	33.6	139.6	134.4
Purchase of Class A shares		2.7	1.6	7.5	6.6
Retained earnings at end of period		\$1,721.9	\$1,603.4	\$1,721.9	\$1,603.4
Earnings per Class A and Class B share	14	\$ 0.70	\$ 0.71	\$ 2.09	\$ 2.44
Diluted earnings per Class A and Class B share	14	\$ 0.69	\$ 0.71	\$ 2.08	\$ 2.43
Dividends paid per Class A and Class B share	14	\$ 0.275	\$ 0.265	\$ 1.10	\$ 1.06

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

		December 31	
	Note	2005	2004
ASSETS			
Current assets			
Cash and short term investments	17	\$ 824.6	\$ 699.5
Accounts receivable		351.3	372.8
Inventories		88.0	172.9
Future income taxes	7	-	0.3
Regulatory assets	2	19.1	5.4
Prepaid expenses		19.9	19.1
		1,302.9	1,270.0
Property, plant and equipment	8	5,208.7	5,042.5
Regulatory assets	2	35.0	30.4
Other assets	9	269.1	274.6
		\$6,815.7	\$6,617.5
LIABILITIES AND SHARE OWNERS' EQUITY			
Current liabilities			
Bank indebtedness	10	\$ 0.2	\$ 1.2
Accounts payable and accrued liabilities		340.5	283.3
Income taxes payable		26.7	42.6
Future income taxes	7	4.1	-
Regulatory liabilities	2	6.4	13.6
Long term debt due within one year	11	-	5.3
Non-recourse long term debt due within one year	11	57.0	50.6
		434.9	396.6
Future income taxes	7	200.3	222.4
Regulatory liabilities	2	161.9	165.6
Deferred credits	12	253.8	146.8
Long term debt	11	2,231.0	2,171.0
Non-recourse long term debt	11	673.8	760.9
Equity preferred shares	13	636.5	636.5
Class A and Class B share owners' equity			
Class A and Class B shares	14	519.1	514.3
Contributed surplus	15	0.7	0.4
Retained earnings		1,721.9	1,603.4
Foreign currency translation adjustment		(18.2)	(0.4)
		2,223.5	2,117.7
		\$6,815.7	\$6,617.5



N.C. SOUTHERN
DIRECTOR



B.K. FRENCH
DIRECTOR

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

	Note	Three Months Ended		Year Ended	
		December 31		December 31	
		2005	2004	2005	2004
<i>(Unaudited)</i>					
Operating activities					
Earnings attributable to Class A and Class B shares		\$ 89.1	\$ 90.3	\$ 265.6	\$ 309.0
Adjustments for:					
Depreciation and amortization		84.5	81.2	311.5	291.5
Future income taxes		0.6	(16.0)	7.7	(18.5)
Gain on transfer of retail energy supply businesses					
- net of income taxes	3	-	-	-	(55.1)
Deferred availability incentives		14.5	8.1	13.7	2.8
TXU Europe settlement - net of income taxes	5	(3.7)	-	45.8	-
Other		2.8	0.8	15.0	8.6
Cash flow from operations		187.8	164.4	659.3	538.3
Changes in non-cash working capital	16	(1.2)	(31.0)	90.2	102.3
		186.6	133.4	749.5	640.6
Investing activities					
Purchase of property, plant and equipment		(181.2)	(149.1)	(526.7)	(535.5)
Proceeds on transfer of retail energy supply businesses					
- net of income taxes	3	-	-	43.4	22.5
Costs on disposal of property, plant and equipment		(4.4)	(0.7)	(5.9)	(2.6)
Contributions by utility customers for extensions to plant		6.7	10.3	44.1	50.9
Non-current deferred electricity costs		(5.7)	4.0	(15.7)	(5.9)
Changes in non-cash working capital	16	24.4	8.3	(3.4)	3.4
Other		(0.1)	2.0	(6.2)	(2.1)
		(160.3)	(125.2)	(470.4)	(469.3)
Financing activities					
Change in notes payable		-	(96.0)	-	-
Issue of long term debt		185.0	300.0	222.0	539.8
Issue of non-recourse long term debt		-	-	-	10.0
Repayment of long term debt		(35.4)	(36.8)	(167.1)	(168.6)
Repayment of non-recourse long term debt		(9.1)	(8.8)	(54.3)	(49.2)
Issue (purchase) of Class A shares		(2.7)	0.2	(2.7)	(3.0)
Dividends paid to Class A and Class B share owners		(34.9)	(33.6)	(139.6)	(134.4)
Income tax reassessment		-	12.9	-	12.9
Changes in non-cash working capital	16	0.3	(1.9)	3.1	(1.8)
Other		(2.1)	(5.3)	(3.2)	(6.3)
		101.1	130.7	(141.8)	199.4
Foreign currency translation					
		0.2	(0.1)	(11.2)	(0.5)
Cash position ⁽¹⁾					
Increase		127.6	138.8	126.1	370.2
Beginning of period		696.8	559.5	698.3	328.1
End of period		\$ 824.4	\$ 698.3	\$ 824.4	\$ 698.3

⁽¹⁾ Cash position includes cash and short term investments less current bank indebtedness.

CANADIAN UTILITIES LIMITED
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2005

(tabular amounts in millions of Canadian dollars)

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, 2005, the Corporation prospectively adopted the Canadian Institute of Chartered Accountants (“CICA”) guideline pertaining to the consolidation of variable interest entities. The guideline requires the Corporation to identify variable interest entities in which it has an interest, determine whether it is the primary beneficiary of such entities, and, if so, to consolidate them. This change in accounting had no effect on the consolidated financial statements for the three months and year ended December 31, 2005.

Effective January 1, 2005, the Corporation prospectively adopted the CICA guideline pertaining to lease arrangements. The guideline requires the Corporation to identify arrangements that do not take the legal form of a lease but convey a right to use a tangible asset in return for a payment or series of payments, and, if so, to account for them as leases. This change in accounting had no effect on the consolidated financial statements for the year ended December 31, 2005.

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 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”.

Effective December 31, 2005, the Corporation retroactively adopted the CICA guideline pertaining to the disclosure and presentation of information by entities subject to rate regulation. This guideline no longer permitted the netting of accrued and regulatory pension and other post employment benefits assets and liabilities, with the result that the Corporation’s total assets and liabilities reported in 2004 increased by \$154.4 million. This change in presentation had no effect on the Corporation’s earnings and earnings per share or cash flows. 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 and employee future benefits, using currently available information. Changes in facts and circumstances may result in revised estimates, and actual results could differ from those estimates.

1. Summary of significant accounting policies (continued)

Revenue Recognition

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

Prior to the transfer of retail energy supply businesses (see Note 3), revenues from regulated sales of natural gas and electricity by ATCO Gas and ATCO Electric were recognized upon delivery, primarily on the basis of meter readings, and included an estimate of usage not yet billed.

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 the sale of natural gas by ATCO Gas from storage, which ended on March 31, 2005, were recognized upon delivery.

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 transportation 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.

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 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 includes purchases of natural gas for regulated operations (see Note 3 regarding the transfer of retail energy supply businesses) and other subsidiaries. Natural gas supply expense for other subsidiaries consists of natural gas volumes purchased for natural gas liquids extraction and sales to third parties.

Prior to the transfer of retail energy supply businesses (see Note 3), natural gas supply expense for the regulated operations was based on the forecast cost of natural gas included in customer rates. Variances from forecast costs were deferred until such time as approval from the Alberta Energy and Utilities Board ("AEUB") was obtained for refund to or collection from customers and revenues and natural gas supply expense were adjusted accordingly.

Subsequent to the transfer of retail energy supply businesses, natural gas supply expense for the regulated operations is based on actual costs incurred.

1. Summary of significant accounting policies (continued)

Purchased Power

Prior to the transfer of retail energy supply businesses (see Note 3), purchased power expense in ATCO Electric was based on the actual cost of electricity purchased, whereas the amount included in customer rates was based on forecast cost. Revenues were adjusted for variances from forecast cost, and the variances were deferred until such time as approval from the AEUB was obtained for refund to or collection from customers.

Purchased power expense 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.

Inventories

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

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 AEUB 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 AEUB 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.

An impairment of property, plant and equipment, intangible assets with finite lives, deferred operating costs and long term prepaid expenses 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.

1. Summary of significant accounting policies (continued)

Deferred Financing Charges

Issue costs of long term debt are amortized over the life of the debt, 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.

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.

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 generating plants of Alberta Power (2000) and other generating plants and 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.

Hedging

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.

The Corporation designates each derivative instrument as a hedge of specific assets or liabilities on the balance sheet or specific firm commitments or anticipated transactions. The Corporation also assesses, both at the hedge's inception and on an ongoing basis, whether the derivative instruments that are used in hedging transactions are effective in offsetting changes in fair values or cash flows of the hedged items.

1. Summary of significant accounting policies (continued)

Payments or receipts on derivative instruments that are designated and effective as hedges are recognized concurrently with, and in the same financial category as, the hedged item.

If a derivative instrument is terminated or ceases to be effective as a hedge prior to maturity, the gain or loss at that date is deferred and recognized in income concurrently with the hedged item. Subsequent changes in the value of the derivative instrument are reflected in income. If the designated hedged item is sold, extinguished or matures prior to the termination of the related derivative instrument, the gain or loss at that date on such derivative instrument is recognized in income.

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 AEUB 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 other assets.

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

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.

1. Summary of significant accounting policies (continued)

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 the foreign currency translation adjustment in share owners' equity.

Monetary assets and liabilities of integrated foreign operations are translated into Canadian dollars at the rate of exchange in effect at the balance sheet date, non-monetary assets and liabilities are translated at rates of exchange in effect when the assets were acquired or liabilities incurred, and revenues and expenses are translated at the average monthly rates of exchange during the year. 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.

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 AEUB, which administers acts and regulations covering such matters as rates, financing, accounting, construction, operation and service area.

The generating plants of Alberta Power (2000) were regulated by the AEUB until December 31, 2000 but are now governed by legislatively mandated PPA's that were approved by the AEUB. 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. The plants will become deregulated upon the expiry of the PPA's. Each PPA is to remain in effect until the earlier of the last day of the estimated life of the related generating plant and December 31, 2020.

The utilities are subject to a cost of service regulatory mechanism under which the AEUB 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 AEUB approved investment in property, plant and equipment, less accumulated depreciation, plus an allowance for working capital. Rate base also excludes no-cost capital, which consists of unamortized contributions by utility customers for extensions to plant. 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.

The AEUB 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. On July 2, 2004, the AEUB established a standardized approach for determining the rate of return on common equity for each utility regulated by the AEUB. 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. In January 2006, the AEUB clarified that the generic return on equity determined on an annual basis in accordance with the generic cost of capital decision should apply 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 AEUB also established the appropriate capital structure for each utility and determined that any proposed changes to the approved capital structure which result from a material change in the investment risk of a utility will be addressed at utility specific rate applications.

2. Accounting for rate regulated operations (continued)

Under the cost of service methodology, the utilities seek approval for their revenue requirement either through submission of general rate applications to the AEUB or a negotiated settlement process with interested parties. In the latter case, the AEUB monitors the negotiated settlement process and approves any agreement that is reached. The AEUB may approve interim rates, 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 AEUB renders a subsequent decision.

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.

The regulatory assets and liabilities comprise the following:

	2005	2004
<i>Regulatory assets – current:</i>		
Deferred hearing costs	\$ 8.8	\$ -
Other regulatory assets	10.3	5.4
	19.1	5.4
<i>Regulatory assets – non-current:</i>		
Regulatory other post employment benefits asset (Note 19)	22.0	16.8
Deferred electricity costs	5.4	-
Deferred hearing costs	1.6	4.9
Reserves for injuries and damages	5.4	7.6
Other regulatory assets	0.6	1.1
	35.0	30.4
	\$ 54.1	\$ 35.8
<i>Regulatory liabilities – current:</i>		
Deferred electricity cost recoveries	\$ 4.0	\$ 11.7
Deferred natural gas cost recoveries	-	0.9
Reserves for injuries and damages	0.8	-
Other regulatory liabilities	1.6	1.0
	6.4	13.6
<i>Regulatory liabilities – non-current:</i>		
Regulatory pension liability (Note 19)	139.4	137.6
Deferred royalty credits	18.1	14.1
Deferred electricity cost recoveries	-	10.3
Deferred hearing costs	2.6	1.9
Reserves for injuries and damages	0.8	1.7
Other regulatory liabilities	1.0	-
	161.9	165.6
	\$168.3	\$179.2

2. Accounting for rate regulated operations (continued)

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 AEUB 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 2005 would have been \$1.6 million lower (2004 – \$10.2 million lower), and other post employment benefit plan cost in 2005 would have been \$3.3 million higher (2004 – \$2.5 million higher), in the absence of rate regulation.

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 AEUB 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 AEUB 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 AEUB 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 AEUB and not adjusted for variances between the returns on forecast and actual rate base.

Consequently, revenues in 2005 would have been \$23.4 million lower (2004 – \$4.8 million higher) in the absence of rate regulation.

Deferred hearing costs

The utilities incur hearing costs on an ongoing basis associated with various AEUB 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 AEUB. Hearing costs are deferred to the balance sheet and are expensed using AEUB 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 AEUB 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 2005 would have been \$4.0 million higher (2004 – \$5.8 million lower) in the absence of rate regulation.

Reserves for injuries and damages

The AEUB 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 AEUB 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 AEUB requesting recovery from or refund to customers. GAAP requires that claims be expensed in the period in which they are incurred. Consequently, expenses in 2005 would have been \$1.1 million lower (2004 – \$2.5 million higher) in the absence of rate regulation.

2. Accounting for rate regulated operations (continued)

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 2005 would have been \$1.0 million lower (2004 – \$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 2005 would have been \$4.0 million lower (2004 – \$3.8 million lower) in the absence of rate regulation.

Other regulatory assets and liabilities

Other regulatory assets and liabilities include the following:

- a) ATCO Gas has received AEUB approval to defer:
 - i) Bad debt and collection agency fees incurred after June 1, 2004 related to billings prior to that date (see transfer of retail energy supply businesses in Note 3) and associated late payment charges net of bad debt recoveries of \$1.4 million (2004 – \$2.6 million);
 - ii) Charges from the Government of Alberta for funding of the office of the Utilities Consumer Advocate and the Consumer Protection and Consumer Choice Campaign of \$1.0 million (2004 – \$1.1 million); and,
 - iii) Removal and abandonment costs related to previously disposed of production properties of \$5.0 million (2004 – \$1.6 million).

GAAP requires that these costs be expensed in the period in which they are incurred. Consequently, expenses in 2005 would have been \$2.1 million higher (2004 – \$4.5 million higher) in the absence of rate regulation. With the exception of \$0.5 million of deferred Utilities Consumer Advocate costs which are deferred in non-current regulatory assets in the balance sheet, these assets are included in current regulatory assets and are recoverable from customers in 2006.

- b) In October 2005, ATCO Gas filed an application with the AEUB to approve the sale of its Red Deer Operating Centre. In December 2005, the AEUB approved the sale and deferred its decision on the distribution of net proceeds of \$1.0 million until the Supreme Court of Canada renders a judgment in the appeal regarding the Calgary Stores Block disposition and allocation of proceeds thereon. The Supreme Court of Canada rendered its decision on the Calgary Stores Block matter on February 9, 2006. ATCO Gas is now required to submit a filing to the AEUB to approve the allocation of the net proceeds. The net proceeds of the sale remain in trust pending AEUB approval. GAAP requires that gains and losses related to asset dispositions be recognized in the period the disposition was made. Consequently, revenues in 2005 would have been \$1.0 million higher in the absence of rate regulation. This liability is included in non-current regulatory liabilities in the balance sheet.
- c) ATCO Pipelines has received AEUB approval to defer the variances between actual and AEUB 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 expects that the recovery of these deferral accounts will occur in the next general rate application. GAAP requires that actual revenues and costs be recognized in the period in which they are earned or incurred. Consequently, revenues in 2005 would have been \$0.1 million lower (2004 – \$12.6 million lower) and expenses would have been \$1.6 million lower (2004 – \$6.8 million lower) in the absence of rate regulation. On the balance sheet, assets of \$2.2 million (2004 – \$0.1 million) are included in current regulatory assets, and liabilities of \$1.6 million (2004 – \$1.0 million) are included in current regulatory liabilities.

2. Accounting for rate regulated operations (continued)

- d) ATCO Pipelines has received AEUB 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 AEUB, 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. GAAP requires that actual revenues and costs be recognized in the period in which they are earned or incurred. Consequently, revenues in 2005 would have been \$1.2 million lower (2004 – nil) in the absence of rate regulation. Assets of \$1.2 million (2004 – nil) are included in current regulatory assets in the balance sheet.

Other items affected by rate regulation

The AEUB 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 7).

3. Transfer of retail energy supply businesses

On May 4, 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. Proceeds of the transfer were \$90 million, of which \$45 million was paid at closing, and the remainder was paid on May 4, 2005. Net proceeds, after adjustments related to legal, transition and other deferred costs pertaining to the transfer of the retail energy supply businesses, resulted in a gain of \$63.3 million before income taxes of \$8.2 million and increased 2004 earnings by \$55.1 million.

The Corporation’s revenues and natural gas supply and purchased power costs after May 4, 2004 were reduced accordingly for 2004 and thereafter. Subsequent to May 4, 2004, ATCO Gas continued to purchase natural gas on behalf of DEML until the transfer of the relevant ATCO Gas natural gas purchase contracts to DEML was completed in September 2004. There will be no ongoing impact on earnings resulting from the transfer of these businesses as natural gas and electricity have historically been sold to customers on a “no-margin” basis. ATCO Gas and ATCO Electric continue to own and operate the natural gas and electricity distribution systems used to deliver energy.

ATCO Pipelines, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical did not participate in this transfer and continue to purchase natural gas and electricity for sale to customers. In addition, the AEUB issued a decision that directed ATCO Gas to continue to reserve for the benefit of utility customers 16.7 petajoules of storage capacity at its Carbon storage facility for the 2004/2005 storage year, which ended on March 31, 2005, and issued a decision that terminates ATCO Pipelines' obligation to purchase natural gas for sale to customers effective October 31, 2005.

Under the various transaction agreements, ATCO Gas and ATCO Electric have transferred to DEML certain retail functions, including the supply of natural gas and electricity to customers and billing and customer care functions (“the transferred functions”).

3. Transfer of retail energy supply businesses (continued)

If DEML fails to perform all or part of the transferred functions, ATCO Gas and ATCO Electric will be required under existing legislation to perform such functions in the interim until DEML is able to perform such functions. 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 AEUB to do so), the agreements will terminate and 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.

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 Business Services in respect of the ongoing relationships contemplated under the transaction agreements. The Centrica guarantee and letter of credit include limits for certain categories of claims, which limits cease to apply if the agreements are terminated. If the amount available to be drawn under the letter of credit at any time falls below \$200 million, the agreements with DEML will terminate and the functions will revert to ATCO Gas and ATCO Electric with no refund of the transfer proceeds to DEML by ATCO Gas and ATCO Electric.

Canadian Utilities Limited has provided a guarantee of ATCO Gas', ATCO Electric's and ATCO I-Tek Business Services' payment and indemnity obligations in respect of the ongoing relationships contemplated under the transaction agreements.

4. Regulatory matters

In May 2005, ATCO Electric filed a general tariff application with the AEUB for the 2005 and 2006 test years requesting, among other things, increased revenues to recover increased financing, depreciation and operating costs associated with increased rate base in Alberta. A decision from the AEUB on the general tariff application is not expected until March 2006. In May and June 2005, ATCO Electric filed applications requesting interim refundable rates for distribution and transmission operations, pending the AEUB's decision on the general tariff application. On July 14, 2005, ATCO Electric received a decision from the AEUB approving its requested interim refundable rates for distribution operations. On September 7, 2005, ATCO Electric received a decision from the AEUB approving an interim refundable rate increase of \$5.0 million for transmission operations. Revenues associated with these interim refundable rates were recorded 2005.

On January 27, 2006, ATCO Gas received a decision on its general rate application which was filed with the AEUB in May 2005 for the 2005, 2006 and 2007 test years. The decision establishes 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. In May 2005, ATCO Gas submitted a general rate application with the AEUB for the 2005, 2006 and 2007 test years. In August 2005, the AEUB approved interim refundable rates which recognized only 28% of the increased operating costs and rate base additions requested in the original application. On January 27, 2006, ATCO Gas received an AEUB decision which did not materially change the earnings based on the 2005 interim rates. The final impact of the decision will not be known until two subsequent regulatory processes are finalized.

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

5. 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 has now been reached with respect to Barking Power's claim.

On March 30, 2005, the Corporation announced that Barking Power will receive £179.3 million (approximately \$410 million) in settlement of its claim, of which the Corporation's share is approximately \$104 million. Barking Power received a first distribution of £112.3 million (approximately \$257 million) on March 30, 2005, of which the Corporation's share was \$65.4 million. Income taxes of approximately \$17.7 million relating to this distribution have been paid. A second distribution of £32.2 million (approximately \$69.6 million) was received on

5. TXU Europe settlement (continued)

August 2, 2005, of which the Corporation's share was \$17.7 million, and a third distribution of £31.8 million (approximately \$65.2 million) was received on January 19, 2006, of which the Corporation's share was \$16.6 million. Income taxes of approximately \$10.3 million relating to the second and third distributions will be paid as part of the Corporation's normal tax installments. A final distribution is expected in the second quarter of 2006.

Based on the foreign currency exchange rate in effect at March 30, 2005, the Corporation's share of this settlement is expected to generate earnings after income taxes of approximately \$69 million, which will be recognized over the remaining term of the TXU Europe contract to September 30, 2010, at approximately \$11 million per year. These earnings will be dependent upon foreign currency exchange rates in effect at the time that the earnings are recognized.

6. Interest and other income

	2005	2004
Interest	\$29.0	\$22.0
Allowance for funds used by regulated operations	7.0	6.2
Other	0.6	2.6
	\$36.6	\$30.8

7. Income taxes

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

	2005		2004	
Earnings before income taxes	\$477.0	%	\$502.8	%
Income taxes, at statutory rates	\$193.8	40.6	\$205.5	40.9
Federal general tax reduction ⁽¹⁾	(18.1)	(3.8)	(18.4)	(3.7)
Manufacturing and processing tax credit	(7.5)	(1.6)	(7.7)	(1.6)
Resource allowance	(2.8)	(0.6)	(3.3)	(0.7)
Crown royalties and other non-deductible Crown payments	1.1	0.2	0.7	0.1
Large Corporations Tax	7.8	1.7	7.8	1.6
Foreign tax rate variance	(6.2)	(1.3)	(4.6)	(0.9)
Non-deductible interest on foreign financing	1.4	0.3	1.8	0.4
Unrecorded future income taxes relating to regulated operations	1.0	0.2	4.4	0.9
Transfer of retail energy supply businesses	-	-	(12.1)	(2.4)
Change in future income taxes resulting from reduction in tax rates	-	-	(2.6)	(0.5)
Change in method of accounting for future income taxes in certain regulated operations	-	-	(15.8)	(3.1)
Other	5.1	1.1	2.3	0.4
	175.6	36.8	158.0	31.4
Current income taxes	185.8		187.6	
Future income taxes (recoveries)	\$ (10.2)		\$ (29.6)	

⁽¹⁾ The federal general tax reduction of 7% (2004 — 7%) is applicable to earnings that have not otherwise benefited from the manufacturing and processing tax credit and/or the resource allowance. An additional federal tax reduction of 3% (2004 — 2%) is applicable to earnings that have benefited from the resource allowance.

7. Income taxes (continued)

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

	2005	2004
Property, plant and equipment	\$222.7	\$216.7
Deferred assets and liabilities	(18.3)	5.5
Tax loss carryforwards	(0.3)	(0.9)
Other	0.3	0.8
	204.4	222.1
Less: Amounts included in current future income taxes	4.1	(0.3)
	\$200.3	\$222.4

Unrecorded future income tax liabilities of the regulated operations amounted to \$171.3 million at December 31, 2005. This balance includes \$28.2 million in respect of Alberta Power (2000)'s generating plants, which will be recovered through future payments received in respect of the PPA's.

Expected future recoveries relating to tax loss carryforwards have been recorded in the amount of \$0.3 million, of which \$0.1 million begins to expire in 2009 and \$0.2 million does not expire. In addition, there are tax loss carryforwards of \$0.7 million for which no tax benefit has been recorded. These losses begin to expire in 2010.

Income taxes paid amounted to \$178.6 million (2004 — \$134.5 million).

8. Property, plant and equipment

	2005			2004	
	Composite Depreciation Rates	Cost	Accumulated Depreciation	Cost	Accumulated Depreciation
Utilities	3.6%	\$6,022.0	\$2,240.8	\$5,593.1	\$2,082.1
Power Generation	3.3%	2,753.9	921.4	2,770.5	849.6
Global Enterprises	8.8%	270.3	127.1	253.5	119.3
Other	5.0%	27.7	6.1	27.0	4.7
		\$9,073.9	3,295.4	\$8,644.1	3,055.7
Property, plant and equipment less accumulated depreciation			5,778.5		5,588.4
Unamortized contributions by utility customers for extensions to plant			569.8		545.9
			\$5,208.7		\$5,042.5

Accumulated depreciation includes amounts provided for future removal and site restoration costs, net of salvage value, of \$323.6 million (2004 — \$297.9 million).

Composite depreciation rates reflect total depreciation in the year as a percentage of mid-year cost, excluding construction work-in-progress of \$91.1 million (2004 — \$75.7 million) and non-depreciable assets of \$41.3 million (2004 — \$40.4 million).

9. Other assets

	2005	2004
Accrued pension asset (Note 19)	\$192.2	\$193.5
Security deposits for debt	20.0	23.1
Deferred financing charges ⁽²⁾	25.4	27.6
Other ⁽¹⁾	31.5	30.4
	\$269.1	\$274.6

⁽¹⁾ Amortization of certain other assets, which was recorded in depreciation and amortization, amounted to \$5.9 million (2004 – \$12.2 million).

⁽²⁾ Amortization of deferred financing charges, which was recorded in interest expense, amounted to \$2.8 million (2004 – \$3.1 million).

10. Bank indebtedness and credit lines

At December 31, 2005, bank indebtedness consists of \$0.2 million (2004 – \$1.2 million), at an interest rate of 5.0%, repayable on demand.

At December 31, 2005, the Corporation has the following credit lines that enable it to obtain financing for general business purposes:

	2005			2004		
	Total	Used	Available	Total	Used	Available
Long term committed	\$326.0	\$11.9	\$314.1	\$ 326.0	\$12.0	\$314.0
Short term committed	600.0	-	600.0	614.1	22.3	591.8
Uncommitted	69.1	8.3	60.8	69.0	11.4	57.6
	\$995.1	\$20.2	\$974.9	\$1,009.1	\$45.7	\$963.4

Of the \$20.2 million used at December 31, 2005, \$11.5 million is included in long term debt, \$0.2 million is included in bank indebtedness and \$8.5 million represents outstanding letters of credit.

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

Long term debt

	2005	2004
CU Inc. debentures – unsecured		
1995 Series 8.43% due June 2005	\$ -	\$ 125.0
2001 4.84% due November 2006	175.0	175.0
2002 4.801% due November 2007	50.0	50.0
2000 6.97% due June 2008	100.0	100.0
1989 Series 10.20% due November 2009	125.0	125.0
1990 Series 11.40% due August 2010	125.0	125.0
2000 7.05% due June 2011	100.0	100.0
2004 5.096% due November 2014	100.0	100.0
2002 6.145% due November 2017	150.0	150.0
2004 5.432% due January 2019	180.0	180.0
1999 Series 6.8% due August 2019	300.0	300.0
1990 Second Series 11.77% due November 2020	100.0	100.0
1991 Series 9.92% due April 2022	125.0	125.0
1992 Series 9.40% due May 2023	100.0	100.0
2004 5.896% due November 2034	200.0	200.0
2005 5.183% due November 2035	185.0	-
Canadian Utilities Limited debentures – unsecured		
2002 6.14% due November 2012	100.0	100.0
	2,215.0	2,155.0
ATCO Power Australia Pty Ltd. credit facility, at Bank Bill rates, payable in Australian dollars, unsecured ⁽¹⁾	-	5.3
ATCO Power Canada Ltd. credit facility, at BA rates, due March 2007, secured by a pledge of cash ⁽¹⁾	11.5	11.5
Other long term obligation, at 5.0%, due June 2007, unsecured	4.5	4.5
	2,231.0	2,176.3
Less: Amounts due within one year	-	5.3
	\$2,231.0	\$2,171.0

Non-recourse long term debt

	2005	2004
Barking Power Limited project financing, payable in British pounds:		
At fixed rates averaging 7.95%, due to 2010	\$ 54.7	\$ 72.2
At LIBOR, due to 2010 ⁽¹⁾	89.6	118.4
Osborne Cogeneration Pty Ltd. project financing, payable in Australian dollars:		
At Bank Bill rates, due to 2013 ⁽¹⁾	1.8	2.3
At 7.3325%, due to 2013 ⁽¹⁾	34.4	42.6
ATCO Power Alberta Limited Partnership (“APALP”) project financing:		
At 7.54% to 2008, at LIBOR thereafter, due to 2016 ⁽¹⁾	3.8	5.1
At 7.317% to 2008, at LIBOR thereafter, due to 2016 ⁽¹⁾	5.4	8.1
At 7.50% to 2011, at LIBOR thereafter, due to 2016 ⁽¹⁾	87.5	89.7
Joffre project financing:		
At 7.286%, due to 2012 ⁽¹⁾	26.7	31.9
At 8.59%, due to 2020	32.0	32.0

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

Non-recourse long term debt (continued)

	2005	2004
Scotford project financing:		
At 5.202%, due to 2008, at BA rates thereafter, due to 2014 ⁽¹⁾	46.2	50.4
At 5.202%, due to 2008, at LIBOR thereafter, due to 2014 ⁽¹⁾	11.6	12.6
At 7.93%, due to 2022	26.9	27.6
Muskeg River project financing:		
At 5.247%, due 2007, at BA rates thereafter, due to 2014 ⁽¹⁾	44.4	47.8
At BA rates, due to 2014 ⁽¹⁾	0.3	0.4
At 7.56%, due to 2022	31.2	33.1
Brighton Beach project financing:		
At 5.8367%, due 2009, at BA or Canadian Eurodollar rates thereafter, due to 2019 ⁽¹⁾	9.4	9.8
At BA or Canadian Eurodollar rates, due to 2019 ⁽¹⁾	2.5	1.3
At 6.575%, due to 2019 ⁽¹⁾	37.8	39.5
At 6.924%, due to 2024	110.5	110.6
Cory project financing:		
At BA rates, due to 2011 ⁽¹⁾	0.3	0.3
At 6.336%, due to 2011 ⁽¹⁾	3.3	3.9
At 7.586%, due to 2025	37.4	38.2
At 7.601%, due to 2026	33.1	33.7
	730.8	811.5
Less: Amounts due within one year	57.0	50.6
	\$673.8	\$760.9

BA – Bankers' Acceptance

LIBOR – London Interbank Offered Rate

⁽¹⁾ The above interest rates have additional margin fees at a weighted average rate of 1.1% (2004 – 1.1%) (Note 20).

The Corporation has fixed interest rates, either directly or through interest rate swap agreements, on 96% (2004 – 95%) of total long term debt and non-recourse long term debt.

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, 2005 was \$1,342.4 million (2004 – \$1,342.5 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) **Equity contributions** – Represents equity funding requirements needed to complete construction of the project being built. At December 31, 2005, there are no further obligations under this guarantee for the Brighton Beach project financing.
- b) **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.

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

The maximum amount of the indemnity is \$20 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.

- c) **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, 2005, no amounts were outstanding under the guarantee.
- d) **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, 2005, the amount of the obligations under these guarantees is:

Project	Major Maintenance	Debt Service
APALP project financing	Nil ⁽¹⁾	\$13.6
Brighton Beach project financing	Nil ⁽²⁾	Nil
Cory project financing	Nil ⁽¹⁾	Nil
Joffre project financing	Nil ⁽³⁾	\$ 4.3
Muskeg River project financing	Nil ⁽¹⁾	\$ 5.1
Scotford project financing	Nil ⁽¹⁾	\$ 5.6

⁽¹⁾ No major maintenance reserve required for this financing.

⁽²⁾ Reserve requirements of \$3.4 million met with project cash flows.

⁽³⁾ Reserve requirements of \$0.7 million met with project cash flows.

- e) **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, 2005, the maximum value of the guarantee is \$31.2 million.
- f) **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

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

- (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, 2005, 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.

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
2006	\$175.0	\$ 57.0	\$232.0
2007	66.0	51.7	117.7
2008	100.0	76.2	176.2
2009	125.0	70.3	195.3
2010	125.0	76.9	201.9
	<u>\$591.0</u>	<u>\$332.1</u>	<u>\$923.1</u>

Of the \$232.0 million due in 2006, \$175.0 million is to be refinanced and is, therefore, excluded from long term debt due within one year in the balance sheet.

Interest expense

Interest on debt is as follows:

	2005	2004
Long term debt	\$154.5	\$148.3
Non-recourse long term debt	51.4	55.6
Notes payable	-	0.7
Bank indebtedness	1.3	1.8
Amortization of deferred financing charges	2.8	3.1
Less: Capitalized on non-regulated projects	-	(5.8)
	<u>\$210.0</u>	<u>\$203.7</u>

Interest paid amounted to \$207.2 million (2004 — \$201.2 million).

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

Fair values

Fair values for the above debt, determined using quoted market prices for the same or similar issues, are shown below. 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.

	2005	2004
<i>Long term debt</i>		
Fixed rate	\$2,656.2	\$2,536.6
Floating rate	11.5	16.8
	\$2,667.7	\$2,553.4
<i>Non-recourse long term debt</i>		
Fixed rate	\$ 683.9	\$ 735.3
Floating rate	94.5	122.8
	\$ 778.4	\$ 858.1

12. Deferred credits

	2005	2004
Accrued other post employment benefits liability (Note 19)	\$ 35.4	\$ 27.7
Deferred revenues (Note 5)	59.6	6.4
Deferred availability incentives	59.7	46.1
Asset retirement obligations	62.2	34.7
Accrued equipment repairs and maintenance	8.8	10.1
Other	28.1	21.8
	\$253.8	\$146.8

Deferred availability incentives

Amortization of deferred availability incentives, which was recorded in revenues, amounted to \$8.9 million (2004 – \$7.6 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:

	2005	2004
Obligations at beginning of year	\$34.7	\$32.3
Obligations incurred	25.4	0.5
Accretion expense	2.1	1.9
Obligations at end of year	\$62.2	\$34.7

The Corporation estimates the undiscounted amount of cash flow required to settle the asset retirement obligations is approximately \$125 million, which will be incurred between 2006 and 2052. The discount rates used to calculate the fair value of the asset retirement obligations have a weighted average rate of 5.6%.

13. Equity preferred shares

Authorized and issued

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

Issued:

	Stated Value (dollars)	Redemption Dates	2005		2004	
			Shares	Amount	Shares	Amount
Cumulative Redeemable Second Preferred Shares						
5.9% Series Q	\$25.00	Open	2,277,675	\$ 56.9	2,277,675	\$ 56.9
5.3% Series R	\$25.00	Open	2,146,730	53.7	2,146,730	53.7
6.6% Series S	\$25.00	Open	635,700	15.9	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						
5.05% Series O	\$25.00	December 2, 2006	1,600,000	40.0	1,600,000	40.0
5.05% Series T	\$25.00	December 2, 2006	1,600,000	40.0	1,600,000	40.0
5.05% Series U	\$25.00	December 2, 2006	800,000	20.0	800,000	20.0
5.25% Series V	\$25.00	October 3, 2007	4,400,000	110.0	4,400,000	110.0
			\$636.5		\$636.5	

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.

Fair values

Fair values for preferred shares determined using quoted market prices for the same or similar issues are \$669.1 million (2004 — \$669.2 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.

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.

14. Class A and Class B shares

In July 2005, the Corporation's board of directors approved a two-for-one share split of the outstanding Class A non-voting and Class B common shares. The share split took the form of a stock dividend whereby share owners received one additional Class A non-voting share for each Class A non-voting share held as of the record date and one additional Class B common share for each Class B common share held as of the record date. The stock dividend was paid on September 15, 2005 to share owners of record at the close of business on August 29, 2005. All share, stock option and per share amounts have been retroactively restated to reflect this share split.

14. Class A and Class B shares (continued)

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, 2003	82,267,418	\$369.6	44,499,852	\$140.9	126,767,270	\$510.5
Purchased	(290,800)	(1.3)	-	-	(290,800)	(1.3)
Stock options exercised	306,600	5.1	-	-	306,600	5.1
Converted: Class B to Class A	457,368	1.4	(457,368)	(1.4)	-	-
December 31, 2004	82,740,586	374.8	44,042,484	139.5	126,783,070	514.3
Purchased	(228,600)	(1.0)	-	-	(228,600)	(1.0)
Stock options exercised	338,000	5.8	-	-	338,000	5.8
Converted: Class B to Class A	26,200	0.1	(26,200)	(0.1)	-	-
December 31, 2005	82,876,186	\$379.7	44,016,284	\$139.4	126,892,470	\$519.1

From January 1, 2006 to February 10, 2006, 63,100 Class A non-voting shares were issued with respect to the exercises of stock options.

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		Year Ended	
	December 31		December 31	
	2005	2004	2005	2004
	<i>(Unaudited)</i>			
Weighted average shares outstanding	126,928,689	126,746,566	126,901,614	126,765,042
Effect of dilutive stock options	685,048	530,826	551,357	498,978
Weighted average diluted shares outstanding	127,613,737	127,277,392	127,452,971	127,264,020

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 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 20,000,000 of the issued and outstanding

14. Class A and Class B shares (continued)

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 20, 2004, Canadian Utilities Limited commenced a normal course issuer bid for the purchase of up to 3% of the outstanding Class A non-voting shares. The bid expired on May 19, 2005. Over the life of the bid, 289,800 shares were purchased, of which 256,800 were purchased in 2004 and 33,000 were purchased in 2005. On May 20, 2005, Canadian Utilities Limited commenced a normal course issuer bid for the purchase of up to 3% of the outstanding Class A non-voting shares. The bid will expire on May 19, 2006. From May 20, 2005, to February 10, 2006, 195,600 shares have been purchased, all of which were purchased in 2005.

15. Stock based compensation plans

Stock option plan

Of the 6,400,000 Class A non-voting shares reserved for issuance in respect of options under Canadian Utilities Limited's stock option plan, 2,747,200 Class A non-voting shares are available for issuance at December 31, 2005. 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:

	2005		2004	
	Class A Shares	Weighted Average Exercise Price	Class A Shares	Weighted Average Exercise Price
Options at beginning of year	1,555,600	\$19.45	1,888,900	\$18.94
Granted	204,000	30.50	6,000	26.45
Exercised	(338,000)	17.07	(306,600)	16.33
Cancelled	(6,100)	24.93	(32,700)	20.57
Options at end of year	1,415,500	\$21.59	1,555,600	\$19.45

Information about stock options outstanding at December 31, 2005 is summarized below:

Range of Exercise Prices	Options Outstanding			Options Exercisable	
	Class A Shares	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Class A Shares	Weighted Average Exercise Price
\$13.06 - \$18.87	600,900	2.7	\$16.57	600,900	\$16.57
\$20.65 - \$28.65	610,600	4.3	23.54	529,800	23.19
\$30.25 - \$43.49	204,000	9.0	30.50	-	-
\$13.06 - \$43.49	1,415,500	4.3	\$21.59	1,130,700	\$19.67

In 2005, Canadian Utilities Limited granted 204,000 options to purchase Class A non-voting shares to officers and certain key employees at a weighted average exercise price of \$30.50 per share. The options have a term of ten years and vest over the first five years.

On January 2, 2006, Canadian Utilities Limited granted 119,000 options to purchase Class A non-voting shares to officers and certain key employees at a weighted average exercise price of \$43.56 per share. The options have a term of ten years and vest over the first five years.

15. Stock based compensation plans (continued)

Changes in contributed surplus are summarized below:

	2005	2004
Contributed surplus at beginning of year	\$ 0.4	\$ 0.3
Stock option expense	0.3	0.1
Contributed surplus at end of year	\$ 0.7	\$ 0.4

The Corporation uses the Black-Scholes option pricing model, which estimated the weighted average fair value of the options granted during 2005 at \$3.21 per option (2004 — \$2.84 per option) using the following weighted average assumptions:

	2005	2004
Risk free interest rate	4.0%	4.2%
Expected holding period prior to exercise	6.3 years	6.5 years
Share price volatility	11.7%	12.7%
Estimated annual Class A share dividend	3.5%	4.0%

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 \$9.0 million (2004 — \$0.9 million).

16. Changes in non-cash working capital

	2005	2004
<i>Operating activities, changes related to:</i>		
Accounts receivable	\$ (6.7)	\$ 217.9
Inventories	85.3	(1.3)
Regulatory assets	(1.4)	23.3
Prepaid expenses	(1.7)	5.3
Accounts payable and accrued liabilities	29.3	(188.2)
Income taxes	(12.0)	41.8
Future income taxes	5.3	(9.0)
Regulatory liabilities	(7.9)	12.5
	\$ 90.2	\$ 102.3
<i>Investing activities, changes related to:</i>		
Inventories	\$ (1.5)	\$ (0.2)
Prepaid expenses	0.1	(0.1)
Accounts payable and accrued liabilities	9.0	(4.5)
Income taxes	(11.0)	11.0
Future income taxes	-	(2.8)
	\$ (3.4)	\$ 3.4
<i>Financing activities, changes related to:</i>		
Accounts receivable	\$ 3.1	\$ (1.8)

17. Joint ventures

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

	2005	2004
<i>Statement of earnings</i>		
Revenues	\$ 528.6	\$ 452.6
Operating expenses	355.1	311.5
Depreciation and amortization	43.1	39.2
Interest	41.5	39.3
	88.9	62.6
Interest and other income	7.7	6.8
Earnings from joint ventures before income taxes	\$ 96.6	\$ 69.4
<i>Balance sheet</i>		
Current assets	\$ 247.4	\$ 148.9
Current liabilities	(159.6)	(122.2)
Property, plant and equipment	922.3	990.0
Deferred items – net	(101.3)	(68.0)
Non-recourse long term debt	(504.2)	(579.6)
Investment in joint ventures	\$ 404.6	\$ 369.1
<i>Statement of cash flows</i>		
Operating activities	\$ 175.4	\$ 91.1
Investing activities	(16.0)	(46.6)
Financing activities	(79.1)	(50.1)
Foreign currency translation	(9.5)	(0.4)
Increase (decrease) in cash position	\$ 70.8	\$ (6.0)

Current assets include cash of \$118.6 million (2004 – \$48.7 million) which is only available for use within the joint ventures (see Note 5).

18. Related party transactions

In transactions with ATCO Ltd. and its wholly owned subsidiary corporations, the Corporation sold fuel in the amount of \$2.5 million (2004 – \$1.8 million), provided computer operations and systems development services totaling \$5.0 million (2004 – \$0.4 million), recovered administrative expenses totaling \$2.4 million (2004 – \$2.3 million) and incurred administrative expenses and corporate signature rights totaling \$7.1 million (2004 – \$7.1 million). The Corporation also incurred advertising and promotion expenses from an entity related through common control totaling \$1.4 million (2004 – \$1.1 million).

At December 31, 2005, accounts receivable due from related parties amounted to \$1.8 million (2004 – \$0.8 million) and accounts payable due to related parties amounted to \$0.5 million (2004 – \$0.4 million).

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

19. Employee future benefits

The Corporation maintains 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.

19. Employee future benefits (continued)

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

	2005		2004	
	Pension Benefit Plans	Other Post Employment Benefit Plans	Pension Benefit Plans	Other Post Employment Benefit Plans
<i>Benefit plan assets, obligations and funded status</i>				
<i>Market value of plan assets:</i>				
Beginning of year	\$1,402.1	\$ -	\$1,322.5	\$ -
Actual return on plan assets	197.0	-	115.8	-
Employee contributions	4.0	-	5.0	-
Benefit payments	(36.4)	-	(36.1)	-
Payments to defined contribution plan	(5.6)	-	(5.1)	-
End of year	\$1,561.1	\$ -	\$1,402.1	\$ -
<i>Accrued benefit obligations:</i>				
Beginning of year	\$1,232.7	\$ 67.0	\$1,092.6	\$ 62.5
Current service cost	32.2	2.5	23.6	2.0
Interest cost	73.9	4.2	69.5	3.8
Employee contributions	4.0	-	5.0	-
Benefit payments from plan assets ⁽¹⁾	(36.4)	-	(36.1)	-
Benefit payments by employer	(4.7)	(1.9)	(4.1)	(2.0)
Experience losses ⁽²⁾	183.3	8.5	82.2	0.7
End of year	\$1,485.0	\$ 80.3	\$1,232.7	\$ 67.0
<i>Funded status:</i>				
Excess (deficiency) of assets over obligations	\$ 76.1	\$(80.3)	\$ 169.4	\$(67.0)
<i>Amounts not yet recognized in financial statements:</i>				
Unrecognized net cumulative experience losses on plan assets and accrued benefit obligations	369.5	21.9	310.3	14.0
Unrecognized net transitional liability (asset)	(253.4)	23.0	(286.2)	25.3
Accrued asset (liability) (Notes 9, 12)	\$ 192.2	\$(35.4)	\$ 193.5	\$(27.7)
Regulatory asset (liability) ⁽³⁾ (Note 2)	\$ (139.4)	\$ 22.0	\$ (137.6)	\$ 16.8

⁽¹⁾ Pension plan benefit payments are indexed to increases in the Canadian Consumer Price Index to a maximum increase of 3% per annum.

⁽²⁾ A change in the liability discount rate assumption resulted in experience losses in 2005 of approximately \$178 million for the pension benefit plans.

⁽³⁾ The regulatory asset (liability) reflects an AEUB decision to record costs of employee future benefits in the regulated operations, excluding Alberta Power (2000), when paid rather than accrued.

19. Employee future benefits (continued)

	2005		2004	
	Pension Benefit Plans	Other Post Employment Benefit Plans	Pension Benefit Plans	Other Post Employment Benefit Plans
<i>Benefit plan cost (income)</i>				
<i>Components of benefit plan cost (income):</i>				
Current service cost	\$ 32.2	\$ 2.5	\$ 23.6	\$ 2.0
Interest cost	73.9	4.2	69.5	3.8
Actual return on plan assets	(197.0)	-	(115.8)	-
Experience losses on accrued benefit obligations	183.3	8.5	82.2	0.7
	92.4	15.2	59.5	6.5
Adjustments to recognize long term nature of employee future benefits:				
Unrecognized portion of actual return on plan assets	108.5	-	29.4	-
Unrecognized portion of experience losses on accrued benefit obligations	(183.3)	(8.5)	(82.2)	(0.7)
Amortization of net cumulative experience losses on plan assets and accrued benefit obligations	15.5	0.6	12.7	0.3
Amortization of net transitional liability (asset)	(32.8)	2.3	(32.8)	2.3
	(92.1)	(5.6)	(72.9)	1.9
Defined benefit plans cost (income)	0.3	9.6	(13.4)	8.4
Defined contribution plans cost	7.0	-	6.4	-
Total cost (income)	7.3	9.6	(7.0)	8.4
Less: Capitalized	1.4	2.3	1.2	2.0
Less: Unrecognized defined benefit plans cost (income) ⁽¹⁾	(1.6)	3.3	(10.2)	2.5
Net cost recognized	\$ 7.5	\$ 4.0	\$ 2.0	\$ 3.9

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

In the unaudited three months ended December 31, 2005, net cost of \$1.7 million (2004 – \$0.6 million) was recognized for pension benefit plans and net cost of \$0.6 million (2004 – \$1.0 million) was recognized for other post employment benefit plans.

19. Employee future benefits (continued)

Weighted average assumptions

	2005		2004	
	Pension Benefit Plans	Other Post Employment Benefit Plans	Pension Benefit Plans	Other Post Employment Benefit Plans
<i>Assumptions regarding benefit plan cost (income):</i>				
Expected long term rate of return on plan assets				
for the year	6.9%	-	7.25%	-
Liability discount rate for the year	5.9%	5.9%	6.25%	6.25%
Average compensation increase for the year	3.25%	-	3.0%	-
<i>Assumptions regarding accrued benefit obligations:</i>				
Liability discount rate at December 31	5.1%	5.1%	5.9%	5.9%
Long term inflation rate	2.5%	(1)	2.5%	(1)

(1) The assumed annual health care cost trend rate increases used in measuring the accumulated post employment benefit obligation are as follows: for drug costs, 9.3% for 2005 grading down over 8 years to 4.5% (2004 – 9.9% for 2004 grading down over 9 years to 4.5%), and, for other medical and dental costs, 4.0% for 2005 and thereafter (2004 – 4.0% for 2004 and thereafter).

The sensitivities of key assumptions used in measuring accrued benefit obligations and benefit plan cost (income) for 2005 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.

	2005 Pension Benefit Plans		2005 Other Post Employment Benefit Plans	
	Accrued Benefit Obligation	Benefit Plan Cost (Income)	Accrued Benefit Obligation	Benefit Plan Cost (Income)
Expected long term rate of return on plan assets				
1% increase ⁽¹⁾	-	\$(3.2)	-	-
1% decrease ⁽¹⁾	-	\$ 3.2	-	-
Liability discount rate				
1% increase ⁽¹⁾	\$(57.7)	\$(4.9)	\$(3.3)	\$(0.3)
1% decrease ⁽¹⁾	\$ 74.0	\$ 6.3	\$ 4.1	\$ 0.4
Future compensation rate				
1% increase ⁽¹⁾	\$ 18.1	\$ 2.5	-	-
1% decrease ⁽¹⁾	\$(15.6)	\$(2.1)	-	-
Long term inflation rate				
1% increase ⁽¹⁾⁽²⁾⁽³⁾	\$ 25.0	\$ 3.2	\$ 3.7	\$ 0.6
1% decrease ⁽¹⁾⁽³⁾	\$(42.7)	\$(5.2)	\$(3.0)	\$(0.5)

(1) Sensitivities are net of the associated regulatory asset (liability) and unrecognized defined benefit plans cost (income), which reflect an AEUB 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.

19. Employee future benefits (continued)

Pension benefit plan assets

	2005		2004	
	Amount	%	Amount	%
<i>Plan asset mix:</i>				
Equity securities ⁽¹⁾	\$ 922.9	59.1	\$ 809.2	57.7
Fixed income securities ⁽²⁾	567.7	36.4	507.2	36.2
Real estate ⁽³⁾	31.1	2.0	34.4	2.4
Cash and other assets ⁽⁴⁾	39.4	2.5	51.3	3.7
	\$1,561.1	100.0	\$1,402.1	100.0

⁽¹⁾ Equity securities consist of investments in domestic and foreign preferred and common shares. At December 31, 2005 the market values of investments in United States' securities and international equities, denominated in a number of different currencies, are \$144.0 million and \$174.0 million, respectively (2004 – \$134.4 million and \$151.6 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, 2005, plan assets include long term debt of CU Inc. having a market value of \$6.0 million (2004 – \$5.3 million), Class A non-voting and Class B common shares of Canadian Utilities Limited having a market value of \$17.6 million (2004 – \$12.4 million) and Class I Non-Voting shares of ATCO Ltd. having a market value of \$14.8 million (2004 – \$10.6 million).

Funding

Employees are required to contribute a percentage of their salary to the 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, 2004, the Corporation is continuing a contribution holiday that began on April 1, 1996. The next actuarial valuation for funding purposes is required as of December 31, 2007.

Included in the accrued benefit obligations are certain supplementary defined benefit pension plans that are paid by the Corporation out of general revenues. These supplementary plans had accrued benefit obligations of \$77.4 million at December 31, 2005 (2004 – \$71.5 million).

20. 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 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.

20. Risk management and financial instruments (continued)

Interest rate risk

Long term debt and non-recourse long term debt have variable interest rates that have been hedged through the following interest rate swap agreements:

Swap Fixed Interest Rate ⁽¹⁾	Variable Debt Interest Rate	Completion Date	Principal/Face Value	
			2005	2004
5.247%	90 day BA	December 2007	\$ 44.4	\$ 47.8
5.202%	90 day BA	September 2008	59.2	63.7
7.54%	90 day BA	November 2008	3.8	5.1
7.317%	90 day BA	December 2008	5.4	8.1
5.8367%	90 day BA	June 2009	9.4	9.8
6.336%	90 day BA	June 2011	3.3	3.9
7.50%	6 month LIBOR	December 2011	87.5	90.6
7.286%	90 day BA	September 2012	28.2	32.5
7.3325%	Bank Bill Rate in Australia	December 2013	34.4	42.6
6.575%	90 day BA	March 2019	37.8	39.5
			\$313.4	\$343.6

BA – Bankers' Acceptance

LIBOR – London Interbank Offered Rate

⁽¹⁾ The above swap fixed interest rates include any long term debt margin fees (Note 11).

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.

The Corporation has entered into foreign exchange forward contracts in order to fix the exchange rate on certain planned equipment expenditures denominated in U.S. dollars and Euros. At December 31, 2005, the contracts consist of purchases of \$2.6 million U.S. (2004 – nil) and sales of 2.0 million Euros (2004 – nil).

Energy commodity price risk

In March 2004, the AEUB issued a decision respecting the operation of ATCO Gas' Carbon storage facility for the 2004/2005 storage year, which ended on March 31, 2005. The decision directed ATCO Gas to continue to reserve 16.7 petajoules of storage capacity for the benefit of utility customers. As a result of an AEUB approved storage plan, ATCO Gas entered into certain energy contracts for the forward purchase and sale of natural gas for storage purposes. All associated costs and benefits of these contracts were passed to customers through regulated rates and, accordingly, ATCO Gas did not bear any risk for price fluctuations provided that the contracts were in accordance with the storage plan.

ATCO Gas has leased the entire storage capacity of the Carbon facility to ATCO Midstream for the period April 1, 2005 to March 31, 2006. At December 31, 2005, there were no contracts outstanding for natural gas sales (2004 – 12,802 terajoules ("TJ") for \$76.3 million) or natural gas purchases (2004 – 107 TJ for \$0.6 million).

20. Risk management and financial instruments (continued)

Fair values

The fair values of derivatives have been estimated using year-end market rates. These fair values approximate the amount that the Corporation would either pay or receive to settle the contract at December 31.

	2005			2004		
	Notional Principal	Fair Value (Payable) Receivable	Maturity	Notional Principal	Fair Value (Payable) Receivable	Maturity
Interest rate swaps	\$313.4	\$(10.5)	2007-2019	\$343.6	\$(16.0)	2007-2019
Foreign exchange forward contracts	\$ 5.9	\$ (0.1)	2006	-	-	-

Credit risk

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. 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.

21. Commitments and contingencies

Commitments

The Corporation has contractual obligations in the normal course of business, including long term operating leases for office premises and equipment. Future minimum lease payments are as follows:

2006	2007	2008	2009	2010	Total of All Subsequent Years
\$15.9	\$14.4	\$13.2	\$6.7	\$6.0	\$7.0

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 AEUB.

The Government of Canada has filed a claim in the amount of \$70 million which alleges that the Corporation is liable for the destruction of property owned by the Governments of Canada and the United States. The Corporation believes that the claim is without merit and, in any event, has sufficient insurance coverage in place to cover any material amounts that might become payable as a result of the claim. Accordingly, the claim is not expected to have any material impact on the financial position of the Corporation.

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.

22. 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 distribution and transmission of electric energy by ATCO Electric and its subsidiaries, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical, the regulated transportation of natural gas by ATCO Pipelines, the regulated transmission and distribution of water by CU Water, and the provision of non-regulated complementary projects by ATCO Utility Services.

The **Power Generation** Business Group includes the non-regulated supply of electricity and cogeneration steam by ATCO Power and the regulated supply of electricity by Alberta Power (2000).

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 by ATCO I-Tek, the provision of billing services, payment processing, credit, collection and call centre services by ATCO I-Tek's subsidiary, ATCO I-Tek Business Services, the sale of fly ash and other combustion byproducts produced in coal fired electrical generating plants by ASHCOR Technologies, the manufacture of wood preservation products by Genics and the sale of travel services to both business and consumer sectors by ATCO Travel.

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

Segmented results – Three months ended December 31

2005		Power	Global	Corporate	Intersegment	
2004	Utilities	Generation	Enterprises	and Other	Eliminations	Consolidated
<i>(Unaudited)</i>						
Revenues – external	\$299.1	\$208.2	\$172.7	\$ 0.3	\$ -	\$680.3
	\$293.8	\$183.9	\$158.9	\$ 0.4	\$ -	\$637.0
Revenues – intersegment ⁽¹⁾	6.4	-	30.0	2.9	(39.3)	-
	4.1	-	29.3	3.5	(36.9)	-
Revenues	\$305.5	\$208.2	\$202.7	\$ 3.2	\$(39.3)	\$680.3
	\$297.9	\$183.9	\$188.2	\$ 3.9	\$(36.9)	\$637.0
Earnings attributable to	\$ 32.5	\$ 36.1	\$ 28.2	\$(7.5)	\$ (0.2)	\$ 89.1
Class A and Class B shares	\$ 38.5	\$ 24.1	\$ 30.8	\$(3.6)	\$ 0.5	\$ 90.3

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

22. Segmented information (continued)

Segmented results – Year ended December 31

	Utilities	Power Generation	Global Enterprises	Corporate and Other	Intersegment Eliminations	Consolidated
2005						
2004						
Revenues – external	\$1,173.5 \$1,771.6	\$ 761.7 \$ 653.2	\$579.4 \$585.4	\$ 1.2 \$ 1.2	\$ - \$ -	\$2,515.8 \$3,011.4
Revenues – intersegment ⁽¹⁾	22.4 18.2	- -	108.6 334.7	11.2 10.4	(142.2) (363.3)	- -
Revenues	1,195.9 1,789.8	761.7 653.2	688.0 920.1	12.4 11.6	(142.2) (363.3)	2,515.8 3,011.4
Operating expenses	716.9 1,328.6	414.7 346.7	538.8 789.1	24.4 11.2	(140.9) (368.1)	1,553.9 2,107.5
Depreciation and amortization	189.3 178.9	95.8 89.5	24.8 22.0	1.6 1.1	- -	311.5 291.5
Interest expense	124.9 118.8	84.8 84.5	2.4 2.4	154.6 148.0	(156.7) (150.0)	210.0 203.7
Gain on transfer of retail energy supply businesses	- (63.3)	- -	- -	- -	- -	- (63.3)
Interest and other income	(11.8) (8.6)	(9.3) (7.9)	(2.0) (2.4)	(170.2) (161.9)	156.7 150.0	(36.6) (30.8)
Earnings before income taxes	176.6 235.4	175.7 140.4	124.0 109.0	2.0 13.2	(1.3) 4.8	477.0 502.8
Income taxes	60.2 56.3	69.1 56.8	43.0 36.9	3.7 6.2	(0.4) 1.8	175.6 158.0
	116.4 179.1	106.6 83.6	81.0 72.1	(1.7) 7.0	(0.9) 3.0	301.4 344.8
Dividends on equity preferred shares	10.4 10.4	3.6 3.6	- -	21.8 21.8	- -	35.8 35.8
Earnings attributable to Class A and Class B shares	\$ 106.0 \$ 168.7	\$ 103.0 \$ 80.0	\$ 81.0 \$ 72.1	\$(23.5) \$(14.8)	\$ (0.9) \$ 3.0	\$ 265.6 \$ 309.0
Total assets	\$3,524.7 \$3,422.4	\$2,216.9 \$2,210.3	\$306.4 \$307.8	\$614.9 \$528.3	\$152.8 \$148.7	\$6,815.7 \$6,617.5
Purchase of property, plant and equipment	\$ 472.9 \$ 426.3	\$ 41.2 \$ 77.0	\$ 11.9 \$ 14.5	\$ 0.7 \$ 17.7	\$ - \$ -	\$ 526.7 \$ 535.5

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

Geographic segments

	Domestic		Foreign		Consolidated	
	2005	2004	2005	2004	2005	2004
Revenues	\$2,253.6	\$2,790.6	\$262.2	\$220.8	\$2,515.8	\$3,011.4
Property, plant and equipment	\$4,905.9	\$4,688.1	\$302.8	\$354.4	\$5,208.7	\$5,042.5