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FOR THE NINE MONTHS ENDED
SEPTEMBER 30, 2008

TO THE SHARE OWNERS:

Canadian Utilities Limited reported earnings of $66.7 million ($0.53 per share) for the three months ended September 30, 2008, compared to earnings of $72.2 million ($0.58 per share) for the same three months in 2007, were reported by Canadian Utilities. Canadian Utilities reported an increase in "adjusted earnings" [(1)] for the third quarter, which excludes certain items not in the normal course of business or a result of day-to-day operations. Adjusted earnings for the three months ended September 30, 2008, were $71.3 million ($0.57 per share) compared to adjusted earnings of $70.6 million ($0.56 per share) for the same three months in 2007.

Earnings for the nine months ended September 30, 2008, were $298.9 million ($2.38 per share) compared to earnings of $288.0 million ($2.30 per share) for the same nine months in 2007. Adjusted earnings for the nine months ended September 30, 2008, were $291.3 million ($2.32 per share) compared to adjusted earnings of $268.3 million ($2.14 per share) for the same nine months in 2007.

Financial Summary and Reconciliation of Adjusted Earnings	For the Three Months Ended September 30		For the Nine Months Ended September 30	
	2008	2007	**2008**	2007
($ Millions except per share data)		(unaudited)		
Reported Earnings	**66.7**	72.2	**298.9**	288.0
ATCO Power Mark-to-Market Adjustment	**7.6**	2.4	**0.9**	(0.1)
2007 Change in Preferred Share Taxes	**-**	-	**-**	(15.6)
2007 Changes in Income Taxes & Rates	**-**	(4.0)	**-**	(4.0)
Reallocation of Post Employment Benefits	**-**	-	**(5.5)**	-
Federal Court of Appeal Tax Decision	**(3.0)**	-	**(3.0)**	-
Adjusted Earnings [(1)]	**71.3**	70.6	**291.3**	268.3
Earnings Per Share	**0.53**	0.58	**2.38**	2.30
Adjusted Earnings Per Share [(1)]	**0.57**	0.56	**2.32**	2.14
Revenues	**638.4**	489.9	**2,034.6**	1,747.8
Funds Generated By Operations [(1)] [(2)]	**191.0**	150.4	**580.1**	545.9

(1) This measure is not defined by Generally Accepted Accounting Principles and may not be comparable to similar measures used by other companies.
(2) This measure is cash flow from operations before changes in non-cash working capital.

Adjusted earnings for the three months ended September 30, 2008, increased primarily due to increased business activity in ATCO Frontec's operations and a reduction in income tax expense relating to the treatment of major maintenance expenses in Alberta Power (2000). These increases were partially offset by lower spark spreads in ATCO Power's Alberta generating plants and the earnings impact of $5.3 million due to the change in quarterly depreciation expense allocation in ATCO Gas.

Adjusted earnings for the nine months ended September 30, 2008, increased primarily due to increased business activity in ATCO Frontec's operations and higher margins for natural gas liquids extraction in ATCO Midstream. These increases were partially offset by lower storage fees in ATCO Midstream.

Revenues for the three months ended September 30, 2008, increased primarily due to the 2007 refund of future income tax balances with a corresponding decrease in revenues and the impact of higher 2008 Alberta Utilities Commission (AUC) approved customer rates resulting from the 2007 and 2008 ATCO Electric general tariff decision (ATCO Electric GTA), increased business activity in ATCO Frontec's operations, higher natural gas fuel purchases recovered on a "no-margin" basis and improved merchant operations in ATCO Power's U.K. operations and AUC approved interim customer rates in ATCO Gas associated with the 2008 and 2009 general rate application (ATCO Gas Interim Rates). These increases were partially offset by decreased merchant performance in ATCO Power's Alberta generating plants.

Revenues for the nine months ended September 30, 2008, increased primarily due to increased business activity in ATCO Frontec's operations, the 2007 refund of future income tax balances with a corresponding decrease in revenues and the impact of higher AUC approved customer rates resulting from the ATCO Electric GTA and ATCO Gas Interim Rates, and the impact of higher franchise fees collected on behalf of cities and municipalities in ATCO Gas. These increases were partially offset by lower storage revenues due to the timing and demand of natural gas storage capacity sold and lower storage fees in ATCO Midstream.

Funds generated by operations for the three months ended September 30, 2008, increased primarily due to increased cash flow after removal of non-cash items and increased deferred availability incentives in Alberta Power (2000).

Funds generated by operations for the nine months ended September 30, 2008, increased primarily due to increased cash flow after removal of non-cash items, partially offset by an inclusion in 2007 of $15.6 million related to the change in the taxation of preferred share dividends.

RECENT DEVELOPMENTS

- On October 1, 2008, ATCO Frontec and the Fort McKay First Nation officially opened the Creeburn Lake Lodge. The 500-room Lodge, located 65 kilometres north of Fort McMurray, brings much-needed, high quality accommodation to the Alberta oilsands region.

- On September 30, 2008, Canadian Utilities announced the launch of ATCO Water, a company focused on designing, building and operating leading edge water and wastewater infrastructure and facilities for both industry and municipalities.

- During the third quarter, ATCO Power's construction of its new 45 megawatt clean natural gas fired power plant in Valleyview was completed ahead of schedule and under budget bolstering electricity supply in fast-growing northwestern Alberta.

- On September 9, 2008, ATCO Electric reported that they have reached an alliance agreement with UK-based Balfour Beatty and Australia-based United Group Limited to provide engineering, construction, procurement and project management services to supplement ATCO Electric's own expertise.

- On September 8, 2008, Canadian Utilities reported that indirectly wholly owned subsidiary, ATCO Pipelines, and TransCanada Corporation's wholly owned subsidiary, NOVA Gas Transmission Ltd., had reached a proposed agreement to provide seamless natural gas transmission service to customers. The gas transmission model will utilize a single suite of services to provide integrated gas transmission service which is expected to add value for customers as a result of efficient service throughout Alberta.

- On August 18, 2008, ATCO Frontec and the Fort McKay First Nation announced an agreement to construct and operate a 603-room complex that will provide accommodations to Albian Sands Energy. The complex will be added to the existing Barge Landing Lodge built for Suncor earlier this year. Operated under a services agreement with Albian Sands, this new facility will utilize a common dining room, games room, fitness centre, meeting rooms and television rooms. Barge Landing Lodge is located across from the recently opened Creeburn Lake Lodge on Fort McKay First Nation land.

Canadian Utilities Limited is part of the ATCO Group of Companies (www.atco.com). Canadian Utilities Limited is a Canadian-based worldwide organization of companies with assets of approximately $7.7 billion and more than 6,500 employees, actively engaged in three main business divisions: Power Generation, Utilities (natural gas and electricity transmission and distribution) and Global Enterprises (technology, logistics and energy services).

N.C. Southern
President & Chief Executive Officer
Deputy Chair

R.D. Southern
Chairman of the Board

CANADIAN UTILITIES LIMITED
Management's Discussion and Analysis (MD&A)
For the Nine Months Ended September 30, 2008

This MD&A should be read in conjunction with the Company's unaudited interim consolidated financial statements for the nine months ended September 30, 2008, and the audited consolidated financial statements and MD&A for the year ended December 31, 2007 (2007 MD&A). **Information contained in the 2007 MD&A that is not discussed in this document remains substantially unchanged.** This MD&A is dated October 27, 2008. Additional information relating to the Company, including the Company's Annual Information Form, is available on SEDAR at www.sedar.com.

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Glossary

Adjusted Earnings means earnings attributable to Class A and Class B shares after adjustments for items that are not in the normal course of business nor a result of day-to-day operations. These items are usually of a non-recurring or one-time nature. Refer to Reconciliation of Earnings Attributable to Class A and Class B shares and Adjusted Earnings section for a description of these items (non GAAP items).

Adjusted Earnings per Class A and Class B share is calculated by dividing Adjusted Earnings for a period by the weighted average number of Class A and Class B shares outstanding during the period (non GAAP items).

AESO means the Alberta Electric System Operator.

Alberta Power Pool means the market for electricity in Alberta operated by AESO.

AUC means the Alberta Utilities Commission and its predecessor, the Alberta Energy and Utilities Board.

Availability means a measure of time, expressed as a percentage of continuous operation, that a generating unit is capable of producing electricity, regardless of whether the unit is actually generating electricity.

Class A shares means Class A non-voting shares of the Company.

Class B shares means Class B common shares of the Company.

Class I Shares means Class I Non-Voting Shares of ATCO Ltd.

Class II Shares means Class II Voting Shares of ATCO Ltd.

Company means Canadian Utilities Limited and, unless the context otherwise requires, includes its subsidiaries.

Frac spread means the premium or discount between the purchase price of natural gas and the selling price of extracted natural gas liquids on a heat content equivalent basis.

GAAP means Canadian generally accepted accounting principles.

GHG means any greenhouse gas which has the potential to retain heat in the atmosphere, including water vapour, carbon dioxide, methane, nitrous oxide and hydrofluorocarbons.

Gigajoule (GJ) means a unit of energy equal to approximately 948.2 thousand British thermal units.

Mark-to-market means assigning a value to a contract or financial instrument based on the current market prices for that instrument or similar instruments.

Megawatt (MW) means a measure of electric power equal to 1,000,000 watts.

Megawatt hour (MWh) means a measure of electricity consumption equal to the use of 1,000,000 watts of power over a one-hour period.

NGL means natural gas liquids, such as ethane, propane, butane and pentanes plus, that are extracted from natural gas and sold as distinct products or as a mix.

OPEB means other post employment benefits, which principally include health, dental and life insurance payments for retirees and their dependants.

Petajoule (PJ) means a unit of energy equal to approximately 948.2 billion British thermal units.

Placeholder means an AUC approved interim cost which has been included in utility customer rates pending an AUC review in a separate proceeding. This cost is subject to adjustment once the proceeding is completed and may result in refunds to or recoveries from customers.

PPA means Power Purchase Arrangements that became effective on January 1, 2001, as part of the process of restructuring the electric utility business in Alberta. The PPAs are legislatively mandated and approved by the AUC.

Propane Plus means propane, butane, pentane and other hydrocarbons other than methane and ethane.

Shrinkage Gas means the natural gas which is used to replace, on a heat equivalent basis, the NGL extracted during NGL extraction operations.

Spark spread means the difference between the selling price of electricity and the marginal cost of producing electricity from natural gas. In this MD&A, spark spreads are based on an approximate industry heat rate of 7.5 GJ per MWh.

U.K. means United Kingdom.

Company Overview

The consolidated financial statements include the accounts of Canadian Utilities Limited (Canadian Utilities) and all of its subsidiaries. The consolidated financial statements have been prepared in accordance with GAAP and the reporting currency is the Canadian dollar.

The Company operates in the following business segments:

The **Utilities** Business Group includes:

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

The **Power Generation** Business Group includes:

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

The **Global Enterprises** Business Group includes:

- the non-regulated gathering, processing, storage, purchase and sale of natural gas by ATCO Midstream;
- the provision of project management and technical services for customers in the industrial, defence and transportation sectors by ATCO Frontec;
- the development, operation and support of information systems and technologies, and the provision of billing services, payment processing, credit, collection and call centre services by ATCO I-Tek; and
- the sale of travel services to both business and consumer sectors by ATCO Travel.

The Corporate and Other segment includes cash balances and commercial real estate owned by the Company in Alberta.

Transactions between business segments are eliminated in all reporting of the Company's consolidated financial information. For additional information on the Company's business segments, refer to Note 9 to the unaudited interim consolidated financial statements for the nine months ended September 30, 2008.

POTENTIAL ACQUISITION OF ATCO FRONTEC BY ATCO LTD.

The Company's Board of Directors has established a special committee of independent directors of the Board to review the potential acquisition of its wholly-owned subsidiary, ATCO Frontec Corp., by ATCO Ltd. The mandate of the special committee is to investigate, review, assess and evaluate the proposed transaction with the assistance of independent legal and financial advisors. The proposed transaction is subject to Board of Directors', regulatory and other applicable approvals and there can be no assurance that acceptable terms will be concluded or that this transaction will be completed. It is now expected that the committee will make a recommendation to the Board of Directors in the first six months of 2009.

FINANCIAL MARKETS

Significant challenges are currently being experienced in domestic and international financial markets. These challenges are having an impact on the ability of certain borrowers to finance existing operations and capital programs. To date, these issues in the financial markets have not had a direct impact on the operations of the Company. As discussed elsewhere in this MD&A, the Utilities Business Group has a capital program of approximately $3.1 billion over the next three years. The Company completed a $325 million debenture issue in May 2008 to fund the 2008 portion of the Utilities Business Group's capital program and to fund scheduled maturities of previous debenture issues. In addition, the Company has cash balances of approximately $0.9 billion and available committed and uncommitted lines of credit of approximately $1.1 billion which can be utilized for general corporate purposes.

While the current financial situation has not directly impacted the Company's ability to fund capital projects and ongoing operations, future borrowing may be impacted by these financial markets through increased carrying costs and the ability to raise debt and capital. The Company is unable to determine what future changes in the financial markets could occur and how these changes could affect the Company.

Forward-Looking Information

Certain statements contained in this MD&A constitute forward-looking information. Forward-looking information is often, but not always, identified by the use of words such as "anticipate", "plan", "estimate", "expect", "may", "will", "intend", "should", and similar expressions. Forward-looking information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information. The Company believes that the expectations reflected in the forward-looking information are reasonable, but no assurance can be given that these expectations will prove to be correct and such forward-looking information should not be unduly relied upon.

In particular, this MD&A contains forward-looking information pertaining to contractual obligations, planned capital expenditures, the impact of changes in government regulation and the impact of commodity prices. Actual results could differ materially from those anticipated in this forward-looking information as a result of regulatory decisions, competitive factors in the industries in which the Company operates, prevailing economic conditions, and other factors, many of which are beyond the control of the Company.

Non-GAAP Measures

The Company uses the measures "funds generated by operations", "Adjusted Earnings" and "Adjusted Earnings per Class A and Class B share" in this MD&A. These measures do not have any standardized meaning under GAAP and might not be comparable to similar measures presented by other companies.

Funds generated by operations is defined as cash flow from operations before changes in non-cash working capital. In management's opinion, funds generated by operations is a significant performance indicator of the Company's ability to generate cash during a period to fund its capital expenditures without regard to changes in non-cash working capital during the period.

Adjusted Earnings is defined as earnings attributable to Class A and Class B shares after adjustments for items that are not in the normal course of business nor a result of day-to-day operations. These items are usually of a non-recurring or one-time nature. Management believes Adjusted Earnings allow for a more effective analysis of operating performance and trends. A reconciliation of Adjusted Earnings to earnings attributable to Class A and Class B shares is presented in the Results of Operations – Selected Quarterly Information section.

Internal Control Over Financial Reporting

There were no changes in the Company's internal control over financial reporting that occurred during the three months ended September 30, 2008, that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Results of Operations

SELECTED QUARTERLY INFORMATION

	For the Three Months Ended [1] [2] [3]			
($ millions except per share data)	**Mar. 31**	**Jun. 30**	**Sep. 30**	**Dec. 31**
		(unaudited)		
2008				
Revenues	740.6	655.6	638.4	-
Earnings attributable to Class A and Class B shares	150.0	82.2	66.7	-
Earnings per Class A and Class B share	1.20	0.65	0.53	-
Diluted earnings per Class A and Class B share	1.19	0.65	0.53	-
Adjusted Earnings [4]	149.7	70.3	71.3	-
Adjusted Earnings per Class A and Class B share [4]	1.19	0.56	0.57	-
2007				
Revenues	697.6	560.3	489.9	657.1
Earnings attributable to Class A and Class B shares	134.7	81.1	72.2	98.7
Earnings per Class A and Class B share	1.07	0.65	0.58	0.78
Diluted earnings per Class A and Class B share	1.07	0.64	0.58	0.78
Adjusted Earnings [4]	130.2	67.5	70.6	75.5
Adjusted Earnings per Class A and Class B share [4]	1.04	0.54	0.56	0.60
2006				
Revenues	-	-	-	671.1
Earnings attributable to Class A and Class B shares	-	-	-	100.0
Earnings per Class A and Class B share	-	-	-	0.80
Diluted earnings per Class A and Class B share	-	-	-	0.80
Adjusted Earnings	-	-	-	100.0
Adjusted Earnings per Class A and Class B share	-	-	-	0.80

Notes:

(1) *There were no discontinued operations or extraordinary items during these periods.*

(2) *Due to certain factors, revenues, earnings and Adjusted Earnings for any quarter are not necessarily indicative of operations on an annual basis. These factors include the seasonal nature of the Company's operations, changes in electricity prices in Alberta, the timing and demand of natural gas storage capacity sold, changes in natural gas storage fees, changes in NGL prices and natural gas costs and the timing of rate decisions.*

(3) *The above data (other than Adjusted Earnings and Adjusted Earnings per Class A and Class B share) has been extracted from the financial statements, which have been prepared in accordance with GAAP and the reporting currency is the Canadian dollar.*

(4) *Refer to Significant Non-Operating Financial Items section for a description of the adjustments made to earnings attributable to Class A and Class B shares to obtain Adjusted Earnings.*

The principal factors that caused variations in **financial condition** and **results of operations** over the past eight quarters necessary to understand general trends that have developed and the seasonality of the businesses disclosed in the 2007 MD&A remain substantially unchanged.

RECONCILIATION OF EARNINGS ATTRIBUTABLE TO CLASS A AND CLASS B SHARES AND ADJUSTED EARNINGS

Adjusted Earnings are referred to in various sections of this MD&A. The following table reconciles Adjusted Earnings, which are earnings attributable to Class A and Class B shares after adjustments for items that are not in the normal course of business nor a result of day-to-day operations. These items are usually of a non-recurring or one-time nature. A description of each adjustment is provided in the Significant Non-Operating Financial Items section.

	For the Three Months Ended September 30			**For the Nine Months Ended September 30**		
($ millions)	**2008**	2007	Change to 2008 (2008-2007)	**2008**	2007	Change to 2008 (2008-2007)
			(unaudited)			
Earnings attributable to Class A and Class B shares	**66.7**	72.2	(8%)	**298.9**	288.0	4%
Mark-to-Market Adjustment [(1)]	**7.6**	2.4	217%	**0.9**	(0.1)	1,000%
2007 Change in the Taxation of Preferred Share Dividends [(2)]	**-**	-	-	**-**	(15.6)	-
2007 Changes in Income Taxes and Rates [(3)]	**-**	(4.0)	-	**-**	(4.0)	-
Other Post Employment Benefits [(4)]	**-**	-	-	**(5.5)**	-	-
Federal Court of Appeal Decision – Mining Assets [(5)]	**(3.0)**	-	-	**(3.0)**	-	-
Adjusted Earnings	**71.3**	70.6	1%	**291.3**	268.3	9%

SIGNIFICANT NON-OPERATING FINANCIAL ITEMS

Consolidated and segmented financial results include the following Significant Non-Operating Financial Items.

(1) Natural Gas Purchase Contracts and Associated Power Generation Revenue Contract Liability (Mark-to-Market Adjustment)

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

As all but the excess volume of natural gas is committed to ATCO Power's power generation obligations, ATCO Power could not recognize the entire fair values of these natural gas purchase contracts in its revenues. Consequently, ATCO Power has recognized a provision for a power generation revenue contract and records adjustments to the power generation revenue contract liability concurrently with the

Mark-to-Market Adjustments for the natural gas purchase contracts derivative asset. This power generation revenue contract liability is included in deferred credits in the consolidated balance sheet.

The Mark-to-Market Adjustment for the derivative asset and the corresponding adjustment for the associated power generation revenue contract liability decreased earnings by $7.6 million for the three months ended September 30, 2008 (2007 – decrease of $2.4 million) and decreased earnings by $0.9 million for the nine months ended September 30, 2008 (2007 - increase of $0.1 million). At September 30, 2008, the natural gas purchase contracts derivative asset is $66.9 million (2007 - $58.4 million) and the power generation revenue contract liability is $49.8 million (2007 - $44.0 million).

(2) 2007 Change in the Taxation of Preferred Share Dividends

On June 15, 2007, the federal government announced an amendment to tax legislation pertaining to Part VI.1 tax (the tax payable on preferred share dividends paid by corporations). Prior to this change, corporations that had Part VI.1 tax payable were entitled to an income tax deduction equal to 9/4ths of the Part VI.1 tax payable. Effective January 1, 2003, this deduction was increased to three times the amount of the Part VI.1 tax payable. The Canada Revenue Agency (CRA) has been assessing corporate tax returns based on this proposed change being in effect since January 1, 2003, resulting in a reduction of taxes paid to the Canadian government. In the second quarter of 2007, the Company recorded a one-time reduction to current income tax expense which resulted in increased earnings of $15.6 million relating to years prior to 2007. Funds generated by operations increased by $15.6 million, offset by a similar reduction in changes in non-cash working capital, leaving the Company's cash position unchanged.

The earnings impact of the Part VI.1 tax adjustment by Business Group was as follows:

($ millions)	**Years Prior to 2007**
Utilities	4.2
Power Generation	1.3
Global Enterprises	1.4
Corporate & Other and Intersegment Eliminations	8.7
Total	15.6

(3) 2007 Changes in Income Taxes and Rates

In 2007, the British Parliament enacted a 2% reduction in the corporate income tax rate effective April 1, 2008, which impacted ATCO Power's operations in the U.K. This resulted in an increase in the Company's third quarter 2007 earnings, due to recalculation of future income tax liabilities, of $4.0 million.

(4) Other Post Employment Benefits

In June 2008, the Company prospectively changed the method of apportioning the costs of OPEB plans to individual subsidiaries. Formerly, each subsidiary was apportioned a percentage of its payroll costs at a rate calculated for the plan as a whole. The revised method determines the accrued OPEB liabilities and costs on a company-by-company basis. Total consolidated accrued OPEB liabilities and costs did not change. Under the new method of apportioning, the OPEB liability for the regulated subsidiaries increased by $10.4 million with a corresponding increase to non-current regulatory assets. Pursuant to an AUC decision effective January 1, 2000, the regulated operations, excluding Alberta Power (2000), are required to expense contributions for OPEB plans as paid. Consequently, there was no change to their

earnings for the three and nine months ended September 30, 2008. The difference between the amounts accrued and paid is deferred in non-current regulatory assets.

The OPEB liability for the non-regulated subsidiaries decreased which resulted in an increase to earnings of $5.5 million recorded in the second quarter of 2008.

The earnings impact of the OPEB adjustment by Business Group was as follows:

($ millions)	**Years Prior to 2008**
Power Generation	1.2
Global Enterprises	4.2
Corporate & Other and Intersegment Eliminations	0.1
Total	5.5

(5) Federal Court of Appeal Decision – Mining Assets

On May 22, 2008, the Federal Court of Appeal issued a decision overturning previous CRA reassessments pertaining to the computation of resource allowances and corresponding capital cost allowances for mining assets related to the Company's coal-fired power generation business. On July 8, 2008, the CRA advised that it would not seek leave to appeal to the Supreme Court of Canada in respect of this matter. This appeal and subsequent court decision applies to the 1997 to 1998 taxation years and allows ATCO Electric, and Alberta Power (2000) (as successor to ATCO Electric in the coal-fired generating plants), to claim additional resource allowance and capital cost allowance. ATCO Electric and Alberta Power (2000) have recorded a reduction in current income tax expense and a decrease in interest expense which resulted in increases to the Company's earnings of $3.0 million for the three and nine months ended September 30, 2008.

The earnings impact of this Federal Court of Appeal Tax Decision by Business Group was as follows:

($ millions)	**Total**
Utilities	2.2
Power Generation	0.8
Total	3.0

CONSOLIDATED REVENUES AND EARNINGS

Revenues for the three months ended September 30, 2008, **increased** by $148.5 million (30%) over the same period of 2007. This increase was primarily attributable to a $85.5 million (46%) increase in revenues in the Utilities segment, a $19.6 million (10%) increase in revenues in the Power Generation segment and a $45.3 million (31%) increase in revenues in the Global Enterprises segment.

Increases in revenues for the three months ended September 30, 2008, were primarily attributable to the 2007 refund of future income tax balances with a corresponding decrease in revenues, and the impact of higher 2008 AUC approved customer rates resulting from the 2007 and 2008 ATCO Electric general tariff decision (ATCO Electric GTA). In addition, increased business activity in ATCO Frontec's operations, higher natural gas fuel purchases recovered on a "no-margin" basis and improved merchant operations in ATCO Power's U.K. operations, AUC approved interim customer rates in ATCO Gas

associated with the 2008 and 2009 general rate application (ATCO Gas Interim Rates) and higher prices for NGL extraction in ATCO Midstream contributed to the increase in revenues. These increases were partially offset by decreased merchant performance in ATCO Power's Alberta generating plants.

Revenues for the nine months ended September 30, 2008, **increased** by $286.8 million (16%) over the same period of 2007. This increase was primarily attributable to a $128.0 million (16%) increase in revenues in the Utilities segment, a $61.4 million (11%) increase in revenues in the Power Generation segment and a $107.3 million (23%) increase in revenues in the Global Enterprises segment.

Increases in revenues for the nine months ended September 30, 2008, were primarily attributable to increased business activity in ATCO Frontec's operations, the 2007 refund of future income tax balances with a corresponding decrease in revenues, and the impact of higher AUC approved customer rates resulting from the ATCO Electric GTA. In addition, ATCO Gas Interim Rates and the impact of higher franchise fees collected on behalf of cities and municipalities in ATCO Gas, higher natural gas fuel purchases recovered on a "no-margin" basis and improved merchant operations in ATCO Power's U.K. operations and higher prices for NGL extraction in ATCO Midstream contributed to the increase in revenues. These increases were partially offset by lower storage revenues due to the timing and demand of natural gas storage capacity sold and lower storage fees in ATCO Midstream.

Earnings for the three months ended September 30, 2008, were $66.7 million, a **decrease** of $5.5 million (8%) over the same period of 2007, including the impact of the adjustments identified in the Significant Non-Operating Financial Items section.

For the three months ended September 30, 2008, **Adjusted Earnings** were $71.3 million, an **increase** of $0.7 million (1%) over the same period of 2007. The primary reasons for the increased Adjusted Earnings were increased business activity in ATCO Frontec's operations and a reduction in income tax expense relating to the treatment of major maintenance expenses in Alberta Power (2000). These increases were partially offset by lower spark spreads in ATCO Power's Alberta generating plants and the earnings impact of $5.3 million due to the change in quarterly depreciation expense allocation in ATCO Gas (ATCO Gas Depreciation Expense Adjustment, refer to Segmented Information – Utilities - Depreciation Expense Adjustment section).

Earnings for the nine months ended September 30, 2008, were $298.9 million, an **increase** of $10.9 million (4%) over the same period of 2007, including the impact of the adjustments identified in the Significant Non-Operating Financial Items section.

For the nine months ended September 30, 2008, **Adjusted Earnings** were $291.3 million, an **increase** of $23.0 million (9%) over the same period of 2007. The primary reasons for the increased Adjusted Earnings were increased business activity in ATCO Frontec's operations, higher margins for NGL extraction in ATCO Midstream, ATCO Gas Interim Rates net of cost increases and colder temperatures in ATCO Gas and the impact of the ATCO Electric GTA. These increases were partially offset by lower storage fees in ATCO Midstream.

Interest and other income for the three months ended September 30, 2008, **decreased** by $5.8 million to $5.6 million, mainly due to the Mark-to-Market Adjustment in ATCO Power, partially offset by increased interest income on higher cash balances.

Interest and other income for the nine months ended September 30, 2008, **increased** by $1.5 million to $44.5 million, mainly due to increased interest income on higher cash balances, partially offset by the Mark-to-Market Adjustment in ATCO Power.

CONSOLIDATED EXPENSES

	For the Three Months Ended September 30			For the Nine Months Ended September 30		
($ millions)	**2008**	2007	Change to 2008 (2008-2007)	**2008**	2007	Change to 2008 (2008-2007)
			(unaudited)			
Operating expenses:						
Natural gas supply	**12.3**	8.0	54%	**34.3**	17.3	98%
Purchased power	**11.9**	11.1	7%	**39.2**	36.3	8%
Operation and maintenance	**284.8**	219.3	30%	**823.1**	690.2	19%
Selling and administrative	**51.7**	47.6	9%	**157.6**	139.7	13%
Franchise fees	**26.7**	20.6	30%	**132.7**	113.8	17%
	387.4	306.6	26%	**1,186.9**	997.3	19%
Depreciation and amortization	**105.4**	77.3	36%	**288.6**	252.5	14%
Interest	**58.9**	54.1	9%	**173.2**	162.4	7%
Dividends on equity preferred shares	**8.1**	8.3	(2%)	**24.3**	26.0	(7%)
Income taxes	**17.5**	(17.2)	202%	**107.2**	64.6	66%

Operating expenses for the three months ended September 30, 2008, **increased** by $80.8 million (26%) over the same period in 2007. Operation and maintenance expenses were higher primarily due to increased business activity in ATCO Frontec's operations and higher operating and fuel costs in ATCO Power. Selling and administrative expenses increased primarily as a result of the impact of inflation, increased employment costs associated with higher employment levels resulting from increased growth and higher project development costs. Increased franchise fees, recovered on a flow through basis, were paid in ATCO Gas.

Operating expenses for the nine months ended September 30, 2008, **increased** by $189.6 million (19%) over the same period in 2007. Natural gas supply expense rose primarily as a result of increases in natural gas purchased for customers by ATCO Midstream. Operation and maintenance expenses were higher primarily due to higher operating and fuel costs in ATCO Power and increased business activity in ATCO Frontec's operations. Selling and administrative expenses increased primarily as a result of the impact of inflation, increased employment costs associated with higher employment levels resulting from increased growth and higher project development costs. Increased franchise fees, recovered on a flow through basis, were paid in ATCO Gas.

For the three and nine months ended September 30, 2008, **depreciation and amortization expenses increased** by $28.1 million (36%) and by $36.1 million (14%), respectively, over the same periods in 2007, primarily due to the ATCO Gas Depreciation Expense Adjustment and capital additions in 2007 and 2008 in the Utilities and Global Enterprises segments.

Interest expense for the three and nine months ended September 30, 2008, **increased** by $4.8 million (9%) and by $10.8 million (7%), respectively, over the same periods in 2007, primarily due to increased amounts of debt outstanding (net of redemptions) resulting from new financings issued in 2007 and 2008 to fund capital expenditures in the Utilities segment, partially offset by the repayment of ATCO Power's non-recourse financings in 2007 and 2008.

For the three months ended September 30, 2008, **income taxes increased** by $34.7 million (202%) over the same period in 2007, primarily due to the impact of the ATCO Electric GTA. The decision directed ATCO Electric to change its income tax methodology for the recording of federal income taxes in the third quarter of 2007. This change in methodology does not affect earnings as ATCO Electric's revenues and income tax expense were reduced by similar amounts. These increases were partially offset in 2008 by a reduction in income tax expense relating to the treatment of major maintenance expenses in Alberta Power (2000).

For the nine months ended September 30, 2008, **income taxes increased** by $42.6 million (66%) over the same period in 2007, primarily due to the impact of the ATCO Electric GTA. The decision directed ATCO Electric to change its income tax methodology for the recording of federal income taxes in the third quarter of 2007 and a $15.6 million Part VI.1 Tax Adjustment in 2007 (refer to Significant Non-Operating Financial Items - 2007 Change in Taxation of Preferred Share Dividends section). These increases were partially offset by lower corporate income tax rates and a reduction in income tax expense relating to the treatment of major maintenance expenses in Alberta Power (2000).

SEGMENTED INFORMATION

	For the Three Months Ended September 30					
($ millions)	Utilities	Power Generation	Global Enterprises	Corporate & Other	Intersegment Eliminations	Total
			(unaudited)			
2008						
Revenues	**273.3**	**217.2**	**189.7**	**3.9**	**(45.7)**	**638.4**
Earnings attributable to Class A and Class B Shares	**14.5**	**28.8**	**25.6**	**(1.9)**	**(0.3)**	**66.7**
Mark-to-Market Adjustment [1]	**-**	**7.6**	**-**	**-**	**-**	**7.6**
Federal Court of Appeal Decision - Mining Assets [5]	**(2.2)**	**(0.8)**	**-**	**-**	**-**	**(3.0)**
Adjusted Earnings	**12.3**	**35.6**	**25.6**	**(1.9)**	**(0.3)**	**71.3**
2007						
Revenues	187.8	197.6	144.4	3.4	(43.3)	489.9
Earnings attributable to Class A and Class B Shares	14.3	38.6	20.9	(0.8)	(0.8)	72.2
Mark-to-Market Adjustment [1]	-	2.4	-	-	-	2.4
2007 Changes in Income Taxes and Rates [3]	-	(4.0)	-	-	-	(4.0)
Adjusted Earnings	14.3	37.0	20.9	(0.8)	(0.8)	70.6

Notes:
[1] [3] [5] *Refer to Significant Non-Operating Financial Items section for a description of the adjustments.*

			For the Nine Months Ended September 30			
($ millions)	Utilities	Power Generation	Global Enterprises	Corporate & Other	Intersegment Eliminations	Total
			(unaudited)			
2008						
Revenues	**931.2**	**640.5**	**581.7**	**10.8**	**(129.6)**	**2,034.6**
Earnings attributable to Class A and Class B Shares	**103.2**	**105.0**	**95.0**	**(3.4)**	**(0.9)**	**298.9**
Mark-to-Market Adjustment (1)	**-**	**0.9**	**-**	**-**	**-**	**0.9**
Other Post Employment Benefits (4)	**-**	**(1.2)**	**(4.2)**	**(0.1)**	**-**	**(5.5)**
Federal Court of Appeal Decision - Mining Assets (5)	**(2.2)**	**(0.8)**	**-**	**-**	**-**	**(3.0)**
Adjusted Earnings	**101.0**	**103.9**	**90.8**	**(3.5)**	**(0.9)**	**291.3**
2007						
Revenues	803.2	579.1	474.4	10.1	(119.0)	1,747.8
Earnings attributable to Class A and Class B Shares	91.7	109.2	82.3	7.2	(2.4)	288.0
Mark-to-Market Adjustment (1)	-	(0.1)	-	-	-	(0.1)
2007 Change in the Taxation of Preferred Share Dividends (2)	(4.2)	(1.3)	(1.4)	(8.7)	-	(15.6)
2007 Changes in Income Taxes and Rates (3)	-	(4.0)	-	-	-	(4.0)
Adjusted Earnings	87.5	103.8	80.9	(1.5)	(2.4)	268.3

Notes:
(1) to (5) *Refer to Significant Non-Operating Financial Items section for a description of the adjustments.*

Utilities

Utilities **revenues** for the three months ended September 30, 2008, **increased** by $85.5 million (46%) over the same period in 2007. Items that contributed to increased revenues were the 2007 refund of future income tax balances with a corresponding decrease in revenues, and the impact of higher AUC approved customer rates resulting from the ATCO Electric GTA and ATCO Gas Interim Rates.

Temperatures in ATCO Gas for the three months ended September 30, 2008, were 17% warmer than normal, compared to 9.9% colder than normal in the corresponding period in 2007 (refer to Business Risks - Regulated Operations - Temperatures section).

Utilities **revenues** for the nine months ended September 30, 2008, **increased** by $128.0 million (16%) over the same period in 2007. Items that contributed to increased revenues were the 2007 refund of future

income tax balances with a corresponding decrease in revenues, and the impact of higher AUC approved customer rates resulting from the ATCO Electric GTA and ATCO Gas Interim Rates and the impact of higher franchise fees collected on behalf of cities and municipalities in ATCO Gas.

Temperatures in ATCO Gas for the nine months ended September 30, 2008, were 1.8% colder than normal, compared to 2% warmer than normal in the corresponding period in 2007 (refer to Business Risks - Regulated Operations - Temperatures section).

Earnings for the three months ended September 30, 2008, were $14.5 million, an **increase** of $0.2 million (1%) over the same period of 2007, including the impact of the adjustments identified in the Significant Non-Operating Financial Items section.

For the three months ended September 30, 2008, **Adjusted Earnings** were $12.3 million, a **decrease** of $2.0 million (14%) over the same period of 2007. The primary reason for the decrease was the ATCO Gas Depreciation Expense Adjustment and warmer temperatures in ATCO Gas, partially offset by the suspension of the Carbon natural gas storage facility rate riders in ATCO Gas (refer to Regulatory Developments – ATCO Gas- Carbon Natural Gas Storage Facility) and the impact of the ATCO Electric GTA.

Earnings for the nine months ended September 30, 2008, were $103.2 million, an **increase** of $11.5 million (13%) over the same period of 2007, including the impact of the adjustments identified in the Significant Non-Operating Financial Items section.

For the nine months ended September 30, 2008, **Adjusted Earnings** were $101.0 million, an **increase** of $13.5 million (15%) over the same period of 2007. The primary reasons for the increase were the ATCO Gas Interim Rates net of cost increases and colder temperatures in ATCO Gas and the impact of the ATCO Electric GTA. These increases were partially offset by the ATCO Gas Depreciation Expense Adjustment.

Depreciation Expense Adjustment

Effective January 1, 2008, ATCO Gas prospectively changed the allocation of annual depreciation and amortization expense on a quarterly basis. The method of quarterly allocation has been changed from an estimate based on the timing of revenues to the straight line basis. This resulted in an increase to ATCO Gas' depreciation and amortization expense for the three and nine months ended September 30, 2008, of $7.5 million and by $4.9 million, respectively, as compared to the methodology used for the depreciation and amortization expense recorded in the corresponding periods of 2007. The annual depreciation and amortization expense continues to be on the straight line basis and therefore, this change does not affect the total depreciation and amortization expense recognized for the year. This resulted in a decrease to the Company's earnings for the three and nine months ended September 30, 2008, of $5.3 million and $3.5 million, respectively, as compared to the methodology used in the corresponding periods of 2007.

Regulatory Developments

The AUC administers acts and regulations regarding rates, financing, accounting, construction, operation, and service area. The return on common equity for regulated utility operations was established by the AUC using its standardized rate of return methodology for utilities in Alberta. The rate of return was established in 2004 and is adjusted annually by 75% of the change in long term Government of Canada bond yield, similar to the adjustment mechanism used by the National Energy Board. The rate of return for 2007 was 8.51% and for 2008 has been set at 8.75%. If no rate applications are filed for a particular year, then there will be no adjustment to the common equity rate of return for that year.

In February 2008, the AUC initiated a generic proceeding to determine whether the standardized rate of return methodology and the utility capital structures should be reviewed. A regulatory process has been established by the AUC with a hearing currently scheduled for May 5, 2009 to review the generic return on equity formula as well as to review the capital structure for each of the Alberta utilities. The AUC also indicated that any changes which result from this proceeding would be applied beginning in 2009. As ATCO Gas and ATCO Pipelines have filed general rate applications, for 2008 and 2009 a separate module within the generic proceeding will address 2008 cost of capital issues relating to the capital structure for ATCO Gas and the capital structure and rate of return on common equity for ATCO Pipelines, respectively, as inclusion of these items has been removed from their current 2008/2009 general rate applications.

Benchmarking

ATCO Electric, ATCO Gas, and ATCO Pipelines purchase information technology services from ATCO I-Tek. ATCO Electric and ATCO Gas also purchase customer care and billing services from ATCO I-Tek. The recovery of these costs in customer rates is subject to AUC approval. Since 2003, the costs have been approved on a placeholder basis, and are subject to final AUC approval after completion of a collaborative benchmarking process. The benchmarking report, dealing with the period of 2003-2007, was received on January 23, 2008. In February 2008, the benchmarking report along with an application to adjust the placeholder rates was filed with the AUC. In April 2008, an agreement with the customer group concerning the adjustment to placeholders was submitted to the AUC for approval. Should this agreement be approved by the AUC it is not expected to have a material impact on consolidated earnings. The AUC is currently deliberating on whether any further process is required to approve the agreement with the customer group and its consequent impact on customer rates.

Effective January 1, 2008, price changes for ATCO I-Tek's information technology services to ATCO Electric, ATCO Gas and ATCO Pipelines were implemented. Price changes relating to ATCO I-Tek's customer care and billing contract services for ATCO Gas and ATCO Electric were effective March 1, 2008. For 2008 and beyond, a new regulatory process will be set up to approve rates for information technology and customer care and billing services provided by ATCO I-Tek that can be included in customer rates.

Utility Asset Disposition Rate Review Proceeding

In March 2008, the AUC initiated a proceeding to consider the potential rate related implications for Alberta utilities of the Supreme Court of Canada's 2006 Calgary Stores Block Decision (Stores Block Decision). The Calgary Stores Block matter involved the disposition by ATCO Gas of its Calgary Stores Block facility and adjacent property in downtown Calgary. The Supreme Court held that utility shareholders were entitled to receive all proceeds resulting from the sale.

The AUC has indicated that the Stores Block Decision may have various implications with respect to regulation of Alberta utility companies (including the potential impact of the Carbon Natural Gas Storage Facility discussed below). The AUC would like to develop a comprehensive understanding of these potential implications through this proceeding and then apply this understanding in a consistent manner in future decisions. At the conclusion of this proceeding, the AUC will issue a decision reflecting its conclusions with respect to the interpretation and application of the guidance provided by the courts and the resulting implications to be used in future proceedings.

ATCO Gas

2005, 2006, and 2007 General Rate Application

In May 2006, the City of Calgary filed a Review and Variance application with the AUC, alleging that the AUC made errors in ATCO Gas' 2005-2007 general rate application decision related to the calculation of working capital needed by ATCO Gas to operate its Carbon natural gas storage facility. The AUC issued a decision on January 17, 2007, denying the City of Calgary's application. On February 15, 2007, the City of Calgary filed for leave to appeal this decision with the Alberta Court of Appeal. On June 19, 2007 the appeal was heard with the court granting the City of Calgary leave to appeal on August 31, 2007. The original hearing date of the appeal, September 9, 2008, has been postponed, allowing the AUC time to address the Alberta Court of Appeal decision related to the removal of the Carbon assets from regulation.

Carbon Natural Gas Storage Facility

ATCO Gas owns a 43.5 petajoule natural gas storage facility located at Carbon, Alberta. ATCO Gas has leased the entire storage capacity of the facility to ATCO Midstream. ATCO Gas has taken the position that the facility is no longer required for utility service and should be removed from regulation.

In the process of obtaining AUC approval a number of significant events have occurred. In July 2004, the AUC initiated a written process to consider its role in regulating the operations of the facility. In June 2005, the AUC issued a decision with respect to this process. In addition to addressing other matters, the decision found that the AUC has the authority, when necessary in the public interest, to direct a utility to utilize a particular asset in a specific manner, even over the objection of the utility. ATCO Gas filed for leave to appeal the decision with the Alberta Court of Appeal.

In October 2005, the AUC established processes to review the use of the facility for utility purposes. A hearing to review the use of the facility for revenue generation was held in April 2006, and a hearing to review the use of the facility for load balancing was held in June 2006. On October 11, 2006, the AUC issued a decision confirming ATCO Gas' position that the facility is no longer required for utility service with respect to the use of the facility for load balancing purposes. The City of Calgary then filed a leave to appeal and a review and variance application of this decision.

On February 5, 2007, the AUC issued a decision in which it determined that a legitimate utility use for the facility is that it be used for purposes of generating revenues to offset customer rates. This decision required ATCO Gas to maintain the status quo with respect to the use of the facility including the lease of the entire facility to ATCO Midstream.

On February 26, 2007, ATCO Gas filed for leave to appeal this decision with the Alberta Court of Appeal. The Alberta Court of Appeal granted ATCO Gas' leave to appeal on October 24, 2007. On May 9, 2008, the Alberta Court of Appeal heard the appeal and subsequently issued a decision on May 27, 2008. The Court found that the AUC had erred in law or jurisdiction when it included the Carbon storage facilities in rate base for the purpose of generating revenues to offset customer rates. On August 22, 2008, the City of Calgary filed a leave to appeal this decision with the Supreme Court of Canada.

As a result of the Alberta Court of Appeal's May 27, 2008 decision, ATCO Gas requested and received approval from the AUC to suspend rate riders to customer rates on an interim basis effective July 1, 2008. These riders were approved by the AUC in the past to distribute net revenues related to the facility to customers. As a result of the suspension of the rate riders, ATCO Gas recognized revenues of $4.9 million and earnings of $3.4 million in the third quarter of 2008 for the period July 1, 2008 to September 30, 2008. Due to certain factors, revenues and earnings from this matter in the third quarter are not necessarily indicative of revenues or earnings on an annual basis.

Additionally, ATCO Gas, on July 11, 2008, filed a compliance application with the AUC requesting removal of the facility from the utility rate base and revenue requirement effective April 1, 2005, consistent with the Alberta Court of Appeal decision. This application, in addition to the amounts recognized above, is seeking to recover from customers an additional $29.1 million, excluding interest, related to those amounts refunded to customers over the April 1, 2005, to June 30, 2008, period. This additional $29.1 million and related interest has not been recorded in ATCO Gas' earnings and is pending an AUC decision on the compliance application. On September 29, 2008, the AUC suspended ATCO Gas' compliance application submitted on July 11, 2008, pending the completion of the Utility Asset Disposition Rate Review Proceeding. On October 15, 2008, ATCO Gas filed an application with the Alberta Court of Appeal to direct the AUC to comply with its May 27, 2008, decision. At this time it is unknown what the final outcome of these processes will be (refer to Business Risks - Regulated Operations - Carbon Natural Gas Storage Facility section).

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 the Company'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 City of Calgary filed a leave to appeal the AUC's decision. ATCO Gas filed a cross appeal of the AUC's decision. On July 7, 2006, the Alberta Court of Appeal issued its decision granting the City of Calgary's leave to appeal on the question of whether the AUC erred in law or jurisdiction in assuming that it had the authority to allow recovery in 2005 of costs relating to prior years. At a hearing on April 13, 2007, the Alberta Court of Appeal declined to consider the City of Calgary's appeal and referred the jurisdictional question back to the AUC. On January 3, 2008, the AUC issued a decision confirming its jurisdiction to approve the prior period adjustment it had approved previously. In February 2008, the City of Calgary filed a leave to appeal the AUC's January 3, 2008, decision with the Alberta Court of Appeal. The hearing date for the appeal has been changed from September 9, 2008, to December 16, 2008.

ATCO Pipelines

2008 and 2009 General Rate Application

On October 1, 2007, ATCO Pipelines filed a general rate application for the 2008 and 2009 test years requesting increased revenues to recover increased financing, depreciation, and operating costs associated with an increased rate base in Alberta. In November 2007, ATCO Pipelines filed an application requesting interim adjustable rates pending the AUC's decision on the general rate application. In December 2007, ATCO Pipelines received a decision from the AUC approving interim adjustable rate increases amounting to 40% of ATCO Pipelines' requested revenue increase. A decision from the AUC is not expected until the second quarter of 2009.

On October 5, 2007, the AUC approved ATCO Pipelines' request to negotiate, until January 11, 2008, a settlement with customers for revenue requirements. On January 11, 2008, ATCO Pipelines informed the AUC that a negotiated settlement had not been reached. On October 3, 2008, ATCO Pipelines requested permission from the AUC to resume negotiations on all aspects of revenue requirements, including capital structure and return on equity. On October 9, 2008, the AUC granted consent to resume negotiations.

Recent Developments

On September 8, 2008, ATCO Pipelines and Nova Gas Transmission Ltd. (NGTL) announced that they had reached a proposed agreement to provide natural gas transmission service to their customers. The proposal will allow ATCO Pipelines and NGTL to combine physical assets under a single rates and services structure with a single commercial interface for Alberta customers. Each company would separately manage assets within distinct operating territories within Alberta. This proposal, if approved by the AUC, is expected to end duplicate tolling and operational activities and result in more efficient regulatory processes.

Other Matters

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

Power Generation

Power Generation **revenues** for the three months ended September 30, 2008, **increased** by $19.6 million (10%) over the third quarter of 2007, primarily as a result of higher natural gas fuel purchases recovered on a "no-margin" basis and improved merchant operations in ATCO Power's U.K. operations. These increases were partially offset by decreased merchant performance in ATCO Power's Alberta generating plants.

Power Generation **revenues** for the nine months ended September 30, 2008, **increased** by $61.4 million (11%) over the corresponding period in 2007, primarily as a result of higher natural gas fuel purchases recovered on a "no-margin" basis and improved merchant operations in ATCO Power's U.K. operations, improved merchant performance in ATCO Power's Alberta generating plants and the recognition of insurance proceeds from an unplanned outage at the Barking generating plant (Barking Outage). These increases were partially offset by the impact of lower U.K. exchange rates on conversion of revenues to Canadian dollars in ATCO Power's U.K. operations.

Earnings for the three and nine months ended September 30, 2008, were $28.8 million, a **decrease** of $9.8 million (25%) and $105.0 million, a decrease of $4.2 million (4%), respectively, over the corresponding periods in 2007, including the impact of the adjustments identified in the Significant Non-Operating Financial Items section.

Adjusted Earnings for the three months ended September 30, 2008, were $35.6 million, a **decrease** of $1.4 million (4%) over the corresponding period in 2007, primarily due to lower spark spreads in ATCO Power's Alberta generating plants. These decreases were partially offset by a reduction in income tax expense relating to the treatment of major maintenance expenses in Alberta Power (2000).

Adjusted Earnings for the nine months ended September 30, 2008, were $103.9 million, an **increase** of $0.1 million over the corresponding period in 2007, primarily due to the recognition of insurance proceeds from the Barking Outage and a reduction in income tax expense relating to the treatment of major maintenance expenses in Alberta Power (2000). These increases were partially offset by reduced availability and lower exchange rates on conversion of earnings to Canadian dollars in ATCO Power's U.K. operations.

Availability of the Power Generation generating plants by geographic region is set forth below:

	For the Three Months Ended September 30			For the Nine Months Ended September 30		
	2008 %	2007 %	Change to 2008 (2008-2007)	**2008 %**	2007 %	Change to 2008 (2008-2007)
ATCO Power [1]:						
Canada	**93.0**	96.5	(3.5%)	**94.9**	95.7	(0.8%)
U.K. [2]	**90.0**	83.4	6.6%	**84.2**	93.0	(8.8%)
Australia	**95.4**	84.5	10.9%	**98.2**	93.8	4.4%
Alberta Power (2000) [1]:						
Canada	**96.0**	88.9	7.1%	**90.3**	90.3	-%

Notes:

(1) *Generating plant availability will fluctuate on a quarterly basis resulting from the timing and duration of outages.*

(2) *The lower availability for the nine months ended September 30, 2008, reflects the unplanned outage at the Barking generating plant which commenced on October 25, 2007. The plant returned to service in the first quarter of 2008.*

Unplanned Outage at Barking Generating Plant

On October 25, 2007, ATCO Power's 1,000 MW Barking generating plant in the U.K. experienced an unplanned outage due to failure in a steam turbine generator. On March 6, 2008, ATCO Power announced that the plant had returned to service. This outage reduced the plant capacity to approximately 400 MWs during this period. The financial impact of the failure, prior to the recognition of insurance proceeds, was a decrease to ATCO Power's earnings of $13.4 million (2007 earnings were decreased by $8.6 million and 2008 first quarter earnings were reduced by $4.8 million). Additionally, during the first quarter of 2008, $8.1 million of business interruption and property damage insurance proceeds were recorded, ($3.3 million related to 2007 and $4.8 million related to the first quarter of 2008).

The financial impact of the failure, including the recognition of the insurance proceeds, was a decrease to ATCO Power's earnings of $8.6 million in 2007 and an increase to earnings of $3.3 million for the nine months ended September 30, 2008, which was recorded in the first quarter of 2008. Discussions are ongoing with insurers and their advisers to arrive at a final settlement. At this time, an amount for the final insurance settlement cannot be determined.

Other Power Generation Developments

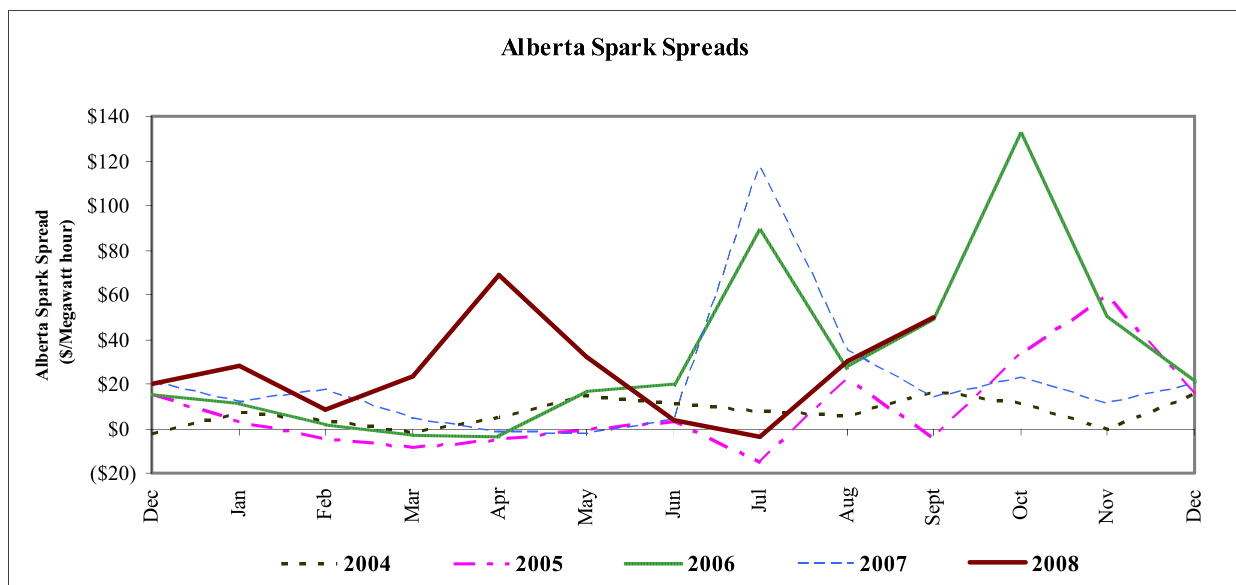
On January 30, 2008, the 150 MW Unit 4 at Alberta Power (2000)'s Battle River generating plant experienced an unplanned outage due to a failure in the unit's generator (Battle River Unplanned Outage). The unit returned to service on March 27, 2008. Alberta Power (2000) claimed relief under the force majeure provisions of its PPA. These provisions provide protection for the operator against mechanical failures which last more than forty-two days, except for circumstances where it is found that the operator failed to follow good operating practices. On July 11, 2008, the Balancing Pool notified Alberta Power (2000) that it disagrees with Alberta Power (2000)'s claim for relief under the force majeure provisions of the PPA. Unless settlement on the claim can be reached with the PPA counterparty, it is anticipated that this claim will proceed to arbitration. The cash impact resulting from this outage is approximately $11.8 million, however, due to Alberta Power (2000)'s availability incentive pool deferral account there will be no material earnings impact.

On September 16, 2008, ATCO Power announced that it had completed construction of its 45 MW gas-fired generating unit at its Valleyview, Alberta generating plant. The new unit commenced operations in early September, one month ahead of schedule. All of the electricity produced by this peaking facility is being sold to the Alberta Power Pool. ATCO Power owns an 80% interest in the plant and ATCO Resources, a wholly owned subsidiary of ATCO Ltd., owns 20%.

The majority of ATCO Power's electricity sales to the Alberta Power Pool are from natural gas-fired generating plants and, as a result, earnings are affected by natural gas prices and Alberta Power Pool prices. Alberta Power Pool electricity prices averaged $80.21 per MWh and $88.20 per MWh for the three and nine months ended September 30, 2008, respectively, compared to average prices of $92.88 per MWh and $68.68 per MWh in the corresponding periods of 2007. Natural gas prices averaged $7.35 per GJ and $8.19 per GJ for the three and nine months ended September 30, 2008, respectively, compared to average prices of $4.86 per GJ and $6.20 per GJ in the corresponding periods of 2007. These electricity and natural gas prices resulted in an average spark spread of $25.10 per MWh and $26.77 per MWh for the three and nine months ended September 30, 2008, respectively, compared to $56.47 per MWh and $22.20 per MWh in the corresponding periods of 2007.

Changes in spark spread affect the results of approximately 442 MW of plant capacity owned in Alberta by ATCO Power and Alberta Power (2000) out of a total Alberta-owned capacity of approximately 1,745 MWs and approximately 70 MW of plant capacity owned in the U.K. by ATCO Power out of a total U.K.-owned capacity of approximately 262 MW and a worldwide owned capacity by ATCO Power and Alberta Power (2000) of approximately 2,510 MW.

The following chart demonstrates the volatility of Alberta spark spreads experienced by ATCO Power for the period of December 2003 to September 2008.



The Company's merchant power sales are affected by volatility in power and natural gas prices caused by market forces such as fluctuating supply and demand for electricity. The Company manages this volatility through its adoption of asset optimization strategies for bidding its merchant power into both the Alberta and U.K. power markets.

Alberta Power (2000)

Under the terms of the PPAs, Alberta Power (2000) is subject to an incentive/penalty regime related to generating unit availability. Incentives are payable by the PPA counterparties for availability in excess of predetermined targets, and penalties are payable by Alberta Power (2000) when the availability targets are not achieved.

During the three months ended September 30, 2008, the **deferred availability incentive** account **increased** by $12.3 million to $45.2 million, mainly due to reduced outages in the quarter, as compared to the corresponding period in 2007. During the three months ended September 30, 2008, the amortization of deferred availability incentives, recorded in revenues, increased by $0.1 million to $3.1 million, compared to the corresponding period in 2007.

During the nine months ended September 30, 2008, the **deferred availability incentive** account **increased** by $3.4 million to $45.2 million, mainly due to additional availability incentives received for plant availability in excess of amortization and planned outages. During the nine months ended September 30, 2008, the amortization of deferred availability incentives, recorded in revenues, increased by $0.2 million to $9.1 million, compared to the corresponding period in 2007.

Greenhouse Gas Emissions

In 2007, Alberta Power (2000) began to record GHG emissions fees recovered from its customers in accordance with the PPAs which cover costs of recent changes in environmental laws (refer to Business Risks - Environmental Matters section). As the collection of the majority of these fees is on a flow through basis, there is minimal impact on the earnings of Alberta Power (2000).

Global Enterprises

Global Enterprises **revenues increased** for the three months ended September 30, 2008, by $45.3 million (31%), as compared with the corresponding period in 2007. Items that increased revenues included increased business activity in ATCO Frontec’s operations and higher prices for NGL extraction in ATCO Midstream. These increases were partially offset by lower storage revenues due to the timing and demand of natural gas storage capacity sold and lower storage fees in ATCO Midstream.

Global Enterprises **revenues increased** for the nine months ended September 30, 2008, by $107.3 million (23%), as compared with the corresponding period in 2007. Items that increased revenues included increased business activity in ATCO Frontec’s operations and higher prices for NGL extraction in ATCO Midstream. These increases were partially offset by lower storage revenues due to the timing and demand of natural gas storage capacity sold and lower storage fees in ATCO Midstream.

Earnings and **Adjusted Earnings** for the three months ended September 30, 2008, were $25.6 million, an **increase** of $4.7 million (22%) over the corresponding period in 2007, primarily due to increased business activity in ATCO Frontec’s operations and higher margins for NGL extraction in ATCO Midstream.

Earnings for the nine months ended September 30, 2008, were $95.0 million, an **increase** of $12.7 million (15%) over the corresponding period in 2007, including the impact of the adjustments identified in the Significant Non-Operating Financial Items section.

Adjusted Earnings for the nine months ended September 30, 2008, were $90.8 million, an **increase** of $9.9 million (12%) over the corresponding period in 2007, primarily due to increased business activity in

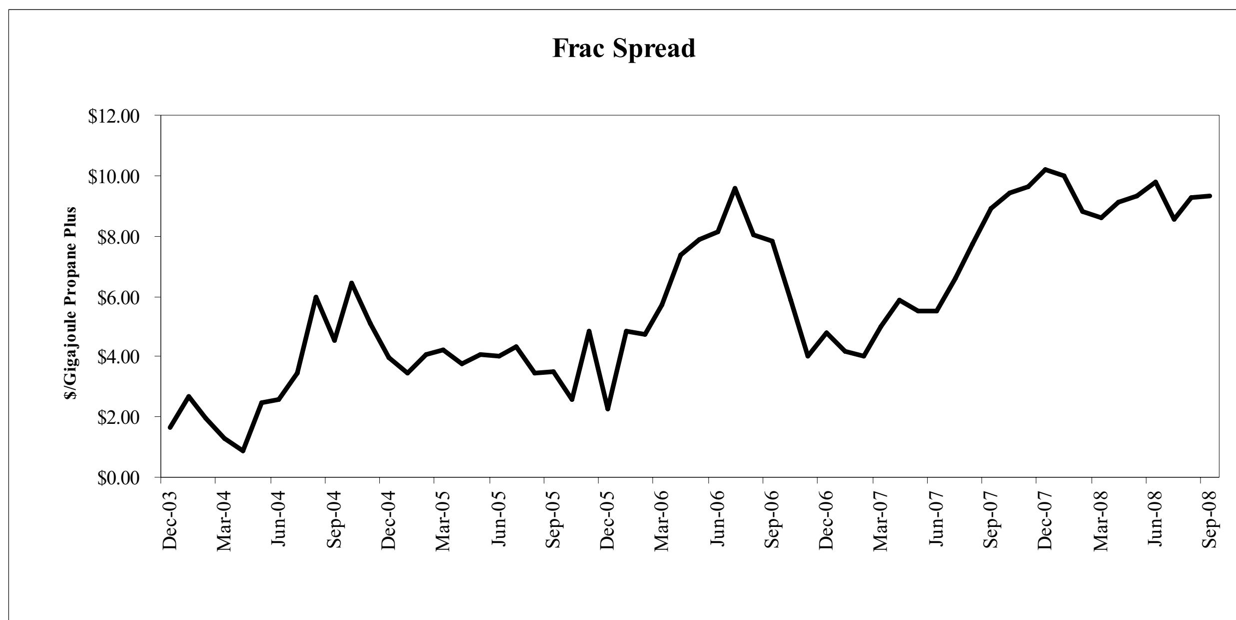
ATCO Frontec's operations and higher margins for NGL extraction in ATCO Midstream. These increases were partially offset by lower storage fees in ATCO Midstream.

ATCO Midstream

NGL Extraction Operations

A portion of ATCO Midstream's revenues is derived from the extraction of NGL from natural gas and the marketing of NGL products under supply or marketing contracts. ATCO Midstream owns a net working interest of 411 million cubic feet per day in its NGL extraction plants.

ATCO Midstream's NGL extraction operations involve the extraction of NGL from natural gas and the replacement (on a heat content equivalent basis) of the NGL extracted with shrinkage gas. For Propane Plus, the difference between the price of natural gas and the value of the liquids extracted is commonly referred to as the frac spread. Frac spreads vary with fluctuations in the price of natural gas and the prices of the applicable liquid extracted. Frac spreads can be volatile, as shown in the following graph, which illustrates monthly frac spreads during the period of December 2003 to September 2008.



Note:
(1) The above chart represents measurements of frac spreads in Alberta, as reported by an independent consultant.

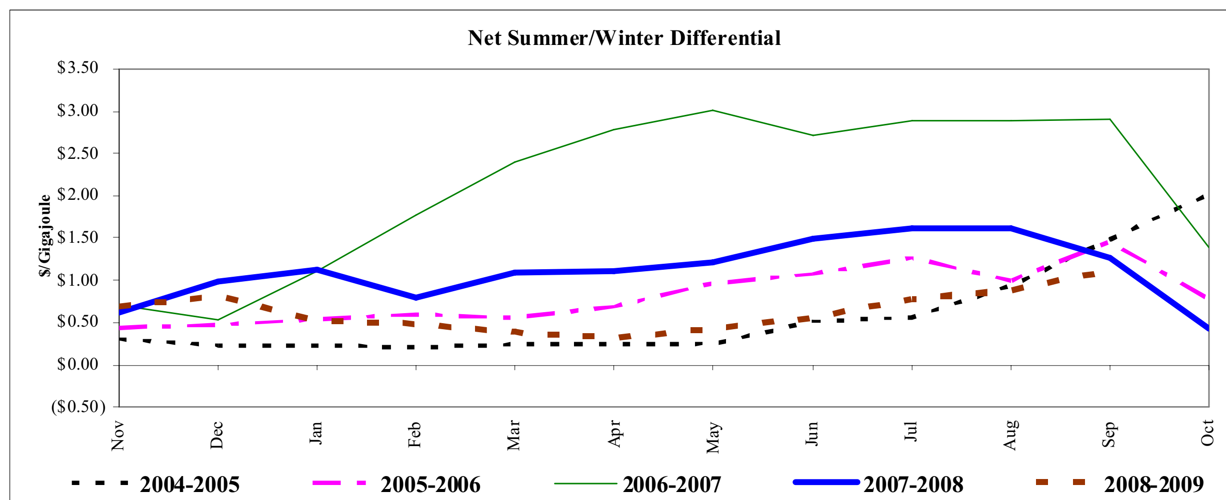
Fluctuations in frac spreads affect ATCO Midstream's earnings and cash flow from operations. A $1.00 change in the average annual frac spread impacts annual earnings by approximately $6 million.

Storage Operations

The majority of ATCO Midstream's natural gas storage revenues come from seasonal differences (summer/winter) in the price of natural gas (price differentials). Recognition of ATCO Midstream's revenues is determined through the terms of the contractual arrangements.

Summer/winter natural gas price differentials can be volatile, as shown in the following graph, which illustrates a range of seasonal spreads experienced during the storage periods from 2004-2005 to 2008-2009. Price differentials at any point in time may not always be indicative of the storage revenue and

earnings for the same period due to the types of contracts and the timing of the revenue recognition associated with these contracts.



ATCO Midstream faces risks associated with changes to seasonal natural gas commodity price differentials. To mitigate this risk, ATCO Midstream maintains portfolios of varied contracts, delivery terms, capacities and customers for its storage operations.

ATCO Frontec

Recent Developments

On April 14, 2008, ATCO Frontec announced that the first phase of the 500-room Creeburn Lake Lodge in Fort McMurray, Alberta had opened for operations. Due to the demand for lodging, evaluation is underway to consider doubling capacity to 1,000 rooms under the existing joint venture with the Fort McKay First Nation.

On April 28, 2008, ATCO Frontec and its partner, the Fort McKay First Nation, announced that they had been selected by Suncor Energy Inc. to create and operate a 1,148-room accommodation complex to support oil sands development north of Fort McMurray. ATCO Structures supplied the rooms in modular units. The Barge Landing Lodge opened in two phases, an initial 686 rooms in June 2008, and the final phase of 462 rooms in July 2008. On August 18, 2008, an additional 603-room expansion was announced under the existing joint venture with the Fort McKay First Nation. The expansion will be operated under a services agreement with Albian Sands Energy Inc.

Corporate and Other

Earnings for the three and nine months ended September 30, 2008, were $(1.9) million, a **decrease** of $1.1 million (138%) and $(3.4) million, a decrease of $10.6 million (147%), respectively, over the corresponding periods in 2007, including the impact of the adjustments identified in the Significant Non-Operating Financial Items section.

Adjusted Earnings for the three and nine months ended September 30, 2008, were $(1.9) million, a **decrease** of $1.1 million (138%) and $(3.5) million, a decrease of $2.0 million (133%), respectively, over the corresponding periods in 2007.

Liquidity and Capital Resources

A major portion of the Company's operating income and funds generated by operations is generated from its utility operations. Canadian Utilities and its wholly owned subsidiary, CU Inc., use short term bank loans and commercial paper borrowings to provide flexibility in the timing and amounts of long term financing.

SUMMARY OF CASH FLOW

	For the Three Months Ended September 30			For the Nine Months Ended September 30		
($ millions)	**2008**	2007	Change to 2008 (2008-2007)	**2008**	2007	Change to 2008 (2008-2007)
			(unaudited)			
Cash position, beginning of period	**1,067.4**	813.0	31%	**747.2**	798.8	(6%)
Cash provided by (used in)						
Operating activities	**188.1**	105.3	79%	**646.5**	579.8	12%
Investing activities	**(234.4)**	(171.6)	37%	**(522.8)**	(440.2)	19%
Financing activities	**(63.0)**	(58.0)	(9%)	**83.3**	(240.6)	135%
Foreign currency impact on cash balances	**(12.0)**	(5.8)	(107%)	**(8.1)**	(14.9)	46%
Cash position, end of period	**946.1**	682.9	39%	**946.1**	682.9	39%

OPERATING ACTIVITIES

For the three months ended September 30, 2008, **cash flow from operations** was $188.1 million, an **increase** of $82.8 million (79%) over the same period in 2007, primarily due to funds generated by operations, partially offset by changes in non-cash working capital. **Funds generated by operations** were $191.0 million, an **increase** of $40.6 million (27%) over the same period in 2007, primarily due to increased cash flow after removal of non-cash items and increased deferred availability incentives in Alberta Power (2000).

For the nine months ended September 30, 2008, **cash flow from operations** was $646.5 million, an **increase** of $66.7 million (12%) over the same period in 2007, primarily due to funds generated by operations and increased changes in non-cash working capital. **Funds generated by operations** were $580.1 million, an **increase** of $34.2 million (6%) over the same period in 2007, primarily due to increased cash flow after removal of non-cash items, partially offset by an inclusion in 2007 of $15.6 million related to the change in the taxation of preferred share dividends (refer to Results of Operations – Significant Non-Operating Financial Items – (2) 2007 Change in the Taxation of Preferred Share Dividends section).

INVESTING ACTIVITIES

For the three months ended September 30, 2008, cash used in **investing activities increased** by 37%, primarily due to changes in non-cash working capital and higher capital expenditures in 2008. **Capital expenditures** for the three months ended September 30, 2008, **increased** by $18.5 million, primarily due

to increased investment in regulated electric distribution and transmission projects, partially offset by lower investment in ATCO Frontec projects.

For the nine months ended September 30, 2008, cash used in **investing activities increased** by 19%, primarily due to higher capital expenditures in 2008, partially offset by increased contributions by utility customers for extensions to plant. **Capital expenditures** for the nine months ended September 30, 2008, **increased** by $146.4 million, primarily due to increased investment in regulated electric and natural gas distribution and transmission projects.

Capital expenditures to maintain capacity, meet planned growth, and fund future development activities are expected to be approximately $1.1 billion in 2008, an increase of 57% from 2007. The majority of these expenditures relate to the Utilities segment. For the 2008 to 2010 period, capital expenditures in the Utilities segment are expected to be approximately $3.1 billion.

The planned capital expenditures for the Utilities segment are based on the following assumptions:

- the AESO projects approved in principle by the AUC will proceed as currently scheduled;
- the remaining planned capital expenditures in the Utilities segment are required to maintain capacity and meet planned growth in the Company's service areas. These expenditures are consistent with the anticipated growth in the Alberta economy and in the Company's service areas; and
- The regulatory system in Alberta will remain substantially unchanged.

In the opinion of the Company, these assumptions are reasonable, but no assurance can be given that these assumptions will prove to be correct.

ATCO Electric, ATCO Gas and ATCO Pipelines are regulated primarily by the AUC, which administers acts and regulations covering such matters as rates, financing, accounting, construction, operation and service area. The AUC approves customer rates based on the revenue required to recover estimated costs of service, including a fair return on rate base, estimated operating expenses, depreciation and taxes, all in respect of a future test year. Return on rate base is designed to meet the cost of interest on long term debt and dividends on preferred shares and to provide the shareowners with a reasonable opportunity to earn a fair return on their investment.

ATCO Electric, ATCO Gas and ATCO Pipelines are subject to the normal risks faced by companies that are regulated. These risks include the approval by the AUC of customer rates that permit a reasonable opportunity to recover on a timely basis the estimated costs of providing service, including a fair return on rate base. In addition, these risks include the disallowance of capital expenditures incurred if the AUC determines that such costs were not prudently incurred. This risk is mitigated by the inclusion of capital expenditures in general rate applications approved by the AUC. Furthermore, all major electric transmission projects assigned by the AESO to ATCO Electric are required to be approved by the AUC prior to commencing construction.

Tightness in labour and materials markets in Alberta in recent years has resulted in substantial growth in costs of many construction projects, and while the Company attempts to mitigate the risk of delays and cost overruns by careful planning and entering into long term contracts when possible, there can be no assurance that significant cost overruns or delays will not occur.

On September 9, 2008, ATCO Electric announced it had entered into an agreement with UK-based Balfour Beatty and Australia-based United Group Limited for engineering, construction, procurement and project management services to supplement ATCO Electric's own expertise in completing its capital expenditure program. Individual projects assigned pursuant to this agreement will be jointly estimated and

a target project cost agreed to before construction commences. Construction will be undertaken with a full disclosure of actual costs, with any savings or overruns relative to target project costs shared equally.

FINANCING ACTIVITIES

For the three months ended September 30, 2008, the Company had **net debt decreases** of $20.4 million. **Redemptions** were comprised of $8.2 million of long term debt and $12.2 million of non-recourse long term debt.

For the nine months ended September 30, 2008, the Company had **net debt increases** of $201.9 million. Issuance of debt included $200.0 million of 5.580% Debentures due May 2038, $125.0 million of 5.563% Debentures due May 2028 and $41.7 million of other long term debt. Redemptions were comprised of $100.0 million of 6.97% Debentures which matured in June 2008, $8.2 million of other long term debt and $56.6 million of non-recourse long term debt.

For the three months ended September 30, 2008, the Company had **no issues or redemptions** of equity preferred shares.

For the nine months ended September 30, 2008, the Company had **no issues or redemptions** of equity preferred shares in 2008, compared to an issue of $115 million of equity preferred shares by a subsidiary and a redemption of $126.5 million of equity preferred shares in 2007.

For the three months ended September 30, 2008 and September 30, 2007, there were **no purchases** of Canadian Utilities' Class A non-voting shares under the normal course issuer bids. For the three months ended September 30, 2008, **issues** of Canadian Utilities Class A non-voting shares due to stock option exercises were nil, a decrease of $0.2 million over the corresponding period in 2007.

For the nine months ended September 30, 2008 and September 30, 2007, there were **no purchases** of Canadian Utilities' Class A non-voting shares under the normal course issuer bids. For the nine months ended September 30, 2008, **issues** of Canadian Utilities Class A non-voting shares due to stock option exercises were $4.9 million, an increase of $3.6 million over the corresponding period in 2007.

On May 23, 2007, the Company commenced a **normal course issuer bid** for the purchase of up to 5% of the outstanding Class A shares. The bid expired on May 22, 2008. From May 23, 2007, to May 22, 2008, 157,800 shares have been purchased all of which were purchased in 2007. On May 23, 2008, the Company commenced a new **normal course issuer bid** for the purchase of up to 3% of the outstanding Class A shares. The bid will expire on May 22, 2009. From May 23, 2008, to October 27, 2008, no shares have been purchased.

Total **dividends** for the three and nine months ended September 30, 2008, **increased** by 6% to $41.8 million and by 7% to $125.1 million, respectively, over the same periods in 2007. For the three and nine months ended September 30, 2008, the quarterly dividend payment on the Company's Class A and Class B shares was **increased** by $0.0175 to $0.3325 per share over the corresponding periods in 2007. The Company has increased its annual common share dividend each year since its inception as a holding company in 1972. The payment of any dividend is at the discretion of the Board of Directors and depends on the financial condition of the Company and other factors.

FOREIGN CURRENCY TRANSLATION

Foreign currency translation for the three and nine months ended September 30, 2008, impacted the Company's cash position by $(6.2) million and by $6.8 million, respectively, over the same periods in 2007, as a result of changes in U.K. and Australian exchange rates used for balance sheet translations.

SHORT TERM INVESTMENT POLICY

The Company has a long-standing policy not to invest any of its cash balances in asset-backed securities; consequently, the recent turmoil in the asset-backed commercial paper market has had no impact on the Company. Cash and short term investment credit risk is reduced by investing in instruments issued by credit worthy financial institutions and in federal government issued short term investments.

LINES OF CREDIT

At September 30, 2008, the Company had the following credit lines that enable it to obtain funding for general corporate purposes.

($ millions)	Total	Used	Available
Long term committed	367.7	79.2	288.5
Short term committed	600.0	30.0	570.0
Uncommitted	99.1	36.0	63.1
Total	1,066.8	145.2	921.6

The amount and timing of future financings will depend on market conditions and the specific needs of the Company.

CONTRACTUAL OBLIGATIONS

Contractual obligations disclosed in the 2007 MD&A remain substantially unchanged as at September 30, 2008.

CURRENT AND LONG TERM FUTURE INCOME TAXES

Current and long term future income taxes of $163.0 million at September 30, 2008, are attributable to differences between the financial statement carrying amounts of assets and liabilities and their tax bases. These differences result primarily from recognizing revenue and expenses in different years for financial and tax reporting purposes. Future income taxes will become payable when such differences are reversed through the settlement of liabilities and realization of assets.

BASE SHELF PROSPECTUS

On May 16, 2008, CU Inc. filed a **base shelf prospectus** which permits CU Inc. to issue up to an aggregate of $1,500.0 million of debentures over the twenty-five month life of the prospectus. As at September 30, 2008, the following debentures had been issued:

- on May 26, 2008, CU Inc. issued $200.0 million of 5.580% Debentures due May 26, 2038, at a price of 100 to yield 5.580%, and
- on May 26, 2008, CU Inc. issued $125.0 million of 5.563% Debentures due May 26, 2028, at a price of 100 to yield 5.563%.

The proceeds of these issues were advanced to ATCO Electric, ATCO Gas and ATCO Pipelines to be used to fund capital expenditures, to repay indebtedness and for other general corporate purposes.

Share Capital

The equity securities of the Company consist of Class A shares and Class B shares.

At October 24, 2008, the Company had outstanding 83,464,894 Class A shares, 42,041,226 Class B shares and options to purchase 1,242,250 Class A shares.

Business Risks

Information contained in the 2007 MD&A related to Business Risks which is not discussed in this section remains substantially unchanged.

FINANCIAL MARKETS

Significant challenges are currently being experienced in domestic and international financial markets. These challenges are having an impact on the ability of certain borrowers to finance existing operations and capital programs. To date, these issues in the financial markets have not had a direct impact on the operations of the Company. As discussed elsewhere in this MD&A, the Utilities Business Group has a capital program of approximately $3.1 billion over the next three years. The Company completed a $325 million debenture issue in May 2008 to fund the 2008 portion of the Utilities Business Group's capital program and to fund scheduled maturities of previous debenture issues. In addition, the Company has cash balances of approximately $0.9 billion and available committed and uncommitted lines of credit of approximately $1.1 billion which can be utilized for general corporate purposes.

While the current financial situation has not directly impacted the Company's ability to fund capital projects and ongoing operations, future borrowing may be impacted by these financial markets through increased carrying costs and the ability to raise debt and capital. The Company is unable to determine what future changes in the financial markets could occur and how these changes could affect the Company.

ENVIRONMENTAL MATTERS

The Company's operating subsidiaries and the industries in which they operate are subject to extensive federal, provincial and local environmental protection laws concerning emissions to the air, discharges to surface and subsurface waters, land use activities and the handling, manufacturing, processing, use, emission and disposal of materials and waste products.

On March 10, 2008, the government of Canada released details of its regulatory framework originally announced on April 26, 2007. Electricity sector companies must achieve an initial GHG reduction in 2010 of 18% from their company-wide emission intensity, with a 2% continuous improvement required annually thereafter. New facilities (2004 or later) are allowed a 3-year grace period after which they must improve emission intensity by 2% per year below the clean fuel standard. For cogeneration facilities, steam production GHG emissions are subjected to the reduction target and electricity production emissions are compared to a deemed emission target. Compliance may be achieved by reduction or capture, limited investment in a technology fund, emission credit trading, purchase of offset credits, *Kyoto Protocol Clean Development Mechanisms* (maximum 10%) and very limited opportunity for early action credits. The government reiterated that it still intends to implement fixed emission caps in the 2020 to 2025 time period. A draft regulation has yet to be released, however, final regulations on GHG emissions are expected to be published in the fall of 2009.

The Federal government also announced plans to set targets to regulate air pollutants (sulphur dioxide, nitrogen oxides, particulate matter, volatile organic compounds and mercury) from industrial sources by 2015. Air pollutant elements will be added to the draft regulations once the regulatory framework for air pollutants has been finalized.

Alberta legislation requires large emitters to reduce GHG emission intensities by 12% starting July 1, 2007. Baseline emission values for Alberta Power (2000)'s and ATCO Power's facilities have been established and compliance reports with compensation for 2007 GHG obligations were submitted to Alberta Environment on March 31, 2008. For Alberta Power (2000)'s coal-fired units, the PPA counterparties have reimbursed Alberta Power (2000) for amounts it paid to Alberta Environment for its 2007 GHG obligations.

Alberta regulation requires coal-fired generating plant operators, including Alberta Power (2000), to monitor mercury emissions and capture at least 70% of the mercury in the coal commencing January 1, 2011. A full scale test at the Battle River generating plant, Unit 5 is underway to test the mercury control method to ensure the capture objective can be met.

It is anticipated that the PPAs will allow Alberta Power (2000) to recover most of the costs associated with complying with both the Federal and Alberta regulations during the PPA term.

Due to lower emissions per unit of output, ATCO Power's gas-fired generating units have minimal exposure to changes in GHG regulations, and therefore it is anticipated that there will not be a material impact from complying with the Alberta regulations. ATCO Power is currently evaluating the impact of complying with the federal regulations.

REGULATED OPERATIONS

Carbon Natural Gas Storage Facility

ATCO Gas leases the entire storage capacity of the Carbon natural gas storage facility to ATCO Midstream at AUC approved placeholder rates. Additionally, at the AUC's direction ATCO Gas has been using these revenues to offset customer rates. On February 5, 2007, the AUC issued a decision that left in question these placeholder rates and the effect that these placeholder rates would have on future ATCO Gas revenues and customer rates. Subsequent to a decision received from the Alberta Court of Appeal on May 27, 2008, which set aside the February 5, 2007 AUC decision, ATCO Gas requested, and received, approval from the AUC to suspend rate riders relating to the distribution of revenues and the costs associated with the Carbon operations (refer to Utilities – Regulatory Developments - ATCO Gas - Carbon Natural Gas Storage Facility section).

Temperatures

Temperature fluctuations have a significant impact on throughput in ATCO Gas. As approximately 50% of ATCO Gas' delivery charge is recovered based on throughput, ATCO Gas' revenues and earnings are sensitive to temperature. Temperatures that are 10% warmer or colder than normal temperatures impact ATCO Gas' annual earnings by approximately $9.7 million.

As part of its 2008 and 2009 general rate application filed with the AUC in November 2007, ATCO Gas is seeking approval from the AUC to set up a deferral account mechanism which would, if approved, eliminate the impact of temperature on ATCO Gas' earnings.

Benchmarking

ATCO Electric, ATCO Gas, and ATCO Pipelines purchase information technology services from ATCO I-Tek. ATCO Electric and ATCO Gas also purchase customer care and billing services from ATCO I-Tek. The recovery of these costs in customer rates is subject to AUC approval. Since 2003, the costs have been approved on a placeholder basis, and are subject to final AUC approval after completion of a collaborative benchmarking process. The benchmarking report, dealing with the period of 2003-2007, was received on January 23, 2008. In February 2008, the benchmarking report along with an application to adjust the placeholder rates was filed with the AUC. In April 2008, an agreement with the customer group concerning the adjustment to placeholders was submitted to the AUC for approval. Should this agreement be approved by the AUC, it is not expected to have a material impact on consolidated earnings. The AUC is currently deliberating on whether any further process is required to approve the agreement with the customer group and its consequent impact on customer rates.

Changes in Accounting Policies

Effective January 1, 2008, the Company adopted the Canadian Institute of Chartered Accountants (CICA) recommendations for capital disclosures which require disclosure of qualitative and quantitative information regarding the Company's objectives, policies and processes for managing capital (refer to Note 6 to the unaudited interim consolidated financial statements for the nine months ended September 30, 2008). The recommendation requires additional disclosure in the notes to the financial statements.

Effective January 1, 2008, the Company adopted the CICA recommendations pertaining to disclosure and presentation of financial instruments which require disclosure of the classification of the Company's financial instruments and additional qualitative and quantitative information regarding the nature and extent of risks arising from financial instruments to which the Company is exposed (refer to Note 7 to the unaudited interim consolidated financial statements for the nine months ended September 30, 2008). The recommendation requires additional disclosure in the notes to the financial statements.

Effective January 1, 2008, the Company prospectively adopted the CICA recommendations for measurement and disclosure of inventories which provide guidance on the determination of cost and its subsequent recognition as an expense, including any write-down to net realizable value, and on the cost formulas that are used to assign costs to inventories. The recommendations also clarified that major spare parts are to be included in property, plant and equipment. As a result of adopting these recommendations, the Company reclassified $1.8 million of inventories to property, plant, and equipment related to major spare parts on January 1, 2008 (refer to Note 1 to the unaudited interim consolidated financial statements for the nine months ended September 30, 2008).

FUTURE ACCOUNTING CHANGES

Effective for the Company beginning January 1, 2009, the CICA has removed a temporary exemption in its accounting recommendations that permitted assets and liabilities arising from rate regulation to be recognized and measured on a basis other than in accordance with the primary sources of GAAP. As permitted by Canadian GAAP, the Company will use standards issued by the Financial Accounting Standards Board in the United States that allow for the recognition and measurement of rate regulated assets and liabilities as another source of Canadian GAAP. The adoption of these standards is not expected to have a material impact on the earnings of the Company. However, it is anticipated that the reserves for future removal and site restoration costs, which are currently netted against property, plant and equipment, will be reclassified to non-current liabilities, resulting in an increase to the Company's total assets and liabilities. The amount of such future removal and site restoration costs at December 31, 2007 was $417.0 million. The CICA has also issued new recommendations that will require the

recognition of future income tax assets and liabilities as well as a separate regulatory asset or liability for the amount of future income taxes expected to be included in future rates and recovered from or paid to future customers. The amount of unrecorded future income tax liabilities of the regulated operations at December 31, 2007 was $159.4 million. These recommendations will be applied prospectively.

The CICA has issued new accounting recommendations for goodwill and intangible assets which establish standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets (including internally developed intangible assets). These recommendations are effective for the Company beginning January 1, 2009. Goodwill and intangible assets that are not assets as defined by GAAP will be derecognized and charged to the equity of the Company at that date. The adoption of these recommendations is not expected to have a material impact on the earnings or assets of the Company.

International Financial Reporting Standards

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

The Company has established a Steering Committee, a project team, and working groups to review the adoption of IFRS. The project team and working groups provide position papers and regular updates to management, the Steering Committee and the Audit Committee. Employee education sessions have been, and will continue to be, provided to increase knowledge and awareness of IFRS and its impacts. An external expert advisor has been engaged. The Company is participating in various industry groups, including the Canadian Energy Pipeline Association, the Canadian Gas Association and the Canadian Electric Association.

The Company's IFRS Conversion Project consists of three phases: Assessment and Diagnostic; Design and Planning; and Implementation and Review. Position papers are being prepared on issue-specific accounting differences between Canadian GAAP and IFRS. As a number of the IFRS standards are changing, the position papers will be updated to reflect any changes resulting from the final standards.

The Company reviews discussion papers, exposure drafts and standards released by the International Accounting Standards Board and the International Financial Reporting Interpretations Committee. The Company will continue to assess the impact of the proposed standards on its financial statements and disclosure as additional information becomes available. Financial impacts cannot be reasonably determined at this time.

Based on initial assessments the Company has identified that the following areas have the greatest potential impact to ATCO's accounting: property, plant and equipment, joint arrangements, leases, rate regulated operations and employee benefits. There will also be a significant amount of effort to comply with the IFRS' requirements for initial adoption of IFRS.

A more detailed analysis and evaluation of the financial impact of the issues identified in the assessment and diagnostic phases will be completed in 2009. The evaluation will include determination of financial reporting system changes required including computer systems.

Canadian Utilities Limited
Consolidated Statement of Earnings and Retained Earnings

(Millions of Canadian Dollars except per share data)

	Note	Three Months Ended September 30		Nine Months Ended September 30	
		2008	2007	**2008**	2007
		(Unaudited)		*(Unaudited)*	
Revenues		**$ 638.4**	$ 489.9	**$2,034.6**	$1,747.8
Costs and expenses					
Natural gas supply		**12.3**	8.0	**34.3**	17.3
Purchased power		**11.9**	11.1	**39.2**	36.3
Operation and maintenance		**284.8**	219.3	**823.1**	690.2
Selling and administrative		**51.7**	47.6	**157.6**	139.7
Depreciation and amortization	1	**105.4**	77.3	**288.6**	252.5
Interest		**49.7**	43.6	**145.2**	129.1
Interest on non-recourse long term debt		**9.2**	10.5	**28.0**	33.3
Franchise fees		**26.7**	20.6	**132.7**	113.8
		551.7	438.0	**1,648.7**	1,412.2
		86.7	51.9	**385.9**	335.6
Interest and other income	7	**5.6**	11.4	**44.5**	43.0
Earnings before income taxes		**92.3**	63.3	**430.4**	378.6
Income taxes		**17.5**	(17.2)	**107.2**	64.6
		74.8	80.5	**323.2**	314.0
Dividends on equity preferred shares		**8.1**	8.3	**24.3**	26.0
Earnings attributable to Class A and Class B shares		**66.7**	72.2	**298.9**	288.0
Retained earnings at beginning of period		**2,184.9**	1,951.4	**2,036.0**	1,813.3
		2,251.6	2,023.6	**2,334.9**	2,101.3
Dividends on Class A and Class B shares		**41.8**	39.5	**125.1**	117.2
Retained earnings at end of period		**$2,209.8**	$1,984.1	**$2,209.8**	$1,984.1
Earnings per Class A and Class B share	5	**$ 0.53**	$ 0.58	**$ 2.38**	$ 2.30
Diluted earnings per Class A and Class B share	5	**$ 0.53**	$ 0.58	**$ 2.37**	$ 2.29
Dividends paid per Class A and Class B share	5	**$ 0.3325**	$ 0.315	**$ 0.9975**	$ 0.935

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

	Note	September 30		December 31
		2008	2007	2007
		(Unaudited)		*(Audited)*
ASSETS				
Current assets				
Cash and short term investments		**$ 946.1**	$ 682.9	$ 747.2
Accounts receivable		**314.7**	332.1	373.9
Inventories	1, 3	**102.7**	98.2	101.8
Future income taxes		**3.5**	2.3	-
Regulatory assets		**14.5**	7.3	10.2
Derivative assets	7	**0.1**	0.3	0.8
Prepaid expenses		**31.3**	34.2	29.8
		1,412.9	1,157.3	1,263.7
Property, plant and equipment		**5,909.4**	5,587.3	5,678.5
Regulatory assets		**93.4**	64.0	75.6
Derivative assets	7	**67.1**	58.9	73.3
Other assets		**196.7**	194.3	194.3
		$7,679.5	$7,061.8	$7,285.4
LIABILITIES AND SHARE OWNERS' EQUITY				
Current liabilities				
Accounts payable and accrued liabilities		**$ 384.2**	$ 380.0	$ 375.0
Income taxes payable		**0.6**	2.2	1.2
Future income taxes		**-**	-	1.7
Regulatory liabilities		**18.8**	9.7	-
Derivative liabilities	7	**2.6**	1.9	2.6
Long term debt due within one year	4	**15.6**	-	-
Non-recourse long term debt due within one year		**46.0**	61.2	65.4
		467.8	455.0	445.9
Future income taxes		**166.5**	166.9	153.8
Regulatory liabilities		**143.2**	144.2	146.5
Derivative liabilities	7	**5.3**	2.9	3.3
Deferred credits	7	**300.6**	295.7	307.9
Long term debt	4	**2,841.9**	2,399.4	2,603.2
Non-recourse long term debt		**440.5**	495.7	478.1
Equity preferred shares		**625.0**	625.0	625.0
Class A and Class B share owners' equity				
Class A and Class B shares	5	**521.8**	517.4	516.9
Contributed surplus		**2.6**	1.8	1.9
Retained earnings		**2,209.8**	1,984.1	2,036.0
Accumulated other comprehensive income		**(45.5)**	(26.3)	(33.1)
Retained earnings and accumulated other comprehensive income		**2,164.3**	1,957.8	2,002.9
		2,688.7	2,477.0	2,521.7
		$7,679.5	$7,061.8	$7,285.4

Canadian Utilities Limited
Consolidated Statement of Cash Flows

(Millions of Canadian Dollars)

	Note	Three Months Ended September 30		Nine Months Ended September 30	
		2008	2007	**2008**	2007
		(Unaudited)		*(Unaudited)*	
Operating activities					
Earnings attributable to Class A and Class B shares		**$ 66.7**	$ 72.2	**$ 298.9**	$ 288.0
Adjustments for:					
Depreciation and amortization	1	**105.4**	77.3	**288.6**	252.5
Future income taxes		**-**	3.2	**4.5**	3.8
TXU Europe settlement - net of income taxes		**(2.4)**	(2.7)	**(7.4)**	(8.6)
Mark to market of natural gas purchase contracts	7	**10.5**	3.4	**1.2**	(0.1)
Other post employment benefit adjustment	8	**-**	-	**(7.3)**	-
Deferred availability incentives		**12.3**	(5.3)	**3.4**	(2.3)
Other		**(1.5)**	2.3	**(1.8)**	12.6
Funds generated by operations		**191.0**	150.4	**580.1**	545.9
Changes in non-cash working capital		**(2.9)**	(45.1)	**66.4**	33.9
Cash flow from operations		**188.1**	105.3	**646.5**	579.8
Investing activities					
Purchase of property, plant and equipment		**(234.9)**	(216.4)	**(634.6)**	(488.2)
Proceeds (costs) on disposal of property, plant and equipment		**(3.4)**	2.3	**(5.6)**	(1.5)
Contributions by utility customers for extensions to plant		**23.2**	28.7	**137.9**	65.4
Non-current deferred electricity costs		**(9.5)**	(2.7)	**(7.1)**	(5.1)
Deferred natural gas transmission costs		**(2.8)**	(2.5)	**(11.9)**	(2.5)
Distributions from (contributions to) joint venture		**0.3**	-	**(10.1)**	-
Changes in non-cash working capital		**(4.7)**	22.6	**12.1**	7.1
Other		**(2.6)**	(3.6)	**(3.5)**	(15.4)
		(234.4)	(171.6)	**(522.8)**	(440.2)
Financing activities					
Issue of long term debt	4	**-**	-	**366.7**	-
Repayment of long term debt	4	**(8.2)**	-	**(108.2)**	-
Repayment of non-recourse long term debt		**(12.2)**	(19.3)	**(56.6)**	(110.5)
Issue of equity preferred shares by subsidiary		**-**	-	**-**	115.0
Redemption of equity preferred shares		**-**	-	**-**	(126.5)
Net issue of Class A shares		**-**	0.2	**4.9**	1.3
Dividends paid to Class A and Class B share owners		**(41.8)**	(39.5)	**(125.1)**	(117.2)
Changes in non-cash working capital		**-**	-	**0.1**	-
Other		**(0.8)**	0.6	**1.5**	(2.7)
		(63.0)	(58.0)	**83.3**	(240.6)
Foreign currency translation		**(12.0)**	(5.8)	**(8.1)**	(14.9)
Cash position [1]					
Increase (decrease)		**(121.3)**	(130.1)	**198.9**	(115.9)
Beginning of period		**1,067.4**	813.0	**747.2**	798.8
End of period		**$ 946.1**	$ 682.9	**$ 946.1**	$ 682.9

[1] Cash position consists of cash and short term investments and includes $110.8 million (2007 - $129.3 million) which is only available for use in joint ventures.

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

	Three Months Ended September 30		Nine Months Ended September 30	
	2008	2007	**2008**	2007
	(Unaudited)		*(Unaudited)*	
Earnings attributable to Class A and Class B shares	**$ 66.7**	$ 72.2	**$298.9**	$288.0
Other comprehensive income, net of income taxes:				
Cash flow hedges	**(1.2)**	(1.3)	**(2.7)**	2.3
Foreign currency translation adjustment	**(26.6)**	(11.0)	**(9.7)**	(24.4)
	(27.8)	(12.3)	**(12.4)**	(22.1)
Comprehensive income	**$ 38.9**	$ 59.9	**$286.5**	$265.9

Canadian Utilities Limited
Notes to Consolidated Financial Statements
September 30, 2008

(Unaudited, Tabular Amounts in Millions of Canadian Dollars)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Financial statement presentation

The accompanying consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and should be read in conjunction with the consolidated financial statements and related notes included in the Corporation's Financial Information contained in its 2007 Annual Report. These interim financial statements have been prepared using the same accounting policies as used in the financial statements for the year ended December 31, 2007, except as described below.

Effective January 1, 2008, the Corporation adopted the Canadian Institute of Chartered Accountants ("CICA") recommendations for capital disclosures which require disclosure of qualitative and quantitative information regarding the Corporation's objectives, policies and processes for managing capital (see Note 6).

Effective January 1, 2008, the Corporation adopted the CICA recommendations pertaining to disclosure and presentation of financial instruments which require disclosure of the classification of the Corporation's financial instruments (as described in the Financial Instruments section below) and additional qualitative and quantitative information regarding the nature and extent of risks arising from financial instruments to which the Corporation is exposed (see Note 7).

Effective January 1, 2008, the Corporation prospectively adopted the CICA recommendations for measurement and disclosure of inventories which provide guidance on the determination of cost and its subsequent recognition as an expense, including any write-down to net realizable value, and on the cost formulas that are used to assign costs to inventories. The recommendations also clarified that major spare parts are to be included in property, plant and equipment. As a result of adopting these recommendations, the Corporation reclassified $1.8 million of inventories to property, plant, and equipment related to major spare parts on January 1, 2008.

Due to certain factors, the consolidated statements of earnings, retained earnings and comprehensive income for the three and nine months ended September 30, 2008 and September 30, 2007 are not necessarily indicative of operations on an annual basis. These factors include: the seasonal nature of the Corporation's operations, changes in electricity prices in Alberta, the timing and demand of natural gas storage capacity sold, changes in natural gas storage fees, changes in natural gas liquids prices and natural gas costs and the timing of rate decisions.

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

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.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

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

Effective January 1, 2008, ATCO Gas prospectively changed the allocation of annual depreciation and amortization expense on a quarterly basis. The method of quarterly allocation has been changed from an estimate based on the timing of revenues to the straight line basis. The annual depreciation and amortization expense continues to be on the straight line basis and, therefore, this change does not affect the total depreciation and amortization expense recognized for the year. This change in allocation resulted in a decrease to consolidated earnings of $5.3 million and $3.5 million for the three and nine months ended September 30, 2008, respectively, as compared to the methodology used in the corresponding periods in 2007.

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, 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.

Future Accounting Changes

The following accounting recommendations are in addition to those future accounting changes disclosed in the December 31, 2007 consolidated financial statements.

Effective for the Corporation beginning January 1, 2009, the CICA has removed a temporary exemption in its accounting recommendations that permitted assets and liabilities arising from rate regulation to be recognized and measured on a basis other than in accordance with the primary sources of GAAP. As permitted by Canadian GAAP, the Corporation will use standards issued by the Financial Accounting

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Standards Board in the United States that allow for the recognition and measurement of rate regulated assets and liabilities as another source of Canadian GAAP. The adoption of these standards is not expected to have a material impact on the earnings of the Corporation. However, it is anticipated that the reserves for future removal and site restoration costs, which are currently netted against property, plant and equipment, will be reclassified to non-current liabilities, resulting in an increase to the Corporation's total assets and liabilities. The amount of such future removal and site restoration costs at December 31, 2007 was $417.0 million. The CICA has also issued new recommendations that will require the recognition of future income tax assets and liabilities as well as a separate regulatory asset or liability for the amount of future income taxes expected to be included in future rates and recovered from or paid to future customers. The amount of unrecorded future income tax liabilities of the regulated operations at December 31, 2007 was $159.4 million. These recommendations will be applied prospectively.

The CICA has issued new accounting recommendations for goodwill and intangible assets which establish standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets (including internally developed intangible assets). These recommendations are effective for the Corporation beginning January 1, 2009. Goodwill and intangible assets that are not assets as defined by GAAP will be derecognized and charged to the equity of the Corporation at that date. The adoption of these recommendations is not expected to have a material impact on the earnings or assets of the Corporation.

In 2006, the CICA announced that accounting standards in Canada are to converge with International Financial Reporting Standards (IFRS). The Corporation will begin reporting under IFRS in the first quarter of 2011 with comparative data for the prior year. IFRS uses a conceptual framework similar to Canadian GAAP, but there could be significant differences on recognition, measurement and disclosures that will need to be addressed. The Corporation continues to evaluate the potential impacts of the convergence with IFRS.

2. REGULATORY MATTERS

In September 2007, ATCO Electric received a decision on its General Tariff Application for 2007 and 2008 which approved a return on common equity of 8.75% for 2008 and 8.51% for 2007. ATCO Gas' and ATCO Pipelines' General Rate Applications for 2008 and 2009 contain placeholder returns on common equity of 8.75% for 2008. If no rate applications are filed for a particular year, then there will be no adjustment to the common equity rate of return for that year.

A process continues with respect to the pricing of services provided by ATCO I-Tek to the utilities. A benchmarking report was received in January 2008 and filed with the Alberta Utilities Commission ("AUC") in February 2008, along with an application to adjust placeholders. In April 2008, an agreement with the customer group concerning the adjustment to placeholders was submitted to the AUC for approval. Should this agreement be approved by the AUC, it is not expected to have a material impact on consolidated earnings. The AUC is currently deliberating on whether any further process is required to approve the agreement with the customer group and its consequent impact on customer rates.

As a result of the Alberta Court of Appeal's May 27, 2008 decision, ATCO Gas requested and received approval from the AUC effective July 1, 2008 to suspend rate riders to customer rates on an interim basis.

2. REGULATORY MATTERS (continued)

The suspension of the rate riders increased earnings for the three and nine months ended September 30, 2008 by $3.4 million. Additionally, ATCO Gas, on July 11, 2008, filed a compliance application with the AUC requesting removal of the Carbon facility from the utility rate base and revenue requirement effective April 1, 2005, consistent with the Alberta Court of Appeal decision.

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

3. INVENTORIES

	September 30	
	2008	2007
Natural gas and fuel in storage	**$ 41.2**	$40.0
Raw materials and consumables	**61.5**	58.2
	$102.7	$98.2

For the three months ended September 30, 2008, the amount of inventories recognized as an expense was $29.5 million (2007 – $25.8 million). For the nine months ended September 30, 2008, the amount of inventories recognized as an expense was $81.1 million (2007 – $80.0 million). There have been no write-downs to net realizable value and there have been $0.2 million reversals of previous write-downs to net realizable value.

Inventories in the amount of $17.5 million are pledged as security for liabilities.

4. LONG TERM DEBT

At September 30, 2008, ATCO Frontec has a net borrowing of $35.1 million ($15.6 million of which is due within one year) repayable in Euros at a floating Euro Interbank Offered Rate ("Euribor") maturing on October 1, 2010 and secured by a pledge of their assets including certain of their contracts. The floating interest rate on this borrowing has been hedged with interest rate swaps (see Note 7).

On May 26, 2008, CU Inc. issued $200.0 million of 5.580% Debentures maturing May 26, 2038 and $125.0 million of 5.563% Debentures maturing May 26, 2028. The proceeds from these issues were used in part to redeem the $100.0 million of 6.97% Debentures that matured on June 2, 2008.

5. CLASS A AND CLASS B SHARES

There were 81,933,886 (2007 – 81,637,086) Class A non-voting shares and 43,570,984 (2007 – 43,806,584) Class B common shares outstanding on September 30, 2008. In addition, there were 1,243,500 options to purchase Class A non-voting shares outstanding at September 30, 2008 under the Corporation's stock option plan. From October 1, 2008, to October 24, 2008, no stock options were granted or cancelled, 1,250 stock options were exercised, 1,529,758 Class B common shares were exchanged for Class A non-voting shares and no Class A non-voting shares were purchased under the Corporation's normal course issuer bid.

The average number of shares used to calculate earnings per share are as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2008	2007	**2008**	2007
Weighted average shares outstanding	**125,504,740**	125,433,940	**125,382,065**	125,415,320
Effect of dilutive stock options	**374,447**	536,860	**392,646**	516,633
Weighted average dilutive shares outstanding	**125,879,187**	125,970,800	**125,774,711**	125,931,953

6. CAPITAL DISCLOSURES

The Corporation's objectives when managing capital are:

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

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

The Corporation's utility operations are regulated primarily by the AUC, which, through the generic cost of capital decision issued in 2004, established the capital structure for each utility. The utility operations are, therefore, capitalized consistent with the generic cost of capital decision. The capitalization involves the use of long term debt and preferred share financings; the AUC approved the continued use of the latter in a decision issued in 2006.

While the Corporation's utility operations are 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).

6. CAPITAL DISCLOSURES (continued)

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

Capital is monitored through an equity capitalization measure which is calculated as total equity divided by total capitalization. Total equity is comprised of Class A and Class B shares, contributed surplus, retained earnings, accumulated other comprehensive income and equity preferred shares. Total capitalization is comprised of long term debt, non-recourse long term debt and total equity. The Corporation's strategy, which is unchanged from 2007, is to maintain the equity capitalization allowed by the regulator for the regulated operations and to structure the non-regulated operations so as to sustain access to cost effective financing by maintaining high credit ratings on debt and preferred shares. The Corporation looks to maintain an equity capitalization in the range of 45% to 55%.

Other measures that are taken into consideration are interest coverage and interest and preferred dividend coverage. Interest coverage is calculated by dividing earnings before income taxes, interest expense and dividends on equity preferred shares by total interest expense. Interest and preferred dividend coverage is calculated by dividing earnings before income taxes, interest expense and dividends on equity preferred shares by interest expense and dividends on equity preferred shares (grossed up to pre-tax equivalents). The Corporation looks to maintain interest coverage of at least 2.5 and interest and preferred dividend coverage of at least 2.0; these objectives are unchanged from 2007.

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:

	September 30	
	2008	2007
Class A and Class B shares	**$ 521.8**	$ 517.4
Contributed surplus	**2.6**	1.8
Retained earnings	**2,209.8**	1,984.1
Accumulated other comprehensive income	**(45.5)**	(26.3)
Equity preferred shares	**625.0**	625.0
Total equity	**3,313.7**	3,102.0
Long term debt	**2,841.9**	2,399.4
Non-recourse long term debt	**440.5**	495.7
Total debt	**3,282.4**	2,895.1
Total capitalization	**$6,596.1**	$5,997.1
Equity capitalization	**50%**	52%

The equity capitalization is consistent with the Corporation's objectives. Total equity increased primarily due to higher earnings of the Corporation reflected in increased retained earnings and higher Class A and Class B shares due to the exercise of stock options offset by decreased accumulated other comprehensive income resulting from the impact of foreign currency translation of self-sustaining foreign operations. Total debt increased primarily due to financings for utility capital expenditures and ATCO Frontec's European operations partially offset by redemptions of long term debt and non-recourse long term debt.

6. CAPITAL DISCLOSURES (continued)

Interest coverage and interest and preferred dividend coverage are managed on an annual basis by the Corporation. Due to the seasonal nature of the Corporation's operations, changes in electricity prices in Alberta, the timing and demand of natural gas storage capacity sold, changes in natural gas storage fees, changes in natural gas liquids prices and natural gas costs and the timing of rate decisions, revenues and earnings for any quarter are not necessarily indicative of operations on an annual basis. Therefore, quarterly coverage ratios are not presented as they are not necessarily indicative of the annual performance. The amounts presented below are the most recent annual coverage ratios:

	December 31 2007
Interest coverage [(1)]	3.3
Interest and preferred dividend coverage [(1)]	2.7

[(1)] The coverage ratios for 2007 were negatively impacted by the AUC decision that directed ATCO Electric to refund future income taxes to customers. The total reduction in revenues and income taxes recorded in 2007 was $39.6 million. If the reduction in revenues had not occurred, interest coverage would have been 3.5 and interest and preferred dividend coverage would have been 2.8.

For the nine months ended September 30, 2008, the Corporation was in compliance with externally imposed requirements on its capital (including debt covenants). The Corporation has a number of regulatory filings and regulatory hearing submissions before the AUC for which decisions have not been received, the outcome of which could affect the capital structure of the Corporation.

7. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

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

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

At September 30, 2008 and September 30, 2007, the following derivative instruments were outstanding: interest rate swaps that hedge interest rate risk on the variable future cash flows associated with a portion of long term debt and non-recourse long term debt, foreign currency forward contracts that hedge foreign currency risk on the future cash flows associated with specific firm commitments or anticipated transactions and certain natural gas purchase contracts.

7. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (continued)

The derivative assets and liabilities comprise the following:

	September 30	
	2008	2007
Derivative assets – current:		
Interest rate swap agreements	**$ 0.1**	$ 0.3
Derivative assets – non-current:		
Natural gas purchase contracts	**$66.9**	$58.4
Interest rate swap agreements	**0.2**	0.5
	$67.1	$58.9
Derivative liabilities – current:		
Interest rate swap agreements	**$ 2.5**	$ 1.2
Foreign currency forward swaps	**0.1**	0.7
	$ 2.6	$ 1.9
Derivatives liabilities – non-current:		
Interest rate swap agreements	**$ 5.3**	$ 2.9

Interest rate risk

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

Financing	Swap Fixed Interest Rate [1]	Variable Debt Interest Rate	Maturity Date	Notional Principal	
				2008	2007
ATCO Frontec European operations: (€23.4 million)	5.457%	90 day Euribor	October 2010	**$ 35.1**	-
Osborne: ($27.3 million AUD (2007 - $33.3 million AUD))	7.343%	Bank Bill Rate in Australia	December 2013	**22.9**	29.4
APALP:	7.790%	90 day BA	November 2008	**0.6**	1.9
	7.567%	90 day BA	December 2008	**0.9**	2.7
	7.750%	6 month LIBOR	December 2011	**67.8**	79.0
Joffre:	7.536%	90 day BA	September 2012	**16.8**	21.0
Scotford:	5.332%	90 day BA	September 2008	**-**	51.4
	4.685%	30 day BA	December 2008	**42.3**	-

7. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (continued)

Financing	Swap Fixed Interest Rate [1]	Variable Debt Interest Rate	Maturity Date	Notional Principal 2008	2007
Muskeg River:	5.287%	90 day BA	December 2007	**-**	39.9
	5.515%	90 day BA	December 2012	**27.0**	-
	5.615%	3 month LIBOR	December 2012	**6.7**	-
Brighton Beach:	5.867%	30 day BA	June 2009	**8.1**	8.6
	6.605%	90 day BA	March 2019	**32.7**	34.7
Cory:	6.586%	90 day BA	June 2011	**1.7**	2.2
				$262.6	$270.8

BA – Bankers' Acceptance
LIBOR – London Interbank Offered Rate
Euribor – Euro Interbank Offered Rate

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

The Corporation has fixed interest rates, either directly or through interest rate swap agreements, on 98% (2007 ─ 98%) of total long term debt and non-recourse long term debt. Consequently, the exposure to fluctuations in future cash flows, with respect to debt, as a result of changes in market interest rates is limited. Interest rate swaps are designated as cash flow hedges; changes in the fair value of highly effective cash flow hedges, which include all but the Joffre interest rate swap, are recorded in other comprehensive income. Changes in the fair value of the Joffre interest rate swap were $0.1 million and were recognized in earnings.

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

Foreign currency exchange rate risk

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

Foreign currency exchange rate risk arises from financial instruments denominated in a currency other than the functional currency. The Corporation has entered into foreign currency forward contracts in order to fix the exchange rate on certain service contracts, planned equipment expenditures and operational cash flows denominated in U.S. dollars. At September 30, 2008, the contracts consist of purchases of $1.1 million U.S. in return for Canadian dollars and $14.9 million U.S. in return for Australian dollars (2007 ─ purchases of $8.4 million U.S. and £1.4 million in return for Canadian dollars).

7. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (continued)

Natural gas purchase contracts and associated power generation revenue contract liability

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

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

Interest and other income for the three months ended September 30, 2008 includes a loss of $38.0 million (2007 – loss of $10.7 million) related to the change in fair value of the natural gas purchase contracts derivative asset. This loss is offset by a gain of $27.5 million (2007 – gain of $7.4 million) related to the change in fair value of the associated power generation revenue contract liability. Interest and other income for the nine months ended September 30, 2008 includes a loss of $5.6 million (2007 – loss of $0.6 million) related to the change in fair value of the natural gas purchase contracts derivative asset. This loss is offset by a gain of $4.4 million (2007 – gain of $0.8 million) related to the change in fair value of the associated power generation revenue contract liability.

The mark-to-market adjustment for the derivative asset and the corresponding adjustment for the associated power generation revenue contract liability decreased earnings by $7.6 million for the three months ended September 30, 2008 (2007 – decrease of $2.4 million) and decreased earnings by $0.9 million for the nine months ended September 30, 2008 (2007 – increase of $0.1 million). At September 30, 2008, the natural gas purchase contracts derivative asset is $66.9 million (2007 – $58.4 million) and the power generation revenue contract liability is $49.8 million (2007 – $44.0 million).

Credit risk

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

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

7. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (continued)

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. A significant portion of loans and receivables arise from the Corporation's operations in Alberta.

Accounts receivable are non-interest bearing and are generally due in 30 to 90 days. At September 30, 2008, the provision for impairment of credit losses was $1.8 million. The changes in the provision for impairment were as follows:

	2008
Provision at beginning of period	**$ 1.5**
Impairment of receivables	**0.4**
Receivables written off as uncollectible	**(0.1)**
Provision at end of period	**$ 1.8**

At September 30, 2008, the aging analysis of trade receivables that are past due but not impaired is as follows:

	2008
30 to 90 days	**$15.6**
Greater than 90 days	**3.6**
	$19.2

No other impairments have been identified within accounts receivable.

Liquidity risk

Liquidity risk is the risk that the Corporation will not be able to meet its obligations associated with financial liabilities. Funds generated by operations provide a substantial portion of the Corporation's cash requirements. Additional cash requirements are met externally through bank borrowings and the issuance of long term debt, non-recourse long term debt and preferred shares. Commercial paper borrowings and short term bank loans are used under available credit lines to provide flexibility in the timing and amounts of long term financing. The Corporation has a policy not to invest any of its cash balances in asset backed securities; consequently, the recent turmoil in the asset-backed commercial paper market has had no impact on the Corporation.

Contractual obligations have not changed substantially from those disclosed in the Corporation's December 31, 2007 consolidated financial statements.

7. 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:

	September 30			
	2008		2007	
	Carrying Value	**Fair Value**	Carrying Value	Fair Value
Financial Assets				
Held For Trading:				
Cash [1]	**$ 27.7**	**$ 27.7**	$ 197.2	$ 197.2
Held to Maturity:				
Short term investments [1]	**918.4**	**918.4**	485.7	485.7
Loans and Receivables:				
Accounts receivable [1]	**314.7**	**314.7**	332.1	332.1
Financial Liabilities				
Other Liabilities:				
Accounts payable and accrued liabilities[2]	**384.2**	**384.2**	380.0	380.0
Long term debt [3]	**2,857.5**	**2,910.6**	2,399.4	2,650.5
Non-recourse long term debt [3]	**486.5**	**511.1**	556.9	587.3

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

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

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

7. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (continued)

Fair value of derivative financial instruments

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

	September 30					
	2008			2007		
	Notional Principal[(1)]	**Fair Value Receivable (Payable)[(3)]**	**Maturity**	Notional Principal[(1)]	Fair Value Receivable (Payable)[(3)]	Maturity
Held For Trading:						
Interest rate swaps	**$262.6**	**$ (7.5)**	**2008-2019**	$270.8	$(3.3)	2007-2019
Foreign currency forward contracts	**$ 16.9**	**$ (0.1)**	**2008-2010**	$ 11.7	$(0.7)	2007-2008
Natural gas purchase contracts	**N/A [(2)]**	**$66.9**	**2014**	N/A [(2)]	$58.4	2014

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

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

(3) Fair values for the interest rate swaps and the foreign currency forward contracts have been estimated using period-end market rates, and fair values for the natural gas purchase contracts have been estimated using period-end forward market prices for natural gas. These fair values approximate the amount that the Corporation would either pay or receive to settle the contract at September 30.

Sensitivity analysis

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

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

7. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (continued)

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

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

	Three Months Ended September 30, 2008		Nine Months Ended September 30, 2008	
	Earnings	Other Comprehensive Income	Earnings	Other Comprehensive Income
Canadian interest rates				
25 basis points increase	$ -	$ (0.2)	$ 0.1	$ 0.8
25 basis points decrease	$ -	$ 0.2	$(0.1)	$ (0.8)
Australian interest rates				
25 basis points increase	$ -	$ (0.1)	$ -	$ 0.1
25 basis points decrease	$ -	$ 0.1	$ -	$ (0.1)
Euribor interest rates				
25 basis points increase	$ -	$ (0.2)	$ -	$ (0.1)
25 basis points decrease	$ -	$ 0.2	$ -	$ 0.1
U.S. dollar to Canadian dollar exchange rate				
10% increase	$ (0.8)	$ -	$ 2.7	$ -
10% decrease	$ 0.8	$ -	$ (2.7)	$ -
Forward price of natural gas				
10% increase	$ (0.8)	$ -	$ 2.7	$ -
10% decrease	$ 0.8	$ -	$ (2.7)	$ -

The sensitivity to a change in the Australian dollar to the U.S. dollar exchange rate of +/- 10% is less than $0.1 million.

8. EMPLOYEE FUTURE BENEFITS

In the three months ended September 30, 2008, net expense of $3.1 million (2007 – $3.9 million) was recognized for pension benefit plans and net expense of $0.7 million (2007 – $0.6 million) was recognized for other post employment benefit plans.

In the nine months ended September 30, 2008, net expense of $8.8 million (2007 – $11.2 million) was recognized for pension benefit plans and net income of $6.0 million (2007 – net expense of $3.3 million) was recognized for other post employment benefit plans.

8. EMPLOYEE FUTURE BENEFITS (continued)

In June 2008, the Corporation prospectively changed the method of apportioning the costs of other post employment benefit ("OPEB") plans to individual subsidiaries. Formerly, each subsidiary was apportioned a percentage of its payroll costs at a rate calculated for the plan as a whole. The revised method determines the accrued OPEB liabilities and costs on a company-by-company basis. Total consolidated accrued OPEB liabilities and costs did not change. Under the new method of apportioning, the OPEB liability for the regulated subsidiaries increased by $10.4 million with a corresponding increase to non-current regulatory assets. Pursuant to an AUC decision effective January 1, 2000, the regulated operations, excluding Alberta Power (2000), are required to expense contributions for other post employment benefit plans as paid. Consequently, there was no change to their earnings for the three and nine months ended September 30, 2008. The difference between the amounts accrued and paid is deferred in non-current regulatory assets.

The OPEB liability for the non-regulated subsidiaries decreased which resulted in an increase to earnings of $5.5 million for the nine months ended September 30, 2008.

9. SEGMENTED INFORMATION

Segmented results – Three months ended September 30

2008 2007	Utilities	Power Generation	Global Enterprises	Corporate and Other	Intersegment Eliminations	Consolidated
(Unaudited)						
Revenues – external	**$ 266.9**	**$ 217.2**	**$153.7**	**$ 0.6**	**$ -**	**$ 638.4**
	$ 181.6	$ 197.6	$110.2	$ 0.5	$ -	$ 489.9
Revenues – intersegment [1]	**6.4**	**-**	**36.0**	**3.3**	**(45.7)**	**-**
	6.2	-	34.2	2.9	(43.3)	-
Revenues	**$ 273.3**	**$ 217.2**	**$189.7**	**$ 3.9**	**$ (45.7)**	**$ 638.4**
	$ 187.8	$ 197.6	$144.4	$ 3.4	$ (43.3)	$ 489.9
Earnings attributable to Class A and Class B shares	**$ 14.5** $ 14.3	**$ 28.8** $ 38.6	**$ 25.6** $ 20.9	**$ (1.9)** $ (0.8)	**$ (0.3)** $ (0.8)	**$ 66.7** $ 72.2

Segmented results – Nine months ended September 30

2008 2007	Utilities	Power Generation	Global Enterprises	Corporate and Other	Intersegment Eliminations	Consolidated
(Unaudited)						
Revenues – external	**$ 912.2**	**$ 640.5**	**$480.7**	**$ 1.2**	**$ -**	**$2,034.6**
	$ 784.6	$ 579.1	$382.8	$ 1.3	$ -	$1,747.8
Revenues – intersegment [1]	**19.0**	**-**	**101.0**	**9.6**	**(129.6)**	**-**
	18.6	-	91.6	8.8	(119.0)	-
Revenues	**$ 931.2**	**$ 640.5**	**$581.7**	**$ 10.8**	**$(129.6)**	**$2,034.6**
	$ 803.2	$ 579.1	$474.4	$ 10.1	$(119.0)	$1,747.8
Earnings attributable to Class A and Class B shares	**$ 103.2** $ 91.7	**$ 105.0** $ 109.2	**$ 95.0** $ 82.3	**$ (3.4)** $ 7.2	**$ (0.9)** $ (2.4)	**$ 298.9** $ 288.0
Total assets	**$4,498.4**	**$2,149.3**	**$354.8**	**$779.8**	**$(102.8)**	**$7,679.5**
	$3,968.2	$2,222.0	$308.5	$477.9	$ 85.2	$7,061.8

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

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