



CANADIAN UTILITIES LIMITED
An **ATCO** Company

CANADIAN UTILITIES LIMITED

CONSOLIDATED FINANCIAL STATEMENTS

**FOR THE YEAR ENDED
DECEMBER 31, 2009**

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, 2009 and 2008 and the consolidated statements of earnings and retained earnings, cash flows and comprehensive income for each of the years in the two year period ended December 31, 2009. These consolidated financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the company as at December 31, 2009 and 2008 and the results of its operations and its cash flows for each of the years in the two year period ended December 31, 2009 in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta

February 17, 2010

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	
		2009	2008	2009	2008
<i>(Unaudited)</i>					
Revenues	1	\$ 675.6	\$ 744.3	\$2,584.0	\$2,778.9
Costs and expenses					
Natural gas supply		4.3	3.6	23.2	37.9
Purchased power		14.3	14.9	54.1	54.1
Operation and maintenance		233.5	300.4	965.5	1,123.5
Selling and administrative		80.2	87.2	258.7	244.8
Depreciation and amortization	1	80.4	100.1	329.7	387.2
Interest	7, 14	60.7	60.3	241.6	233.5
Franchise fees		43.9	42.5	163.5	175.2
		517.3	609.0	2,036.3	2,256.2
		158.3	135.3	547.7	522.7
Gain on ATCO Structures & Logistics transaction	4	-	-	33.9	-
Earnings from investment in ATCO Structures & Logistics	4	4.1	-	7.8	-
Interest and other income	6	9.6	14.6	43.3	59.1
Earnings before income taxes		172.0	149.9	632.7	581.8
Income taxes	7	34.1	27.2	125.4	134.8
		137.9	122.7	507.3	447.0
Dividends on equity preferred shares		10.8	8.2	40.7	32.5
Earnings attributable to Class A and Class B shares	1	127.1	114.5	466.6	414.5
Retained earnings at beginning of period as restated	8	2,485.8	2,206.3	2,279.1	2,031.4
		2,612.9	2,320.8	2,745.7	2,445.9
Dividends on Class A and Class B shares		44.3	41.7	177.1	166.8
Retained earnings at end of period		\$2,568.6	\$2,279.1	\$2,568.6	\$2,279.1
Earnings per Class A and Class B share	17	\$ 1.01	\$ 0.91	\$ 3.71	\$ 3.30
Diluted earnings per Class A and Class B share	17	\$ 1.01	\$ 0.91	\$ 3.71	\$ 3.29
Dividends paid per Class A and Class B share	17	\$ 0.3525	\$ 0.3325	\$ 1.41	\$ 1.33

Canadian Utilities Limited
Consolidated Balance Sheet
(Millions of Canadian Dollars)

		December 31	
	Note	2009	2008
ASSETS			
Current assets			
Cash and short term investments	21	\$ 796.0	\$ 748.6
Accounts receivable		366.4	385.5
Inventories	9	79.8	109.3
Income taxes recoverable	7	8.5	-
Future income taxes	7	6.6	5.9
Regulatory assets	1, 2	37.4	55.8
Derivative assets	24	1.2	1.7
Prepaid expenses and other assets	1, 12	32.0	28.3
		1,327.9	1,335.1
Property, plant and equipment	1, 10	6,732.7	6,007.5
Intangibles	1, 11	241.8	209.4
Investment in ATCO Structures & Logistics	4	121.9	-
Regulatory assets	1, 2	383.9	65.3
Derivative assets	24	31.4	60.4
Other assets	1, 12	244.0	182.3
		\$9,083.6	\$7,860.0
LIABILITIES AND SHARE OWNERS' EQUITY			
Current liabilities			
Bank indebtedness	13	\$ -	\$ 22.0
Accounts payable and accrued liabilities		382.1	479.5
Income taxes payable	3, 7	-	4.9
Regulatory liabilities	1, 2	26.1	29.3
Derivative liabilities	24	2.9	5.4
Long term debt due within one year	14	2.8	17.7
Non-recourse long term debt due within one year	14	49.0	44.8
		462.9	603.6
Future income taxes	1, 7	478.1	163.3
Regulatory liabilities	1, 2	571.2	148.6
Derivative liabilities	24	5.9	12.4
Deferred credits	15	277.3	301.9
Long term debt	14	3,102.3	2,844.3
Non-recourse long term debt	14	354.8	412.4
Equity preferred shares	16	785.0	625.0
Class A and Class B share owners' equity			
Class A and Class B shares	17	528.3	521.9
Contributed surplus	19	3.2	2.6
Retained earnings		2,568.6	2,279.1
Accumulated other comprehensive income	25	(54.0)	(55.1)
Retained earnings and accumulated other comprehensive income		2,514.6	2,224.0
		3,046.1	2,748.5
		\$9,083.6	\$7,860.0

[Original signed by N.C. Southern]

[Original signed by J.W. Simpson]

DIRECTOR

DIRECTOR

Canadian Utilities Limited
Consolidated Statement of Cash Flows
(Millions of Canadian Dollars)

	Note	Three Months Ended December 31		Year Ended December 31	
		2009	2008	2009	2008
<i>(Unaudited)</i>					
Operating activities					
Earnings attributable to Class A and Class B shares		\$ 127.1	\$ 114.5	\$ 466.6	\$ 414.5
Adjustments for:					
Depreciation and amortization	1	80.4	100.1	329.7	387.2
Future income taxes	1	(5.3)	(8.7)	0.8	(3.8)
Gain on ATCO Structures & Logistics transaction	4	-	-	(33.9)	-
Earnings from investment in ATCO Structures & Logistics less dividends received	4	1.0	-	(1.9)	-
TXU Europe settlement - net of income taxes	5	(2.1)	(2.4)	(8.9)	(9.8)
Mark to market of natural gas purchase and power generation revenue contracts	6	2.7	1.6	9.9	2.8
Other post employment benefit adjustment		-	(2.1)	-	(9.4)
Deferred availability incentives		3.7	16.1	5.9	19.5
Changes in non-current regulatory assets and liabilities	1	31.4	25.5	41.6	(7.2)
Allowance for equity funds used during construction		(3.5)	(2.6)	(9.0)	(6.9)
Other		(6.3)	7.1	(7.4)	9.6
		229.1	249.1	793.4	796.5
Changes in non-cash working capital	20	(65.9)	(79.2)	(55.1)	(12.8)
Cash flow from operations	1	163.2	169.9	738.3	783.7
Investing activities					
Purchase of property, plant and equipment	1, 12	(243.8)	(355.4)	(887.5)	(959.2)
Proceeds on disposal of property, plant and equipment		-	(2.7)	0.2	(2.0)
Contributions by utility customers for extensions to plant		20.7	38.4	114.1	176.3
Purchase of intangibles	1	(29.9)	(20.9)	(58.6)	(51.7)
Changes in non-cash working capital	20	52.8	25.3	(29.5)	37.4
Other		4.0	(2.1)	9.2	(6.9)
	1	(196.2)	(317.4)	(852.1)	(806.1)
Financing activities					
Issue of long term debt	14	23.7	4.0	399.7	370.7
Repayment of long term debt	14	(125.3)	(3.8)	(134.1)	(112.0)
Repayment of non-recourse long term debt	14	(12.2)	(28.6)	(55.8)	(85.2)
Issue of equity preferred shares by subsidiary	16	-	-	160.0	-
Net issue of Class A shares		3.7	0.1	6.4	5.0
Dividends paid to Class A and Class B share owners		(44.3)	(41.7)	(177.1)	(166.8)
Changes in non-cash working capital	20	-	(0.2)	-	(0.1)
Other		1.0	1.4	(2.1)	1.5
	1	(153.4)	(68.8)	197.0	13.1
Foreign currency translation		(1.4)	(3.2)	(4.9)	(11.3)
Cash position⁽¹⁾					
Increase (decrease)		(187.8)	(219.5)	78.3	(20.6)
Decrease in cash on ATCO Structures & Logistics transaction	4	-	-	(8.9)	-
Beginning of period		983.8	946.1	726.6	747.2
End of period		\$ 796.0	\$ 726.6	\$ 796.0	\$ 726.6

⁽¹⁾ Cash position consists of cash and short term investments less bank indebtedness

Canadian Utilities Limited
Consolidated Statement of Comprehensive Income
(Millions of Canadian Dollars)

	Note	Three Months Ended December 31		Year Ended December 31	
		2009	2008	2009	2008
<i>(Unaudited)</i>					
Earnings attributable to Class A and Class B shares		\$127.1	\$114.5	\$466.6	\$414.5
Other comprehensive income, net of income taxes:					
Cash flow hedges	25	1.3	(4.2)	8.3	(6.9)
Foreign currency translation adjustment	25	(3.1)	(5.4)	(6.1)	(15.1)
		(1.8)	(9.6)	2.2	(22.0)
Comprehensive income		\$125.3	\$104.9	\$468.8	\$392.5

Canadian Utilities Limited
Notes to Consolidated Financial Statements
December 31, 2009

(tabular amounts in millions of Canadian dollars)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Financial Statement Presentation and Consolidation

The accompanying consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles (“GAAP”). The consolidated financial statements include the accounts of Canadian Utilities Limited and its subsidiaries, including a proportionate share of joint venture investments and an equity accounted for investment in ATCO Structures & Logistics (the “Corporation”). Significant investments and principal subsidiaries are listed below. Subsidiaries are wholly-owned, unless otherwise indicated.

Significant Investments and Principal Operating Subsidiaries	Principal activity
ATCO Structures & Logistics ⁽¹⁾	Infrastructure solutions including support services & logistics, modular building solutions and supply, and construction of noise management solutions
ATCO Power	Power generation
ATCO Midstream	Natural gas gathering, processing, storage and natural gas liquids extraction
ATCO I-Tek	Information systems and technologies
CU Inc.	Holding company
ATCO Gas ⁽²⁾	Natural gas distribution
ATCO Pipelines ⁽²⁾	Natural gas transmission
ATCO Electric ⁽²⁾	Electric transmission and distribution
Alberta Power (2000) ⁽²⁾	Power generation

⁽¹⁾ At December 31, 2009, the Corporation has an ownership interest of 24.5% and ATCO Ltd. (the parent company of the Corporation) has an ownership interest of 75.5%. The Corporation accounts for its investment in ATCO Structures & Logistics under the equity method.

⁽²⁾ Wholly owned by CU Inc.

Significant joint venture investments consist principally of power generation plants; a substantial portion of ATCO Power’s operations are conducted through joint ventures.

Accounting Changes

Accounting for Rate Regulated Operations

Effective January 1, 2009, the Canadian Institute of Chartered Accountants (“CICA”) removed a temporary exemption in its accounting recommendations that permitted assets and liabilities arising from rate regulation to be recognized and measured on a basis other than in accordance with the primary sources of GAAP. Previously, the Corporation followed Canadian GAAP recommendations, which were similar to standards issued by the Financial Accounting Standards Board (“FASB”) in the United States, which provide guidance on the recognition and measurement of assets and liabilities arising from rate regulation. As permitted by Canadian GAAP, the Corporation has applied standards issued by FASB as

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

another source of Canadian GAAP. This change in accounting policy has been adopted prospectively with changes identified below. Although the standards are similar, key differences are outlined below.

The reserves for future removal and site restoration costs for the utility operations, which were previously netted against property plant and equipment, have been reclassified to non-current regulatory liabilities, resulting in an increase to the Corporation's total assets and total liabilities. The Corporation reclassified \$376.2 million at January 1, 2009, corresponding to these reserves.

Previously, depreciation expense for property, plant and equipment included a provision for future removal and site restoration costs for the utility operations. An amount corresponding to this provision is incorporated into rates charged to customers and was previously recognized in revenues. Under the new method of accounting, the Corporation does not recognize this amount in depreciation and amortization expense and revenues. The Corporation now recognizes operation and maintenance expense and revenues as actual removal and site restoration costs are incurred. As a result of the change in accounting, for the unaudited three months ended December 31, 2009, depreciation and amortization expense was \$13.8 million lower, revenues were \$5.9 million lower, and operations and maintenance expense was \$7.9 million higher, resulting in no change in earnings. For the year ended December 31, 2009, depreciation and amortization expense was \$54.0 million lower, revenues were \$36.4 million lower, and operations and maintenance expense was \$17.6 million higher, resulting in no change in earnings.

Effective January 1, 2009, the Corporation also adopted the CICA recommendations requiring the recognition of future income tax assets and liabilities as well as a separate regulatory asset or liability for the amount of future income taxes expected to be included in future rates and recovered from or paid to future customers in the utility operations. As a result of adopting these recommendations, the Corporation recorded future income tax liabilities and non-current regulatory assets of \$255.6 million at January 1, 2009.

Concurrent with the changes in accounting for rate regulated operations noted above, the Corporation changed its presentation of changes in regulatory accounts within the statement of cash flows. Certain items relating to changes in rate regulated assets and liabilities that were previously included in investing and financing activities are now reported in operating activities. The inclusion of changes in the non-current regulatory assets and liabilities in operating activities provides more relevant information on the activities of the Corporation. Comparative figures have been restated as follows:

	Three Months Ended December 31, 2008			Year Ended December 31, 2008		
	Amount Previously Reported	Amount Reclassified	Amount Restated	Amount Previously Reported	Amount Reclassified	Amount Restated
	<i>(Unaudited)</i>					
Cash flow from operations	\$ 145.3	\$ 24.6	\$ 169.9	\$ 791.8	\$(8.1)	\$ 783.7
Investing activities	(290.3)	(27.1)	(317.4)	(813.1)	7.0	(806.1)
Financing activities	(71.3)	2.5	(68.8)	12.0	1.1	13.1

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Intangible Assets

Effective January 1, 2009, the Corporation adopted the CICA recommendations for goodwill and intangible assets which established standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets (including internally developed intangible assets).

This change in accounting has been adopted retrospectively and had the following effect on the consolidated financial statements for the years ended December 31, 2009 and December 31, 2008:

- (a) Restatement of opening retained earnings at January 1, 2008, to recognize the prior years' earnings effect of amounts capitalized prior to 2008 that do not meet the definition of intangible assets as now defined by GAAP (see Note 8).
- (b) Restatement of depreciation and amortization expense and future income taxes for 2008 for the effect of amounts capitalized and amortized in 2008 and prior periods that do not meet the definition of assets as now defined by GAAP. The amounts are not material.
- (c) Restatement of opening accumulated other comprehensive income at January 1, 2008, for the effect of amounts capitalized prior to 2008 that do not meet the definition of assets as now defined by GAAP. The amounts are not material.
- (d) Reclassification of \$209.4 million included in property, plant and equipment and other assets to intangible assets on the balance sheet at December 31, 2008.
- (e) Restatement of operating activities in the statement of cash flows for the impact of changes resulting from (b) above and a reclassification within investing activities of \$51.7 million from purchases of property, plant and equipment to purchases of intangibles for 2008.

Certain comparative figures, in addition to those identified above, have been reclassified to conform to the current presentation.

Rate Regulation

ATCO Electric and its subsidiaries, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical, the ATCO Gas and ATCO Pipelines divisions of ATCO Gas and Pipelines Ltd. and the Battle River and Sheerness generating plants of Alberta Power (2000), all of which are wholly owned subsidiaries of Canadian Utilities Limited's wholly owned subsidiary, CU Inc., are collectively referred to in these consolidated financial statements as the "regulated operations". Accounting for rate regulated operations is described in Note 2. The Corporation records revenues and/or other adjustments arising from an interim or final rate decision related to current and/or prior years upon receipt of the decision.

Significant Judgments and Estimates

The preparation of the Corporation's consolidated financial statements in accordance with GAAP requires management to make judgments, estimates and assumptions that affect the application of policies and 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 revenue recognition, regulatory assets and liabilities, depreciation and amortization methods, useful lives and impairment of long-lived assets, amortization of deferred availability incentives, asset retirement obligations, pensions and other post-employment benefits and the fair value of financial instruments, using currently available information. Changes in facts and circumstances may result in revised estimates, and actual results could

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

differ from those estimates. Revisions to accounting estimates are recognized in the period in which the estimate is revised if the revision affects only that period, or in the period of the revision and future periods if the revision affects both current and future periods.

Revenue Recognition

Regulated Operations:

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

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

Revenues for the use of ATCO Electric's regulated transmission facilities are based on an annual tariff and are recognized evenly throughout the year.

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

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.

Measurement of the estimate of usage not yet billed is based on historical consumption patterns. Management applies judgment to the measurement of the estimated consumption and to the valuation of that consumption.

Incentives and penalties associated with Alberta Power (2000)'s Power Purchase Arrangements ("PPA") are recognized as described under the accounting policy for deferred availability incentives.

Non-regulated Operations:

Revenues from generating plants are recognized upon delivery of output or upon availability of delivery as prescribed by contractual arrangements.

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 resulting from the supply of contracted products and 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. Billings in excess of earned revenue are deferred as unearned revenue.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Natural Gas Supply

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

Purchased Power

Purchased power expense for regulated operations of ATCO Electric 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.

Franchise Fees

Franchise fees are charged to ATCO Electric, ATCO Gas and ATCO Pipelines (the “utilities”) by municipal governments for the exclusive right to provide service in their community. These costs are charged to the related customers through rates that must first be approved by the Alberta Utilities Commission (“AUC”). Franchise fee revenues and expenses are therefore recognized separately and are not recorded on a net basis.

Income Taxes

The Corporation follows 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. For the regulated operations, effective January 1, 2009, a separate regulatory asset or liability is recognized for the amount of future income taxes expected to be included in future rates and recovered from or paid to future customers in the utility operations. Previously the regulated operations’ future income tax assets or liabilities were not recognized unless future income taxes were provided in the income tax component of current rates.

Cash and Short Term Investments

Short term investments consist of bankers’ acceptances, certificates of deposit issued or guaranteed by credit worthy financial institutions and federal government issued short term investments with maturities generally of 90 days or less at purchase.

Inventories

Inventories are valued at the lower of cost or net realizable value. The cost of inventories is assigned using the weighted average cost method. Net realizable value is the estimated selling price in the ordinary course of business, less applicable variable selling expenses.

The cost of inventories is comprised of all costs of purchase, costs of conversion and other costs to bring the inventories to their present condition and location. The costs of purchase comprise the purchase price, import duties and non-recoverable taxes, and transport, handling and other costs directly attributable to the acquisition of finished goods, materials or services. The costs of conversion include direct material

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

and labour costs and a systematic allocation of fixed and variable overheads incurred in converting materials into finished goods.

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 AUC for debt and equity capital. Property, plant and equipment in the non-regulated subsidiaries include capitalized interest incurred during construction.

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

Depreciation is provided on assets on a straight-line basis over their estimated useful lives. Depreciation rates for regulated assets, excluding Alberta Power (2000)'s generating plants, are approved by the AUC. 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.

Intangibles

Intangibles mainly include computer software not directly attributable to the operation of property, plant and equipment and land rights and are recorded at cost less accumulated amortization and unamortized contributions by utility customers. The assets are amortized on a straight-line basis over their useful lives; which are not longer than 10 years for computer software and between 75 and 100 years for land rights.

Impairment

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

Deferred Financing Charges

Issue costs of long term debt are amortized over the life of the debt using the effective interest method. Issue costs of preferred shares relating to regulated operations are amortized over the expected life of the issue in accordance with regulatory practice and issue costs of preferred shares relating to non-regulated subsidiaries are charged to retained earnings. Unamortized premiums and issue costs of redeemed long term debt and preferred shares relating to regulated operations are amortized over the life of the issue funding the redemption. The Corporation's presentation of long term debt and non-recourse long term debt are reduced by the respective deferred financing charges.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Leases

The Corporation is party to certain arrangements that convey the right to use non-regulated electric transmission assets and are classified as leases with the Corporation as the lessor. Leases are classified as finance leases when the terms of the lease transfer substantially all the risks and rewards incidental to ownership of the leased asset to the lessee. Amounts due from lessees under finance leases are recorded as receivables included within other assets. Finance lease receivables are initially recognized at amounts equal to the present value of the minimum lease payments receivable. Finance lease income is recognized in a manner that produces a constant rate of return on the Corporation's investment in the lease and is included in interest and other income.

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 discounted future cash flows.

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

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

Long Term Debt Due Within One Year

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Financial Instruments

The Corporation establishes the classification of financial instruments at their initial recognition. Financial assets are classified as held for trading, available for sale, held to maturity or loans and receivables. Financial liabilities are classified as held for trading or other liabilities.

Financial instruments classified as held for trading, other than derivative instruments that are effective hedging instruments, are measured at fair value with changes in fair value recognized in earnings. Derivatives that are designated as, and continue to be, highly effective cash flow hedging instruments have gains and losses in fair values recognized through other comprehensive income. Derivatives that are designated as fair value hedging instruments have gains and losses recognized in earnings.

Financial instruments classified as available for sale are measured at fair value using quoted prices in an active market. Changes in fair value are recognized in other comprehensive income until the item is derecognized or determined to be impaired, at which time the cumulative gain or loss previously reported in other comprehensive income is recognized in earnings. When actively quoted prices are not available, fair value is determined using other valuation techniques. If fair value cannot be reliably estimated, the item is carried at cost.

Financial instruments classified as held to maturity, loans and receivables or other liabilities are measured at fair value upon initial recognition but are subsequently measured at their amortized cost using the effective interest method.

In estimating fair value, the Corporation utilizes quoted market prices when available. Models incorporating observable market data along with transaction specific factors are also utilized in estimating fair value. Financial assets and liabilities are classified in the fair value hierarchy according to the lowest level of input that is significant to the fair value measurement. Assessment of the significance of a particular input to the fair value measurement requires judgment and may affect placement within the fair value hierarchy levels. The hierarchy is as follows:

- Level 1: quoted prices (unadjusted) in active markets for identical assets or liabilities.
- Level 2: inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly (i.e., as prices) or indirectly (i.e., derived from prices).
- Level 3: inputs for the asset or liability that are not based on observable market data (unobservable inputs)

Derivative Financial Instruments

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

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

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

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

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

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

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

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

Hedge gains or losses that were recognized in other comprehensive income are added to the initial carrying amount of a non-financial asset or non-financial liability when:

- (i) an anticipated transaction for a non-financial asset or non-financial liability becomes a specific firm commitment for which fair value hedge accounting is applied or,
 - (ii) a cash flow hedge of an anticipated transaction subsequently results in the recognition of the non-financial asset or non-financial liability.
- (b) A non-hedge derivative instrument is recorded on the consolidated balance sheet at fair value and subsequent changes in fair value are recorded in earnings.

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

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

Employee Future Benefits

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

Pension plan assets at the end of the year are reported at market value. The expected long term rate of return on plan assets is determined at the beginning of the year on the basis of the long bond yield rate at the beginning of the year plus an equity and management premium that reflects the plan asset mix.

Expected return on plan assets for the year is calculated by applying the expected long term rate of return to the market related value of plan assets, which is the average of the market value of plan assets at the end of the preceding three years.

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

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

Pursuant to an AUC decision effective January 1, 2000, the regulated operations, excluding Alberta Power (2000), are required to expense contributions for other post employment benefit and certain other defined benefit pension plans as paid. The difference between the amounts accrued and paid is deferred in non-current regulatory 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 accumulated other comprehensive income in share owners' equity.

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

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

2. ACCOUNTING FOR RATE REGULATED OPERATIONS

Nature and economic effects of rate regulation

ATCO Electric, ATCO Gas and ATCO Pipelines (the "utilities") are regulated primarily by the AUC. The AUC administers acts and regulations covering such matters as rates, financing, accounting, and service area.

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

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

2. ACCOUNTING FOR RATE REGULATED OPERATIONS (continued)

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

The AUC approves rates of return for the debt and preferred share components of rate base based on the actual or forecast weighted average cost of each utility's debt and preferred shares and establishes the capital structure for each utility. Further details with respect to return on equity, capitalization and the generic cost of capital decisions from the AUC are included in Note 3.

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

Financial statement effects of rate regulation

Certain items in these consolidated financial statements are accounted for differently than they would be in the absence of rate regulation. As described in Note 1, effective January 1, 2009, certain of the treatments under accounting for rate regulated operations have been changed by the Corporation. These changes in accounting treatment are noted below in the respective descriptions of the regulatory assets and liabilities.

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

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

2. ACCOUNTING FOR RATE REGULATED OPERATIONS (continued)

The regulatory assets and liabilities comprise the following:

	2009	2008
<i>Regulatory assets – current:</i>		
Deferred electricity cost recoveries ⁽¹⁾	\$ 16.1	\$ 26.1
Deferral of unused vacation costs ⁽²⁾	14.5	14.7
Deferred load balancing transactions ⁽³⁾	5.0	2.9
Current income tax savings associated with future income tax refund to customers ⁽⁴⁾	1.8	1.9
Other regulatory assets ⁽¹²⁾	-	10.2
	\$ 37.4	\$ 55.8
<i>Regulatory assets – non-current:</i>		
Future income tax recoveries ⁽⁵⁾	\$299.2	\$ -
Regulatory other post employment benefits asset (Note 23) ⁽⁶⁾	51.3	46.9
Deferred load balancing transactions ⁽³⁾	14.4	-
Deferred hearing costs ⁽⁷⁾	9.9	8.4
Current income tax savings associated with future income tax refund to customers ⁽⁴⁾	3.2	5.2
Reserves for injuries and damages ⁽⁸⁾	1.5	-
Other regulatory assets ⁽¹²⁾	4.4	4.8
	\$383.9	\$ 65.3
<i>Regulatory liabilities – current:</i>		
Deferred load balancing transactions ⁽³⁾	\$ 18.1	\$ 20.9
Deferred electricity costs ⁽¹⁾	-	5.6
Other regulatory liabilities ⁽¹²⁾	8.0	2.8
	\$ 26.1	\$ 29.3
<i>Regulatory liabilities – non-current:</i>		
Reserves for future removal and site restoration ⁽⁹⁾	\$402.4	\$ -
Regulatory pension liability (Note 23) ⁽⁶⁾	120.9	110.2
Deferred royalty credits ⁽¹⁰⁾	16.8	23.3
Deferral of temperature impact on revenues ⁽¹¹⁾	10.5	2.7
Deferred electricity costs ⁽¹⁾	6.1	-
Reserves for injuries and damages ⁽⁸⁾	1.0	3.3
Other regulatory liabilities ⁽¹²⁾	13.5	9.1
	\$571.2	\$148.6

⁽¹⁾ *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 Electric System Operator ("AESO"). The amount included in customer rates is based on forecast cost. Revenues are adjusted for changes in tariffs, and the variances are deferred until approval from the AUC is obtained for refund to or collection from customers, which is expected to occur in the following year. GAAP requires that in the absence of rate regulation revenues be based on the rates approved by the AUC and not adjusted.

2. ACCOUNTING FOR RATE REGULATED OPERATIONS (continued)

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

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

Consequently, revenues in 2009 would have been \$10.5 million higher (2008 – \$8.6 million lower) in the absence of rate regulation.

(2) Deferral of unused vacation costs

Revenue requirement includes a recovery from customers for vacation entitlement taken by employees during the year. A portion of the vacation entitlement is earned by employees and accrued as a liability in the prior year. GAAP requires that in the absence of rate regulation the vacation pay liability be expensed in the year accrued and not deferred for amounts that will be recovered from customers. Consequently, expenses for 2009 would have been \$0.2 million lower (2008 - \$0.8 million higher) in the absence of rate regulation.

(3) Deferred load balancing transactions

ATCO Gas and ATCO Pipelines have received AUC approval to establish deferral accounts to collect the costs and revenues arising from load balancing transactions. Load balancing requires the purchase or sale of natural gas to maintain appropriate operating pressures on ATCO Gas' and ATCO Pipelines' North and South distribution and transmission pipeline systems.

Should the deferral account for either ATCO Gas' North or South systems exceed \$2.0 million over three successive months, ATCO Gas may submit an application to the AUC requesting recovery from or refund to customers of that particular deferral account. As a result of an AUC decision received on December 14, 2009, the requirements to submit an application were prospectively changed to amounts exceeding \$5.0 million over six successive months or \$10.0 million for one month.

Should the deferral account for either ATCO Pipelines' North or South systems exceed \$2.0 million, ATCO Pipelines may submit an application to the AUC requesting recovery from or refund to customers of that particular deferral amount. On January 29, 2009, a decision was received that increased these amounts to \$7.5 million for the North and \$5.0 million for the South.

GAAP requires that in the absence of rate regulation actual revenues and costs be recognized in the period in which they are earned or incurred. Consequently, expenses in 2009 would have been \$23.3 million higher and revenues in 2009 would have been \$4.3 million higher (2008 – \$26.6 million higher revenues) in the absence of rate regulation.

2. ACCOUNTING FOR RATE REGULATED OPERATIONS (continued)

⁽⁴⁾ Current income tax savings associated with future income tax refund to customers

The AUC directed ATCO Electric to change its income tax methodology for federal purposes, whereby, effective January 1, 2007, ATCO Electric no longer recognizes future income taxes, and to refund to customers the future income taxes of \$34.4 million collected under the previously allowed tax methodology. This change in tax methodology does not affect earnings as ATCO Electric's revenues and income tax expense were reduced by similar amounts. Accordingly, in 2007, ATCO Electric recorded a reduction in future income tax liabilities of \$34.4 million and a liability to customers of \$48.6 million, offset by a regulatory asset of \$14.2 million which represents current income tax savings to be realized in future periods. Unrecorded future income tax liabilities increased by \$34.4 million as a result of this decision.

In December 2007, ATCO Electric refunded \$16.1 million of the liability to transmission customers reducing the liability to customers to \$32.5 million. In addition, the \$16.1 million refund resulted in current income tax savings of \$5.2 million, reducing the regulatory asset to \$9.0 million. The total reduction in revenues and income taxes in 2007 was \$39.6 million. ATCO Electric began refunding the remaining \$32.5 million to distribution customers over a five year period commencing in 2008. ATCO Electric will realize the regulatory asset of \$9.0 million over the same 5 year period with no effect on earnings as current income tax savings will be offset by this reduction in revenues.

GAAP requires that in the absence of rate regulation revenues not be adjusted for the current income tax savings to be realized in future periods. Consequently, revenues for 2009 would have been \$2.2 million higher (2008 - \$2.0 million higher) in the absence of rate regulation.

⁽⁵⁾ Future income tax recoveries

As described in Note 1, the Corporation prospectively adopted the CICA recommendations requiring the recognition of future income tax assets and liabilities as well as a separate regulatory asset or liability for the amount of future income taxes expected to be included in future rates and recovered from or paid to future customers in the utility operations. As a result of adopting these recommendations, the Corporation recorded future income tax liabilities and non-current regulatory assets of \$255.6 million at January 1, 2009. GAAP requires that in the absence of rate regulation future income taxes be expensed in the period in which they are incurred and not deferred for amounts that will be recovered from or paid to customers. Consequently, expenses in 2009 would have been \$43.6 million higher in the absence of rate regulation.

⁽⁶⁾ Employee future benefits

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

GAAP requires that the variances between the amounts accrued and paid be recognized as an expense or reduction in expense in the period in which they are accrued. Consequently, defined benefit pension plan

2. ACCOUNTING FOR RATE REGULATED OPERATIONS (continued)

cost in 2009 would have been \$10.4 million lower (2008 – \$0.9 million lower), and other post employment benefit plan cost in 2009 would have been \$2.4 million higher (2008 – \$2.4 million higher), in the absence of rate regulation.

Upon the adoption of the current accounting standard in 2000, the utilities had recorded deferred pension assets of \$23.0 million. The utilities have been earning an AUC approved rate of return on these assets through customer rates as the assets form part of the utilities' AUC approved rate base. In the absence of rate regulation, the utilities would not be able to earn a return on these assets. Consequently, revenues in 2009 would have been \$0.8 million lower (2008 – \$1.2 million lower). On October 11, 2006, the AUC issued a decision that approved recovery of these assets for a nine-year period commencing January 1, 2005 and permitted the utilities to continue to earn an AUC approved rate of return on the unrecovered portion of these assets over the recovery period. In 2009, the utilities amortized \$3.9 million (2008 – \$3.4 million) of the deferred pension asset.

(7) Deferred hearing costs

The utilities incur hearing costs on an ongoing basis associated with various AUC regulatory proceedings. These costs are comprised primarily of legal and consulting expenses incurred by the utilities in addition to costs incurred by intervenor groups that have been reimbursed by the utilities as directed by the AUC. Prior to 2009, hearing costs were deferred to the balance sheet and amortized using AUC approved annual amounts that are collected through customer rates. Effective January 1, 2009, hearing costs are expensed as actual costs are incurred and revenues are adjusted for variances between the approved annual amounts and actual costs. The variances continue to be deferred until the next general rate application or until a specific application is made to the AUC requesting recovery from or refund to customers. GAAP requires that in the absence of rate regulation, revenues be based on the rates approved by the AUC and not adjusted for variances between approved annual amounts and actual costs and that hearing costs be expensed in the period in which they are incurred. Consequently, revenues in 2009 would have been \$1.5 million lower (2008 - \$4.4 million higher expenses) in the absence of rate regulation.

(8) Reserves for injuries and damages

The AUC has approved the use of a reserve for injuries and damages by the utilities as a means of self-insurance. The reserve for injuries and damages is established based on an annual amount approved by the AUC to be collected through customer rates. Prior to 2009, reserve claims were deferred to the balance sheet and amortized using AUC approved annual amounts that are collected through customer rates. Effective January 1, 2009, reserve claims are now expensed as actual costs are incurred and revenues are adjusted for variances between the approved annual amounts and actual costs. The variances continue to be deferred until the next general rate application or until a specific application is made to the AUC requesting recovery from or refund to customers. GAAP requires that in the absence of rate regulation, revenues be based on the rates approved by the AUC and not adjusted for variances between approved annual amounts and actual costs and that claims be expensed in the period in which they are incurred. Consequently, revenues in 2009 would have been \$3.8 million lower (2008 - \$1.6 million higher expenses) in the absence of rate regulation.

(9) Reserves for future removal and site restoration

As described in Note 1, the reserves for future removal and site restoration costs for the utility operations, which were previously netted against property plant and equipment, have been reclassified to non-current regulatory liabilities, resulting in an increase to the utilities' total assets and total liabilities. The utilities

2. ACCOUNTING FOR RATE REGULATED OPERATIONS (continued)

reclassified \$376.2 million at January 1, 2009, corresponding to these reserves. Prior to 2009, depreciation expense for property, plant and equipment included a provision for future removal and site restoration costs. An amount corresponding to this provision is incorporated into rates charged to customers. Effective January 1, 2009, actual removal and site restoration costs are expensed as incurred and revenues are adjusted for variances between the provision incorporated into rates and actual costs. The variances continue to be deferred as reserves for future removal and site restoration costs. GAAP requires that in the absence of rate regulation, revenues be based on the rates approved by the AUC and not adjusted for variances between the provision incorporated into rates and actual costs. Consequently, revenues in 2009 would have been \$26.2 million higher in the absence of rate regulation.

(10) 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 are expensed on the same average cost basis as reflected in the underlying PPA revenues. GAAP requires that in the absence of rate regulation royalty costs be expensed in the period in which they are incurred. Consequently, expenses in 2009 would have been \$6.5 million higher (2008 - \$0.2 million lower) in the absence of rate regulation.

(11) Deferral of temperature impact on revenues

ATCO Gas has received AUC approval to establish deferral accounts to mitigate the impact of temperature fluctuations on its revenues. Should the deferral account for either the North or the South exceed \$7.0 million at April 30th of any year, ATCO Gas will submit an application to the AUC requesting recovery from or refund to customers of that particular deferral account. Costs related to financing these deferred amounts will be charged monthly to these deferral accounts based on ATCO Gas' weighted average cost of capital. GAAP requires that in the absence of rate regulation the temperature impacted revenues be recognized in the period in which they are realized. Consequently, revenues in 2009 would have been \$11.8 million higher (2008 - \$2.7 million higher) in the absence of rate regulation.

(12) Other regulatory assets and liabilities

Other regulatory assets and liabilities include the following:

- a) ATCO Pipelines has received AUC approval to defer the variances between actual and AUC approved forecast revenues and costs associated with the movement (receipt or delivery) of natural gas between ATCO Pipelines' system and other connected pipeline systems. ATCO Pipelines received AUC approval on February 27, 2009 to recover or refund these deferral account balances in its general rate application negotiated settlement. GAAP requires that in the absence of rate regulation actual revenues and costs be recognized in the period in which they are earned or incurred. Consequently, revenues in 2009 would have been \$2.9 million higher (2008 - \$0.6 million higher) and expenses would have been \$2.4 million lower (2008 - \$0.4 million lower) in the absence of rate regulation. Assets of nil and nil (2008 - \$0.3 million and \$1.9 million) are included in current regulatory assets and non-current regulatory assets, respectively, and liabilities of \$3.3 million and \$1.2 million (2008 - \$1.4 million and \$0.1 million) are included in current and non-current regulatory liabilities respectively.

2. ACCOUNTING FOR RATE REGULATED OPERATIONS (continued)

- b) In November 2009, the AUC directed ATCO Gas to establish a deferral account to capture variances between forecast and actual costs that may be capitalized for accounting purposes but deducted in the year incurred as an expense for income tax purposes. The resulting impact of this decision was to decrease ATCO Gas' 2009 revenues by \$3.6 million. Consequently, revenues in 2009 would have been \$3.6 million higher (2008 – nil) in the absence of rate regulation. Liabilities of \$4.3 million (2008 – nil) are included in non-current regulatory liabilities.
- c) ATCO Pipelines has received AUC approval to establish a deferral account for the Salt Cavern Storage facility to collect the gains or losses and transaction costs associated with the sale of natural gas in the market upon withdrawal from storage. ATCO Pipelines is required to submit an application to the AUC, either separately or in conjunction with a general rate application for that particular year, requesting recovery from or refund to customers of the deferral amount should the deferral account exceed \$2.0 million at the end of the annual injection/withdrawal cycle on March 31 of a particular year. ATCO Pipelines received AUC approval to recover this deferral account balance in its general rate application negotiated settlement on March 18, 2009. GAAP requires that in the absence of rate regulation actual revenues and costs be recognized in the period in which they are earned or incurred. Consequently, expenses in 2009 would have been \$6.3 million lower (2008 – revenues \$1.9 million lower) in the absence of rate regulation. Assets of \$1.5 million are included in non-current regulatory assets (2008 - \$7.8 million included in current regulatory assets) in the balance sheet.

Other items affected by rate regulation

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

3. REGULATORY MATTERS

Generic Cost of Capital Decision

On November 12, 2009, the AUC issued its decision on the 2009 Generic Cost of Capital proceeding. In this decision, the AUC set the 2009 and 2010 generic return on equity (“ROE”) at 9.0% for all Alberta utilities which it regulates. This is an increase over the 8.61% ROE that the adjustment formula formerly in place would have provided for 2009. The AUC has maintained the concept of a single generic ROE for all utilities, with differences in utility or sector specific risk to be recognized through the adjustments of individual common equity ratios. The AUC determined the common equity ratio to be 36% for ATCO Electric’s transmission operations, 39% for both ATCO Electric’s distribution operations and ATCO Gas’ operations and 45% for ATCO Pipelines’ operations. As part of the same decision, the AUC also set the 2011 generic return on equity at 9.0% on an interim basis subject to change following a subsequent generic proceeding. The financial impact of this decision was an increase to ATCO Electric’s earnings of \$4.2 million and ATCO Gas’ earnings of \$2.5 million, of which \$0.4 million relates to 2008. The changes did not apply to ATCO Pipelines for 2009 since capital structure and rate of return were included in ATCO Pipelines’ Negotiated Settlement.

3. REGULATORY MATTERS (continued)

While ATCO Gas' ROE for 2008 was not impacted by the decision issued on November 12, 2009, a separate module within the generic proceeding addressed ATCO Gas' 2008 capital structure, as inclusion of this issue was removed from its 2008/2009 general rate application. The November 12, 2009 decision approved an equity ratio of 39% commencing in the year 2008 for ATCO Gas. The financial impact is identified in the 2008 amount noted above.

Benchmarking

A process continues with respect to the pricing of services provided by ATCO I-Tek to the utilities. A benchmarking report was received on January 23, 2008 and filed with the AUC in February 2008, along with an application to adjust placeholders for 2003 – 2007 for ATCO Gas, ATCO Electric and ATCO Pipelines. A hearing was held in December 2009 and a decision is expected in the first quarter of 2010. A subsequent process to adjust 2008 and 2009 placeholders as well as a separate process to deal with services provided by ATCO I-Tek for 2010 and beyond are expected to occur in 2010.

Income Tax Module

On November 12, 2009, the AUC issued its Income Tax Module decision in which it addressed the 2008-2009 income tax placeholder amounts for ATCO Gas and 2009-2010 placeholders for ATCO Electric. The AUC approved the placeholder amounts as filed and established an income tax deferral account for ATCO Electric and ATCO Gas, resulting in no impact to earnings for ATCO Electric and a \$2.5 million reduction in earnings for ATCO Gas.

Company Specific Decisions

ATCO Electric

In July 2008, ATCO Electric filed a general tariff application with the AUC for 2009 and 2010 requesting, among other things, increased revenues to recover increased financing, depreciation and operating costs associated with increased rate base in Alberta. ATCO Electric filed an application requesting interim refundable rates pending the AUC's decision on the application. In December 2008, ATCO Electric received a decision from the AUC approving interim refundable rate increases amounting to 50% of the requested increase for transmission operations and 25% of the requested increase for distribution operations. On March 11, 2009, ATCO Electric filed an application requesting an increase to its approved interim refundable rates for its distribution operations. A decision from the AUC was received on April 22, 2009, which resulted in an increase to the interim refundable rates to 67% of the requested rate increase.

On July 2, 2009, the AUC issued a decision on ATCO Electric's 2009 and 2010 general tariff application. The effect of the decision increased ATCO Electric's 2009 annual earnings primarily as a result of an increase in rate base. In the decision, the AUC used placeholders for 2009 and 2010 information technology and customer care and billing rates and pension costs. These placeholders will be determined by the AUC in subsequent proceedings. The placeholders in the decision for common equity ratios, preferred share capitalization ratios and ROE were determined as a result of the Generic Cost of Capital Decision discussed above. The placeholders in the decision for the income amounts were determined as a result of the Income Tax Module Decision discussed above.

3. REGULATORY MATTERS (continued)

ATCO Gas

On November 13, 2008, ATCO Gas received a decision on its general rate application for 2008 and 2009. The decision established the amount of revenue requirement ATCO Gas can recover through distribution rates for natural gas distribution service to its customers for 2008 and 2009. The effect of the decision increased ATCO Gas' 2009 annual earnings primarily from an increase in rate base. In the decision, the AUC used placeholders for 2009 information and technology and customer care and billing costs. These placeholders will be determined by the AUC in subsequent proceedings. The placeholders in the decision for common equity ratios, preferred share capitalization ratios and ROE were determined as a result of the Generic Cost of Capital Decision discussed above. The placeholders for income tax amounts were determined as a result of the Income Tax Module Decision discussed above.

As a result of numerous regulatory and legal proceedings, ATCO Gas received approval from the AUC to remove its Carbon storage facility from regulation and, effective July 1, 2008, to suspend rate riders to customer rates (Carbon Rate Riders) on an interim basis. ATCO Gas derecognized regulatory assets and liabilities relating to the Carbon Facility as these amounts were no longer recoverable from or payable to ATCO Gas' customers. The one-time impact of this discontinuation of regulatory accounting for the Carbon Facility was to increase ATCO Gas' earnings by \$1.9 million. Further to its decision suspending Carbon Rate Riders, the AUC on July 28, 2009, issued a decision approving a refund to customers related to the costs of the Carbon facility that were included in ATCO Gas' rates from January through June 2008. Consequently, ATCO Gas recognized increased revenues of \$13.8 million for the impact of the Carbon Rate Rider revenue for the period January 1, 2008 to June 30, 2008 which was previously refunded to customers and decreased revenues of \$7.6 million as a result of excluding any costs for the Carbon Facility in its 2008-2009 general rate application. The net impact was an increase to ATCO Gas' revenues and earnings of \$6.2 million and \$4.5 million, respectively, in 2009.

For the remaining period of April 1, 2005 to December 31, 2007, ATCO Gas is seeking to recover from customers additional amounts that would result in an estimated increase to its earnings of \$20.5 million, excluding interest. On December 16, 2009, a Review and Variance Decision issued by the AUC approved the effective date of removing the Carbon facility from regulation to be April 1, 2005. The finalization of these amounts that ATCO Gas is seeking to recover will be determined in a subsequent process scheduled to occur over the first and second quarters of 2010. As a result, these additional amounts have not yet been recognized by ATCO Gas. The City of Calgary and the Utilities Consumer Advocate have filed a joint Leave to Appeal application with the Alberta Court of Appeal regarding the December 16, 2009 decision. As a result of the Leave to Appeal, the effective removal date of the Carbon assets of April 1, 2005 could be impacted, which could affect the amount ATCO Gas is seeking to recover from customers. A hearing for the Leave to Appeal application has been tentatively scheduled for April 28, 2010.

ATCO Pipelines

In November 2008, ATCO Pipelines filed an application requesting the AUC approve a negotiated settlement with its customers for ATCO Pipelines' 2008 and 2009 revenue requirements. On March 18, 2009, the AUC issued a decision approving the negotiated settlement, including, among other things, a rate of ROE of 8.75% and a common equity ratio of 43% for each of 2008 and 2009. As a result of the decision, ATCO Pipelines recognized additional earnings over existing interim rates of \$4.5 million in the first quarter of 2009, of which \$3.7 million related to 2008.

3. REGULATORY MATTERS (continued)

On June 26, 2009, ATCO Pipelines filed an application with the AUC for the integration of ATCO Pipelines' and NOVA Gas Transmission Ltd.'s gas transmission systems in Alberta (Integration Application). A settlement on ATCO Pipelines 2010, 2011 and 2012 revenue requirements was successfully negotiated with interested parties on October 28, 2009. On November 12, 2009, ATCO Pipelines filed a request with the AUC to approve this negotiated settlement as part of its Integration Application. ATCO Pipelines expects to receive an AUC decision on the Integration Application in the first half of 2010.

Other

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

4. TRANSACTION TO COMBINE ATCO FRONTEC, ATCO STRUCTURES AND ATCO NOISE MANAGEMENT

On July 1, 2009, the Corporation and its parent ATCO Ltd. finalized a transaction combining ATCO Frontec, a wholly-owned subsidiary of the Corporation, with ATCO Structures and ATCO Noise Management, both wholly-owned subsidiaries of ATCO Ltd ("ATCO Structures & Logistics Transaction"). As a result of this transaction, the Corporation and ATCO Ltd. have direct ownership interests of 24.5% and 75.5%, respectively, in the new company named ATCO Structures & Logistics. The ownership interests reflect the proportion of the respective valuations of the combined entities. The valuations were based on analysis prepared by independent financial advisors retained by the special committees of the Boards of Directors of the Corporation and ATCO Ltd.

This is a related party transaction by entities under common control and has been accounted for at the exchange amount by the Corporation; with an after tax gain for accounting purposes of \$29.6 million recorded on closing. Prior to the ATCO Structures & Logistics Transaction, the Corporation consolidated ATCO Frontec as it was a wholly-owned subsidiary. Therefore, all revenues, expenses, assets and liabilities were recognized on a line-by-line basis in the consolidated financial statements of the Corporation for the period up to June 30, 2009. From July 1, 2009, the Corporation has recorded an equity accounted for investment for its 24.5% interest in ATCO Structures & Logistics as it retains significant influence. This is reflected as a single line item called "Earnings from investment in ATCO Structures & Logistics" on the consolidated statement of earnings and a single line item called "Investment in ATCO Structures & Logistics" on the consolidated balance sheet. The Investment in ATCO Structures & Logistics is increased or decreased to include the Corporation's share of earnings and capital transactions from July 1, 2009 onward.

The transaction allows the predecessor companies (ATCO Frontec, ATCO Structures, and ATCO Noise Management) to pursue a more efficient working relationship in response to a changing global market and the demand for bundled services.

4. TRANSACTION TO COMBINE ATCO FRONTEC, ATCO STRUCTURES AND ATCO NOISE MANAGEMENT (continued)

The Corporation's investment in ATCO Structures & Logistics at December 31, 2009 is as follows:

Investment at July 1, 2009	\$121.8
Share of earnings	7.8
Share of other comprehensive income	(1.8)
Dividends received	(5.9)
Investment at December 31, 2009	\$121.9

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 was reached with respect to Barking Power's claim.

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

The Corporation's share of this settlement is being recognized in earnings in equal monthly amounts over the remaining term of the TXU Europe contract to September 30, 2010. Based on the foreign currency exchange rate in effect at December 31, 2009, earnings after income taxes of approximately \$6.4 million have yet to be recognized. These earnings will be dependent upon foreign currency exchange rates in effect at the time that the earnings are recognized.

6. INTEREST AND OTHER INCOME

	2009	2008
Interest	\$22.6	\$43.6
Allowance for funds used during construction by regulated operations	23.4	17.9
(Losses) gains on dispositions of property, plant and equipment and other investments	(0.3)	2.3
Loss on natural gas purchase contracts derivative asset (Note 24)	(34.1)	(12.4)
Gain on power generation revenue contract liability (Note 24)	24.2	9.6
Cash flow hedge gains (losses)	2.1	(4.8)
Finance lease income	3.4	-
Other	2.0	2.9
	\$43.3	\$59.1

7. INCOME TAXES

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

	2009		2008	
Earnings before income taxes	\$632.7	%	\$581.8	%
Income taxes, at statutory rates	\$183.5	29.0	\$171.6	29.5
H.R. Milner income tax reassessment	(7.8)	(1.2)	-	-
Removal of Carbon storage assets from regulation	5.8	0.9	-	-
Benefit of purchased tax losses in UK	(2.4)	(0.4)	-	-
Part VI.1 tax	2.5	0.4	1.6	0.3
Future income taxes relating to regulated operations	(36.7)	(5.8)	(27.2)	(4.7)
Future income taxes recorded at less than current statutory rates	(1.1)	(0.1)	(1.6)	(0.3)
Non-taxable portion of gain on ATCO Structures & Logistics transaction	(4.3)	(0.7)	-	-
Earnings from investment in ATCO Structures & Logistics	(2.3)	(0.4)	-	-
Foreign tax rate variance	(0.7)	(0.1)	(1.5)	(0.3)
Non-deductible interest on foreign financing	1.6	0.2	1.4	0.2
Other tax reassessments	(2.7)	(0.4)	(9.7)	(1.7)
Other	(10.0)	(1.6)	0.2	0.1
	125.4	19.8	134.8	23.1
Current income taxes	114.7		129.8	
Future income taxes	\$ 10.7		\$ 5.0	

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

	2009	2008
Property, plant and equipment	\$501.3	\$212.1
Intangibles	51.8	1.9
Deferred assets and liabilities	(71.2)	(40.2)
Tax loss carryforwards	(17.4)	(19.0)
Derivative financial instruments	1.1	0.3
Other	5.9	2.3
	471.5	157.4
Less: Current future income tax asset	(6.6)	(5.9)
	\$478.1	\$163.3

7. INCOME TAXES (continued)

As described in Note 1, effective January 1, 2009, the Corporation adopted the CICA recommendations requiring the recognition of future income tax assets and liabilities as well as a separate regulatory asset or liability for the amount of future income taxes expected to be included in future rates and recovered from or paid to customers. As a result of adopting these recommendations, the Corporation recorded previously unbooked future income tax liabilities of the regulated operations.

On August 21, 2009, Alberta Power (2000) received a judgment from the Tax Court of Canada ordering Canada Revenue Agency (“CRA”) to reverse its 2006 reassessment of Alberta Power (2000)’s 2001 tax return for the sale of the H.R. Milner generating plant. On September 30, 2009, the appeal period for the judgment elapsed without an appeal from CRA.

The impact of the judgment is a \$7.8 million recovery of income tax and \$5.9 million of related interest expense reassessed by CRA in 2006. In addition, Alberta Power (2000) will receive interest income of approximately \$3.1 million earned on such amounts paid to CRA. These adjustments have resulted in a \$16.8 million increase in earnings for 2009. CRA will be required to refund Alberta Power (2000) approximately \$28.0 million including interest and net of consequential adjustments to other taxation years arising from the judgment. Of this amount, the CRA has refunded \$20.8 million as of December 31, 2009, and approximately \$7.2 million remains outstanding from the Government of Alberta.

In 2009, ATCO Gas removed the Carbon storage assets from regulation (see Note 3). As a result, the Corporation recorded future income taxes of \$5.8 million.

ATCO Power has tax loss carryforwards of \$70.2 million for which it has recorded an income tax benefit. The losses are the result of refileing corporate income tax returns to maximize previous years unclaimed capital cost allowance. Approximately 27% of the losses expire in 2010, with the remaining amounts expiring in 2014 and 2015.

Income taxes paid amounted to \$122.2 million (2008 — \$125.4 million).

8. RETAINED EARNINGS AT BEGINNING OF PERIOD AS RESTATED

	January 1	
	2009	2008
Retained earnings at beginning of period as previously reported	\$2,282.3	\$2,036.0
Cumulative adjustments to retained earnings to recognize the prior years’ effect of the change in the method of accounting for intangible assets (net of income taxes)	(3.2)	(4.6)
Retained earnings at beginning of period as restated	\$2,279.1	\$2,031.4

9. INVENTORIES

	2009	2008
Natural gas and fuel in storage	\$23.5	\$ 45.9
Raw materials and consumables	56.0	63.0
Finished goods	0.3	0.4
	\$79.8	\$109.3

For the year ended December 31, 2009, the amount of inventories recognized as an expense was \$73.6 million (2008 – \$98.9 million). There have been \$0.2 million write-downs to net realizable value and there have been no reversals of previous write-downs to net realizable value.

No inventories are pledged as security for liabilities.

10. PROPERTY, PLANT AND EQUIPMENT

	2009			2008	
	Composite Depreciation Rates	Cost	Accumulated Depreciation	Cost	Accumulated Depreciation
Utilities	2.8%	\$ 8,157.4	\$2,396.7	\$ 7,475.7	\$2,612.4
Energy	3.8%	3,194.0	1,372.8	3,102.9	1,270.1
Corporate & Other ⁽¹⁾	9.2%	88.6	50.4	199.0	87.0
		\$11,440.0	3,819.9	\$10,777.6	3,969.5
Property, plant and equipment					
less accumulated depreciation			7,620.1		6,808.1
Unamortized contributions by utility customers for extensions to plant			887.4		800.6
			\$6,732.7		\$6,007.5

⁽¹⁾ 2008 includes amounts for ATCO Frontec

Accumulated depreciation no longer includes amounts provided for future removal and site restoration costs, net of salvage value (2008 – included \$376.2 million). As described in Note 1, at January 1, 2009, the Corporation reclassified \$376.2 million relating to the utility operations from accumulated depreciation to non-current regulatory liabilities.

Composite depreciation rates reflect total depreciation in the year as a percentage of mid-year cost, excluding construction work-in-progress of \$376.8 million (2008 – \$412.0 million) and non-depreciable assets of \$55.3 million (2008 – \$45.7 million).

11. INTANGIBLES

	December 31			
	2009		2008	
	Cost	Accumulated Amortization	Cost	Accumulated Amortization
Computer Software	\$314.3	\$170.3	\$275.1	\$151.9
Land Rights	115.0	22.1	101.3	20.6
Other	11.4	6.2	11.3	5.4
	\$440.7	198.6	\$387.7	177.9
Intangibles less accumulated amortization		242.1		209.8
Unamortized contributions by utility customers		0.3		0.4
		\$241.8		\$209.4

Amortization expense relating to intangibles was \$23.5 million (2008 – \$22.9 million).

12. OTHER ASSETS

	2009	2008
Accrued pension asset (Note 23)	\$141.6	\$133.4
Security deposits for debt	17.0	17.8
Lease receivable ⁽¹⁾	57.8	-
Long term receivable from joint venture	-	7.3
Other	27.6	23.8
	\$244.0	\$182.3

⁽¹⁾ In June 2009, the Corporation finalized agreements relating to the use of certain non-regulated electric transmission assets that are accounted for as finance leases (with the Corporation as the lessor). As at December 31, 2009, the total net investment in finance leases is \$59.1 million. The current portion which totals \$1.3 million is included in prepaid expenses and other assets and the long-term portion of \$57.8 million is included in other assets above.

13. BANK INDEBTEDNESS AND LINES OF CREDIT

At December 31, 2009, the Corporation has the following lines of credit that enable it to obtain financing for general business purposes:

	2009			2008		
	Total	Used	Available	Total	Used	Available
Long term committed	\$326.0	\$48.0	\$278.0	\$ 326.0	\$ 48.2	\$277.8
Short term committed	600.0	32.0	568.0	600.0	54.1	545.9
Uncommitted	63.7	7.0	56.7	99.1	28.1	71.0
	\$989.7	\$87.0	\$902.7	\$1,025.1	\$130.4	\$894.7

13. BANK INDEBTEDNESS AND LINES OF CREDIT (continued)

Of the \$87.0 million used (2008 – \$130.4 million) at December 31, 2009, \$47.0 million (2008 – \$47.0 million) is included in long term debt, nil (2008 – \$22.0 million) is included in bank indebtedness and \$40.0 million (2008 – \$61.4 million) represents outstanding letters of credit.

14. LONG TERM DEBT AND NON-RECOURSE LONG TERM DEBT

Long term debt

	Effective Interest Rate	2009	2008
<i>Canadian Utilities</i>			
CU Inc. debentures – unsecured			
1989 Series 10.20% due November 2009	10.331%	\$ -	\$ 125.0
1990 Series 11.40% due August 2010	11.537%	125.0	125.0
2000 7.05% due June 2011	7.130%	100.0	100.0
2007 4.883% due November 2012	4.990%	35.0	35.0
2004 5.096% due November 2014	5.162%	100.0	100.0
2002 6.145% due November 2017	6.217%	150.0	150.0
2004 5.432% due January 2019	5.492%	180.0	180.0
1999 6.8% due August 2019	6.861%	300.0	300.0
1990 Second Series 11.77% due November 2020	11.903%	100.0	100.0
2006 4.801% due November 2021	4.854%	160.0	160.0
1991 Series 9.92% due April 2022	10.063%	125.0	125.0
1992 Series 9.40% due May 2023	9.511%	100.0	100.0
2009 6.215% due March 2024	6.278%	120.0	-
2008 5.563% due May 2028	5.614%	125.0	125.0
2004 5.896% due November 2034	5.939%	200.0	200.0
2005 5.183% due November 2035	5.226%	185.0	185.0
2006 5.032% due November 2036	5.072%	160.0	160.0
2007 5.556% due October 2037	5.598%	220.0	220.0
2008 5.580% due May 2038	5.622%	200.0	200.0
2009 6.500% due March 2039	6.550%	150.0	-
CU Inc. other long term obligation, due June 2011, unsecured	2.250%	4.5	4.5
Canadian Utilities Limited debentures – unsecured			
2002 6.14% due November 2012	6.228%	100.0	100.0
Less: Deferred financing charges		(15.3)	(15.0)
		2,924.2	2,779.5
ATCO Midstream Ltd. credit facility, at BA rates, due June 2013, unsecured ⁽¹⁾			
	Floating	25.0	25.0
ATCO Power Canada Ltd. credit facility, at BA rates, due August 2013, secured by a pledge of cash ⁽¹⁾			
	Floating	22.0	22.0
ATCO Power Australia credit facility, at BBSY rates, due June 2015: AUD100.0 million, secured by a pledge of project's assets and contracts			
	Floating ⁽²⁾	94.4	-

14. LONG TERM DEBT AND NON-RECOURSE LONG TERM DEBT (continued)

Long term debt (continued)

	Effective Interest Rate	2009	2008
ATCO Frontec (see note 4) credit facility, at Euribor rates, due October 2010: 2008 - €20.8 million, secured by a pledge of assets and certain contracts	Floating ⁽²⁾	-	35.5
Canadian Utilities Limited non-revolving credit facility at 5.72%, due June 2014	5.884%	39.5	-
		3,105.1	2,862.0
Less: Amounts due within one year		2.8	17.7
		\$3,102.3	\$2,844.3

Non-recourse long term debt

Project Financing	Effective Interest Rate	2009	2008
Barking Power Limited payable in British pounds: Term loans, at fixed rates averaging 7.95%, due to 2010: (£6.6 million (2008 – £12.5 million))	7.95%	\$ 11.2	\$ 22.2
Osborne Cogeneration Pty Ltd., payable in Australian dollars: Term loan, at Bank Bill rates, due to 2013 ⁽¹⁾ : (\$22.1 million AUD (2008 – \$26.2 million AUD))	Floating ⁽²⁾	20.9	22.5
ATCO Power Alberta Limited Partnership (“APALP”): Term loan, at LIBOR, due to 2013 ⁽¹⁾	Floating ⁽²⁾	30.1	49.4
Joffre: Term loan, at BA rates, due to 2012 ⁽¹⁾	Floating ⁽²⁾	0.2	0.3
Term facility, at Canadian Prime Advances, due to 2012 ⁽¹⁾	Floating ⁽²⁾	0.1	0.1
Term loan, at LIBOR, due to 2012 ⁽¹⁾	Floating ⁽²⁾	0.5	0.7
Notes, at fixed rate of 8.59%, due to 2020	8.845%	32.0	32.0
Scotford: Term loan, at BA rates, due to 2014 ⁽¹⁾	Floating ⁽²⁾	27.5	32.3
Term facility, at Canadian Prime Advances, due to 2014 ⁽¹⁾	Floating ⁽²⁾	0.3	0.3
Term loan, at LIBOR, due to 2014 ⁽¹⁾	Floating ⁽²⁾	7.0	8.2
Notes, at fixed rate of 7.93%, due to 2022	8.302%	23.4	24.4
Muskeg River: Term loan, at BA rates, due to 2014 ⁽¹⁾	Floating ⁽²⁾	22.4	26.0
Term facility, at Canadian Prime Advances, due to 2014 ⁽¹⁾	Floating ⁽²⁾	0.1	0.1
Term loan, at LIBOR, due to 2014 ⁽¹⁾	Floating ⁽²⁾	5.6	6.5
Notes, at fixed rate of 7.56%, due to 2022	7.902%	23.9	25.7

14. LONG TERM DEBT AND NON-RECOURSE LONG TERM DEBT (continued)

Non-recourse long term debt (continued)

Project Financing	Effective Interest Rate	2009	2008
Brighton Beach:			
Term loan, at BA rates, due to 2020 ⁽¹⁾	Floating ⁽²⁾	17.2	18.3
Term loan, at LIBOR, due to 2020 ⁽¹⁾	Floating ⁽²⁾	15.5	16.4
Construction overrun facility, at BA rates, due to 2020 ⁽¹⁾	Floating ⁽²⁾	4.2	4.5
Construction overrun facility, at LIBOR, due to 2020 ⁽¹⁾	Floating ⁽²⁾	3.8	4.0
Notes, at fixed rate of 6.924%, due to 2024	7.025%	98.5	101.8
Cory:			
Cost overrun facility, at BA rates, due to 2011 ⁽¹⁾	Floating ⁽²⁾	1.2	1.8
Notes, at fixed rate of 7.586%, due to 2025	7.872%	33.0	34.3
Notes, at fixed rate of 7.601%, due to 2026	7.880%	29.5	30.6
Less: Deferred financing charges		(4.3)	(5.2)
		403.8	457.2
Less: Amounts due within one year		49.0	44.8
		\$354.8	\$412.4

BA – Bankers' Acceptance

LIBOR – London Interbank Offered Rate

Euribor – Euro Interbank Offered Rate

BBSY – Bank Bill Swap Bid Rate

⁽¹⁾ The above interest rates have additional margin fees at a weighted average rate of 1.2% (2008 – 1.2%). The margin fees are subject to escalation.

⁽²⁾ Floating interest rates have been partially or completely hedged with interest rate swaps (see Note 24).

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, 2009 was \$1,095.1 million (2008 – \$1,095.8 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) **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, 2009, no amounts were outstanding under the guarantee.

14. LONG TERM DEBT AND NON-RECOURSE LONG TERM DEBT (continued)

- b) **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, 2009, the amount of the obligations under these guarantees is:

Project	Major Maintenance	Debt Service
APALP project financing	Nil ⁽¹⁾	\$6.2
Brighton Beach project financing	Nil ⁽²⁾	Nil
Cory project financing	Nil ⁽¹⁾	Nil
Joffre project financing	Nil ⁽¹⁾	\$1.5
Muskeg River project financing	Nil ⁽¹⁾	\$5.0
Scotford project financing	Nil ⁽¹⁾	\$5.1

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

⁽²⁾ Reserve requirements of \$0.1 million met with project cash flows.

- c) **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, 2009, the maximum value of the guarantee is \$26.4 million.
- d) **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:
- 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;
 - 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
 - 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, 2009, no such events have occurred.

14. LONG TERM DEBT AND NON-RECOURSE LONG TERM DEBT (continued)

Canadian Utilities Limited has also guaranteed ATCO Power's duties to operate the Barking Power generating plants in accordance with acceptable industry operating standards. The guarantee expires on September 30, 2010.

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.

Contractual maturities of debt

The undiscounted contractual maturities of long term debt and non-recourse long term debt are as follows:

	Long Term Debt		Non-Recourse Long Term Debt		Total	
	Principal	Interest ⁽¹⁾	Principal	Interest ⁽¹⁾	Principal	Interest ⁽¹⁾
2010	\$ 127.8	\$ 200.4	\$ 49.0	\$ 24.7	\$ 176.8	\$ 225.1
2011	107.6	182.7	42.8	22.4	150.4	205.1
2012	138.4	178.8	40.5	20.2	178.9	199.0
2013	50.7	170.5	36.9	17.9	87.6	188.4
2014	138.4	168.9	33.2	16.1	171.6	185.0
2015 and thereafter	2,557.5	1,985.7	205.7	70.9	2,763.2	2,056.6
	\$3,120.4	\$2,887.0	\$408.1	\$172.2	\$3,528.5	\$3,059.2

⁽¹⁾ Interest payments on floating rate debt that has not been hedged have been estimated using rates in effect at December 31, 2009. Interest payments on debt that has been hedged have been estimated using the hedged rates.

Of the \$176.8 million due in 2010, \$125.0 million is to be refinanced with new debt or from existing unused long term credit lines and is, therefore, excluded from long term debt due within one year in the balance sheet.

Interest expense

Interest expense is as follows:

	2009	2008
Long term debt	\$203.8	\$186.3
Non-recourse long term debt	31.8	36.8
Bank indebtedness	2.5	7.2
Amortization of deferred financing charges	3.5	3.2
	\$241.6	\$233.5

Interest paid amounted to \$233.4 million (2008 — \$226.7 million).

15. DEFERRED CREDITS

	2009	2008
Accrued other post employment benefits liability (Note 23)	\$ 64.2	\$ 58.5
Deferred availability incentives	67.1	61.3
Asset retirement obligations	83.2	77.7
Power generation revenue contract liability (Note 24)	20.4	44.6
Liability to customers for refund of future income taxes (Note 2)	12.1	19.2
Deferred revenues	3.8	12.2
Other	26.5	28.4
	\$277.3	\$301.9

Deferred availability incentives

Amortization of deferred availability incentives, which was recorded in revenues, amounted to \$16.3 million (2008 – \$12.6 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:

	2009	2008
Obligations at beginning of year	\$77.7	\$73.1
Accretion expense	4.1	3.6
Obligations incurred	1.4	1.0
Obligations at end of year	\$83.2	\$77.7

The Corporation estimates the undiscounted amount of cash flow required to settle the asset retirement obligations is approximately \$137 million, which will be incurred between 2011 and 2052. The credit-adjusted risk-free discount rates used to calculate the fair value of the asset retirement obligations have a weighted average rate of 5.6%.

16. EQUITY PREFERRED SHARES

CU Inc. equity preferred shares

Authorized and issued

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

Issued:

	Stated Value (dollars)	Redemption Dates	2009		2008	
			Shares	Amount	Shares	Amount
Cumulative Redeemable Preferred Shares						
4.60% Series 1	\$25.00	See below	4,600,000	\$115.0	4,600,000	\$115.0
6.70% Series 2	\$25.00	See below	6,400,000	160.0	-	-
				\$275.0		\$115.0

On March 27, 2009, CU Inc., a subsidiary corporation, issued \$160.0 million Cumulative Redeemable Preferred Shares Series 2 at a price of \$25.00 per share. Holders of the Series 2 preferred shares will be entitled to receive, as and when declared by the Board of Directors of the Corporation, fixed cumulative preferential cash dividends, payable quarterly for an initial period of five years at a rate of \$1.675 per share to yield 6.70% annually. Thereafter the dividend rate will reset every five years to the then current 5-Year Government of Canada bond yield plus 4.81%.

Fair values

Fair values for the CU Inc. preferred shares determined using quoted market prices for the same or similar issues are \$278.3 million (2008 - \$67.2 million).

Redemption privileges

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

On June 1, 2014, and on June 1 of every fifth year thereafter, CU Inc. may redeem the Series 2 Preferred Shares in whole or in part at par. Holders may elect to convert any or all of their Series 2 Preferred Shares into an equal number of Cumulative Redeemable Preferred Shares Series 3 on June 1, 2014, and on June 1 of every fifth year thereafter. Holders of the Series 3 Preferred Shares will be entitled to receive floating rate cumulative preferential cash dividends, payable quarterly for an initial period of five years at a rate equal to the then current 3-month Government of Canada Treasury Bill yield plus 4.81%. On June 1, 2019, and on June 1 of every fifth year thereafter ("Series 3 Conversion Date"), holders of the Series 3 Preferred Shares may elect to convert any or all of their Series 3 Preferred Shares back into an equal number of Series 2 Preferred Shares. On June 1, 2014, or thereafter, CU Inc. may redeem the Series 3 Preferred Shares in whole or in part at \$25.00 on a Series 3 Conversion Date or at \$25.50 on any other date.

16. EQUITY PREFERRED SHARES (continued)

Canadian Utilities Limited equity preferred shares

Authorized and issued

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

Issued:

	Stated Value (dollars)	Redemption Dates	2009		2008	
			Shares	Amount	Shares	Amount
Cumulative Redeemable Second Preferred Shares						
5.8% Series W	\$25.00	See below	6,000,000	\$150.0	6,000,000	\$150.0
6.0% Series X	\$25.00	See below	6,000,000	150.0	6,000,000	150.0
Perpetual Cumulative Second Preferred Shares						
4.35% Series O	\$25.00	December 2, 2011	1,600,000	40.0	1,600,000	40.0
4.35% Series T	\$25.00	December 2, 2011	1,600,000	40.0	1,600,000	40.0
4.35% Series U	\$25.00	December 2, 2011	800,000	20.0	800,000	20.0
4.70% Series V	\$25.00	October 3, 2012	4,400,000	110.0	4,400,000	110.0
				\$510.0		\$510.0
Total CU Inc. and Canadian Utilities Limited equity preferred shares				\$785.0		\$625.0

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 the Canadian Utilities Limited preferred shares determined using quoted market prices for the same or similar issues are \$512.3 million (2008 — \$456.3 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.

17. CLASS A AND CLASS B SHARES

Authorized and issued

	Class A Non-Voting		Class B Common		Total	
	Shares	Amount	Shares	Amount	Shares	Amount
Authorized:	Unlimited		Unlimited			
Issued and outstanding:						
December 31, 2007	81,508,986	\$378.3	43,785,684	\$138.6	125,294,670	\$516.9
Stock options exercised	215,450	5.0	-	-	215,450	5.0
Converted: Class B to Class A	1,798,558	5.7	(1,798,558)	(5.7)	-	-
December 31, 2008	83,522,994	\$389.0	41,987,126	\$132.9	125,510,120	\$521.9
Stock options exercised	349,550	6.4	-	-	349,550	6.4
Converted: Class B to Class A	268,736	0.8	(268,736)	(0.8)	-	-
December 31, 2009	84,141,280	\$396.2	41,718,390	\$132.1	125,859,670	\$528.3

From January 1, 2010 to February 16, 2010, no stock options were granted, cancelled, or exercised and 1,556,100 Class B common shares were converted to Class A non-voting shares.

Earnings per share

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

	Three Months Ended		Year Ended	
	December 31		December 31	
	2009	2008	2009	2008
	<i>(Unaudited)</i>			
Weighted average shares outstanding	125,752,093	125,507,489	125,637,206	125,407,951
Effect of dilutive stock options	156,676	338,936	137,044	376,466
Weighted average dilutive shares outstanding	125,908,769	125,846,425	125,774,250	125,784,417

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

17. CLASS A AND CLASS B SHARES (continued)

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

Normal course issuer bid

On May 23, 2008, Canadian Utilities Limited commenced a normal course issuer bid for the purchase of up to 3% of the outstanding Class A shares. The bid expired on May 22, 2009. From May 23, 2008, to May 22, 2009, no shares were purchased. The Corporation is applying to the Toronto Stock Exchange to recommence its normal course issuer bid in the first quarter of 2010.

18. CAPITAL DISCLOSURES

The Corporation's objectives when managing capital have been:

1. to safeguard the ability to continue as a going concern, so that it can continue to provide returns to share owners and benefits for other stakeholders;
2. to maintain an appropriate credit rating in order to provide efficient and cost effective access to funds required for operations and growth; and
3. to remain within the capital structure approved by the AUC for the utility operations.

The Corporation includes share owners' equity, equity preferred shares, long term debt and non-recourse long term debt in its determination of capitalization. In managing its capital, the Corporation considers both the regulated and non-regulated operations in the consolidated group as well as changes in economic conditions and risks impacting the core assets and operations. In maintaining or adjusting its capital structure, the Corporation may adjust the amount of dividends paid to share owners, issue or purchase Class A and Class B shares, and issue or redeem equity preferred shares, long term debt and non-recourse long term debt.

The Corporation's utility operations are regulated primarily by the AUC, which, through the generic cost of capital decisions issued in 2004 and 2009, established the capital structure for each utility. The capitalization involves the use of long term debt and preferred share financings; the AUC approved the continued use of the latter in a decision issued in 2006. While it has been one of the Corporation's objectives to capitalize its utility operations consistent with the AUC approved capital structure, at December 31, 2009, the Corporation was not capitalized consistent with the 2009 generic cost of capital decision due to the fact that this decision was not received until November 12, 2009. The Corporation will reconsider whether the capital structure should remain consistent with the 2009 generic cost of capital decision for future periods.

While the Corporation's utility operations have had an objective of being capitalized consistent with the AUC decisions, the Corporation itself is not restricted in its capital structure. The capital structure for the Corporation is set relative to risk and to meet the financial and operational objectives of the Corporation (while considering the decisions of the regulator).

18. CAPITAL DISCLOSURES (continued)

Decisions on the level and type of financing are based on assessments by management in line with the Corporation's objectives. In determining the type of financing to be undertaken by a given operation, the Corporation has a goal of managing the financial risk to the Corporation as a whole.

Capital is monitored through an equity capitalization measure which is calculated as total equity divided by total capitalization. Total equity is comprised of Class A and Class B shares, contributed surplus, retained earnings, accumulated other comprehensive income and equity preferred shares. Total capitalization is comprised of long term debt, non-recourse long term debt and total equity. The Corporation's strategy has been to maintain the equity capitalization allowed by the regulator for the regulated operations and to structure the non-regulated operations so as to sustain access to cost effective financing by maintaining high credit ratings on debt and preferred shares. The Corporation looks to maintain an equity capitalization in the range of 45% to 55%.

Other measures that are taken into consideration are interest coverage and interest and preferred dividend coverage. Interest coverage is calculated by dividing earnings before income taxes, interest expense and dividends on equity preferred shares by total interest expense. Interest and preferred dividend coverage is calculated by dividing earnings before income taxes, interest expense and dividends on equity preferred shares by interest expense and dividends on equity preferred shares (grossed up to pre-tax equivalents). The Corporation looks to maintain interest coverage of at least 2.5 and interest and preferred dividend coverage of at least 2.0; these objectives are unchanged from 2008.

Equity capitalization, interest coverage and interest and preferred dividend coverage do not have any standardized meaning under GAAP and might not be comparable to similar measures presented by other companies.

The Corporation's key measures of capital structure are as follows:

	2009	2008
Class A and Class B shares	\$ 528.3	\$ 521.9
Contributed surplus	3.2	2.6
Retained earnings	2,568.6	2,279.1
Accumulated other comprehensive income	(54.0)	(55.1)
Equity preferred shares	785.0	625.0
Total equity	3,831.1	3,373.5
Long term debt	3,102.3	2,844.3
Non-recourse long term debt	354.8	412.4
Total debt	3,457.1	3,256.7
Total capitalization	\$7,288.2	\$6,630.2
Equity capitalization	53%	51%

The equity capitalization is consistent with the Corporation's objectives. Total equity increased primarily due to higher earnings of the Corporation reflected in increased retained earnings and higher equity preferred shares due to the preferred share financing for utility capital expenditures. Total debt increased primarily due to financings for utility capital expenditures, ATCO Energy Solutions' business activities and project expenditures and ATCO Power's Karratha project, partially offset by redemptions of long term debt and non-recourse long term debt.

18. CAPITAL DISCLOSURES (continued)

	2009	2008
Interest coverage	3.5	3.5
Interest and preferred dividend coverage	2.8	2.9

For the year ended December 31, 2009, the Corporation was in compliance with externally imposed requirements on its capital (including debt covenants and credit facilities). The Corporation will continue to assess its capital structure and objectives in light of decisions received from the AUC.

19. STOCK BASED COMPENSATION PLANS

Stock option plan

Of the 6,400,000 Class A non-voting shares authorized for grant in respect of options under Canadian Utilities Limited's stock option plan, 2,989,500 Class A non-voting shares are available for issuance at December 31, 2009. Options may be granted to 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:

	2009		2008	
	Class A Shares	Weighted Average Exercise Price	Class A Shares	Weighted Average Exercise Price
Options at beginning of year	1,238,250	\$30.86	1,304,200	\$28.02
Granted	-	-	149,500	44.38
Exercised	(349,550)	18.19	(215,450)	23.09
Forfeited	(16,800)	46.40	-	-
Options at end of year	871,900	\$35.63	1,238,250	\$30.86

Information about stock options outstanding at December 31, 2009 is summarized below:

Range of Exercise Prices	Class A Shares	Options Outstanding		Options Exercisable	
		Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Class A Shares	Weighted Average Exercise Price
\$20.65 - \$28.65	253,700	1.8	\$23.88	253,700	\$23.88
\$30.25 - \$37.12	202,000	5.0	30.31	161,200	30.30
\$43.49 - \$47.84	416,200	7.1	45.38	168,700	45.32
\$20.65 - \$47.84	871,900	5.1	\$35.63	583,600	\$31.85

19. STOCK BASED COMPENSATION PLANS (continued)

In 2009, no options were granted by Canadian Utilities Limited. Options have a term of ten years and vest over the first five years.

Changes in contributed surplus are summarized below:

	2009	2008
Contributed surplus at beginning of year	\$2.6	\$1.9
Stock option expense	0.6	0.9
Mid-term incentive plan purchases	-	(0.2)
Contributed surplus at end of year	\$3.2	\$2.6

The Corporation uses the Black-Scholes option pricing model, which estimated the weighted average fair value of the options granted. During 2009, no options were granted. The weighted average fair value of the options granted in 2008 was \$6.71 per option. The following are the weighted average assumptions:

	2009	2008
Risk free interest rate	No grants	3.2%
Expected holding period prior to exercise	No grants	6.6 years
Share price volatility	No grants	18.8%
Estimated annual Class A share dividend	No grants	3.0%

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 \$1.1 million (2008 — \$2.0 million income).

20. CHANGES IN NON-CASH WORKING CAPITAL

	2009	2008
<i>Operating activities, changes related to:</i>		
Accounts receivable	\$(24.4)	\$(14.8)
Inventories	13.8	(8.2)
Regulatory assets	23.0	(12.4)
Prepaid expenses	(4.8)	(0.4)
Accounts payable and accrued liabilities	(43.3)	9.1
Income taxes payable	(8.9)	2.0
Regulatory liabilities	(10.5)	11.9
	\$(55.1)	\$(12.8)
<i>Investing activities, changes related to:</i>		
Accounts receivable	\$ (3.9)	\$ -
Inventories	4.1	(1.7)
Prepaid expenses	-	1.6
Accounts payable and accrued liabilities	(29.7)	37.5
	\$(29.5)	\$ 37.4
<i>Financing activities, changes related to:</i>		
Accounts receivable	\$ -	\$ (0.1)

21. JOINT VENTURES

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

	2009	2008
<i>Statement of earnings</i>		
Revenues	\$ 487.2	\$ 609.4
Operating expenses	281.2	378.1
Depreciation and amortization	46.7	46.9
Interest	26.9	31.1
	132.4	153.3
Interest and other income (loss)	(5.3)	2.0
Earnings from joint ventures before income taxes	\$ 127.1	\$ 155.3
<i>Balance sheet</i>		
Current assets	\$ 112.7	\$ 191.2
Current liabilities	(90.2)	(165.9)
Property, plant and equipment	768.6	837.4
Other assets	27.3	63.6
Non-recourse long term debt	(288.3)	(318.4)
Other non-current liabilities	(71.0)	(106.3)
Investment in joint ventures	\$ 459.1	\$ 501.6

21. JOINT VENTURES (continued)

	2009	2008
<i>Statement of cash flows</i>		
Operating activities	\$ 134.3	\$ 185.8
Investing activities	3.0	(30.3)
Financing activities	(150.5)	(149.7)
Foreign currency translation	(1.2)	(2.7)
Increase (decrease) in cash position	\$ (14.4)	\$ 3.1

Current assets include cash of \$38.8 million (2008 — \$70.3 million) which is only available for use within the joint ventures.

22. RELATED PARTY TRANSACTIONS

In transactions with ATCO Ltd. and its subsidiary corporations, the Corporation sold fuel in the amount of \$1.5 million (2008 — \$2.6 million), provided computer operations and systems development services totaling \$3.9 million (2008 — \$14.1 million), recovered administrative expenses totaling \$7.8 million (2008 — \$1.5 million) and incurred administrative expenses and corporate signature rights totaling \$8.8 million (2008 — \$8.9 million). The Corporation incurred no capital expenditures with related parties (2008 — \$10.3 million that were recorded in property, plant and equipment).

In transactions with entities related through common control, the Corporation incurred advertising, promotion and administrative expenses totaling \$1.4 million (2008 — \$1.4 million).

At December 31, 2009, accounts receivable due from related parties amounted to \$3.8 million (2008 — \$3.3 million) and accounts payable due to related parties amounted to \$3.5 million (2008 — \$6.6 million).

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

23. EMPLOYEE FUTURE BENEFITS

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

23. EMPLOYEE FUTURE BENEFITS (continued)

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

	2009		2008	
	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	\$1,399.1	\$ -	\$1,688.6	\$ -
Actual return on plan assets	190.1	-	(236.4)	-
Employee contributions	3.3	-	3.6	-
Employer contributions	1.0	-	1.0	-
Benefit payments	(47.7)	-	(45.5)	-
Payments to defined contribution plans ⁽¹⁾	(15.0)	-	(12.2)	-
End of year	\$1,530.8	\$ -	\$1,399.1	\$ -
<i>Accrued benefit obligations:</i>				
Beginning of year	\$1,399.6	\$ 57.8	\$1,650.7	\$ 79.4
Current service cost	25.9	1.7	37.1	2.1
Interest cost	93.6	4.2	91.8	3.8
Employee contributions	3.3	-	3.6	-
Benefit payments from plan assets ⁽²⁾	(47.7)	-	(45.5)	-
Benefit payments by employer	(4.8)	(1.9)	(4.5)	(2.1)
Experience losses (gains) ⁽³⁾	51.3	6.2	(333.6)	(25.4)
End of year ⁽⁴⁾	\$1,521.2	\$ 68.0	\$1,399.6	\$ 57.8
<i>Funded status:</i>				
Excess (deficiency) of assets over obligations ⁽⁴⁾	\$ 9.6	\$(68.0)	\$ (0.5)	\$(57.8)
Amounts not yet recognized in financial statements:				
Unrecognized net cumulative experience losses on plan assets and accrued benefit obligations	251.4	(10.6)	287.4	(17.2)
Unrecognized net transitional liability (asset)	(119.4)	14.4	(153.5)	16.5
Accrued asset (liability) (Notes 12, 15)	\$ 141.6	\$(64.2)	\$ 133.4	\$(58.5)
Regulatory asset (liability) ⁽⁵⁾ (Note 2)	\$ (120.9)	\$ 51.3	\$ (110.2)	\$ 46.9

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

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

⁽³⁾ A decrease in the liability discount rate at December 31 assumption resulted in the experience losses in 2009 (2008 – an increase in the liability discount rate resulted in experience gains).

⁽⁴⁾ The non-registered, non-funded defined benefit pension plans accrued benefit obligations increased to \$76.3 million at December 31, 2009 (2008 – \$74.1 million) due to a decrease in the liability discount rate. Apart from these obligations, the excess of assets over obligations for the registered defined benefit pension plans at December 31, 2009 was \$85.9 million (2008 – \$73.6 million).

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

23. EMPLOYEE FUTURE BENEFITS (continued)

	2009		2008	
	Pension Benefit Plans	Other Post Employment Benefit Plans	Pension Benefit Plans	Other Post Employment Benefit Plans
Benefit plan cost				
<i>Components of benefit plan cost:</i>				
Current service cost	\$ 25.9	\$ 1.7	\$ 37.1	\$ 2.1
Interest cost	93.6	4.2	91.8	3.8
Actual return on plan assets	(190.1)	-	236.4	-
Experience losses (gains) on accrued benefit obligations	51.3	6.2	(333.6)	(25.4)
	(19.3)	12.1	31.7	(19.5)
<i>Adjustments to recognize long term nature of employee future benefits:</i>				
Unrecognized portion of actual return on plan assets	78.9	-	(343.6)	-
Unrecognized portion of experience gains on accrued benefit obligations	(51.3)	(6.2)	333.6	25.4
Amortization of net cumulative experience losses on plan assets and accrued benefit obligations	8.4	(0.4)	11.7	-
Amortization of net transitional liability (asset)	(34.1)	2.1	(34.0)	1.9
	1.9	(4.5)	(32.3)	27.3
Defined benefit plans cost (income)	(17.4)	7.6	(0.6)	7.8
Defined contribution plans cost	16.2	-	14.1	-
Adjustment to beginning liability	-	-	-	(10.4)
Total cost (income)	(1.2)	7.6	13.5	(2.6)
Less: Capitalized	1.8	2.4	2.0	2.5
Less: Unrecognized defined benefit plans cost (income) ^{(1) (2)}	(10.4)	2.4	(0.9)	2.4
Net cost (income) recognized ⁽²⁾	\$ 7.4	\$ 2.8	\$ 12.4	\$ (7.5)

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

⁽²⁾ Net cost recognized for pension benefit plans in 2009 includes the amortization of \$3.9 million (2008 – \$3.4 million) of the deferred pension assets recorded by the Corporation upon the adoption of the current accounting standard in 2000. On October 11, 2006, the AUC approved recovery of these assets for a nine-year period commencing January 1, 2005 (Note 2).

In the unaudited three months ended December 31, 2009, net cost of \$0.6 million (2008 – \$3.6 million) was recognized for pension benefit plans and net expense of \$0.6 million (2008 – net income of \$1.5 million) was recognized for other post employment benefit plans.

23. EMPLOYEE FUTURE BENEFITS (continued)

Weighted average assumptions

	2009		2008	
	Pension Benefit Plans	Other Post Employment Benefit Plans	Pension Benefit Plans	Other Post Employment Benefit Plans
<i>Assumptions regarding benefit plan cost:</i>				
Expected long term rate of return on plan assets for the year	7.5%	-	7.0%	-
Liability discount rate for the year	7.0%	7.0%	5.5%	5.5%
Average compensation increase for the year	(1)	-	(1)	-
<i>Assumptions regarding accrued benefit obligations:</i>				
Liability discount rate at December 31	6.4%	6.4%	7.0%	7.0%
Long term inflation rate	2.0%	(2)	2.5%	(2)

⁽¹⁾ The assumed average compensation increases are 3.5% for 4 years (2009-2012) and 3.0% thereafter.

⁽²⁾ The assumed annual health care cost trend rate increases used in measuring the accumulated post employment benefit obligation are as follows: for drug costs, 6.5% for 2009 grading down over 15 years to 4.5% (2008 – 7.2% for 2008 grading down over 5 years to 4.5%), for other medical costs, 4.5% for 2009 and 4.0% thereafter, and for dental costs, 4.0% for 2009 and thereafter (2008 – 4.0% for 2008 and thereafter).

The sensitivities of key assumptions used in measuring accrued benefit obligations and benefit plan cost for 2009 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.

23. EMPLOYEE FUTURE BENEFITS (continued)

	2009 Pension Benefit Plans		2009 Other Post Employment Benefit Plans	
	Accrued Benefit Obligation	Benefit Plan Cost	Accrued Benefit Obligation	Benefit Plan Cost
Expected long term rate of return on plan assets				
1% increase ⁽¹⁾	-	\$(4.0)	-	-
1% decrease ⁽¹⁾	-	\$ 4.1	-	-
Liability discount rate				
1% increase ⁽¹⁾	\$(50.3)	\$(3.2)	\$(2.3)	\$(0.2)
1% decrease ⁽¹⁾	\$ 61.7	\$ 5.2	\$ 2.8	\$ 0.3
Future compensation rate				
1% increase ⁽¹⁾	\$ 12.0	\$ 1.9	-	-
1% decrease ⁽¹⁾	\$(11.1)	\$(1.7)	-	-
Long term inflation rate				
1% increase ⁽¹⁾⁽²⁾⁽³⁾	\$ 48.9	\$ 5.8	\$ 2.1	\$ 0.4
1% decrease ⁽¹⁾⁽³⁾	\$(41.6)	\$(5.2)	\$(1.8)	\$(0.3)

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

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

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

Pension benefit plan assets

	2009		2008	
	Amount	%	Amount	%
Plan asset mix:				
Equity securities ⁽¹⁾	\$ 842.6	55.0	\$ 755.5	54.0
Fixed income securities ⁽²⁾	584.1	38.2	526.9	37.7
Real estate ⁽³⁾	90.1	5.9	90.8	6.5
Cash and other assets ⁽⁴⁾	14.0	0.9	25.9	1.8
	\$1,530.8	100.0	\$1,399.1	100.0

⁽¹⁾ Equity securities consist of investments in domestic and foreign preferred and common shares. At December 31, 2009, the market values of investments in United States' securities and international equities, denominated in a number of different currencies, are \$146.4 million and \$151.1 million, respectively (2008 – \$150.8 million and \$136.8 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.

23. EMPLOYEE FUTURE BENEFITS (continued)

At December 31, 2009, plan assets include long term debt of CU Inc. having a market value of \$15.1 million (2008 – \$13.9 million), Class A non-voting and Class B common shares of Canadian Utilities Limited having a market value of \$17.8 million (2008 – \$16.1 million) and Class I Non-Voting Shares of ATCO Ltd. having a market value of \$17.0 million (2008 – \$13.8 million).

Funding

Employees are required to contribute a percentage of their salary to registered pension plans. The Corporation is required to contribute its share of contributions on behalf of the defined contribution members of the pension plans and to provide the balance of the funding necessary to ensure that benefits will be fully provided for at retirement for the members of the defined benefit pension plans.

The Corporation has not made material contributions since April 1, 1996 due to the defined benefit plans' surplus position. Declines in stock and bond markets combined with increasing liabilities due to changes in actuarial assumptions and additional employee service have created funding deficits. Actuarial valuations are expected to be completed by May 2010. Based on the information currently available, the funding contributions for 2010 are expected to be in the range of \$75.0 million to \$90.0 million.

For the purposes of any funding requirements pertaining to utility operations the Corporation includes the cost of funding in its rate applications to the AUC and has filed a pension common matters application with the AUC requesting deferral accounts for 2010. Based on the assumption that the AUC will allow full recovery of these costs, the net funding contributions are expected to be in the range of \$15.0 million to \$20.0 million.

24. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

The Corporation's Board of Directors ("Board") is responsible for understanding the principal risks of the business in which the Corporation is engaged, achieving a proper balance between risks incurred and the potential return to share owners, and confirming that there are systems in place that effectively monitor and manage those risks with a view to the long-term viability of the Corporation. The Board has established a Risk Review Committee, which reviews significant risks associated with future performance, growth and lost opportunities identified by management that could materially affect the Corporation's ability to achieve its strategic or operational targets. This committee is responsible for confirming that management has procedures in place to mitigate identified risks.

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

At December 31, 2009, the following derivative instruments were outstanding: interest rate swaps that hedge interest rate risk on the variable future cash flows associated with a portion of long term debt and non-recourse long term debt, foreign currency forward contracts that hedge foreign currency risk on the future cash flows associated with specific firm commitments or anticipated transactions and certain natural gas purchase contracts that were not considered own-use contracts.

24. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (continued)

The derivative assets and liabilities comprise the following:

	2009	2008
<i>Derivative assets – current:</i>		
Interest rate swap agreements	\$ 1.2	\$ -
Foreign currency forward swaps	-	1.7
	\$ 1.2	\$ 1.7
<i>Derivative assets – non-current:</i>		
Natural gas purchase contracts	\$26.0	\$60.1
Interest rate swap agreements	5.4	-
Foreign currency forward swaps	-	0.3
	\$31.4	\$60.4
<i>Derivative liabilities – current:</i>		
Interest rate swap agreements	\$ 2.4	\$ 5.4
Foreign currency forward swaps	0.5	-
	\$ 2.9	\$ 5.4
<i>Derivatives liabilities – non-current:</i>		
Interest rate swap agreements	\$ 5.9	\$12.4

24. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (continued)

Interest rate risk

The Corporation's interest-bearing assets and liabilities include cash and short-term investments, bank indebtedness, long term debt and non-recourse long term debt. The interest rate risk faced by the Corporation is largely a result of its non-recourse long term debt at variable rates and cash and short term investments. The Corporation has converted certain variable rate long term debt and non-recourse long term debt to fixed rate debt through the following interest rate swap agreements:

Financing	Swap Fixed Interest Rate ⁽¹⁾	Variable Debt Interest Rate	Maturity Date	Notional Principal	
				2009	2008
ATCO Frontec (see Note 4): (2008 - €20.8 million)	5.457%	90 day Euribor	October 2010	\$ -	\$ 35.5
Karratha: (\$100.0 million AUD)	5.710%	Bank Bill Rate in Australia	June 2015	94.4	-
Osborne: (\$21.0 million AUD (2008 - \$24.9 million AUD))	7.433%	Bank Bill Rate in Australia	December 2013	19.7	21.3
APALP:	7.750%	6 month LIBOR	December 2011	40.7	61.7
Joffre:	7.536%	90 day BA	September 2012	11.5	15.6
Scotford:	3.328%	90 day BA	November 2013	27.8	32.6
	3.726%	3 month LIBOR	November 2013	7.0	8.2
Muskeg River:	5.553%	90 day BA	December 2012	22.5	26.1
	5.653%	3 month LIBOR	December 2012	5.6	6.5
Brighton Beach:	5.867%	90 day BA	June 2009	-	8.0
	6.700%	90 day BA	March 2019	30.0	32.2
	4.578%	90 day BA	June 2020	4.2	-
	4.784%	3 month LIBOR	June 2020	3.8	-
Cory:	6.591%	90 day BA	June 2011	0.9	1.5
				\$268.1	\$249.2

BA – Bankers' Acceptance

LIBOR – London Interbank Offered Rate

Euribor – Euro Interbank Offered Rate

⁽¹⁾ The above swap fixed interest rates include any long term debt margin fees; the margin fees are subject to escalation (Note 14).

The Corporation has fixed interest rates, either directly or through interest rate swap agreements, on 95% (2008 — 97%) of total long term debt and non-recourse long term debt. Consequently, the exposure to fluctuations in future cash flows, with respect to debt, as a result of changes in market interest rates is

24. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (continued)

limited. Interest rate swaps are designated as cash flow hedges; changes in the fair value of highly effective cash flow hedges, which include all but the Joffre and APALP interest rate swaps, are recorded in other comprehensive income. Changes in the fair value of the Joffre and APALP interest rate swaps were \$0.7 million and \$1.4 million, respectively, which were recognized in earnings. In the fourth quarter of 2008, the APALP interest rate swap became ineffective. Up to that point, the swap had been highly effective and therefore changes in the fair value were recorded in other comprehensive income. After this, changes in the fair value have been recorded in earnings.

The Corporation's cash and short term investments include fixed rate instruments with maturities of generally 90 days or less that are reinvested as they mature. The Corporation has exposure to interest rate movements that occur beyond the term of maturity of the fixed rate investments.

Foreign currency exchange rate risk

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

Foreign currency exchange rate risk arises from financial instruments denominated in a currency other than the functional currency. The Corporation has entered into foreign currency forward contracts in order to fix the exchange rate on certain service contracts, planned equipment expenditures and operational cash flows denominated in U.S. dollars. At December 31, 2009, the contracts consist of purchases of \$0.2 million U.S. in return for Canadian dollars and \$2.8 million U.S. in return for Australian dollars (2008 — purchases of \$0.5 million U.S. in return for Canadian dollars and \$10.7 million U.S. in return for Australian dollars).

Natural gas purchase contracts and associated power generation revenue contract liability

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

As all but the excess volume of natural gas is committed to the Corporation's power generation obligations, the Corporation could not recognize the entire fair values of these natural gas purchase contracts in its revenues. Consequently, the Corporation has recognized a provision for a power generation revenue contract and records adjustments to the power generation revenue contract liability concurrently with the mark-to-market adjustments for the natural gas purchase contracts derivative asset. This power generation revenue contract liability is included in deferred credits in the consolidated balance sheet.

The mark-to-market adjustment for the derivative asset and the corresponding adjustment for the associated power generation revenue contract liability decreased earnings by \$2.0 million, net of income taxes, for the unaudited three months ended December 31, 2009 (2008 — \$1.1 million) and decreased earnings by \$7.4 million, net of income taxes, for the year ended December 31, 2009 (2008 —

24. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (continued)

\$2.0 million). At December 31, 2009, the natural gas purchase contracts derivative asset is \$26.0 million (2008 – \$60.1 million), a net change of \$34.1 million, and the power generation revenue contract liability is \$20.4 million (2008 – \$44.6 million), a net change of \$24.2 million.

Credit risk

For cash and short term investments and accounts receivable, credit risk represents the carrying amount on the consolidated balance sheet. Cash and short term investments credit risk is reduced by investing in instruments issued by credit worthy financial institutions and in federal government issued short term instruments. Approximately 80% of the short term investments at December 31, 2009 were invested in Government of Canada treasury bills and certificates of deposit issued by Canadian financial institutions.

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.

The maximum exposure to credit risk is the carrying value of loans and receivables and derivative financial instruments on the balance sheet. The Corporation does not have a concentration of credit risk with any counterparties. A significant portion of loans and receivables arise from the Corporation's operations in Alberta.

Accounts receivable credit risk is reduced by a large and diversified customer base, requirement for of credit security such as 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 and the ability to request recovery through customer rates any losses from retailers beyond that covered by the retailer security provided in accordance with provincial regulations.

Accounts receivable are non-interest bearing and are generally due in 30 to 90 days. At December 31, 2009, the provision for impairment of credit losses was \$1.5 million. The changes in the provision for impairment were as follows:

	2009
Provision at beginning of year	\$ 1.9
Adjustment due to ATCO Structures & Logistics transaction (Note 4)	(0.5)
Impairment of receivables	0.2
Receivables written off as uncollectible	(0.1)
Provision at end of year	\$ 1.5

At December 31, 2009, the aging analysis of trade receivables that are past due but not impaired is as follows:

	2009
30 to 90 days	\$3.8
Greater than 90 days	0.9
	\$4.7

No other impairments have been identified within accounts receivable.

24. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (continued)

Liquidity risk

Liquidity risk is the risk that the Corporation will not be able to meet its obligations associated with financial liabilities. Cash flow from operations provides a substantial portion of the Corporation's cash requirements. Additional cash requirements are met with the use of existing cash balances and externally through bank borrowings and the issuance of long term debt, non-recourse long term debt and preferred shares. Commercial paper borrowings and short term bank loans are used under available credit lines to provide flexibility in the timing and amounts of long term financing. The Corporation has a policy not to invest any of its cash balances in asset backed securities.

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

	2010	2011	2012	2013	2014	2015 and thereafter
Accounts payable and accrued liabilities	\$ 382.1	\$ -	\$ -	\$ -	\$ -	\$ -
Operating leases ⁽¹⁾	18.6	16.4	13.0	12.0	10.7	38.0
Long term debt (Note 14)	127.8	107.6	138.4	50.7	138.4	2,557.5
Non-recourse long term debt (Note 14)	49.0	42.8	40.5	36.9	33.2	205.7
Interest expense (Note 14)	225.1	205.1	199.0	188.4	185.0	2,056.6
Purchase obligations:						
Coal purchase contracts ⁽²⁾	51.1	52.3	53.9	55.5	57.1	242.8
Natural gas purchase contracts ⁽³⁾	37.8	12.8	13.1	6.9	0.4	-
Operating and maintenance agreements ⁽⁴⁾	19.3	18.7	16.5	17.8	20.3	45.0
Capital expenditures ⁽⁵⁾	90.9	-	-	-	-	-
Derivatives ⁽⁶⁾	5.6	3.3	2.1	1.3	1.1	2.1
Other	0.8	0.3	0.3	0.2	0.2	0.2
	\$1,008.1	\$459.3	\$476.8	\$369.7	\$446.4	\$5,147.9

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

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

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

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

⁽⁵⁾ Various contracts to purchase goods and services with respect to capital expenditures.

⁽⁶⁾ Payments on outstanding derivatives have been estimated using rates in effect at December 31, 2009.

24. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (continued)

Fair value of non-derivative financial instruments

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

	2009		2008	
	Carrying Value	Fair Value	Carrying Value	Fair Value
<i>Financial Assets</i>				
<i>Held For Trading:</i>				
Cash ⁽¹⁾	\$ 104.2	\$ 104.2	\$ 31.7	\$ 31.7
<i>Held to Maturity:</i>				
Short term investments ⁽¹⁾	691.8	691.8	716.9	716.9
<i>Loans and Receivables:</i>				
Accounts receivable ⁽¹⁾	366.4	366.4	385.5	385.5
Lease receivable ⁽²⁾	59.1	59.1	-	-
<i>Financial Liabilities</i>				
<i>Held For Trading:</i>				
Bank indebtedness ⁽¹⁾	-	-	22.0	22.0
<i>Other Liabilities:</i>				
Accounts payable and accrued liabilities ⁽³⁾	382.1	382.1	479.5	479.5
Liabilities to customers for future income taxes (see Note 15) ⁽³⁾	12.1	12.1	19.2	19.2
Long term debt ⁽⁴⁾	3,105.1	3,397.4	2,862.0	2,879.1
Non-recourse long term debt ⁽⁴⁾	403.8	438.8	457.2	489.1

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

⁽²⁾ Recorded at amortized cost. Fair value approximates the carrying amount as the lease receivable has been recorded at the present value of future minimum lease payments and negligible credit losses.

⁽³⁾ Recorded at cost. Fair value approximates the carrying amounts due to the short term nature of the financial instruments.

⁽⁴⁾ Recorded at amortized cost. Fair values are determined using quoted market prices for the same or similar issues. Where the market prices are not available, fair values are estimated using discounted cash flow analysis based on the Corporation's current borrowing rate for similar borrowing arrangements.

24. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (continued)

Fair value of derivative financial instruments

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

	2009			2008		
	Notional Principal ⁽¹⁾	Fair Value Receivable (Payable) ⁽³⁾	Maturity	Notional Principal ⁽¹⁾	Fair Value Receivable (Payable) ⁽³⁾	Maturity
<i>Held For Trading:</i>						
Interest rate swaps	\$268.1	\$ (1.7)	2010-2019	\$249.2	\$(17.8)	2009-2019
Foreign currency forward contracts	\$ 3.4	\$ (0.5)	2010	\$ 12.3	\$ 2.0	2009-2010
Natural gas purchase contracts	N/A ⁽²⁾	\$26.0	2014	N/A ⁽²⁾	\$ 60.1	2014

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

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

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

Fair value of financial instruments

The hierarchy of the Corporation's financial instruments measured at fair value is as follows (see Note 1 for description of hierarchy):

	Level 1	Level 2	Level 3	Total
Derivative assets	\$ -	\$6.6	\$26.0	\$32.6
Derivative liabilities	-	(8.8)	-	(8.8)
	\$ -	\$(2.2)	\$26.0	\$23.8

Amounts included in Level 3 relate to the natural gas purchase contracts described previously. The changes in amounts classified in Level 3 are as follows:

	2009
Balance at beginning of year	\$ 60.1
Total gains (losses) recognized in earnings	(34.1)
Purchases, sales, issues, and settlements	-
Transfers into (out of) Level 3	-
Balance at end of year	\$ 26.0

24. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (continued)

Sensitivity analysis

The analysis below illustrates the extent to which the Corporation's results are impacted by financial instruments and the underlying market risks (interest rate risk, foreign currency exchange risk, and commodity price risk). Non-derivative financial instruments (listed on the previous page) are recorded at cost and these carrying amounts are not affected by changes in market variables whereas carrying amounts of derivative financial instruments are affected by market variables.

The following table reflects the sensitivity in the fair value of outstanding derivative instruments to reasonably possible changes in Canadian, Australian and Euribor interest rates, the foreign currency exchange rates of the Canadian dollar to the U.S. dollar, the Australian dollar to the U.S. dollar and the forward price of natural gas. The analysis excludes the impact that changes in the underlying market risks would have on non-financial assets and liabilities, foreign currency translation of self-sustaining foreign operations included in accumulated other comprehensive income, and carrying value of employee future benefits. Sensitivities are reflected in changes to earnings and other comprehensive income, after income taxes.

Assumptions made in arriving at the sensitivity analysis are as follows:

- Changes in the fair value of derivative instruments that are highly effective cash flow hedges from movements in interest rates or foreign currency exchange rates are recorded in other comprehensive income.
- Changes in the fair value of derivative instruments that are not designated as hedges, that are fair value hedges or that are ineffective cash flow hedges are recorded in earnings.
- Balance sheet sensitivity to interest rates and foreign currency exchange rates relates only to derivative instruments. There are no available for sale financial assets and other liabilities are carried at amortized cost, in which case the carrying values are not affected by changes in interest rates and foreign currency exchange rates.
- Changes in the forward price of natural gas affect the mark to market adjustment of the natural gas purchase contracts derivative asset and the corresponding adjustment for the associated power generation revenue contract liability.

	2009	
	Earnings	Other Comprehensive Income
Canadian interest rates		
25 basis points increase	\$ 0.1	\$ 0.6
25 basis points decrease	\$(0.1)	\$(0.6)
Australian interest rates		
25 basis points increase	\$ -	\$ 0.8
25 basis points decrease	\$ -	\$(0.8)
Australian dollar to U.S. dollar exchange rate		
10% increase	\$ -	\$ 0.3
10% decrease	\$ -	\$(0.3)
U.S. dollar to Canadian dollar exchange rate		
10% increase	\$ 1.5	\$ -
10% decrease	\$(1.5)	\$ -
Forward price of natural gas		
10% increase	\$ 1.5	\$ -
10% decrease	\$(1.5)	\$ -

25. OTHER COMPREHENSIVE INCOME

Other comprehensive income (“OCI”) of the Corporation is comprised of two components: the unrealized gains and losses on effective cash flow hedging instruments and the foreign currency translation adjustment relating to self-sustaining foreign operations.

Changes in the components of accumulated OCI are summarized below:

	2009	2008
<i>Accumulated OCI at beginning of period:</i>		
Cash flow hedge losses ⁽¹⁾	\$(11.5)	\$ (4.6)
Foreign currency translation adjustment	(43.6)	(28.5)
	(55.1)	(33.1)
<i>Adjustment to accumulated OCI from the ATCO Structures & Logistics Transaction (see Note 4):</i>		
Cash flow hedge losses ⁽²⁾	0.2	-
Foreign currency translation adjustment	(1.3)	-
	(1.1)	-
<i>OCI for the period:</i>		
Changes in fair values of cash flow hedges ⁽³⁾	7.4	(7.7)
Transfers of cash flow hedge losses to earnings ⁽⁴⁾	0.9	0.8
	8.3	(6.9)
Foreign currency translation adjustment	(6.1)	(15.1)
	2.2	(22.0)
<i>Accumulated OCI at end of period:</i>		
Cash flow hedge losses ⁽⁵⁾	(3.0)	(11.5)
Foreign currency translation adjustment	(51.0)	(43.6)
	\$(54.0)	\$(55.1)

⁽¹⁾ Net of income taxes of \$4.2 million and \$1.9 million, respectively.

⁽²⁾ Net of income taxes of \$(0.1) million.

⁽³⁾ Net of income taxes of \$(3.2) million and \$2.3 million, respectively.

⁽⁴⁾ Net of income taxes of nil.

⁽⁵⁾ Net of income taxes of \$0.9 million and \$4.2 million, respectively.

26. CONTINGENCIES

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

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

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

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

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

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

27. SEGMENTED INFORMATION

Description of segments

In the third quarter of 2009, the Corporation reorganized its operating subsidiaries into the following segments: Utilities, Energy, and Corporate & Other. Comparative amounts for prior periods have been restated to reflect the realigned segments.

The **Utilities** segment includes the regulated distribution of natural gas by ATCO Gas, the regulated transmission of natural gas by ATCO Pipelines, and the regulated distribution and transmission of electric energy by ATCO Electric and its subsidiaries, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical.

27. SEGMENTED INFORMATION (continued)

The **Energy** segment includes the non-regulated supply of electricity and cogeneration steam by ATCO Power, the regulated supply of electricity by Alberta Power (2000), and the non-regulated natural gas gathering, processing, storage, and natural gas liquids extraction by ATCO Midstream.

The **Corporate & Other** segment includes the Corporation's equity investment in ATCO Structures & Logistics, the development, operation and support of information systems and technologies and the provision of billing services, payment processing, credit, collection and call centre services by ATCO I-Tek. The cash balances and commercial real estate owned by the Corporation in Alberta are also included in this segment.

Segmented results – Three months ended December 31

2009			Corporate	Intersegment	
2008	Utilities	Energy	& Other	Eliminations	Consolidated
<i>(Unaudited)</i>					
Revenues – external	\$361.8	\$294.7	\$ 19.1	\$ -	\$675.6
	\$323.7	\$325.4	\$ 95.2	\$ -	\$744.3
Revenues – intersegment ⁽¹⁾	6.1	1.4	33.6	(41.1)	-
	6.7	9.6	33.6	(49.9)	-
Revenues	\$367.9	\$296.1	\$ 52.7	\$(41.1)	\$675.6
	\$330.4	\$335.0	\$ 128.8	\$(49.9)	\$744.3
Earnings attributable to Class A and Class B shares	\$ 52.8	\$ 72.5	\$ 1.7	\$ 0.1	\$127.1
	\$ 45.3	\$ 65.9	\$ 3.5	\$ (0.2)	\$114.5

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

27. SEGMENTED INFORMATION (continued)

Segmented results – Year ended December 31

2009 2008	Utilities	Energy	Corporate & Other	Intersegment Eliminations	Consolidated
Revenues – external	\$1,342.8 \$1,235.1	\$1,021.9 \$1,214.3	\$ 219.3 \$ 329.5	\$ - \$ -	\$2,584.0 \$2,778.9
Revenues – intersegment ⁽¹⁾	24.7 25.8	9.5 28.4	125.6 117.8	(159.8) (172.0)	- -
Revenues	1,367.5 1,260.9	1,031.4 1,242.7	344.9 447.3	(159.8) (172.0)	2,584.0 2,778.9
Operating expenses	772.2 718.7	591.5 745.8	262.4 341.4	(161.1) (170.4)	1,465.0 1,635.5
Depreciation and amortization	192.4 248.3	116.8 110.6	20.5 28.3	- -	329.7 387.2
Interest expense	175.5 157.5	64.2 72.6	201.7 190.7	(199.8) (187.3)	241.6 233.5
Gain on ATCO Structures & Logistics transaction	- -	- -	(33.9) -	- -	(33.9) -
Earnings from investment in ATCO Structures & Logistics	- -	- -	(7.8) -	- -	(7.8) -
Interest and other income	(24.0) (25.5)	(15.4) (12.3)	(203.7) (208.6)	199.8 187.3	(43.3) (59.1)
Earnings before income taxes	251.4 161.9	274.3 326.0	105.7 95.5	1.3 (1.6)	632.7 581.8
Income taxes	37.9 3.4	63.4 101.6	23.7 30.3	0.4 (0.5)	125.4 134.8
	213.5 158.5	210.9 224.4	82.0 65.2	0.9 (1.1)	507.3 447.0
Dividends on equity preferred shares	18.1 9.9	1.4 1.4	21.2 21.2	- -	40.7 32.5
Earnings attributable to Class A and Class B shares	\$ 195.4 \$ 148.6	\$ 209.5 \$ 223.0	\$ 60.8 \$ 44.0	\$ 0.9 \$ (1.1)	\$ 466.6 \$ 414.5
Total assets	\$5,921.9 \$4,739.3	\$2,357.1 \$2,302.8	\$791.0 \$811.4	\$ 13.6 \$ 6.5	\$9,083.6 \$7,860.0
Capital expenditures ⁽²⁾	\$ 776.1 \$ 852.6	\$ 151.5 \$ 109.7	\$ 18.5 \$ 48.6	\$ - \$ -	\$ 946.1 \$1,010.9

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

⁽²⁾ Includes purchases of property, plant and equipment and intangibles.

27. SEGMENTED INFORMATION (continued)

Geographic segments

	Domestic		Foreign		Consolidated	
	2009	2008	2009	2008	2009	2008
Revenues	\$2,290.6	\$2,396.2	\$293.4	\$382.7	\$2,584.0	\$2,778.9
Property, plant and equipment and intangibles	\$6,639.4	\$5,909.5	\$335.1	\$307.4	\$6,974.5	\$6,216.9