# CU INC.

# CONSOLIDATED FINANCIAL STATEMENTS

# FOR THE YEAR ENDED DECEMBER 31, 2010

PRICEWATERHOUSECOOPERS

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## Independent Auditor's Report

**To the Share Owner of CU Inc.**

We have audited the accompanying consolidated financial statements of CU Inc., which comprise the consolidated balance sheets as at December 31, 2010 and December 31, 2009 and the consolidated statements of earnings, comprehensive income and retained earnings and cash flows 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.

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**Opinion**
In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of CU Inc. 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.

**Emphasis of matter**
We draw attention to Note 1 of the consolidated financial statements which describes the early adoption of accounting standards under Canadian generally accepted accounting principles. Our opinion is not qualified in respect of this matter.

PricewaterhouseCoopers LLP

**Chartered Accountants**
Calgary, Alberta
February 22, 2011

# CU Inc.
## Consolidated Statement of Earnings, Comprehensive Income and Retained Earnings
*(Millions of Canadian Dollars)*

| | Note | Three Months Ended December 31 | | Year Ended December 31 | |
|---|---|---|---|---|---|
| | | **2010** | 2009 | **2010** | 2009 |
| | | *(Unaudited)* | | | |
| **Revenues** | | **$ 412.0** | $ 367.9 | **$1,476.7** | $1,367.4 |
| **Costs and expenses** | | | | | |
| Natural gas supply | | **0.3** | 0.3 | **1.4** | 1.0 |
| Purchased power | | **14.7** | 14.3 | **54.2** | 54.1 |
| Operation and maintenance | | **96.7** | 92.0 | **339.9** | 315.5 |
| Selling and administrative | | **74.5** | 64.9 | **251.4** | 238.0 |
| Depreciation and amortization | | **54.3** | 48.3 | **211.7** | 192.4 |
| Interest | 11 | **45.3** | 50.2 | **192.2** | 198.7 |
| Franchise fees | | **46.8** | 43.9 | **172.7** | 163.5 |
| | | **332.6** | 313.9 | **1,223.5** | 1,163.2 |
| | | **79.4** | 54.0 | **253.2** | 204.2 |
| **Interest and other income** | 5 | **10.2** | 14.0 | **52.3** | 47.3 |
| **Earnings before income taxes** | | **89.6** | 68.0 | **305.5** | 251.5 |
| **Income taxes** | 6 | **11.6** | 9.9 | **39.0** | 37.9 |
| **Earnings from continuing operations** | | **78.0** | 58.1 | **266.5** | 213.6 |
| **Earnings from discontinued operations** | 4 | **-** | 13.5 | **32.6** | 68.5 |
| **Earnings and comprehensive income** | | **78.0** | 71.6 | **299.1** | 282.1 |
| **Dividends on equity preferred shares** | | **4.2** | 4.0 | **16.2** | 13.5 |
| **Dividends on equity preferred shares to parent corporation** | | **1.2** | 1.2 | **4.6** | 4.6 |
| **Dividends on equity preferred shares to parent corporation from discontinued operations** | 4 | **-** | 0.3 | **1.1** | 1.4 |
| **Earnings attributable to Class A and Class B shares** | | **72.6** | 66.1 | **277.2** | 262.6 |
| **Retained earnings at beginning of period** | | **1,830.5** | 1,599.0 | **1,625.9** | 1,402.5 |
| | | **1,903.1** | 1,665.1 | **1,903.1** | 1,665.1 |
| Dividends on Class A and Class B shares | | **-** | 39.2 | **-** | 39.2 |
| Equity distribution on transfer of Alberta Power (2000) | 4 | **249.5** | - | **249.5** | - |
| **Retained earnings at end of period** | | **$1,653.6** | $1,625.9 | **$1,653.6** | $1,625.9 |

# CU Inc.
## Consolidated Balance Sheet
*(Millions of Canadian Dollars)*

| | Note | December 31 2010 | 2009 |
|---|---|---|---|
| **ASSETS** | | | |
| **Current assets** | | | |
| Short term advances to parent corporation | | **$ -** | $ 69.5 |
| Accounts receivable | | **262.7** | 260.9 |
| Accounts receivable from parent and affiliate corporations | | **3.6** | 7.7 |
| Inventories | 7 | **56.0** | 71.6 |
| Income taxes recoverable | 6 | **-** | 8.8 |
| Future income taxes | 6 | **1.8** | 6.2 |
| Regulatory assets | 2 | **16.9** | 37.4 |
| Long term advances to affiliate corporation due within one year | 18 | **10.3** | - |
| Prepaid expenses | | **6.2** | 8.6 |
| | | **357.5** | 470.7 |
| **Long term advances to affiliate corporation** | 18 | **164.7** | - |
| **Property, plant and equipment** | 8 | **5,364.3** | 5,468.4 |
| **Intangibles** | 9 | **239.1** | 225.3 |
| **Regulatory assets** | 2 | **485.9** | 407.6 |
| **Other assets** | | **25.4** | 20.2 |
| | | **$6,636.9** | $6,592.2 |
| **LIABILITIES AND SHARE OWNER'S EQUITY** | | | |
| **Current liabilities** | | | |
| Bank indebtedness | 10 | **$ 16.0** | $ 5.4 |
| Short term advances from parent corporation | | **39.5** | - |
| Accounts payable and accrued liabilities | | **249.7** | 267.0 |
| Accounts payable to parent and affiliate corporations | | **25.9** | 32.1 |
| Regulatory liabilities | 2 | **17.0** | 26.1 |
| | | **348.1** | 330.6 |
| **Future income taxes** | 6 | **364.1** | 332.8 |
| **Regulatory liabilities** | 2 | **493.8** | 450.3 |
| **Deferred credits** | 12 | **86.7** | 207.3 |
| **Long term debt** | 11 | **2,828.3** | 2,827.4 |
| **Equity preferred shares** | 13 | **350.0** | 275.0 |
| **Equity preferred shares to parent corporation** | 13 | **99.4** | 130.0 |
| **Class A and Class B share owner's equity** | | | |
| Class A and Class B shares | 14 | **412.9** | 412.9 |
| Retained earnings | | **1,653.6** | 1,625.9 |
| | | **2,066.5** | 2,038.8 |
| | | **$6,636.9** | $6,592.2 |

*[Original signed by B.R. Bale]*

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DIRECTOR

*[Original signed by R.J. Urwin]*

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DIRECTOR

# CU Inc.
## Consolidated Statement of Cash Flows
*(Millions of Canadian Dollars)*

| | Note | Three Months Ended December 31 2010 | Three Months Ended December 31 2009 | Year Ended December 31 2010 | Year Ended December 31 2009 |
|---|---|---|---|---|---|
| | | *(Unaudited)* | | | |
| **Operating activities** | | | | | |
| Earnings from continuing operations less dividends on equity preferred shares | | **$ 72.6** | $ 52.9 | **$ 245.7** | $ 195.5 |
| Adjustments for: | | | | | |
| Depreciation and amortization | | **54.3** | 48.3 | **211.7** | 192.4 |
| Future income taxes | | **(12.5)** | (2.0) | **(11.6)** | (2.7) |
| Changes in non-current regulatory assets and liabilities | | **(7.0)** | 28.2 | **34.2** | 30.8 |
| Allowance for funds used during construction | | **(2.8)** | (3.5) | **(7.8)** | (9.0) |
| Other | | **(1.1)** | (3.1) | **(2.7)** | 3.1 |
| | | **103.5** | 120.8 | **469.5** | 410.1 |
| Changes in non-cash working capital | 17 | **10.2** | (50.0) | **(10.3)** | (6.5) |
| **Cash flow from continuing operations** | | **113.7** | 70.8 | **459.2** | 403.6 |
| **Cash flow from discontinued operations** | | **-** | 52.1 | **50.8** | 104.4 |
| **Cash flow from operations** | | **113.7** | 122.9 | **510.0** | 508.0 |
| **Investing activities** | | | | | |
| Purchase of property, plant and equipment | | **(238.2)** | (206.0) | **(748.1)** | (726.3) |
| Proceeds on disposal of property, plant and equipment | | **0.9** | 0.1 | **16.3** | 0.2 |
| Contributions by utility customers for extensions to plant | | **17.7** | 20.7 | **66.0** | 114.1 |
| Purchase of intangibles | | **(18.8)** | (26.2) | **(40.8)** | (49.8) |
| Changes in non-cash working capital | 17 | **12.2** | 49.5 | **(3.7)** | (22.5) |
| Other | | **2.5** | 3.6 | **8.3** | 7.3 |
| Increase in cash on transfer of Alberta Power (2000) | 4 | **20.8** | - | **20.8** | - |
| Investing activities cash flow from discontinued operations | | **-** | (3.3) | **(20.0)** | (18.0) |
| | | **(202.9)** | (161.6) | **(701.2)** | (695.0) |
| **Financing activities** | | | | | |
| Issue of long term debt | 11 | **125.0** | - | **125.0** | 270.0 |
| Repayment of long term debt | 11 | **-** | (125.0) | **(125.0)** | (125.0) |
| Issue of equity preferred shares | 13 | **75.0** | - | **75.0** | 160.0 |
| Dividends paid to Class A and Class B share owner | | **-** | (39.2) | **-** | (39.2) |
| Other | | **(3.2)** | (0.1) | **(3.4)** | (5.7) |
| | | **196.8** | (164.3) | **71.6** | 260.1 |
| **Cash position** [(1)] | | | | | |
| Increase (decrease) | | **107.6** | (203.0) | **(119.6)** | 73.1 |
| Beginning of period | | **(163.1)** | 267.1 | **64.1** | (9.0) |
| **End of period** | | **$ (55.5)** | $ 64.1 | **$ (55.5)** | $ 64.1 |

[(1)] Cash position consists of short term advances to parent corporation less current bank indebtedness and short term advances from parent corporation.

## 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") and include the accounts of CU Inc. and its subsidiaries (the "Corporation"). Principal subsidiaries are listed below. Subsidiaries are wholly-owned.

| Principal Operating Subsidiaries | Principal Activity |
|---|---|
| ATCO Gas | Natural gas distribution |
| ATCO Pipelines | Natural gas transmission |
| ATCO Electric | Electric transmission and distribution |
| Alberta Power (2000) (1) | Power generation |

(1) Effective October 1, 2010, the 100% ownership interest in Alberta Power (2000) Ltd. was transferred from CU Inc. to ATCO Power, a wholly-owned subsidiary of Canadian Utilities Limited, the Corporation's parent (see Note 4).

***Accounting Changes***

***Business Combinations, Consolidated Financial Statements and Non-controlling Interests***

Effective January 1, 2010, the Corporation adopted the Canadian Institute of Chartered Accountants' recommendations for Business Combinations, Consolidated Financial Statements and Non-Controlling Interests.

- *Business Combinations* requires assets and liabilities acquired in a business combination, including contingent consideration and certain acquired contingencies, to be measured at their fair value at the acquisition date and require acquisition related and restructuring costs to be expensed in the period incurred.
- *Consolidated Financial Statements* establishes the requirements for the preparation of consolidated financial statements.
- *Non-controlling Interests* establishes the accounting for a non-controlling interest in the consolidated financial statements. The standard requires a non-controlling interest in a subsidiary to be classified as a separate component of equity and to attribute earnings and other comprehensive income to both the parent and non-controlling interest.

The adoption of these standards resulted in the recognition and presentation of discontinued operations in the consolidated financial statements.

***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.

***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.

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

## 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

***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. The Corporation considers short term advances to, or from, parent corporation to be cash equivalents due to their short term nature and insignificant risk of changes in value.

***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.

## 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

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.

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. 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 is reduced by the deferred financing charges.

***Deferred Availability Incentives***

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

Accumulated incentives in excess of accumulated penalties were deferred. For any of the individual PPAs, should accumulated incentives plus estimated future incentives have exceeded accumulated penalties plus estimated future penalties, the excess was amortized to revenues on a straight-line basis over the remaining term of the PPAs. Should accumulated penalties plus estimated future penalties have exceeded accumulated incentives plus estimated future incentives, the shortfall was expensed in the year the shortfall occurred.

***Asset Retirement Obligations***

Asset retirement obligations are legal obligations associated with the retirement of tangible long lived assets. These obligations were measured and recognized at fair value, which is determined using discounted future cash flows using a credit-adjusted risk-free rate.

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

Asset retirement obligations were recorded for the regulated and non-regulated electricity generating 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 of either the Corporation or its parent corporation, Canadian Utilities Limited, 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.

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.

## 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

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.

***Employee Future Benefits***

The Corporation participates, together with Canadian Utilities Limited and its subsidiary corporations, in a registered group defined benefit pension plan ("the Group Plan"). The assets of the Group Plan are not segregated for each participating entity and are used to provide pensions to all members of this plan. In this circumstance, the Corporation is required to account for the Group Plan as a defined contribution plan whereby contributions are expensed as paid.

The Corporation participates, together with Canadian Utilities Limited and its subsidiary corporations, in other post employment benefit ("OPEB") and non-registered group defined benefit pension plans. These plans are administered on a combined basis, and the Corporation accrues for its obligations under these plans. Costs of these benefits are determined using the projected benefits method prorated on service and reflects management's best estimates of wage and salary increases, age at retirement and expected health care costs. Experience gains and losses and the effect of changes in assumptions in excess of 10% of the accrued benefit obligations, 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.

## 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

For non-registered defined benefit pensions, the Corporation is assessed a percentage of the total cost of the plans.

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

***Stock Based Compensation Plans***

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.

## 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.

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 were considered regulated operations primarily because the PPAs were designed

## 2. ACCOUNTING FOR RATE REGULATED OPERATIONS (continued)

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.

***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.

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 19) [(5)] | **56.3** | 51.3 |
| Regulatory pension asset (Note 19) [(5)] | **25.0** | 23.7 |
| 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 | **12.1** | 9.1 |
| | **$485.9** | $407.6 |
| *Regulatory liabilities – current:* | | |
| Deferred electricity costs [(1)] | **$ 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 |
| Deferred pension recoveries [(10)] | **21.9** | - |
| Deferred royalty credits [(11)] | - | 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 |
| | **$493.8** | $450.3 |

## 2. ACCOUNTING FOR RATE REGULATED OPERATIONS (continued)

### [(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.

## 2. ACCOUNTING FOR RATE REGULATED OPERATIONS (continued)

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.

***(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 participates, together with its parent corporation, Canadian Utilities Limited, and affiliated corporations, in a group defined benefit pension plan ("the Group Plan"). The assets of the Group Plan are not segregated for each participating entity and are used to provide pensions to all members of this plan. In this circumstance, the Corporation is required to account for the Group Plan as a defined contribution plan whereby contributions are expensed as paid. The Corporation accrues for its obligations under other post employment benefit and certain other defined pension plans.

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.

Pursuant to an AUC decision, the Corporation, as of January 1, 2000, is required to expense contributions for other post employment benefit and certain other defined benefit pension plans as paid. The variances between the amounts accrued and paid are recorded as a regulatory asset. GAAP requires that in the absence of rate regulation 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 $0.6 million higher (2009 – $0.9 million higher) 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.

## 2. ACCOUNTING FOR RATE REGULATED OPERATIONS (continued)

### (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.

### (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.

## 2. ACCOUNTING FOR RATE REGULATED OPERATIONS (continued)

***[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.

***[11] Deferred royalty credits***

Under the terms of PPAs, the compensation for certain royalties incurred by Alberta Power (2000) for coal supply were averaged over the term of each PPA. As such, royalty costs were 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. Effective October 1, 2010, the Corporation no longer recognizes Alberta Power (2000) Ltd's financial position, results of operations and cash flows in its consolidated financial statements (see Note 4). Consequently, earnings from discontinued operations in 2010 would have been $2.5 million lower (2009 - $4.7 million lower) 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 September 30, 2010, $97.1 million (December 31, 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.

## 3. REGULATORY MATTERS (continued)

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.

***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.

***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.

## 3. REGULATORY MATTERS (continued)

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.

***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. DISCONTINUED OPERATIONS

Effective October 1, 2010, the Corporation transferred ownership of its wholly-owned subsidiary, Alberta Power (2000) Ltd., to ATCO Power Ltd., a wholly-owned subsidiary of Canadian Utilities Limited, the Corporation's parent ("Alberta Power (2000) Transfer"). As this was a related party transaction by companies under common control, it was accounted for by the Corporation at the carrying amount. The transfer resulted in a non-cash distribution of $249.5 million from the Corporation to its parent, Canadian Utilities Limited. Commencing October 1, 2010, the Corporation no longer recognized Alberta Power (2000) Ltd.'s financial position, results of operations and cash flows in its consolidated financial statements. The results of operations and the cash flows for the periods prior to October 1, 2010, have been presented as a discontinued operation in the consolidated financial statements for the year ended December 31, 2010. These amounts were previously recognized in the Energy Segment.

The earnings from discontinued operations are reported as a separate line item of earnings on the Consolidated Statement of Earnings and Retained Earnings, and comparative period balances have been restated.

## 4. DISCONTINUED OPERATIONS (continued)

Discontinued operations as reported on the Consolidated Statement of Earnings, Comprehensive Income and Retained Earnings are as follows:

| | **2010** | 2009 |
|---|---|---|
| Revenues | **$224.1** | $309.9 |
| Operating expenses | **124.7** | 162.7 |
| Depreciation and amortization | **40.7** | 52.5 |
| Interest expense | **0.3** | 1.6 |
| Interest and other income | **(13.9)** | (11.0) |
| Earnings from discontinued operations before income taxes | **44.5** | 82.1 |
| Income taxes | **11.9** | 13.6 |
| Earnings from discontinued operations | **32.6** | 68.5 |
| Dividends on equity preferred shares to parent corporation from discontinued operations | **1.1** | 1.4 |
| Earnings attributable to Class A and Class B shares from discontinued operations | **$ 31.5** | $ 67.1 |

Discontinued operations as reported on the Consolidated Balance Sheet are as follows:

| | September 30, 2010 | December 31, 2009 |
|---|---|---|
| *Assets:* | | |
| Current assets | $ 80.5 | $ 96.7 |
| Property, plant and equipment | 571.7 | 588.4 |
| Intangibles | 1.1 | 1.4 |
| | $653.3 | $686.5 |
| *Liabilities and Share Owner's Equity:* | | |
| Bank indebtedness | $ 40.8 | $ 45.1 |
| *Other current liabilities* | 20.8 | - |
| Future income taxes | 28.7 | 26.5 |
| Regulatory liabilities | 13.4 | 16.8 |
| Deferred credits | 94.5 | 114.4 |
| Long term debt (1) | 175.0 | 220.2 |
| | 373.2 | 423.0 |
| Equity preferred shares to parent corporation | 30.6 | 30.6 |
| Class A and B share owner's equity | | |
| Class A and B shares | 313.0 | 313.0 |
| Retained Earnings | (63.5) | (80.1) |
| | 249.5 | 232.9 |
| | $653.3 | $686.5 |

(1) *Intercompany amounts with CU Inc. that were eliminated upon consolidation prior to the Alberta Power (2000) Transfer*

Cash flows relating to discontinued operations have been reported as separate line items of cash flow from operating, investing and financing activities on the Consolidated Statement of Cash Flows, and comparative period balances have been restated.

## 5. INTEREST AND OTHER INCOME

| | **2010** | 2009 |
|---|---|---|
| Interest | **$29.8** | $24.3 |
| Allowance for funds used by regulated operations | **20.0** | 23.4 |
| Gains on dispositions of property, plant and equipment | **2.6** | - |
| Other | **(0.1)** | (0.4) |
| | **$52.3** | $47.3 |

## 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 | **$305.5** | **%** | $251.5 | % |
| Income taxes, at statutory rates | **$ 85.5** | **28.0** | $ 72.9 | 29.0 |
| ATCO Pipelines settlement | **(4.4)** | **(1.4)** | - | - |
| Removal of Carbon storage assets from regulation | - | - | 5.8 | 2.3 |
| Future income taxes relating to regulated operations (see Note 2) | **(46.5)** | **(15.2)** | (38.7) | (15.4) |
| Other | **4.4** | **1.4** | (2.1) | (0.8) |
| | **39.0** | **12.8** | 37.9 | 15.1 |
| Current income taxes | **39.1** | | 35.3 | |
| Future income taxes (recoveries) | **$ (0.1)** | | $ 2.6 | |

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

| | **2010** | 2009 |
|---|---|---|
| Property, plant and equipment | **$338.5** | $339.5 |
| Intangibles | **47.1** | 49.0 |
| Deferred assets and liabilities | **(18.4)** | (61.9) |
| Tax loss carryforwards | **(4.9)** | - |
| | **362.3** | 326.6 |
| Less: Current future income tax asset | **(1.8)** | (6.2) |
| | **$364.1** | $332.8 |

In 2010, ATCO Pipelines successfully negotiated a settlement with the Canada Revenue Agency 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.

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 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 $29.9 million (2009 – $19.7 million).

## 7. INVENTORIES

| | **2010** | 2009 |
|---|---|---|
| Natural gas in storage | **$20.0** | $19.4 |
| Raw materials and consumables | **36.0** | 52.2 |
| | **$56.0** | $71.6 |

For the year ended December 31, 2010, the amount of inventories recognized as an expense was $52.0 million (2009 – $56.4 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% | **-** | **-** | 1,427.5 | 839.1 |
| | | **$8,819.4** | **2,555.1** | $9,584.9 | 3,235.8 |
| Property, plant and equipment less accumulated depreciation | | | **6,264.3** | | 6,349.1 |
| Unamortized contributions by utility customers for extensions to plant | | | **900.0** | | 880.7 |
| | | | **$5,364.3** | | $5,468.4 |

Composite depreciation rates reflect total depreciation in the year as a percentage of mid-year cost, excluding construction work-in-progress of $302.5 million (2009 – $261.0 million) and non-depreciable assets of $30.6 million (2009 – $39.5 million).

## 9. INTANGIBLES

| | **2010** | | 2009 | |
|---|---|---|---|---|
| | **Cost** | **Accumulated Amortization** | Cost | Accumulated Amortization |
| Computer software | **$289.5** | **$161.7** | $277.8 | $148.6 |
| Land rights | **130.9** | **23.4** | 115.0 | 22.1 |
| Other | **5.4** | **1.5** | 4.9 | 1.4 |
| | **$425.8** | **186.6** | $397.7 | 172.1 |
| Intangibles less accumulated amortization | | **239.2** | | 225.6 |
| Unamortized contributions by utility customers | | **0.1** | | 0.3 |
| | | **$239.1** | | $225.3 |

Amortization expense relating to intangibles was $25.5 million (2009 – $20.8 million).

## 10. BANK INDEBTEDNESS

At December 31, 2010, bank indebtedness consists of $16.0 million (2009 – $5.4 million), which represents cheques outstanding in excess of cash in bank.

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 |
| Short term committed | **$300.0** | **$35.8** | **$264.2** | $300.0 | $32.0 | $268.0 |
| Uncommitted | **28.7** | **1.6** | **27.1** | 28.7 | 1.9 | 26.8 |
| | **$328.7** | **$37.4** | **$291.3** | $328.7 | $33.9 | $294.8 |

All of the $37.4 million used at December 31, 2010, represents outstanding letters of credit.

## 11. LONG TERM DEBT

| | Effective Interest Rate | **2010** | 2009 |
|---|---|---|---|
| ***Long term debt*** | | | |
| 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** | - |
| Other long term obligation, due June 2012, unsecured | 3.000% | **4.5** | 4.5 |
| Less: Deferred financing charges | | **(14.2)** | (15.1) |
| | | **2,825.3** | 2,824.4 |
| ***Long term debt to parent corporation*** | | | |
| Non-interest bearing promissory note, unsecured | | **3.0** | 3.0 |
| | | **$2,828.3** | $2,827.4 |

## 11. LONG TERM DEBT (continued)

***Contractual maturities of debt***

The undiscounted contractual maturities of long term debt are as follows:

| | Principal | Interest |
|---|---|---|
| 2011 | $ 100.0 | $ 174.3 |
| 2012 | 39.5 | 170.8 |
| 2013 | - | 168.9 |
| 2014 | 100.0 | 168.9 |
| 2015 | - | 163.8 |
| 2016 and thereafter | 2,603.0 | 2,048.1 |
| | $2,842.5 | $2,894.8 |

***Interest expense***

Interest expense is as follows:

| | **2010** | 2009 |
|---|---|---|
| Long term debt | **$185.8** | $195.3 |
| Bank indebtedness | **2.7** | 1.6 |
| Amortization of deferred financing charges | **1.9** | 1.8 |
| Other | **1.8** | - |
| | **$192.2** | $198.7 |

Interest paid amounted to $195.2 million (2009 – $193.4 million).

## 12. DEFERRED CREDITS

| | **2010** | 2009 |
|---|---|---|
| Accrued other post employment benefits liability (Note 19) | **$ 56.1** | $ 51.3 |
| Deferred availability incentives | **-** | 67.1 |
| Asset retirement obligations | **-** | 46.9 |
| Liability to customers for refund of future income taxes | **-** | 12.1 |
| Accrued pension liability (Note 19) | **20.6** | 15.9 |
| Other | **10.0** | 14.0 |
| | **$86.7** | $207.3 |

***Deferred availability incentives***

As a result of the Alberta Power (2000) Transfer (see Note 4), the Corporation, as of October 1, 2010, no longer includes deferred availability incentives related to Alberta Power (2000) in its consolidated balance sheet. Amortization of deferred availability incentives for the nine months ended September 30, 2010, of $10.8 million (2009 – $16.3 million for the year ended December 31, 2009) is included in earnings from discontinued operations.

## 12. DEFERRED CREDITS (continued)

***Asset retirement obligations***

Changes in asset retirement obligations are summarized below:

| | **2010** | 2009 |
|---|---|---|
| Obligations at beginning of year | **$46.9** | $44.4 |
| Accretion expense | **2.0** | 2.5 |
| Adjustment from Alberta Power (2000) Transfer | **(48.9)** | - |
| Obligations at end of year | **$ -** | $46.9 |

As a result of the Alberta Power (2000) Transfer (see Note 4), the Corporation, as of October 1, 2010, no longer includes asset retirement obligations related to Alberta Power (2000) in its consolidated balance sheet.

## 13. EQUITY PREFERRED SHARES AND EQUITY PREFERRED SHARES TO PARENT CORPORATION

***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, the 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 the Corporation, 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 preferred shares determined using quoted market prices for the same or similar issues are $358.3 million (2009 - $278.3 million).

## 13. EQUITY PREFERRED SHARES AND EQUITY PREFERRED SHARES TO PARENT CORPORATION (continued)

***Redemption privileges***

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

On June 1, 2014, and on June 1 of every fifth year thereafter, the Corporation 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 the Corporation, 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, the Corporation 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, the Corporation 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 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 the Corporation, 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, the Corporation 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.

***Equity preferred shares to parent corporation***

***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) | | | | | |
| Perpetual Cumulative Second Preferred Shares | | | | | | |
| 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 | **3,176,578** | **79.4** | 4,400,000 | 110.0 |
| | | | | **$99.4** | | $130.0 |

## 13. EQUITY PREFERRED SHARES AND EQUITY PREFERRED SHARES TO PARENT CORPORATION (continued)

The dividends payable on the Series 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 the Corporation and Canadian Utilities Limited. As a result of the Alberta Power (2000) Transfer (see Note 4), 1,223,422 Series V preferred shares are not included in the Corporation's financial position at December 31, 2010.

***Fair values***

Fair values for preferred shares determined using quoted market prices for the same or similar issues are $101.2 million (2009 – $129.5 million).

***Redemption privileges***

The preferred shares are redeemable on the dates specified above at the option of the Corporation at the stated value plus accrued and unpaid dividends.

## 14. CLASS A AND CLASS B SHARES

| | Class A Non-Voting | | Class B Common | | Total | |
|---|---|---|---|---|---|---|
| | Shares | Amount | Shares | Amount | Shares | Amount |
| Authorized: | Unlimited | | Unlimited | | | |
| Issued and outstanding: | **3,286,124** | **$256.0** | **2,014,076** | **$156.9** | **5,300,200** | **$412.9** |

## 15. 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 its share owner 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 owner's equity, equity preferred shares, equity preferred shares to parent corporation, and long term debt in its determination of capitalization. In managing its capital, the Corporation considers the impact of the AUC's decisions with respect to the Corporation's subsidiaries 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 the share owner, issue or purchase Class A and Class B shares and issue or redeem equity preferred shares and long term debt.

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.

## 15. CAPITAL DISCLOSURES (continued)

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, retained earnings, equity preferred shares and equity preferred shares to parent corporation. Total capitalization is comprised of 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. The Corporation looks to maintain an equity capitalization in the range of 40% to 50%.

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 1.8 and interest and preferred dividend coverage of at least 1.5; 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.

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

| | **2010** | 2009 |
|---|---|---|
| Class A and Class B shares | **$ 412.9** | $ 412.9 |
| Retained earnings | **1,653.6** | 1,625.9 |
| Equity preferred shares | **350.0** | 275.0 |
| Equity preferred shares to parent corporation | **99.4** | 130.0 |
| Total equity | **2,515.9** | 2,443.8 |
| Long term debt | **2,828.3** | 2,827.4 |
| Total capitalization | **$5,344.2** | $5,271.2 |
| Equity capitalization | **47%** | 46% |

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 equity preferred share financings for utility capital expenditures, partially offset by the reduction of equity preferred shares to parent corporation and the equity distribution to parent corporation as a result of the Alberta Power (2000) Transfer (see Note 4). Total debt has remained essentially unchanged as maturing debt was refinanced during the year.

## 15. CAPITAL DISCLOSURES (continued)

| | **2010** | 2009 |
|---|---|---|
| Interest coverage | **2.8** | 2.7 |
| Interest and preferred dividend coverage | **2.4** | 2.3 |

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.

## 16. STOCK BASED COMPENSATION PLANS

***Share appreciation rights***

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

Share appreciation rights expense amounted to $1.0 million (2009 – nil).

## 17. CHANGES IN NON-CASH WORKING CAPITAL

| | **2010** | 2009 |
|---|---|---|
| *Operating activities, changes related to:* | | |
| Accounts receivable | **$(63.3)** | $(10.9) |
| Accounts receivable from parent and affiliate corporations | **4.2** | 2.5 |
| Inventories | **(0.5)** | 3.3 |
| Regulatory assets | **23.8** | 23.0 |
| Prepaid expenses | **1.0** | (0.7) |
| Accounts payable and accrued liabilities | **25.5** | (24.2) |
| Accounts payable to parent and affiliate corporations | **3.9** | (3.4) |
| Income taxes payable | **4.2** | 14.4 |
| Regulatory liabilities | **(9.1)** | (10.5) |
| | **$(10.3)** | $ (6.5) |
| *Investing activities, changes related to:* | | |
| Accounts receivable | **$ -** | $ 0.2 |
| Inventories | **(2.6)** | 4.1 |
| Prepaid expenses | **(0.1)** | - |
| Accounts payable and accrued liabilities | **(1.0)** | (26.8) |
| | **$ (3.7)** | $(22.5) |

## 18. RELATED PARTY TRANSACTIONS

| Entity | Relationship | Transaction | Recorded As | **2010** | 2009 |
|---|---|---|---|---|---|
| Canadian Utilities Limited | Parent | Sale of electricity and natural gas, lease of land, rent and office services | Revenues | **$ 0.1** | $ 0.1 |
| | | Rent and aircraft usage | Selling and administrative | **7.3** | 8.9 |
| | | Purchase of equipment and leasehold improvements | Property, plant and equipment | **6.0** | 2.9 |
| ATCO Ltd. and ATCO Investments Ltd. | Affiliates | Corporate signature rights and rent | Selling and administrative | **4.1** | 3.4 |
| ASHCOR Technologies Ltd., ATCO I-Tek Inc., ATCO Midstream Ltd., ATCO Power Ltd., ATCO Energy Solutions Ltd., ATCO Travel, and ATCO Structures & Logistics Ltd. | Affiliates | Natural gas storage, transportation and other gas services, sale of ash, rent and office services, payroll and accounting services | Revenues | **25.9** | 25.7 |
| | | | Earnings from discontinued operations | **2.5** | 2.0 |
| | | Purchase and storage of natural gas | Natural gas supply | **2.6** | 2.3 |
| | | Purchase of natural gas | Operation and maintenance | **3.0** | 3.0 |
| | | | Earnings from discontinued operations | **(3.6)** | (3.0) |
| | | Purchase of natural gas | Regulatory assets | **3.7** | (13.3) |
| | | Computer operations and systems development, call centre and customer billing services | Operation and maintenance, selling and administrative | **70.6** | 66.2 |
| | | | Earnings from discontinued operations | **(20.2)** | (20.5) |
| | | North Warning System joint venture earnings | Other income | **0.3** | 0.4 |
| | | Purchase of equipment | Property, plant and equipment | **9.6** | 14.3 |
| | | Capitalized software | Intangibles | **8.3** | 28.3 |

The Corporation incurred $0.3 million (2009 – $0.3 million) in advertising and promotion expenses from an entity related through common control.

## 18. RELATED PARTY TRANSACTIONS (continued)

At December 31, 2010, there were no short term advances to parent corporation (2009 – $69.5 million), accounts receivable from related parties amounted to $3.6 million (2009 – $7.7 million), long term advances to affiliate corporation amounted to $175.0 million, short term advances from parent corporation amounted to $39.5 million (2009 – nil), accounts payable to parent and affiliate corporations of related parties amounted to $25.9 million (2009 – $32.1 million) and equity preferred shares to parent corporation amounted to $99.4 million (2009 – $130.0 million). The long term advances to affiliate corporation are with Alberta Power (2000), which subsequent to the Alberta Power (2000) Transfer (see Note 4), are no longer eliminated upon consolidation.

The long term advances to affiliate corporation are as follows:

| | Effective Interest Rate | **2010** | 2009 |
|---|---|---|---|
| 2000 7.05% due June 2011 | 7.130% | **$ 10.3** | $ - |
| 2007 4.883% due November 2012 | 4.990% | **35.0** | - |
| 1999 6.8% due August 2019 | 6.861% | **51.4** | - |
| 1990 Second Series 11.77% due November 2020 | 11.903% | **26.8** | - |
| 1991 Series 9.92% due April 2022 | 10.063% | **35.0** | - |
| 1992 Series 9.40% due May 2023 | 9.511% | **16.5** | - |
| | | **175.0** | $ - |
| Less: Amounts due within one year | | **10.3** | - |
| | | **$164.7** | $ - |

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

## 19. EMPLOYEE FUTURE BENEFITS

The Corporation, together with Canadian Utilities Limited and its subsidiary corporations, 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, together with Canadian Utilities Limited and its subsidiary corporations, also maintains non-registered, non-funded defined benefit pension plans for certain officers and key employees.

Contributions to the Group Plan, which is accounted for as a defined contribution pension plan, are expensed as paid. Other post employment benefit and non-registered group defined benefit pension plans, which the Corporation funds out of general revenues, are administered on a combined basis with Canadian Utilities Limited and its subsidiary corporations. For non-registered defined benefit pensions, the Corporation is assessed a percentage of the total cost of the plans. Pursuant to an AUC decision effective January 1, 2000, the Utilities are required to expense contributions for other post employment benefit and non-registered defined benefit pension plans as paid. The differences between the amounts accrued and paid are deferred in regulatory assets.

## 19. 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 cost:* | | | | |
| Defined benefit plan cost | **$ 54.7** | **$ 6.6** | $ 9.8 | $ 6.1 |
| Defined contribution plan cost | **11.3** | **-** | - | - |
| Total cost | **66.0** | **6.6** | 9.8 | 6.1 |
| Less: Capitalized | **25.2** | **2.7** | 1.9 | 2.4 |
| Less: Regulatory deferral [1] | **0.6** | **2.9** | 0.9 | 2.4 |
| Net cost recognized [2] | **$ 40.2** | **$ 1.0** | $ 7.0 | $ 1.3 |
| *Accrued defined benefit plan assets and liabilities:* | | | | |
| Accrued liability at beginning of year | **$(15.9)** | **$(51.3)** | $(10.6) | $(47.2) |
| Defined benefit plan cost | **(54.7)** | **(6.6)** | (9.8) | (6.1) |
| Benefit payments | **3.7** | **1.6** | 3.5 | 2.0 |
| Defined benefit contributions | **46.3** | **-** | 1.0 | - |
| Other | **-** | **0.2** | - | - |
| Accrued liability at end of year (Note 12) | **$(20.6)** | **$(56.1)** | $(15.9) | $(51.3) |
| *Regulatory benefit plan assets [1] (Note 2):* | | | | |
| Regulatory asset at beginning of year | **$ 23.7** | **$ 51.3** | $ 22.3 | $ 46.9 |
| Adjustment to beginning liability | **-** | **-** | - | 0.3 |
| Regulatory cost deferral | **0.6** | **2.9** | 0.9 | 2.4 |
| Regulatory cost capitalized | **0.3** | **2.1** | 0.5 | 1.7 |
| Other regulatory adjustments | **0.4** | **-** | - | - |
| Regulatory asset at end of year | **$ 25.0** | **$ 56.3** | $ 23.7 | $ 51.3 |

[1] *The regulatory deferral of benefit plan cost and the regulatory asset reflect 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).*

In the unaudited three months ended December 31, 2010, net expense of $8.5 million (2009 – $1.6 million) was recognized for pension benefit plans and net expense of $0.2 million (2009 – $0.3 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 costs from customers.

## 19. EMPLOYEE FUTURE BENEFITS (continued)

***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:* | | | | |
| 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).*

***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 have 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 $58 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 in its rate applications to the AUC, thereby, with the consent of the AUC, recovering approximately 100% of the costs of funding its pension plans from utility customers.

## 20. 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 the share owner, 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. 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. There are no derivative instruments outstanding at December 31, 2010.

***Credit risk***

For short term advances to parent corporation and accounts receivable, credit risk represents the carrying amount on the consolidated balance sheet. Credit risk on cash and short term investments (when held by the Corporation) is reduced by investing in instruments issued by credit worthy financial institutions and in federal government issued short term instruments.

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

Accounts receivable credit risk is reduced by a large and diversified customer base, requirement for credit security such as letters of credit, 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.

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 $0.3 million; this provision is unchanged from December 31, 2009.

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 | **$2.1** | $1.7 |
| Greater than 90 days | **0.5** | 0.9 |
| | **$2.6** | $2.6 |

No other impairments have been identified within accounts receivable.

## 20. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (continued)

***Liquidity risk***

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

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

| | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 and thereafter |
|---|---|---|---|---|---|---|
| Short term advances from parent corporation | $ 39.5 | $ - | $ - | $ - | $ - | $ - |
| Accounts payable and accrued liabilities | 249.7 | - | - | - | - | - |
| Accounts payable to parent and affiliate corporations | 25.9 | - | - | - | - | - |
| Operating leases [1] | 12.0 | 10.3 | 8.6 | 7.6 | 7.3 | 20.6 |
| Long term debt (Note 11) | 100.0 | 39.5 | - | 100.0 | - | 2,603.0 |
| Interest expense (Note 11) | 174.3 | 170.8 | 168.9 | 168.9 | 163.8 | 2,048.1 |
| Purchase obligations: | | | | | | |
| Natural gas purchase contracts | 0.2 | 0.2 | 0.2 | 0.2 | - | - |
| Operating and maintenance agreements | 0.3 | - | - | - | - | - |
| Capital expenditures [2] | 86.5 | - | - | - | - | - |
| | $688.4 | $220.8 | $177.7 | $276.7 | $171.1 | $4,671.7 |

[1] *Operating leases are comprised primarily of long term leases for office premises and equipment.*
[2] *Various contracts to purchase goods and services with respect to capital expenditures.*

## 20. 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:* | | | | |
| Short term advances to parent corporation [1] | **$ -** | **$ -** | $ 69.5 | $ 69.5 |
| *Loans and Receivables:* | | | | |
| Accounts receivable [1] | **262.7** | **262.7** | 260.9 | 260.9 |
| Accounts receivable from parent and affiliate corporations [1] | **3.6** | **3.6** | 7.7 | 7.7 |
| Long term advances to affiliate corporation [2] | **175.0** | **227.6** | - | - |
| ***Financial Liabilities*** | | | | |
| *Held For Trading:* | | | | |
| Bank indebtedness [1] | **16.0** | **16.0** | 5.4 | 5.4 |
| Short term advances from parent corporation [1] | **39.5** | **39.5** | - | - |
| *Other Liabilities:* | | | | |
| Accounts payable and accrued liabilities [3] | **249.7** | **249.7** | 267.0 | 267.0 |
| Accounts payable to parent and affiliate corporation [3] | **25.9** | **25.9** | 32.1 | 32.1 |
| Liability to customers for refund of future income taxes [3] | **-** | **-** | 12.1 | 12.1 |
| Long term debt [4] | **2,825.3** | **3,285.7** | 2,824.4 | 3,107.6 |
| Long term debt to parent corporation [5] | **3.0** | **3.0** | 3.0 | 3.0 |

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

[2] *Recorded at cost. Fair 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.*

[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.*

[5] *Recorded at carrying amount. The long term debt to parent corporation is repayable on demand; therefore, the fair value is equal to carrying amount.*

***Fair value of financial instruments***

The Corporation does not have any financial instruments recorded at fair value at December 31, 2010.

## 21. CONTINGENCIES

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

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

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

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

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

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