CANADIAN UTILITIES LIMITED

An ATCO Company

CANADIAN UTILITIES LIMITED

CONSOLIDATED FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2010

PricewaterhouseCoopers LLP
Chartered Accountants
111 5 Avenue SW, Suite 3100
Calgary, Alberta
Canada T2P 5L3
Telephone +1 403 509 7500
Facsimile +1 403 781 1825
www.pwc.com/ca

Independent Auditor's Report

To the Share Owners of Canadian Utilities Limited

We have audited the accompanying consolidated financial statements of Canadian Utilities Limited, which comprise the consolidated balance sheets as at December 31, 2010 and December 31, 2009 and the consolidated statements of earnings and retained earnings, cash flows and comprehensive income for the years then ended, and the related notes including a summary of significant accounting policies.

Management's responsibility for the consolidated financial statements
Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statement that are free from material misstatement, whether due to fraud or error.

Auditor's responsibility
Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

PRICEWATERHOUSECOOPERS

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Canadian Utilities Limited as at December 31, 2010 and December 31, 2009 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta
February 22, 2011

Canadian Utilities Limited
Consolidated Statement of Earnings and Retained Earnings
(Millions of Canadian Dollars except per share data)

		Three Months Ended December 31		Year Ended December 31	
	Note	**2010**	2009	**2010**	2009
		(Unaudited)			
Revenues		**$ 709.3**	$ 675.6	**$2,657.2**	$2,584.0
Costs and expenses					
Natural gas supply		**51.4**	4.3	**88.7**	23.2
Purchased power		**14.7**	14.3	**54.2**	54.1
Operation and maintenance		**218.2**	233.5	**974.8**	965.5
Selling and administrative		**80.6**	80.2	**266.7**	258.7
Depreciation and amortization		**82.4**	80.4	**335.5**	329.7
Interest	12	**55.7**	60.7	**235.9**	241.6
Franchise fees		**46.8**	43.9	**172.7**	163.5
		549.8	517.3	**2,128.5**	2,036.3
		159.5	158.3	**528.7**	547.7
Gain on ATCO Structures & Logistics transaction	4	**-**	-	**-**	33.9
Earnings from investment in ATCO Structures & Logistics	4	**4.9**	4.1	**19.7**	7.8
Interest and other income	5	**8.2**	9.6	**39.3**	43.3
Earnings before income taxes		**172.6**	172.0	**587.7**	632.7
Income taxes	6	**32.9**	34.1	**109.2**	125.4
		139.7	137.9	**478.5**	507.3
Dividends on equity preferred shares		**11.1**	10.8	**43.5**	40.7
Earnings attributable to Class A and Class B shares		**128.6**	127.1	**435.0**	466.6
Retained earnings at beginning of period		**2,728.0**	2,485.8	**2,568.6**	2,279.1
		2,856.6	2,612.9	**3,003.6**	2,745.7
Dividends on Class A and Class B shares		**47.5**	44.3	**190.0**	177.1
Purchase of Class A shares		**1.4**	-	**5.9**	-
Retained earnings at end of period		**$2,807.7**	$2,568.6	**$2,807.7**	$2,568.6
Earnings per Class A and Class B share	15	**$ 1.02**	$ 1.01	**$ 3.46**	$ 3.71
Diluted earnings per Class A and Class B share	15	**$ 1.02**	$ 1.01	**$ 3.45**	$ 3.71
Dividends paid per Class A and Class B share	15	**$ 0.3775**	$ 0.3525	**$ 1.51**	$ 1.41

Canadian Utilities Limited
Consolidated Balance Sheet

(Millions of Canadian Dollars)

	Note	December 31 2010	2009
ASSETS			
Current assets			
Cash and short term investments	19	**$ 539.6**	$ 796.0
Accounts receivable		**407.9**	366.4
Inventories	7	**82.0**	79.8
Income taxes recoverable	6	**-**	8.5
Future income taxes	6	**2.0**	6.6
Regulatory assets	2	**16.9**	37.4
Derivative assets	22	**2.9**	1.2
Prepaid expenses and other assets		**30.7**	32.0
		1,082.0	1,327.9
Property, plant and equipment	8	**7,036.3**	6,732.7
Intangibles	9	**259.1**	241.8
Investment in ATCO Structures & Logistics	4	**137.9**	121.9
Regulatory assets	2	**460.7**	383.9
Derivative assets	22	**5.8**	31.4
Other assets	10	**433.5**	244.0
		$9,415.3	$9,083.6
LIABILITIES AND SHARE OWNERS' EQUITY			
Current liabilities			
Accounts payable and accrued liabilities		**$ 404.9**	$ 382.1
Income taxes payable		**0.6**	-
Regulatory liabilities	2	**17.0**	26.1
Derivative liabilities	22	**2.9**	2.9
Long term debt due within one year	12	**3.3**	2.8
Non-recourse long term debt due within one year	12	**38.3**	49.0
		467.0	462.9
Future income taxes	6	**540.7**	478.1
Regulatory liabilities	2	**666.1**	571.2
Derivative liabilities	22	**6.1**	5.9
Deferred credits	13	**237.1**	277.3
Long term debt	12	**3,060.3**	3,102.3
Non-recourse long term debt	12	**302.8**	354.8
Equity preferred shares	14	**860.0**	785.0
Class A and Class B share owners' equity			
Class A and Class B shares	15	**533.1**	528.3
Contributed surplus	17	**1.2**	3.2
Retained earnings		**2,807.7**	2,568.6
Accumulated other comprehensive income	23	**(66.8)**	(54.0)
Retained earnings and accumulated other comprehensive income		**2,740.9**	2,514.6
		3,275.2	3,046.1
		$9,415.3	$9,083.6

[Original signed by N.C. Southern]
____
DIRECTOR

[Original signed by J.W. Simpson]
____
DIRECTOR

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

	Note	Three Months Ended December 31 **2010**	2009	Year Ended December 31 **2010**	2009
		(Unaudited)			
Operating activities					
Earnings attributable to Class A and Class B shares		**$ 128.6**	$ 127.1	**$ 435.0**	$ 466.6
Adjustments for:					
Depreciation and amortization		**82.4**	80.4	**335.5**	329.7
Future income taxes		**(11.6)**	(5.3)	**(7.4)**	0.8
Gain on ATCO Structures & Logistics transaction	4	**-**	-	**-**	(33.9)
Earnings from investment in ATCO Structures & Logistics		**(4.9)**	(4.1)	**(19.7)**	(7.8)
Dividends received from ATCO Structures & Logistics	4	**2.5**	5.1	**4.9**	5.9
TXU Europe settlement - net of income taxes		**-**	(2.1)	**(6.0)**	(8.9)
Mark to market of natural gas purchase and power generation revenue contracts	5	**2.2**	2.7	**7.8**	9.9
Deferred availability incentives		**3.3**	3.7	**(18.9)**	5.9
Changes in non-current regulatory assets and liabilities		**(7.0)**	31.4	**30.9**	41.6
Allowance for equity funds used during construction		**(2.8)**	(3.5)	**(7.8)**	(9.0)
Other		**(6.5)**	(6.3)	**(16.1)**	(7.4)
		186.2	229.1	**738.2**	793.4
Changes in non-cash working capital	18	**4.2**	(65.9)	**26.1**	(55.1)
Cash flow from operations		**190.4**	163.2	**764.3**	738.3
Investing activities					
Purchase of property, plant and equipment		**(249.7)**	(243.8)	**(822.1)**	(887.5)
Proceeds on disposal of property, plant and equipment		**0.8**	-	**16.3**	0.2
Contributions by utility customers for extensions to plant		**17.7**	20.7	**66.0**	114.1
Purchase of intangibles		**(20.7)**	(29.9)	**(46.9)**	(58.6)
Changes in non-cash working capital	18	**12.9**	52.8	**(3.1)**	(29.5)
Other		**3.0**	4.0	**12.3**	9.2
		(236.0)	(196.2)	**(777.5)**	(852.1)
Financing activities					
Issue of long term debt	12	**125.0**	23.7	**125.0**	399.7
Repayment of long term debt	12	**(2.3)**	(125.3)	**(175.1)**	(134.1)
Repayment of non-recourse long term debt	12	**(14.9)**	(12.2)	**(61.7)**	(55.8)
Issue of equity preferred shares by subsidiary	14	**75.0**	-	**75.0**	160.0
Net issue (purchase) of Class A shares		**1.9**	3.7	**(1.1)**	6.4
Dividends paid to Class A and Class B share owners		**(47.5)**	(44.3)	**(190.0)**	(177.1)
Other		**(3.2)**	1.0	**(4.4)**	(2.1)
		134.0	(153.4)	**(232.3)**	197.0
Foreign currency translation		**(5.6)**	(1.4)	**(10.9)**	(4.9)
Cash position (1)					
Increase (decrease)		**82.8**	(187.8)	**(256.4)**	78.3
Decrease in cash on ATCO Structures & Logistics transaction	4	**-**	-	**-**	(8.9)
Beginning of period		**456.8**	983.8	**796.0**	726.6
End of period		**$ 539.6**	$ 796.0	**$ 539.6**	$ 796.0

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

		Three Months Ended December 31		Year Ended December 31	
	Note	**2010**	2009	**2010**	2009
		(Unaudited)			
Earnings attributable to Class A and Class B shares		**$128.6**	$127.1	**$435.0**	$466.6
Other comprehensive income, net of income taxes:					
Cash flow hedges	23	**2.5**	1.3	**1.4**	8.3
Foreign currency translation adjustment	23	**(9.2)**	(3.1)	**(14.2)**	(6.1)
		(6.7)	(1.8)	**(12.8)**	2.2
Comprehensive income		**$121.9**	$125.3	**$422.2**	$468.8

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
Alberta Power (2000) [2]	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 [3]	Natural gas distribution
ATCO Pipelines [3]	Natural gas transmission
ATCO Electric [3]	Electric transmission and distribution

(1) At December 31, 2010, the Corporation has an ownership interest of 24.5% and ATCO Ltd., the Corporation's parent, has an ownership interest of 75.5%. The Corporation accounts for its investment in ATCO Structures & Logistics under the equity method.
(2) Effective October 1, 2010, the 100% ownership interest in Alberta Power (2000) Ltd. was transferred from CU Inc. to ATCO Power Ltd. This transfer had no impact on the financial position, results of operations and cash flows of the Corporation.
(3) Wholly owned by CU Inc.

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

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) 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.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

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 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

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.

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.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

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.

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 Utilities 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.

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 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 accounting for rate regulated operations 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.

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 PPAs, 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 PPAs, 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 PPAs. 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. 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 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.

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.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

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)

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

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

Derivative Financial Instruments

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.

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

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

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

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

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

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

  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.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

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 at the beginning of the year, 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 Utilities are required to expense contributions for other post employment benefit and 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 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

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 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 return on utility investment, or rate base. Whereas actual operating conditions may vary from forecast, actual returns achieved can differ from approved returns.

Rate base for each utility is the aggregate of the AUC approved investment in property, plant and equipment 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.

2. ACCOUNTING FOR RATE REGULATED OPERATIONS (continued)

The AUC approves rates of return for the debt and preferred share components of rate base based on the actual or forecast weighted average cost of each utility's debt and preferred shares and establishes the capital structure for each utility. 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.

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 PPAs that were approved by the AUC. These plants are considered regulated operations primarily because the PPAs 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 PPAs. 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 PPAs 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 PPAs 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.

Financial statement effects of rate regulation

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:

	2010	2009
Regulatory assets – current:		
Deferred electricity cost recoveries[(1)]	**$ -**	$ 16.1
Deferral of unused vacation costs[(2)]	**10.4**	14.5
Deferred load balancing transactions[(3)]	**5.8**	5.0
Other regulatory assets	**0.7**	1.8
	$ 16.9	$ 37.4
Regulatory assets – non-current:		
Future income tax recoveries[(4)]	**$361.4**	$299.2
Regulatory other post employment benefits asset (Note 21) [(5)]	**56.3**	51.3
Deferred electricity cost recoveries[(1)]	**16.8**	-
Deferred load balancing transactions[(3)]	**3.7**	14.4
Deferred hearing costs[(6)]	**10.6**	9.9
Other regulatory assets	**11.9**	9.1
	$460.7	$383.9
Regulatory liabilities – current:		
Deferred electricity costs[(1)]	**$ 2.1**	$ -
Deferred load balancing transactions[(3)]	**1.4**	18.1
Deferral of temperature impact on revenues[(7)]	**-**	4.0
Negotiated settlement deferrals[(8)]	**8.0**	-
Other regulatory liabilities	**5.5**	4.0
	$ 17.0	$ 26.1
Regulatory liabilities – non-current:		
Reserves for future removal and site restoration [(9)]	**$436.2**	$402.4
Regulatory pension liability (Note 21) [(5)]	**160.5**	120.9
Deferred pension recoveries[(10)]	**21.9**	-
Deferred royalty credits[(11)]	**11.8**	16.8
Deferral of temperature impact on revenues[(7)]	**12.1**	10.5
Deferred electricity costs[(1)]	**12.1**	6.1
Other regulatory liabilities	**11.5**	14.5
	$666.1	$571.2

(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.

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 2010 would have been $7.4 million higher (2009 – $10.5 million higher) 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 2010 would have been $4.1 million lower (2009 - $0.2 million lower) 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 million over six successive months or $10 million for one month.

Should the deferral account for 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 the 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 2010 would have been $14.4 million lower and revenues in 2010 would have been $26.1 million lower (2009 – $23.3 million higher expenses and $4.3 million higher revenues) in the absence of rate regulation.

2. ACCOUNTING FOR RATE REGULATED OPERATIONS (continued)

[4] *Future income tax recoveries*

The Corporation recognizes 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. 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 2010 would have been $62.2 million higher (2009 – $43.6 million higher) in the absence of rate regulation.

[5] *Employee future benefits*

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

GAAP requires that the variances between the amounts accrued and paid be recognized as an expense or reduction in expense in the period in which they are accrued. Consequently, defined benefit pension plan cost in 2010 would have been $7.4 million higher (2009 – $10.4 million lower), and other post employment benefit plan cost in 2010 would have been $2.9 million higher (2009 – $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 2010 would have been $0.8 million lower (2009 – $0.8 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 2010, the Utilities amortized $3.7 million (2009 – $3.9 million) of the deferred pension asset.

[6] *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 intervener groups that have been reimbursed by the Utilities as directed by the AUC. The Utilities have received approval to defer the variances between actual hearing costs incurred and AUC approved forecast hearing costs collected through customer rates. 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 are deferred until the next general rate application or until a specific application is made to the AUC requesting recovery from or refund to customers. GAAP requires that 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 2010 would have been $0.7 million lower (2009 - $1.5 million lower) in the absence of rate regulation.

2. ACCOUNTING FOR RATE REGULATED OPERATIONS (continued)

(7) 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 2010 would have been $2.4 million lower (2009 – $11.8 million higher) in the absence of rate regulation.

(8) Negotiated settlement deferrals

ATCO Pipelines received AUC approval for its 2010-2012 Revenue Requirement Settlement Application in May 2010, resulting in new deferral accounts fixing revenues, property taxes, and the amount of costs spent on the integration of ATCO Pipelines system with that of NOVA Gas Transmission Ltd. ("NOVA") at the levels included in the application. The deferrals are to be refunded or collected from customers in the following year. 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 2010 would have been $8.0 million higher in the absence of rate regulation.

(9) Reserves for future removal and site restoration

The reserves for future removal and site restoration costs for the Utilities is established based on an annual amount approved by the AUC to be collected through customer rates and is recorded in non-current regulatory liabilities. Actual removal and site restoration costs are expensed as incurred and revenues are adjusted for variances between approved annual amounts and actual costs. The variances are 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 2010 would have been $33.8 million higher (2009 - $26.2 million higher) in the absence of rate regulation.

(10) Deferred pension recoveries

The Utilities requested and received AUC approval to recover from customers amounts contributed in 2010 to the Canadian Utilities pension plan. The contributions are recorded as expense or are capitalized to property, plant and equipment as the funding is incurred. As these amounts are recovered from customers, revenues are adjusted by the amount capitalized to property, plant and equipment. These adjustments are deferred as a regulatory liability and amortized to earnings on the same basis as the property, plant and equipment to which they relate. GAAP requires that in the absence of rate regulation revenues be based on the rates approved by the AUC. Consequently, revenues in 2010 would have been $21.9 million higher in the absence of rate regulation.

2. ACCOUNTING FOR RATE REGULATED OPERATIONS (continued)

(11) Deferred royalty credits

Under the terms of PPAs, 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 2010 would have been $5.0 million higher (2009 - $6.5 million higher) in the absence of rate regulation.

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. During the year, the Corporation capitalized $20.0 million (2009 – $23.4 million) relating to AFU.

The Corporation capitalized costs in accordance with the PPAs which would otherwise have been expensed. At December 31, 2010, $98.5 million (2009 – $96.5 million) was included in property, plant, and equipment relating to these costs which are being depreciated over the life of the plants. In the absence of rate regulation these costs would have been expensed to earnings at the time incurred.

3. REGULATORY MATTERS

Generic Cost of Capital

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. 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. On December 16, 2010, the AUC initiated a 2011 Generic Cost of Capital proceeding, the scope of which includes, among other things, a full review of cost of capital matters including capital structure and the ROE for 2011. It will also include consideration of whether a formula approach to ROE can be reinstated for 2012. In the absence of a formula approach to ROE, the AUC will then consider how the ROE will be set for 2012. The proceeding is scheduled to be completed in the third quarter of 2011 and a decision is expected in the fourth quarter of 2011.

3. REGULATORY MATTERS (continued)

Pension Hearing

In July 2009, the Utilities submitted an application to the AUC requesting recovery of the expected 2010 contributions to the Canadian Utilities pension plan. Prior to 2010, there had been no required contributions since 1996. The Utilities also requested the establishment of deferral accounts due to projected funding requirements and the potential for fluctuations in pension asset values and resulting funding requirements. A hearing was held in January 2010 and an AUC decision was issued on April 30, 2010, approving the requested funding and establishing deferral accounts for funding fluctuations beyond the control of the Utilities. This decision did not result in a material change in the Utilities' earnings.

On December 15, 2010, the Utilities submitted an application supporting the pension methodology, specifically the determination of the cost of living allowance provision, used in the determination of pension costs included in the 2011 and future years' revenue requirements of the Utilities. The AUC expanded the scope of the application so that it will also be the basis to determine the 2011/2012 pension cost recovery for the Utilities. The application is a result of a directive issued by the AUC in the pension decision issued on April 30, 2010. A decision is expected in the fourth quarter of 2011.

Benchmarking

On March 8, 2010, the AUC issued a decision on the hearing held in December 2009 which addressed the 2003 – 2007 placeholder amounts for the pricing of services provided by ATCO I-Tek to the Utilities. The AUC decision approved the adjustments to the placeholder amounts as filed based on fair market value resulting in no material change to earnings. For the 2008 and 2009 period, a separate regulatory process has been established to approve rates for information technology and customer care and billing services provided by ATCO I-Tek that can be included in customer rates. The proceeding is scheduled to be completed in the first quarter of 2011 and a decision is expected in the second quarter of 2011. A further regulatory process to deal with rates for information technology and customer care and billing services provided by ATCO I-Tek for 2010 and beyond has been established and the AUC is expected to set a schedule for this regulatory process after the completion of the 2008 – 2009 process.

Company Specific Decisions

ATCO Electric

In May 2010, ATCO Electric filed a general tariff application with the AUC for 2011 and 2012 requesting, among other things, increased revenues to recover increased financing, depreciation, and operating costs associated with increased rate base in Alberta. The application also requested that construction work in progress for projects that are directly assigned from the AESO be included in rate base. This request would not impact earnings but would improve cash flow during the construction of the major transmission projects currently being undertaken. A decision is expected in the second quarter of 2011.

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. The respective placeholders were determined by the AUC as a result of the Generic Cost of Capital, Pension and Benchmarking decisions discussed above.

3. REGULATORY MATTERS (continued)

ATCO Gas

In December 2010, ATCO Gas filed a general rate application with the AUC for 2011 and 2012 requesting, among other things, increased revenues to recover increased financing, depreciation, and operating costs associated with increased rate base in Alberta. A decision is expected in the fourth quarter of 2011. ATCO Gas also filed an application requesting interim adjustable rates pending the AUC's decision on the general rate application. A decision on the interim adjustable rates application is expected in the first quarter of 2011.

Carbon Natural Gas Storage Facility

As a result of numerous regulatory and legal proceedings, ATCO Gas received approval from the AUC to remove its Carbon Facility from regulation. On December 16, 2009, a Review and Variance decision issued by the AUC confirmed the effective date of removing the Carbon Facility from regulation to be April 1, 2005. On October 19, 2010, the AUC released the Carbon Compliance decision, approving a recovery from customers of $43.7 million plus interest in the amount of $5.9 million to September 30, 2010. Through numerous regulatory processes, ATCO Gas previously recorded revenues and earnings of $13.8 million and $9.9 million, respectively, in 2009. On April 20, 2010, ATCO Gas received a decision from the AUC approving, on an interim adjustable basis, the implementation of Carbon recovery riders resulting in an increase in ATCO Gas' revenues and earnings of $15.7 million and $11.3 million, respectively. In the third quarter of 2010, ATCO Gas recognized the remaining amounts pertaining to the Carbon Compliance application and related decision issued by the AUC resulting in an increase in ATCO Gas' revenues, interest income and earnings of $14.2 million, $5.9 million, and $14.5 million, respectively.

ATCO Gas filed an application with the AUC on December 1, 2010, to approve the internal transfer of the Carbon Facility to ATCO Midstream. The transaction is subject to the completion of documentation and receipt of all necessary approvals, including regulatory approval, in a form satisfactory to the Board of Directors of Canadian Utilities Limited. The transaction is expected to be completed in the second quarter of 2011.

Deferred Gas Account

ATCO Gas filed an application with the AUC to address, among other things, corrections required to historical transportation imbalances (the process whereby third party natural gas supplies are reconciled to amounts actually shipped in a corporation's pipelines) that have impacted ATCO Gas' deferred gas account. In April 2005, the AUC issued a decision resulting in a 15% decrease in the transportation imbalance adjustments sought by ATCO Gas. The decision resulted in ATCO Gas recovering $9.2 million in natural gas supply costs from customers.

The City of Calgary's appeal with respect to this decision was heard by the Alberta Court of Appeal on January 13, 2010. On April 23, 2010, the Alberta Court of Appeal issued a decision allowing the appeal and vacating orders under appeal and returned the matter to the AUC for consideration. The AUC completed a process to address the Alberta Court of Appeal decision and on October 15, 2010, issued a decision requiring ATCO Gas to refund to customers approximately 85% of the transportation imbalance adjustment amounts in question resulting in a refund of approximately $9.7 million, including interest of $1.7 million, and a decrease in ATCO Gas' 2010 earnings of $7.1 million.

3. REGULATORY MATTERS (continued)

ATCO Pipelines

Alberta System Integration

In 2009, ATCO Pipelines filed an application with the AUC for the integration of ATCO Pipelines' and NOVA's gas transmission systems in Alberta (Integration Application), and filed a second application with the AUC to approve its 2010, 2011 and 2012 negotiated settlement, which was a condition precedent of the Integration Application. The Integration Application requested the AUC to approve that (i) integration is in the public interest, (ii) ATCO Pipelines approved revenue requirements be charged to NOVA, (iii) ATCO Pipelines customers be transitioned to NOVA, with NOVA as the customer commercial point of contact, and (iv) ATCO Pipelines and NOVA swap assets in order to establish operating areas. A negotiated settlement on ATCO Pipelines' 2010, 2011 and 2012 revenue requirements was a condition precedent of the 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 its 2010, 2011 and 2012 Revenue Requirement Settlement Application as part of its Integration Application.

The AUC issued a decision on May 27, 2010 approving integration and the 2010, 2011 and 2012 negotiated settlement but requested ATCO Pipelines to submit subsequent applications to address the specific details on: (i) the transition of ATCO Pipelines' customers to NOVA, and (ii) the asset swap between ATCO Pipelines and NOVA in order to establish operating areas. ATCO Pipelines has submitted an application to the AUC to address the transition of customers and a decision is expected in the second quarter of 2011. An application to address the asset swap will be submitted to the AUC in the first quarter of 2011.

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

On July 1, 2009, the Corporation and its parent corporation, 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.

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

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. 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 accounts for its 24.5% interest in ATCO Structures & Logistics on the equity basis 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 Corporation's investment in ATCO Structures & Logistics 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**
Share of earnings	**19.7**
Share of other comprehensive income	**1.2**
Dividends received	**(4.9)**
Investment at December 31, 2010	**$137.9**

5. INTEREST AND OTHER INCOME

	2010	2009
Interest	**$ 20.8**	$ 22.6
Allowance for funds used by regulated operations	**20.0**	23.4
Gains (losses) on dispositions of property, plant and equipment	**2.7**	(0.3)
Unrealized loss on natural gas purchase contracts derivative asset (Note 22)	**(26.7)**	(34.1)
Unrealized gain on power generation revenue contract liability (Note 22)	**18.9**	24.2
Cash flow hedge gains	**1.3**	2.1
Other	**2.3**	5.4
	$ 39.3	$ 43.3

6. INCOME TAXES

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

	2010		2009	
Earnings before income taxes	**$587.7**	**%**	$632.7	%
Income taxes, at statutory rates	**$164.6**	**28.0**	$183.5	29.0
ATCO Pipelines settlement	**(4.4)**	**(0.7)**	-	-
H.R. Milner income tax reassessment	-	-	(7.8)	(1.2)
Removal of Carbon storage assets from regulation	-	-	5.8	0.9
Benefit of purchased United Kingdom tax pools	-	-	(2.4)	(0.4)
Future income taxes relating to regulated operations (see Note 2)	**(46.5)**	**(8.0)**	(36.7)	(5.8)
Non-taxable portion of gain on ATCO Structures & Logistics transaction	-	-	(4.3)	(0.7)
Earnings from investment in ATCO Structures & Logistics	**(5.5)**	**(0.9)**	(2.3)	(0.4)
Foreign tax rate variance	**0.5**	**0.1**	(0.7)	(0.1)
Other	**0.5**	**0.1**	(9.7)	(1.5)
	109.2	**18.6**	125.4	19.8
Current income taxes	**102.7**		114.7	
Future income taxes	**$ 6.5**		$ 10.7	

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

	2010	2009
Property, plant and equipment	**$549.5**	$501.3
Intangibles	**50.6**	51.8
Deferred assets and liabilities	**(47.8)**	(71.2)
Tax loss carryforwards	**(17.6)**	(17.4)
Derivative financial instruments	**(0.2)**	1.1
Other	**4.2**	5.9
	538.7	471.5
Less: Current future income tax asset	**(2.0)**	(6.6)
	$540.7	$478.1

In 2010, ATCO Pipelines successfully negotiated a settlement with the Canada Revenue Agency ("CRA") regarding the classification of certain compressor assets for the years 2000 through 2004. The result of this settlement is a reduction in tax expense of $4.4 million and $0.7 million of related interest income.

On August 21, 2009, Alberta Power (2000) received a judgment from the Tax Court of Canada ordering 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 was 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) received interest income of approximately $3.1 million earned on such amounts paid to CRA. These adjustments resulted in a $16.8 million increase in earnings for 2009. In total, Alberta Power (2000) received refunds of approximately $28.0 million, including interest, and net of consequential adjustments to other taxation years arising from the judgment.

6. INCOME TAXES (continued)

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 $49.4 million for which it has recorded an income tax benefit. Approximately 88% of the losses expire in 2014 and 2015, with the remaining amounts expiring in 2029 and 2030. ATCO Electric has a tax loss carryforward of $19.7 million for which it has recorded a tax benefit. The loss expires in 2030.

Income taxes paid amounted to $93.2 million (2009 – $122.2 million).

7. INVENTORIES

	2010	2009
Natural gas and fuel in storage	**$21.9**	$23.5
Raw materials and consumables	**60.1**	56.3
	$82.0	$79.8

For the year ended December 31, 2010, the amount of inventories recognized as an expense was $70.5 million (2009 – $73.6 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.

8. PROPERTY, PLANT AND EQUIPMENT

		2010		2009	
	Composite Depreciation Rates	**Cost**	**Accumulated Depreciation**	Cost	Accumulated Depreciation
Utilities	2.7%	**$ 8,819.4**	**$2,555.1**	$ 8,157.4	$2,396.7
Energy	3.7%	**3,104.4**	**1,463.1**	3,194.0	1,372.8
Corporate & Other	9.5%	**92.6**	**55.9**	88.6	50.4
		$12,016.4	**4,074.1**	$11,440.0	3,819.9
Property, plant and equipment less accumulated depreciation			**7,942.3**		7,620.1
Unamortized contributions by utility customers for extensions to plant			**906.0**		887.4
			$7,036.3		$6,732.7

Composite depreciation rates reflect total depreciation in the year as a percentage of mid-year cost, excluding construction work-in-progress of $310.7 million (2009 – $376.8 million) and non-depreciable assets of $63.3 million (2009 – $55.3 million).

9. INTANGIBLES

	2010		2009	
	Cost	**Accumulated Amortization**	Cost	Accumulated Amortization
Computer software	**$333.7**	**$187.2**	$314.3	$170.3
Land rights	**130.9**	**23.4**	115.0	22.1
Other	**11.9**	**6.7**	11.4	6.2
	$476.5	**217.3**	$440.7	198.6
Intangibles less accumulated amortization		**259.2**		242.1
Unamortized contributions by utility customers		**0.1**		0.3
		$259.1		$241.8

Amortization expense relating to intangibles was $30.4 million (2009 – $23.5 million).

10. OTHER ASSETS

	2010	2009
Accrued pension asset (Note 21)	**$185.9**	$141.6
Security deposits for debt	**15.7**	17.0
Lease receivables	**197.1**	57.8
Other	**34.8**	27.6
	$433.5	$244.0

Lease receivables

During 2010 the two unit 86 MW natural gas-fired simple cycle generating plant in Karratha, Western Australia ("the Karratha plant"), commenced commercial operations. Due to the nature of the contract governing the Karratha plant's revenues, GAAP requires that this agreement be accounted for as a finance lease (with the Corporation as the lessor). The total net investment in the finance lease is equal to the present value of the minimum lease payments receivable.

As this lease is considered a sales-type finance lease for accounting purposes, $129.8 million was recorded in revenues to recognize the fair value of the lease receivable. These revenues were offset by $124.8 million in operation and maintenance expense associated with the construction costs of the two units which were removed from construction work in progress. This transaction resulted in an increase in earnings of $3.5 million for 2010.

11. BANK INDEBTEDNESS AND LINES OF CREDIT

At December 31, 2010, the Corporation has the following lines of credit that enable it to obtain financing for general business purposes:

	2010			2009		
	Total	**Used**	**Available**	Total	Used	Available
Long term committed	**$326.0**	**$ 3.0**	**$323.0**	$326.0	$48.0	$278.0
Short term committed	**600.0**	**35.8**	**564.2**	600.0	32.0	568.0
Uncommitted	**53.7**	**7.6**	**46.1**	63.7	7.0	56.7
	$979.7	**$46.4**	**$933.3**	$989.7	$87.0	$902.7

All of the $46.4 million used at December 31, 2010, represents outstanding letters of credit.

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

Long term debt

	Effective Interest Rate	**2010**	2009
Canadian Utilities			
CU Inc. debentures – unsecured			
1990 Series 11.40% due August 2010	11.537%	**$ -**	$ 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**	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**	150.0
2010 4.947% due November 2050	4.988%	**125.0**	-
CU Inc. other long term obligation, due June 2012, unsecured	3.000%	**4.5**	4.5
Canadian Utilities Limited debentures – unsecured			
2002 6.14% due November 2012	6.228%	**100.0**	100.0
Less: Deferred financing charges		**(14.3)**	(15.3)
		2,925.2	2,924.2

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

***Long term debt** (continued)*

	Effective Interest Rate	**2010**	2009
ATCO Midstream Ltd. credit facility, at BA rates, due June 2013, unsecured (1)	Floating	**-**	25.0
ATCO Power Canada Ltd. credit facility, at BA rates, due August 2013, secured by a pledge of cash (1)	Floating	**-**	22.0
ATCO Power Australia credit facility, payable in Australian dollars, at Bank Bill rates, due June 2015, secured by a pledge of project assets and contracts ($98.1 million AUD (2009 – $100.0 million AUD))	Floating (2)	**99.9**	94.4
Canadian Utilities Limited non-revolving credit facility at 5.72%, due June 2014	5.884%	**38.5**	39.5
		3,063.6	3,105.1
Less: Amounts due within one year		**3.3**	2.8
		$3,060.3	$3,102.3

Non-recourse long term debt

Project Financing	Effective Interest Rate	**2010**	2009
Barking Power Limited payable in British pounds:			
Term loans, at fixed rates averaging 7.95%, due to 2010 (2009 – £6.6 million)	7.95%	**$ -**	$ 11.2
Osborne Cogeneration Pty Ltd., payable in Australian dollars:			
Term loan, at Bank Bill rates, due to 2013 (1) ($17.9 million AUD (2009 – $22.1 million AUD))	Floating (2)	**18.2**	20.9
ATCO Power Alberta Limited Partnership ("APALP"):			
Term loan, at LIBOR, due to 2013 (1)	Floating (2)	**6.3**	30.1
Joffre:			
Term loan, at BA rates, due to 2012 (1)	Floating (2)	**0.1**	0.2
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)	**0.3**	0.5
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)	**22.6**	27.5
Term facility, at Canadian Prime Advances, due to 2014 (1)	Floating (2)	**0.1**	0.3
Term loan, at LIBOR, due to 2014 (1)	Floating (2)	**5.7**	7.0
Notes, at fixed rate of 7.93%, due to 2022	8.302%	**22.3**	23.4

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

***Non-recourse long term debt** (continued)*

Project Financing	Effective Interest Rate	**2010**	2009
Muskeg River:			
Term loan, at BA rates, due to 2014 [1]	Floating [2]	**18.3**	22.4
Term facility, at Canadian Prime Advances, due to 2014 [1]	Floating [2]	**0.2**	0.1
Term loan, at LIBOR, due to 2014 [1]	Floating [2]	**4.6**	5.6
Notes, at fixed rate of 7.56%, due to 2022	7.902%	**22.1**	23.9
Brighton Beach:			
Term loan, at BA rates, due to 2020 [1]	Floating [2]	**16.1**	17.2
Term loan, at LIBOR, due to 2020 [1]	Floating [2]	**14.5**	15.5
Construction overrun facility, at BA rates, due to 2020 [1]	Floating [2]	**3.9**	4.2
Construction overrun facility, at LIBOR, due to 2020 [1]	Floating [2]	**3.6**	3.8
Notes, at fixed rate of 6.924%, due to 2024	7.025%	**95.0**	98.5
Cory:			
Cost overrun facility, at BA rates, due to 2011 [1]	Floating [2]	**0.6**	1.2
Notes, at fixed rate of 7.586%, due to 2025	7.872%	**31.6**	33.0
Notes, at fixed rate of 7.601%, due to 2026	7.880%	**28.4**	29.5
Less: Deferred financing charges		**(5.5)**	(4.3)
		341.1	403.8
Less: Amounts due within one year		**38.3**	49.0
		$302.8	$354.8

BA – Bankers' Acceptance
LIBOR – London Interbank Offered Rate

(1) *The above interest rates have additional margin fees at a weighted average rate of 1.5% (2009 — 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 22).*

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, 2010, was $859.6 million (2009 — $1,095.1 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, 2010, no amounts were outstanding under the guarantee.

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, 2010, 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)	$4.0
Joffre project financing	Nil (1)	$1.5
Muskeg River project financing	Nil (1)	$4.9
Scotford project financing	Nil (1)	$5.2

(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 2011, when the project debt is to be fully repaid. At December 31, 2010, the maximum value of the guarantee is $25.2 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:

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

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

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

These guarantees remain in effect until the project debt is fully repaid. At December 31, 2010, no such events have occurred.

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

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

The foregoing guaranteed amounts represent ATCO Power's 80% interest. Canadian Utilities Limited has also guaranteed similar obligations in respect of ATCO Resources' 20% interest. ATCO Ltd. has indemnified and agreed to reimburse Canadian Utilities Limited for any amounts it may be required to pay under these guarantees in respect of ATCO Resources' 20% interest. ATCO Ltd.'s indemnification to reimburse Canadian Utilities Limited for any amounts payable under ATCO Resources 20% interest was cancelled effective January 1, 2011, when ATCO Resources was transferred to ATCO Power (see Note 26).

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)]
2011	$ 103.3	$ 188.7	$ 38.3	$ 22.1	$ 141.6	$ 210.8
2012	143.0	185.1	33.6	20.0	176.6	205.1
2013	3.8	176.8	35.7	18.0	39.5	194.8
2014	138.6	175.5	33.1	15.9	171.7	191.4
2015	89.1	166.6	20.7	14.3	109.8	180.9
2016 and thereafter	2,600.0	2,048.1	185.2	56.7	2,785.2	2,104.8
	$3,077.8	$2,940.8	$ 346.6	$ 147.0	$3,424.4	$3,087.8

(1) *Interest payments on floating rate debt that has not been hedged have been estimated using rates in effect at December 31, 2010. Interest payments on debt that has been hedged have been estimated using the hedged rates.*

Of the $141.6 million due in 2011, $100.0 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:

	2010	2009
Long term debt	**$199.5**	$203.8
Non-recourse long term debt	**27.4**	31.8
Bank indebtedness	**3.5**	2.5
Amortization of deferred financing charges	**3.8**	3.5
Other	**1.7**	-
	$235.9	$241.6

Interest paid amounted to $237.1 million (2009 — $233.4 million).

13. DEFERRED CREDITS

	2010	2009
Accrued other post employment benefits liability (Note 21)	**$ 69.8**	$ 64.2
Deferred availability incentives	**48.2**	67.1
Asset retirement obligations	**86.9**	83.2
Power generation revenue contract liability (Note 22)	**1.5**	20.4
Liability to customers for refund of future income taxes	**-**	12.1
Other	**30.7**	30.3
	$237.1	$277.3

Deferred availability incentives

Amortization of deferred availability incentives, which was recorded in revenues, amounted to $14.1 million (2009 – $16.3 million).

The amount to be amortized is dependent upon estimates of future generating unit availability and future electricity prices over the term of the PPAs. 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:

	2010	2009
Obligations at beginning of year	**$ 83.2**	$77.7
Accretion expense	**4.4**	4.1
Obligations incurred	**2.6**	1.4
Revisions to estimates	**(3.3)**	-
Obligations at end of year	**$ 86.9**	$83.2

The Corporation estimates the undiscounted amount of cash flow required to settle the asset retirement obligations is approximately $148 million, which will be incurred between 2012 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%.

14. EQUITY PREFERRED SHARES

CU Inc. equity preferred shares

Authorized and issued

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

Issued:

	Stated Value	Redemption Dates	**2010**		2009	
			Shares	**Amount**	Shares	Amount
	(dollars)					
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**	6,400,000	$160.0
3.80% Series 4	$25.00	See below	**3,000,000**	**75.0**	-	-
				$350.0		$275.0

On December 2, 2010, CU Inc., a subsidiary corporation, issued $75.0 million Cumulative Redeemable Preferred Shares Series 4 at a price of $25.00 per share. Holders of the Series 4 Preferred Shares will be entitled to receive, as and when declared by the Board of Directors of CU Inc., fixed cumulative preferential cash dividends, payable quarterly for an initial period of five years at an annual rate of $0.95 per share to yield 3.80% annually. Thereafter the dividend rate will reset every five years to the then current 5-Year Government of Canada bond yield plus 1.36%.

Fair values

Fair values for the CU Inc. Preferred Shares determined using quoted market prices for the same or similar issues are $358.3 million (2009 - $278.3 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, as and when declared by the Board of Directors of CU Inc., 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.

On June 1, 2016, and on June 1 of every fifth year thereafter, CU Inc. may redeem the Series 4 Preferred Shares in whole or in part at par. Holders may elect to convert any or all of their Series 4 Preferred

14. EQUITY PREFERRED SHARES (continued)

Shares into an equal number of Cumulative Redeemable Preferred Shares Series 5 on June 1, 2016, and on June 1 of every fifth year thereafter. Holders of the Series 5 Preferred Shares will be entitled to receive, as and when declared by the Board of Directors of CU Inc., 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 1.36%. On June 1, 2021, and on June 1 of every fifth year thereafter ("Series 5 Conversion Date"), holders of the Series 5 Preferred Shares may elect to convert any or all of their Series 5 Preferred Shares back into an equal number of Series 4 Preferred Shares. On June 1, 2016, or thereafter, CU Inc. may redeem the Series 5 Preferred Shares in whole or in part at $25.00 on a Series 5 Conversion Date or at $25.50 on any other date.

Canadian Utilities Limited equity preferred shares

Authorized and issued

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

Issued:

	Stated Value	Redemption Dates	**2010**		2009	
			Shares	**Amount**	Shares	Amount
	(dollars)					
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				**$860.0**		$785.0

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 $519.5 million (2009 – $512.3 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.

14. EQUITY PREFERRED SHARES (continued)

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

15. CLASS A AND CLASS B SHARES

Authorized and issued

	Class A Non-Voting		Class B Common		Total	
	Shares	Amount	Shares	Amount	Shares	Amount
Authorized:	Unlimited		Unlimited			
Issued and outstanding:						
December 31, 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**
Purchased and cancelled	**(138,850)**	**(0.6)**	**-**	**-**	**(138,850)**	**(0.6)**
Stock options exercised	**209,350**	**5.4**	**-**	**-**	**209,350**	**5.4**
Converted: Class B to Class A	**1,753,612**	**5.6**	**(1,753,612)**	**(5.6)**	**-**	**-**
December 31, 2010	**85,965,392**	**$406.6**	**39,964,778**	**$126.5**	**125,930,170**	**$533.1**

From January 1, 2011, to February 18, 2011, 6,800 stock options were exercised, no stock options were granted or cancelled, 44,000 Class B common shares were converted to Class A non-voting shares, and 1,059,658 Class A non-voting shares and 489,171 Class B common shares were issued by the Corporation to ATCO Ltd. related to the transfer of ATCO Resources (see Note 26).

Earnings per share

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

	Three Months Ended December 31		Year Ended December 31	
	2010	2009	**2010**	2009
	(Unaudited)			
Weighted average shares outstanding	**125,892,718**	125,752,093	**125,850,797**	125,637,206
Effect of dilutive stock options	**161,243**	156,676	**120,625**	137,044
Weighted average dilutive shares outstanding	**126,053,961**	125,908,769	**125,971,422**	125,774,250

15. CLASS A AND CLASS B SHARES (continued)

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 at shareholder meetings and to exchange at any time each share held for one Class A non-voting share.

If a take-over bid is made for the Class B common shares which would result in the offeror owning more than 50% of the outstanding Class B common shares and which would constitute a change in control of Canadian Utilities Limited, owners of Class A non-voting shares are entitled, for the duration of the bid, to exchange their Class A non-voting shares for Class B common shares and to tender such Class B common shares pursuant to the terms of the take-over bid. Such right of exchange is conditional upon the completion of the take-over bid giving rise to the right of exchange, and if the take-over bid is not completed, then the right of exchange shall be deemed never to have existed. In addition, owners of the Class A non-voting shares are entitled to exchange their shares for Class B common shares of Canadian Utilities Limited if ATCO Ltd., the present controlling share owner of Canadian Utilities Limited, ceases to own or control, directly or indirectly, more than 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 March 1, 2010, Canadian Utilities Limited commenced a normal course issuer bid for the purchase of up to 3% of the outstanding Class A shares. The bid will expire on February 28, 2011. From March 1, 2010, to February 18, 2011, 138,850 shares were purchased, all of which were in 2010, for $6.5 million and resulted in a decrease to share capital and retained earnings, respectively, of $0.6 million and $5.9 million.

16. 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 Utilities.

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.

16. CAPITAL DISCLOSURES (continued)

The Utilities 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 Utilities are capitalized consistent with the generic cost of capital decisions. 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 the Utilities 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).

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 2009.

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.

16. CAPITAL DISCLOSURES (continued)

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

	2010	2009
Class A and Class B shares	**$ 533.1**	$ 528.3
Contributed surplus	**1.2**	3.2
Retained earnings	**2,807.7**	2,568.6
Accumulated other comprehensive income	**(66.8)**	(54.0)
Equity preferred shares	**860.0**	785.0
Total equity	**4,135.2**	3,831.1
Long term debt	**3,060.3**	3,102.3
Non-recourse long term debt	**302.8**	354.8
Total debt	**3,363.1**	3,457.1
Total capitalization	**$7,498.3**	$7,288.2
Equity capitalization	**55%**	53%

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 decreased primarily due to redemptions of long term debt and non-recourse long term debt.

	2010	2009
Interest coverage	**3.5**	3.5
Interest and preferred dividend coverage	**2.8**	2.8

For the year ended December 31, 2010, 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.

17. 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, 2,946,200 Class A non-voting shares are available for issuance at December 31, 2010. 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.

17. STOCK BASED COMPENSATION PLANS (continued)

Changes in shares under option are summarized below:

	2010		2009	
	Class A Shares	**Weighted Average Exercise Price**	Class A Shares	Weighted Average Exercise Price
Options at beginning of year	**871,900**	**$35.63**	1,238,250	$30.86
Granted	**53,000**	**47.29**	-	-
Exercised	**(209,350)**	**26.00**	(349,550)	18.19
Forfeited	**(9,700)**	**45.99**	(16,800)	46.40
Options at end of year	**705,850**	**$39.23**	871,900	$35.63

Information about stock options outstanding at December 31, 2010, is summarized below:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Class A Shares	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Class A Shares	Weighted Average Exercise Price
$24.52 - $28.65	71,050	1.8	$25.76	71,050	$25.76
$30.25 - $37.12	202,000	4.0	30.31	201,600	30.30
$43.49 - $47.84	432,800	6.5	45.60	221,300	45.31
$24.52 - $47.84	705,850	5.3	$39.23	493,950	$36.37

In 2010, Canadian Utilities Limited granted 53,000 options to purchase Class A non-voting shares at a weighted average exercise price of $47.29 per share. Options have a term of ten years and vest over the first five years.

Changes in contributed surplus are summarized below:

	2010	2009
Contributed surplus at beginning of year	**$3.2**	$2.6
Stock option expense	**0.3**	0.6
Mid-term incentive plan purchases	**(2.3)**	-
Contributed surplus at end of year	**$1.2**	$3.2

The Corporation uses the Black-Scholes option pricing model, which estimated the weighted average fair value of the options granted during 2010 at $6.66 per option (2009 – no options granted) based on the following weighted average assumptions:

	2010	2009
Risk free interest rate	2.8%	N/A
Expected holding period prior to exercise	8.4 years	N/A
Share price volatility	16.1%	N/A
Estimated annual Class A share dividend	3.1%	N/A

17. STOCK BASED COMPENSATION PLANS (continued)

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 $4.2 million (2009 – $1.1 million).

18. CHANGES IN NON-CASH WORKING CAPITAL

	2010	2009
Operating activities, changes related to:		
Accounts receivable	**$(42.2)**	$(24.4)
Inventories	**(0.2)**	13.8
Regulatory assets	**23.8**	23.0
Prepaid expenses	**(3.1)**	(4.8)
Accounts payable and accrued liabilities	**54.5**	(43.3)
Income taxes payable	**2.4**	(8.9)
Regulatory liabilities	**(9.1)**	(10.5)
	$26.1	$(55.1)
Investing activities, changes related to:		
Accounts receivable	**$ 2.7**	$ (3.9)
Inventories	**(2.6)**	4.1
Prepaid expenses	**(0.1)**	-
Accounts payable and accrued liabilities	**(3.1)**	(29.7)
	$(3.1)	$(29.5)

19. JOINT VENTURES

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

	2010	2009
Statement of earnings		
Revenues	**$ 349.7**	$ 487.2
Operating expenses	**205.6**	281.2
Depreciation and amortization	**39.2**	46.7
Interest	**23.7**	26.9
	81.2	132.4
Interest and other income (loss)	**(3.4)**	(5.3)
Earnings from joint ventures before income taxes	**$ 77.8**	$ 127.1

19. JOINT VENTURES (continued)

	2010	2009
Balance sheet		
Current assets	**$ 114.0**	$ 112.7
Current liabilities	**(80.2)**	(90.2)
Property, plant and equipment	**730.8**	768.6
Other assets	**2.8**	27.3
Non-recourse long term debt	**(265.2)**	(288.3)
Other non-current liabilities	**(57.5)**	(71.0)
Investment in joint ventures	**$ 444.7**	$ 459.1
Statement of cash flows		
Operating activities	**$ 104.1**	$ 134.3
Investing activities	**(5.1)**	3.0
Financing activities	**(93.2)**	(150.5)
Foreign currency translation	**(2.6)**	(1.2)
Increase (decrease) in cash position	**$ 3.2**	$ (14.4)

Current assets include cash of $43.9 million (2009 ─ $38.8 million) which is only available for use within the joint ventures.

20. RELATED PARTY TRANSACTIONS

In transactions with ATCO Ltd. and its subsidiary corporations, the Corporation sold fuel in the amount of $1.4 million (2009 ─ $1.5 million), provided computer operations and systems development services totaling $5.0 million (2009 – $3.9 million), recovered administrative expenses totaling $2.4 million (2009 ─ $7.8 million) and incurred administrative expenses and corporate signature rights totaling $9.5 million (2009 ─ $8.8 million).

In transactions with entities related through common control, the Corporation incurred advertising, promotion and administrative expenses totaling $1.1 million (2009 ─ $1.4 million).

At December 31, 2010, accounts receivable due from related parties amounted to $7.0 million (2009 – $3.8 million) and accounts payable due to related parties amounted to $4.6 million (2009 – $3.5 million).

These transactions are in the normal course of business and under normal commercial terms, measured at the exchange amount.

21. 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.

21. EMPLOYEE FUTURE BENEFITS (continued)

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

	2010		2009	
	Pension Benefit Plans	**Other Post Employment Benefit Plans**	Pension Benefit Plans	Other Post Employment Benefit Plans
Benefit plan assets, obligations and funded status				
Market value of plan assets:				
Beginning of year	**$1,530.8**	**$ -**	$1,399.1	$ -
Actual return on plan assets	**166.3**	**-**	190.1	-
Employee contributions	**3.2**	**-**	3.3	-
Employer contributions	**54.7**	**-**	1.0	-
Benefit payments	**(51.4)**	**-**	(47.7)	-
Payments to defined contribution plans [1]	**-**	**-**	(15.0)	-
End of year	**$1,703.6**	**$ -**	$1,530.8	$ -
Accrued benefit obligations:				
Beginning of year	**$1,521.2**	**$ 68.0**	$1,399.6	$ 57.8
Current service cost	**31.1**	**1.8**	25.9	1.7
Interest cost	**103.8**	**4.3**	93.6	4.2
Employee contributions	**3.2**	**-**	3.3	-
Benefit payments from plan assets [2]	**(51.4)**	**-**	(47.7)	-
Benefit payments by employer	**(5.1)**	**(1.8)**	(4.8)	(1.9)
Experience losses (gains) [3]	**303.7**	**7.2**	51.3	6.2
End of year [4]	**$1,906.5**	**$ 79.5**	$1,521.2	$ 68.0
Funded status:				
Excess (deficiency) of assets over obligations [4]	**$ (202.9)**	**$(79.5)**	$ 9.6	$(68.0)
Amounts not yet recognized in financial statements:				
Unrecognized net cumulative experience losses on plan assets and accrued benefit obligations	**474.1**	**(3.3)**	251.4	(10.6)
Unrecognized net transitional liability (asset)	**(85.3)**	**13.0**	(119.4)	14.4
Accrued asset (liability) (Notes 10, 13)	**$ 185.9**	**$(69.8)**	$ 141.6	$(64.2)
Regulatory asset (liability) [5] (Note 2)	**$ (160.5)**	**$ 56.3**	$ (120.9)	$ 51.3

(1) *Employer contributions for certain of the Corporation's defined contribution pension plans were paid from the assets of the defined benefit pension plans prior to 2010.*

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

(3) *Decrease in the liability discount rate assumption at December 31 resulted in the experience losses in 2010 and 2009.*

(4) *The non-registered, non-funded defined benefit pension plans accrued benefit obligations increased to $90.4 million at December 31, 2010, (2009 – $76.3 million) due to a decrease in the liability discount rate. Apart from these obligations, the deficiency of assets compared to obligations for the registered defined benefit pension plans at December 31, 2010, was $112.5 million (2009 – excess of assets over obligations of $85.9 million).*

(5) *The regulatory asset (liability) reflects an AUC decision to record costs of employee future benefits in the Utilities when paid rather than accrued.*

21. EMPLOYEE FUTURE BENEFITS (continued)

	2010		2009	
	Pension Benefit Plans	**Other Post Employment Benefit Plans**	Pension Benefit Plans	Other Post Employment Benefit Plans
Benefit plan cost				
Components of benefit plan cost:				
Current service cost	**$ 31.1**	**$ 1.8**	$ 25.9	$ 1.7
Interest cost	**103.8**	**4.3**	93.6	4.2
Actual return on plan assets	**(166.3)**	**-**	(190.1)	-
Experience losses on accrued benefit obligations	**303.7**	**7.2**	51.3	6.2
	272.3	**13.3**	(19.3)	12.1
Adjustments to recognize long term nature of employee future benefits:				
Unrecognized portion of actual return on plan assets	**63.7**	**-**	78.9	-
Unrecognized portion of experience gains on accrued benefit obligations	**(303.7)**	**(7.2)**	(51.3)	(6.2)
Amortization of net cumulative experience losses on plan assets and accrued benefit obligations	**17.3**	**(0.1)**	8.4	(0.4)
Amortization of net transitional liability (asset)	**(34.1)**	**2.0**	(34.1)	2.1
	(256.8)	**(5.3)**	1.9	(4.5)
Defined benefit plans cost (income)	**15.5**	**8.0**	(17.4)	7.6
Employer contributions by the Utilities [1]	**46.2**	**-**	-	-
Defined contribution plans cost	**16.4**	**-**	16.2	-
Total cost (income)	**78.1**	**8.0**	(1.2)	7.6
Less: Capitalized	**25.4**	**2.7**	1.8	2.4
Less: Unrecognized defined benefit plans cost (income) [1] [2]	**7.4**	**2.9**	(10.4)	2.4
Net cost recognized [2]	**$ 45.3**	**$ 2.4**	$ 7.4	$ 2.8

(1) The unrecognized defined benefit plans cost (income) reflects an AUC decision to record costs of employee future benefits in the Utilities when paid rather than accrued.

(2) Net cost recognized for pension benefit plans in 2010 includes the amortization of $3.7 million (2009 – $3.9 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).

21. EMPLOYEE FUTURE BENEFITS (continued)

In the unaudited three months ended December 31, 2010, net expense of $9.3 million (2009 – $0.6 million) was recognized for pension benefit plans and net expense of $0.6 million (2009 – $0.6 million) was recognized for other post employment benefit plans. The net expense for the pension benefit plans includes a cash expense of $8.5 million related to the Utilities which is in accordance with the AUC decision to recover funding from customers.

Weighted average assumptions

	2010		2009	
	Pension Benefit Plans	**Other Post Employment Benefit Plans**	Pension Benefit Plans	Other Post Employment Benefit Plans
Assumptions regarding benefit plan cost:				
Expected long term rate of return on plan assets for the year	**7.0%**	-	7.5%	-
Liability discount rate for the year	**6.4%**	**6.4%**	7.0%	7.0%
Average compensation increase for the year	**(1)**	-	(1)	-
Assumptions regarding accrued benefit obligations:				
Liability discount rate at December 31	**5.6%**	**5.6%**	6.4%	6.4%
Long term inflation rate	**2.25%**	**(2)**	2.0%	(2)

(1 *The assumed average compensation increases are 3.75% until 2011 and 3.25% thereafter (2009 - 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, 6.4% for 2010 grading down over 14 years to 4.5% (2009 – 6.5% for 2009 grading down over 15 years to 4.5%), for other medical costs, 4.5% for 2010 and thereafter (2009 - 4.5% for 2009 and 4.0% thereafter), and for dental costs, 4.0% for 2010 and thereafter (2009 – 4.0% for 2009 and thereafter).*

The sensitivities of key assumptions used in measuring accrued benefit obligations and benefit plan cost for 2010 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.

21. EMPLOYEE FUTURE BENEFITS (continued)

	2010 Pension Benefit Plans		2010 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]	-	$(3.2)	-	-
1% decrease [1]	-	$ 3.2	-	-
Liability discount rate				
1% increase [1]	$(57.6)	$(4.6)	$(2.4)	$(0.3)
1% decrease [1]	$ 71.4	$ 5.3	$ 2.9	$ 0.1
Future compensation rate				
1% increase [1]	$ 11.8	$ 1.5	-	-
1% decrease [1]	$(11.3)	$(1.5)	-	-
Long term inflation rate				
1% increase [1] [2] [3]	$ 42.7	$ 5.1	$ 2.2	$ 0.2
1% decrease [1] [3]	$(48.9)	$(5.9)	$(1.9)	$(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 Utilities 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

	2010		2009	
	Amount	**%**	Amount	%
Plan asset mix:				
Equity securities [1]	**$ 945.9**	**55.5**	$ 842.6	55.0
Fixed income securities [2]	**636.1**	**37.4**	584.1	38.2
Real estate [3]	**90.7**	**5.3**	90.1	5.9
Cash and other assets [4]	**30.9**	**1.8**	14.0	0.9
	$1,703.6	**100.0**	$1,530.8	100.0

(1) *Equity securities consist of investments in domestic and foreign preferred and common shares. At December 31, 2010, the market values of investments in United States' securities and international equities, denominated in a number of different currencies, are $176.7 million and $173.7 million, respectively (2009 – $146.4 million and $151.1 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.*
(5) *All of the plan assets have a fair value hierarchy of level 1 except for $311.8 million of fixed income securities and $18.6 million of real estate funds which are level 2 and $43.6 million of equity securities and $48.4 million of real estate funds which are level 3 (refer to Note 1 for hierarchy description).*

21. EMPLOYEE FUTURE BENEFITS (continued)

At December 31, 2010, plan assets include long term debt of CU Inc. having a market value of \$13.8 million (2009 – \$15.1 million), Class A non-voting and Class B common shares of Canadian Utilities Limited having a market value of \$22.1 million (2009 – \$17.8 million) and Class I Non-Voting Shares of ATCO Ltd. having a market value of \$21.7 million (2009 – \$17.0 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.

Declines in stock and bond markets, changes in actuarial assumptions and additional employee service created funding deficits in the Corporation's defined benefit pension plans. Prior to 2010, the Corporation had not made material contributions since April 1, 1996, as a result of the defined benefit plans' surplus position. In addition, the Corporation had obtained regulatory approval to fund the employer's contributions to the defined contribution component of the pension plan from the defined benefit plan surplus.

Based on these changes, material current service and deficit funding contributions resumed in 2010. The actual funding contributions for 2010 were established based on actuarial valuations for funding purposes as of December 31, 2009. Based on these final actuarial valuations, the employer contributions relating to both the defined contribution and the defined benefit components of the plan for 2010 were approximately \$71 million. Contributions commenced during the first quarter of 2010. The next actuarial valuation for funding purposes is required to be completed as of December 31, 2012.

For purposes of any pension funding requirements pertaining to utility operations, the AUC has directed that the cash basis of accounting be used in customer rate applications. Accordingly, the Corporation includes the cost of funding in its rate applications to the AUC, thereby, with the consent of the AUC, recovering approximately 78% of the costs of funding its pension plans from utility customers. The net funding contribution amounts (actual funding contributions less recovery from utility customers) were approximately \$16 million.

22. 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, 2010, 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, forward power sales, forward gas purchases and greenhouse gas emission credit purchases to fix spark spreads for a portion of availability at the Barking Power Station and certain natural gas purchase contracts that were not considered own-use contracts.

The derivative assets and liabilities comprise the following:

	2010	2009
Derivative assets – current:		
Interest rate swap agreements	**$ 1.2**	$ 1.2
Forward gas purchase contracts	**1.2**	-
Greenhouse gas emissions credits purchase contracts	**0.5**	-
	$ 2.9	$ 1.2
Derivative assets – non-current:		
Interest rate swap agreements	**$ 4.3**	$ 5.4
Natural gas purchase contract	**1.5**	26.0
	$ 5.8	$31.4
Derivative liabilities – current:		
Interest rate swap agreements	**$ 1.7**	$ 2.4
Forward power sale contracts	**1.2**	-
Foreign currency forward swaps	**-**	0.5
	$ 2.9	$ 2.9
Derivatives liabilities – non-current:		
Interest rate swap agreements	**$ 3.9**	$ 5.9
Natural gas purchase contract	**2.2**	-
	$ 6.1	$ 5.9

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:

22. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (continued)

Financing	Swap Fixed Interest Rate [(1)]	Variable Debt Interest Rate	Maturity Date	Notional Principal 2010	Notional Principal 2009
Karratha: ($98.1 million AUD (2009 – $100.00 million AUD))	6.160%	Bank Bill Rate in Australia	June 2015	**$ 99.8**	$ 94.4
Osborne: ($17.0 million AUD (2009 - $21.0 million AUD))	7.433%	Bank Bill Rate in Australia	December 2013	**17.3**	19.7
APALP:	7.750%	6 month LIBOR	December 2011	**18.2**	40.7
Joffre:	7.536%	90 day BA	September 2012	**7.3**	11.5
Scotford:	3.443%	90 day BA	November 2013	**22.8**	27.8
	3.840%	3 month LIBOR	November 2013	**5.7**	7.0
Muskeg River:	5.635%	90 day BA	December 2012	**18.6**	22.5
	5.753%	3 month LIBOR	December 2012	**4.6**	5.6
Brighton Beach:	6.700%	90 day BA	March 2019	**27.7**	30.0
	4.578%	90 day BA	June 2020	**4.0**	4.2
	4.784%	3 month LIBOR	June 2020	**3.6**	3.8
Cory:	6.711%	90 day BA	June 2011	**0.3**	0.9
				$229.9	$268.1

BA – Bankers' Acceptance
LIBOR – London Interbank Offered Rate

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

The Corporation has fixed interest rates, either directly or through interest rate swap agreements, on 96% (2009 – 95%) 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 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 $0.4 million and $0.5 million (2009 – $0.7 million and $1.4 million), respectively, which were recognized in earnings as the interest rate swaps are ineffective.

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. In 2009, the Corporation 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, 2010, the Corporation has no foreign currency forward contracts (2009 ─ purchases of $0.2 million U.S. in return for Canadian dollars and $2.8 million U.S. in return for Australian dollars).

Energy commodity price risk

On September 30, 2010, the Barking Power Station's long term power offtake contract expired. The contract covered 725 MW of the power stations capacity, of which the Corporation's share was 185 MW. A new tolling contract for 178 MW of the plant's capacity, of which the Corporation's share is 45 MW, was entered into for a one-year term commencing October 1, 2010. The balance of the plant's capacity is sold in the United Kingdom merchant electricity market via forward spark spread derivatives whereby power, natural gas and greenhouse gas emissions credits are simultaneously sold and purchased to secure spark spreads for future delivery.

Natural gas for the capacity under long term power purchase agreements is provided either under a long term supply agreement or is the responsibility of the offtaker. Natural gas for uncontracted capacity is purchased on a daily basis at spot prices or is purchased in the UK within the spark spread derivatives described above.

Inability to supply energy under certain long term power purchase agreements requires the Corporation to pay market prices for substitute energy.

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 liability 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.

22. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (continued)

The mark-to-market adjustment for the derivative asset and liability and the corresponding adjustment for the associated power generation revenue contract liability decreased earnings by $2.0 million, for the unaudited three months ended December 31, 2010, (2009 – $2.0 million) and decreased earnings by $5.9 million, for the year ended December 31, 2010 (2009 – $7.4 million). At December 31, 2010, the natural gas purchase contract derivative asset is $1.5 million (2009 – $26.0 million), the natural gas purchase contract derivative liability is $2.2 million (2009 – nil), and the power generation revenue contract liability is $1.5 million (2009 – $20.4 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 73% of the short term investments at December 31, 2010, 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.

Lease receivable credit risk arises from the possibility that a counterparty to a lease arrangement fails to make its lease payments according to the terms and conditions of that contract. Lease receivable 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, except for the lease receivables, which by their nature are with single counterparties. A significant portion of loans and receivables arise from the Corporation’s operations in Alberta, with the exception of the lease receivable for the Karratha plant in Australia.

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

22. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (continued)

Accounts receivable are non-interest bearing and are generally due in 30 to 90 days. At December 31, 2010, the provision for impairment of credit losses was $1.2 million. The changes in the provision for impairment were as follows:

	2010
Provision at beginning of year	**$ 1.5**
Impairment of receivables	**(0.1)**
Receivables written off as uncollectible	**(0.2)**
Provision at end of year	**$ 1.2**

At December 31, 2010, the aging analysis of trade receivables that are past due but not impaired is as follows:

	2010	2009
30 to 90 days	**$3.7**	$1.7
Greater than 90 days	**0.8**	0.9
	$4.5	$2.6

No other impairments have been identified within accounts receivable.

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.

22. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (continued)

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

	2011	2012	2013	2014	2015	2016 and thereafter
Accounts payable and accrued liabilities	$ 404.9	$ -	$ -	$ -	$ -	$ -
Operating leases [1]	21.5	15.0	13.7	11.9	10.4	28.5
Long term debt (Note 12)	103.3	143.0	3.8	138.6	89.1	2,600.0
Non-recourse long term debt (Note 12)	38.3	33.6	35.7	33.1	20.7	185.2
Interest expense (Note 12)	210.8	205.1	194.8	191.4	180.9	2,104.8
Purchase obligations:						
Coal purchase contracts [2]	66.3	67.2	65.5	76.3	87.7	348.2
Natural gas purchase contracts [3]	13.2	13.4	7.0	0.2	-	-
Operating and maintenance agreements [4]	19.9	17.1	21.1	24.0	8.0	30.3
Capital expenditures [5]	88.3	-	-	-	-	-
Derivatives [6]	2.8	1.8	1.0	0.8	0.6	1.0
Other	9.0	8.4	7.9	2.8	0.3	0.2
	$978.3	$ 504.6	$ 350.5	$ 479.1	$ 397.7	$5,298.2

(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, 2010.*

22. 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:

	2010		2009	
	Carrying Value	**Fair Value**	Carrying Value	Fair Value
Financial Assets				
Held For Trading:				
Cash [(1)]	**$ 134.4**	**$ 134.4**	$ 104.2	$ 104.2
Held to Maturity:				
Short term investments [(1)]	**405.2**	**405.2**	691.8	691.8
Loans and Receivables:				
Accounts receivable [(1)]	**407.9**	**407.9**	366.4	366.4
Lease receivables [(2)]	**197.1**	**197.1**	59.1	59.1
Financial Liabilities				
Other Liabilities:				
Accounts payable and accrued liabilities [(3)]	**404.9**	**404.9**	382.1	382.1
Liabilities to customers for future income taxes (see Note 13) [(3)]	**-**	**-**	12.1	12.1
Long term debt [(4)]	**3,063.6**	**3,531.7**	3,105.1	3,397.4
Non-recourse long term debt [(4)]	**341.1**	**386.6**	403.8	438.8

(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.*

22. 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:

	2010			2009		
	Notional Principal[(1)]	**Fair Value Receivable (Payable)[(3)]**	**Maturity**	Notional Principal[(1)]	Fair Value Receivable (Payable)[(3)]	Maturity
Held For Trading:						
Interest rate swaps	**$229.9**	**$ (0.1)**	**2011-2020**	$268.1	$ (1.7)	2010-2019
Foreign currency forward contracts	**$ -**	**$ -**	**-**	$ 3.4	$ (0.5)	2010
Natural gas purchase contracts	**N/A [(2)]**	**$(0.7)**	**2014**	N/A [(2)]	$26.0	2014
Forward power sales contracts	**N/A [(2)]**	**$(1.2)**	**2011**	-	$ -	$ -
Forward gas purchase contracts	**N/A [(2)]**	**$ 1.2**	**2011**	-	$ -	$ -
Greenhouse gas emissions credits purchase contracts	**N/A [(2)]**	**$ 0.5**	**2011**	-	$ -	$ -

(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. The notional amount for the forward sale and purchase contracts are the commodity volumes committed in 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	$ -	$7.2	$1.5	$8.7
Derivative liabilities	-	(6.8)	(2.2)	(9.0)
	$ -	$0.4	$(0.7)	$(0.3)

22. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (continued)

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:

	2010
Balance at beginning of year	**$ 26.0**
Total gains (losses) recognized in earnings	**(26.7)**
Balance at end of year	**$ (0.7)**

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 and Australian 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.
- Changes in the forward prices of United Kingdom power sales, gas purchases and greenhouse gas emissions credits purchases comprising spark spread forward positions are recorded in earnings.
- Changes in the forward prices of greenhouse gas emissions credits in the United Kingdom for the advanced sales of allowances granted under the European Union Emissions Trading Scheme are recorded in earnings.

22. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (continued)

	2010	
	Earnings	Other Comprehensive Income
Canadian interest rates		
25 basis points increase	$ -	$ 0.5
25 basis points decrease	$ -	$(0.5)
Australian interest rates		
25 basis points increase	$ -	$ 0.7
25 basis points decrease	$ -	$(0.7)
Forward price of natural gas		
10% increase	$ 5.1	$ -
10% decrease	$(6.7)	$ -
Forward price of power in the United Kingdom		
10% increase	$(0.8)	$ -
10% decrease	$ 0.8	$ -
Forward price of greenhouse gas emissions credits in Europe		
10% increase	$(0.5)	$ -
10% decrease	$ 0.5	$ -

23. 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:

	2010	2009
Accumulated OCI at beginning of period:		
Cash flow hedge losses [(1)]	**$ (3.0)**	$(11.5)
Foreign currency translation adjustment	**(51.0)**	(43.6)
	(54.0)	(55.1)
Adjustment to accumulated OCI from the ATCO Structures & Logistics Transaction:		
Cash flow hedge losses [(2)]	**-**	0.2
Foreign currency translation adjustment	**-**	(1.3)
	-	(1.1)
OCI for the period:		
Changes in fair values of cash flow hedges [(3)]	**0.3**	7.4
Transfers of cash flow hedge losses to earnings [(4)]	**1.1**	0.9
	1.4	8.3
Foreign currency translation adjustment	**(14.2)**	(6.1)
	(12.8)	2.2
Accumulated OCI at end of period:		
Cash flow hedge losses [(5)]	**(1.6)**	(3.0)
Foreign currency translation adjustment	**(65.2)**	(51.0)
	$(66.8)	$(54.0)

(1) *Net of income taxes of $1.0 million and $4.2 million, respectively.*
(2) *Net of income taxes of $(0.1) million.*
(3) *Net of income taxes of $(0.8) million and $(3.2) million, respectively.*
(4) *Net of income taxes of nil.*
(5) *Net of income taxes of $0.2 million and $0.9 million, respectively.*

24. CONTINGENCIES

Measurement inaccuracies occur from time to time with respect to the Utilities' metering facilities. Measurement adjustments for the Utilities 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.

25. SEGMENTED INFORMATION

Description of 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 electricity by ATCO Electric and its subsidiaries, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical.

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, and 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

2010 2009	Utilities	Energy	Corporate & Other	Intersegment Eliminations	Consolidated
(Unaudited)					
Revenues – external	**$405.3** $361.8	**$283.9** $294.7	**$20.1** $19.1	$ - $ -	**$709.3** $675.6
Revenues – intersegment[1]	**6.7** 6.1	**3.1** 1.4	**38.1** 33.6	**(47.9)** (41.1)	**-** -
Revenues	**$412.0** $367.9	**$287.0** $296.1	**$58.2** $52.7	**$(47.9)** $(41.1)	**$709.3** $675.6
Earnings attributable to Class A and Class B shares	**$ 71.5** $ 52.8	**$ 44.1** $ 72.5	**$13.3** $ 1.7	**$ (0.3)** $ 0.1	**$128.6** $127.1

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

25. SEGMENTED INFORMATION (continued)

Segmented results – Year ended December 31

2010 2009	Utilities	Energy	Corporate & Other	Intersegment Eliminations	Consolidated
Revenues – external	**$1,451.7** $1,342.8	**$1,129.8** $1,021.9	**$ 75.7** $219.3	**$ -** $ -	**$2,657.2** $2,584.0
Revenues – intersegment [(1)]	**25.1** 24.7	**13.6** 9.5	**130.5** 125.6	**(169.2)** (159.8)	**-** -
Revenues	**1,476.8** 1,367.5	**1,143.4** 1,031.4	**206.2** 344.9	**(169.2)** (159.8)	**2,657.2** 2,584.0
Operating expenses	**819.6** 772.2	**764.9** 591.5	**140.1** 262.4	**(167.5)** (161.1)	**1,557.1** 1,465.0
Depreciation and amortization	**211.7** 192.4	**111.6** 116.8	**12.2** 20.5	**-** -	**335.5** 329.7
Interest expense	**176.8** 175.5	**59.4** 64.2	**188.4** 201.7	**(188.7)** (199.8)	**235.9** 241.6
Gain on ATCO Structures & Logistics Transaction	**-** -	**-** -	**-** (33.9)	**-** -	**-** (33.9)
Earnings from investment in ATCO Structures & Logistics	**-** -	**-** -	**(19.7)** (7.8)	**-** -	**(19.7)** (7.8)
Interest and other income	**(35.3)** (24.0)	**(1.0)** (15.4)	**(191.7)** (203.7)	**188.7** 199.8	**(39.3)** (43.3)
Earnings before income taxes	**304.0** 251.4	**208.5** 274.3	**76.9** 105.7	**(1.7)** 1.3	**587.7** 632.7
Income taxes	**38.6** 37.9	**56.4** 63.4	**14.6** 23.7	**(0.4)** 0.4	**109.2** 125.4
	265.4 213.5	**152.1** 210.9	**62.3** 82.0	**(1.3)** 0.9	**478.5** 507.3
Dividends on equity preferred shares	**20.8** 18.1	**1.4** 1.4	**21.3** 21.2	**-** -	**43.5** 40.7
Earnings attributable to Class A and Class B shares	**$ 244.6** $ 195.4	**$ 150.7** $ 209.5	**$ 41.0** $ 60.8	**$ (1.3)** **$** 0.9	**$ 435.0** $ 466.6
Total assets	**$6,471.9** $5,921.9	**$2,254.9** $2,357.1	**$586.8** $791.0	**$ 101.7** $ 13.6	**$9,415.3** $9,083.6
Capital expenditures [(2)]	**$ 788.9** $ 776.1	**$ 67.1** $ 151.5	**$ 13.0** $ 18.5	**$ -** $ -	**$ 869.0** $ 946.1

[(1)] *Intersegment revenues are recognized on the basis of prevailing market or regulated prices.*
[(2)] *Includes purchases of property, plant and equipment and intangibles.*

25. SEGMENTED INFORMATION (continued)

Geographic segments

	Domestic		Foreign		Consolidated	
	2010	2009	**2010**	2009	**2010**	2009
Revenues	**$2,327.3**	$2,290.6	**$329.9**	$293.4	**$2,657.2**	$2,584.0
Property, plant and equipment and Intangibles	**$7,083.3**	$6,639.4	**$212.1**	$335.1	**$7,295.4**	$6,974.5

26. SUBSEQUENT EVENT

On January 1, 2011, ATCO Ltd., the Corporation's parent, transferred its wholly owned subsidiary, ATCO Resources, to ATCO Power, a wholly owned subsidiary of the Corporation. The fair value of the common shares of ATCO Resources, net of its existing debt obligations, was $82.5 million, as estimated by an independent financial advisor and supported by management.

ATCO Ltd. transferred its common shares of ATCO Resources to Canadian Utilities Limited in exchange for 1,059,658 Class A non-voting shares and 489,171 Class B common shares of Canadian Utilities, having a value of $82.5 million. This is a related party transaction between entities under common control and will be measured at the carrying amount.