CANADIAN UTILITIES LIMITED
An ATCO Company

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE YEAR ENDED DECEMBER 31, 2008

CANADIAN UTILITIES LIMITED

Management's Discussion and Analysis (MD&A)
For the year ended December 31, 2008

This MD&A should be read in conjunction with the Company's unaudited consolidated financial statements for the three months ended December 31, 2008, and the audited consolidated financial statements for the year ended December 31, 2008. This MD&A is dated February 17, 2009. Additional information relating to the Company, including the Company's annual information form, is available on SEDAR at www.sedar.com.

Table of Contents

Glossary

Adjusted Earnings means earnings attributable to Class A and Class B Shares after adjustment 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 item).

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 item).

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 is 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.

Carbon offset means a financial instrument representing a reduction in greenhouse gas emissions. Companies, governments and other entities buy carbon offsets in order to comply with caps on the total amount of greenhouse gases they are allowed to emit or to mitigate their greenhouse gas emissions.

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 contract or instrument or similar contracts or instruments.

Megawatt (MW) is 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 or future proceeding. This cost is subject to adjustment once the separate or future 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

Canadian Utilities Limited, an Alberta-based worldwide organization of companies with assets of approximately $7.9 billion, and more than 6,800 employees, is comprised of three main business divisions: Utilities (natural gas and electric transmission and distribution); Power Generation; and Global Enterprises (technology, logistics and energy services).

The consolidated financial statements include the accounts of Canadian Utilities Limited 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 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.

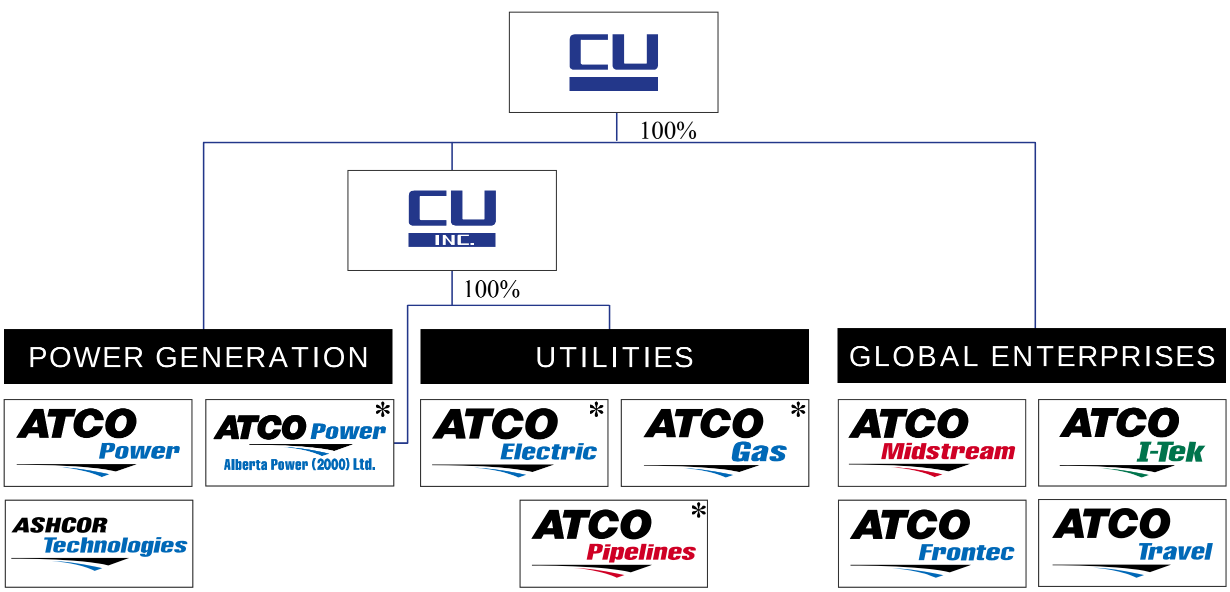
The **Global Enterprises** Business Group includes:

- 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 resource, defence and telecommunications 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 24 to the consolidated financial statements.

Simplified Organizational Structure



* Regulated operations include ATCO Electric, ATCO Gas, ATCO Pipelines and the generating plants of Alberta Power (2000) Ltd.

POTENTIAL TRANSACTION COMBINING ATCO STRUCTURES AND ATCO FRONTEC

The Company's Board of Directors has established a special committee of independent directors of the Board to review a transaction that would combine the operations of ATCO Structures, a wholly owned subsidiary of ATCO Ltd., and of ATCO Frontec Corp., a wholly-owned subsidiary of the Company. 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. As discussed elsewhere in this MD&A, the Utilities Business Group has a capital program of $2.0 billion and, depending on infrastructure spending, could be as much as $4.0 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. On January 28, 2009, ATCO Power entered into an Australian $100 million credit facility with the Commonwealth Bank of Australia to finance the design and construction of the Karratha generating plant located in Western Australia. In addition, the Company has cash balances of approximately $0.7 billion and available committed and uncommitted lines of credit of approximately $0.9 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 equity capital. The Company is unable to determine what future changes in the financial markets could occur and how these changes could affect the Company. In addition, the deterioration in the domestic and international economic activity may impact the operations of the Company.

COMMODITY PRICES

Commodity prices, particularly oil and natural gas prices, have fallen significantly since September 2008. These lower prices have had an impact on the Company's operations, particularly the lower frac spreads on ATCO Midstream's NGL business. The Company is unable to determine what future changes in commodity markets could occur and how these changes could affect the Company.

PENSION PLANS

Recent declines in stock and bond markets have resulted in a reduction in the value of the Company's defined benefit pension plans, creating a pension plan deficit that may require the Company to make contributions to the pension plans commencing in 2009.

Employees are required to contribute a percentage of their salary to the registered defined benefit pension plans. The Company is required to provide the balance of the funding, based on triennial actuarial valuations, necessary to ensure that benefits will be fully provided for at retirement. Based on the most recent actuarial valuation for funding purposes as of December 31, 2006 the Company is continuing a contribution holiday that began on April 1, 1996 for all but one of the registered pension plans; commencing in 2007, the Company is required to make annual contributions of approximately

$0.7 million to cover the unfunded liability of that plan. The next actuarial valuation for funding purposes is required as of December 31, 2009. The government of Alberta has issued a white paper which, if it becomes law, would require an actuarial valuation to be filed as at December 31, 2008, for those plans that wish to continue their contribution holidays in 2009. Depending on the outcome of the full actuarial valuation, current service contributions may be required to resume in 2009.

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.

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 adjustment 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 – Reconciliation of Earnings Attributable to Class A and Class B Shares and Adjusted Earnings section.

Controls and Procedures

DISCLOSURE CONTROLS AND PROCEDURES

As of December 31, 2008, the Company’s management evaluated the effectiveness of the Company’s disclosure controls and procedures, as defined under rules adopted by the Canadian Securities Administrators. This evaluation was performed under the supervision of, and with the participation of, the Chief Executive Officer (CEO) and the Chief Financial Officer (CFO).

Disclosure controls and procedures are controls and other procedures designed to provide reasonable assurance that information required to be disclosed in documents filed with securities regulatory authorities is recorded, processed, summarized and reported on a timely basis and is accumulated and communicated to the Company’s management, including the CEO and the CFO, as appropriate, to allow timely decisions regarding required disclosure.

The Company's management, inclusive of the CEO and the CFO, does not expect that the Company's disclosure controls and procedures will prevent or detect all error and all fraud. The inherent limitations in all control systems are such that they can provide only reasonable, not absolute, assurance that all control issues and instances of fraud or error, if any, within the Company have been detected.

Based on this evaluation, the CEO and the CFO have concluded that, subject to the inherent limitations noted above, the Company's disclosure controls and procedures are effective in providing reasonable assurance that material information relating to the Company and its consolidated subsidiaries is made known to the CEO and the CFO by others within those entities on a timely basis.

INTERNAL CONTROL OVER FINANCIAL REPORTING

As of December 31, 2008, the Company's management evaluated the effectiveness of the Company's internal control over financial reporting, as defined under rules adopted by the Canadian Securities Administrators. This evaluation was performed under the supervision of, and with the participation of, the CEO and the CFO.

The Company's internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Internal control over financial reporting, no matter how well designed, has inherent limitations. Therefore, internal control over financial reporting can provide only reasonable assurance with respect to financial statement preparation and may not prevent or detect all misstatements.

Based on this evaluation, the CEO and the CFO have concluded that, subject to the inherent limitations noted above, the Company's internal control over financial reporting is effective in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

There was no change in the Company's internal control over financial reporting that occurred during the period beginning on October 1, 2008, and ended on December 31, 2008, that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

Annual Results of Operations

SELECTED INFORMATION

($ millions, except per share data, outstanding shares and % return on equity) [1][2]	For the Year Ended December 31		
	2008	2007	2006
Revenues	**2,778.9**	2,404.9	2,430.4
Earnings attributable to Class A and Class B shares	**413.1**	386.7	323.9
Adjusted Earnings [3]	**401.8**	343.8	320.8
Total assets	**7,864.4**	7,305.2	6,993.5
Long term debt	**2,844.3**	2,603.2	2,411.5
Non-recourse long term debt	**412.4**	478.1	626.7
Equity preferred shares	**625.0**	625.0	636.5
Class A and Class B share owners' equity	**2,751.7**	2,521.7	2,324.7
Return on equity	**15.7**	16.0	14.3
Cash flow from operations	**791.8**	706.9	617.9
Funds generated by operations	**804.6**	725.9	657.5
Capital expenditures	**1,010.9**	700.8	567.7
Earnings per Class A and Class B share	**3.29**	3.08	2.57
Diluted earnings per Class A and Class B share	**3.28**	3.07	2.56
Adjusted Earnings per Class A and Class B share [3]	**3.20**	2.74	2.54
Cash dividends declared per share:			
Series Second Preferred Shares:			
Series O [4]	**1.09**	1.13	1.26
Series Q [5]	**-**	0.68	1.48
Series R [5]	**-**	0.61	1.33
Series S [5]	**-**	0.77	1.65
Series T [4]	**1.09**	1.09	1.26
Series U [4]	**1.09**	1.09	1.26
Series V [6]	**1.18**	1.28	1.31
Series W	**1.45**	1.45	1.45
Series X	**1.50**	1.50	1.50
Class A and Class B share	**1.33**	1.25	1.40
Equity per Class A and Class B share	**21.92**	20.13	18.54
Class A and Class B shares outstanding, year end (thousands)	**125,510**	125,295	125,388
Weighted average Class A and Class B shares outstanding (thousands):			
Basic	**125,408**	125,409	126,219
Diluted	**125,784**	125,934	126,687

Notes:

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

(2) *The above data (other than Adjusted Earnings, Adjusted Earnings per Class A and Class B share, return on equity and equity 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.*

(3) *Refer to Significant Non-Operating Financial Items section for a description of adjustments to obtain Adjusted Earnings.*

(4) *The dividend rate was reset to $1.09 (from 5.05% to 4.35%) for the period between December 2, 2006, and December 2, 2011.*

(5) *Series Second Preferred Shares Q, R and S were redeemed on May 18, 2007.*
(6) *The dividend rate was reset to $1.18 (from 5.25% to 4.70%) for the period between October 3, 2007, and October 3, 2012.*

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 Year Ended December 31	
($ millions)	**2008**	2007
Earnings attributable to Class A and Class B Shares	**413.1**	386.7
Mark-to-Market Adjustment (1)	**2.0**	(2.9)
Other Post Employment Benefits (2)	**(7.0)**	-
Federal Court of Appeal Decision – Mining Assets (3)	**(3.0)**	-
2008 Tax Assessment (4)	**(3.3)**	-
2007 Change in the Taxation of Preferred Share Dividends (5)	-	(15.6)
2007 Changes in Income Taxes and Rates (6)	-	(14.9)
ATCO Gas Tax Reassessments (7)	-	(9.5)
Adjusted Earnings	**401.8**	343.8

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 the Company 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 Company is required to designate these entire contracts as derivative instruments. The Company 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 Company's power generation obligations, the Company could not recognize the entire fair values of these natural gas purchase contracts in its revenues. Consequently, the Company 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 $1.1 million, net of income taxes, for the unaudited three months ended December 31, 2008 (2007 – increase of $2.8 million) and decreased earnings by $2.0 million, net of income taxes, for the year ended December 31, 2008 (2007 – increase of $2.9 million). At December 31, 2008, the natural gas purchase contracts derivative asset is $60.1 million (2007 – $72.5 million), a net change of $12.4 million, and the power generation revenue contract liability is $44.6 million (2007 – $54.2 million), a net change of $9.6 million.

(2) 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, excluding Alberta Power (2000), 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 and certain other defined benefit pension plans as paid. Consequently, there was no change to their earnings for the unaudited three months and year ended December 31, 2008. The difference between the amounts accrued and paid is deferred in non-current regulatory assets.

The OPEB liability for Alberta Power (2000) and the non-regulated subsidiaries decreased which resulted in an increase to earnings of $7.0 million, of which $5.5 million was recorded in the second quarter of 2008 and $1.5 million was recorded in the fourth quarter of 2008.

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

($ millions)	**Years Prior to 2008**
Power Generation	2.7
Global Enterprises	4.2
Corporate & Other and Intersegment Eliminations	0.1
Total	7.0

(3) Federal Court of Appeal Decision – Mining Assets

On May 22, 2008, the Federal Court of Appeal issued a decision overturning previous Canada Revenue Agency (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. This reduced current income tax expense and increased interest income which resulted in an increase to earnings of $3.0 million.

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

(4) 2008 Tax Assessment

In 2008 the Company received a favorable tax decision from the CRA to treat certain previously reported capital outlays as current expenditures for tax purposes in ATCO Electric and ATCO Pipelines. As a result the Company recognized a reduction in current income tax expense and an increase in interest income in respect of prior taxation years which resulted in an increase in earnings of $3.3 million.

(5) 2007 Change in the Taxation of Preferred Share Dividends

In 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 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

(6) 2007 Changes in Income Taxes and Rates

In 2007, the federal government announced a reduction in corporate tax rates from 19% to 15% by 2012. As a result of these changes, the Company made an adjustment to future income taxes amounting to $10.9 million in the fourth quarter of 2007. This one-time adjustment resulted in increased earnings of $10.9 million relating to the change in the future income tax liability as at December 31, 2006. An additional increase to earnings of $1.5 million was recorded relating to the change in the future income tax liability for the first nine months of 2007.

Additionally, 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 a further increase in the Company's 2007 earnings of $4.0 million.

The earnings impact of the 2007 changes in income taxes and rates adjustment by Business Group was as follows:

	December 31, 2006 Balance	First Nine Months of 2007	Total
($ millions)			
Canadian tax changes:			
Utilities	0.3	-	0.3
Power Generation	8.2	1.3	9.5
Corporate & Other and Intersegment Eliminations	2.4	0.2	2.6
	10.9	1.5	12.4
U.K. tax changes in Power Generation	4.0	-	4.0
Total	14.9	1.5	16.4

(7) ATCO Gas Tax Reassessments

In the fourth quarter of 2007, ATCO Gas successfully appealed previous CRA reassessments which resulted in an $8.8 million decrease in income taxes and an increase in interest income, net of income taxes, of $0.7 million for an overall increase to earnings of $9.5 million. These ATCO Gas CRA reassessments applied to the 1999 to 2006 taxation years and allowed ATCO Gas to treat previously reported capital outlays as current expenditures for income tax purposes.

CONSOLIDATED REVENUES AND EARNINGS

Consolidated 2008 **revenues increased** by $374.0 million (16%) over 2007. This increase was primarily attributable to a $146.0 million (13%) increase in revenues in the Utilities segment, a $116.6 million (15%) increase in revenues in the Power Generation segment and a $118.1 million (18%) increase in revenues in the Global Enterprises segment.

The **increase** in **revenues** was primarily attributable to increased business activity in ATCO Frontec's operations and higher natural gas fuel purchases recovered on a "no-margin" basis, improved merchant operations, increased availability and the recognition of insurance proceeds from the Barking outage in ATCO Power's U.K. operations. In addition, the 2007 refund of future income tax balances with a corresponding decrease in 2007 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) contributed to the increase in revenues. Other contributing factors were AUC approved interim customer rates in ATCO Gas associated with the 2008 and 2009 general rate application (ATCO Gas GRA) and improved merchant performance in ATCO Power's Alberta generating plants. These increases were partially offset by the impact of lower exchange rates on conversion of revenues to Canadian dollars in ATCO Power's U.K. operations, and lower storage revenues due to the timing and demand of natural gas storage capacity sold and lower storage fees in ATCO Midstream.

Earnings in 2008 were $413.1 million, an **increase** of $26.4 million (7%), over 2007, including the impact of the adjustments identified in the Significant Non-Operating Financial Items section.

In 2008, **Adjusted Earnings** were $401.8 million, an **increase** of $58.0 million (17%), over 2007. The primary reasons for the increased Adjusted Earnings were improved merchant performance in ATCO Power's Alberta generating plants and increased availability and the recognition of insurance proceeds from the Barking outage in ATCO Power's U.K. operations. The impact of the ATCO Gas GRA net of cost increases and suspension of the Carbon rate riders (refer to Regulatory Matters – ATCO Gas – Carbon Natural Gas Storage Facility) also contributed to the increase in Adjusted Earnings. Other contributing factors were the impact of the ATCO Electric GTA and increased business activity in ATCO Frontec's operations. These increases were partially offset by lower storage fees in ATCO Midstream.

Interest and other income decreased by $5.2 million to $59.1 million mainly due to the mark-to-market adjustment in ATCO Power and lower rates of interest earned on lower cash balances, partially offset by the recognition of carbon offsets by ATCO Power.

CONSOLIDATED EXPENSES

($ millions)	For the Year Ended December 31		
	2008	2007	Change to 2008 (2008-2007)
Operating expenses:			
Natural gas supply	**37.9**	42.1	(10%)
Purchased power	**54.1**	49.9	8%
Operation and maintenance	**1,123.5**	941.6	19%
Selling and administrative	**244.8**	216.8	13%
Franchise fees	**175.2**	151.2	16%
	1,635.5	1,401.6	17%
Depreciation and amortization	**389.1**	351.5	11%
Interest	**233.5**	217.4	7%
Income taxes	**134.3**	77.7	73%
Dividends on equity preferred shares	**32.5**	34.3	(5%)

In 2008, **operating expenses increased** by $233.9 million (17%) over 2007. Natural gas supply expense decreased primarily as a result of reduced business activity in NGL extraction operations in ATCO Midstream. Operation and maintenance expenses were higher primarily as a result of higher operating and fuel costs on a "no-margin" basis in ATCO Power, increased business activity in ATCO Frontec, and growth in ATCO Electric. 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 in ATCO Power. Increased franchise fees due to higher natural gas prices, recovered on a flow through basis, were paid in ATCO Gas.

Depreciation and amortization expenses increased by $37.6 million, primarily due to capital additions in 2007 and 2008 in the Utilities segment and in ATCO Frontec.

Interest expense increased by $16.1 million (7%) over 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.

In 2008, **income taxes increased** by $56.6 million (73%) over 2007, primarily due to the impact of a number of tax adjustments in 2007 and 2008. The following table indicates the significant items included in determining income tax expense for 2007 and 2008.

	For the Year Ended December 31, 2008
($ millions)	
Income taxes - 2007	77.7
Increase in 2008 income taxes due to higher earnings before tax	24.0
2007 Adjustments:	
2007 Changes in Income Taxes and Rates [(1)]	14.9
2007 Change in the Taxation of Preferred Share Dividends [(1)]	15.6
Refund of ATCO Electric future income taxes [(2)]	34.4
ATCO Gas Tax Reassessments [(1)]	8.8
Flow through adjustments pertaining to rate regulated operations	4.9
2008 Adjustments:	
Change in 2008 tax rates	(13.1)
Tax reassessments	(9.7)
Flow through adjustments pertaining to rate regulated operations	(27.2)
Other	4.0
Income taxes - 2008	134.3

Note:
(1) *Refer to Significant Non-Operating Financial Items section for a description of the adjustments.*
(2) *Refer to Segmented Information – Utilities – Regulatory Developments – ATCO Electric – 2007 and 2008 General tariff Application section.*

Dividends on equity preferred shares decreased by $1.8 million (5%) primarily due to lower dividend rates and lower number of equity preferred shares outstanding.

SEGMENTED INFORMATION

($ millions)	Utilities	Power Generation	Global Enterprises	Corporate & Other	Intersegment Eliminations	Total
	For the Year Ended December 31					
2008						
Revenues	**1,262.5**	**889.6**	**790.7**	**14.4**	**(178.3)**	**2,778.9**
Earnings attributable to Class A and Class B Shares	**149.0**	**151.0**	**126.9**	**(12.7)**	**(1.1)**	**413.1**
Mark-to-Market Adjustment (1)	**-**	**2.0**	**-**	**-**	**-**	**2.0**
Other Post Employment Benefits (2)	**-**	**(2.7)**	**(4.2)**	**(0.1)**	**-**	**(7.0)**
Federal Court of Appeal Decision – Mining Assets (3)	**(2.2)**	**(0.8)**	**-**	**-**	**-**	**(3.0)**
2008 Tax Assessment (4)	**(3.3)**	**-**	**-**	**-**	**-**	**(3.3)**
Adjusted Earnings	**143.5**	**149.5**	**122.7**	**(12.8)**	**(1.1)**	**401.8**
Capital expenditures	**869.4**	**75.8**	**56.2**	**9.5**	**-**	**1,010.9**
Operating expenses	**719.8**	**505.0**	**569.3**	**17.7**	**(176.3)**	**1,635.5**
2007						
Revenues	1,116.5	773.0	672.6	13.6	(170.8)	2,404.9
Earnings attributable to Class A and Class B Shares	139.7	134.7	110.0	3.1	(0.8)	386.7
Mark-to-Market Adjustment (1)	-	(2.9)	-	-	-	(2.9)
2007 Changes in the Taxation of Preferred Share Dividends (5)	(4.2)	(1.3)	(1.4)	(8.7)	-	(15.6)
2007 Changes in Income Taxes and Rates (6)	(0.3)	(12.2)	-	-	(2.4)	(14.9)
ATCO Gas Tax Reassessments (7)	(9.5)	-	-	-	-	(9.5)
Adjusted Earnings	125.7	118.3	108.6	(5.6)	(3.2)	343.8
Capital expenditures	588.9	49.2	62.7	-	-	700.8
Operating expenses	640.6	422.6	486.1	18.6	(166.3)	1,401.6

Notes:
(1) to (7) *Refer to Significant Non-Operating Financial Items section for a description of the adjustments.*

Utilities

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. These utilities are subject to a cost of service regulatory mechanism under which the AUC establishes the revenues required (i) to recover the forecast operating costs, including depreciation and amortization and income taxes, of providing the regulated service, and (ii) to provide a fair and reasonable return on utility investment, or rate base. Rate base for each utility is the aggregate of the AUC approved investment in property, plant and equipment, less accumulated depreciation, and contributions by utility customers for extensions to plant, plus an allowance for working capital. The utilities earn a return on rate base intended to meet the cost of the debt and preferred share components of rate base and to provide share owners with a fair return on the common equity component of rate base.

Utilities **revenues** in 2008 **increased** by $146.0 million (13%) from 2007. Items that contributed to increased revenues were the ATCO Electric GTA, the ATCO Gas GRA and the impact of higher franchise fees collected on behalf of cities and municipalities in ATCO Gas.

Temperatures in ATCO Gas in 2008 were 1.8% colder than normal, compared to 1.0% warmer than normal in 2007. ATCO Gas, pursuant to the AUC decision on its 2008-2009 general rate application issued on November 13, 2008, has received approval to establish deferral accounts deferring the impact of temperature fluctuations on ATCO Gas' revenues commencing January 1, 2008. The deferral account mechanism largely eliminates the impact of temperature on ATCO Gas' earnings.

Earnings for 2008 were $149.0 million, an **increase** of $9.3 million (7%) over 2007, including the impact of the adjustments identified in the Significant Non-Operating Financial Items section.

In 2008, **Adjusted Earnings** were $143.5 million, an **increase** of $17.8 million (14%) over 2007. The primary reasons for higher Adjusted Earnings were the impact of the ATCO Gas GRA net of cost increases and suspension of the Carbon natural gas storage facility rate riders (refer to Regulatory Matters – ATCO Gas – Carbon Natural Gas Storage Facility section) and the impact of the ATCO Electric GTA.

Capital expenditures to maintain capacity and meet planned growth were $869.4 million in 2008. Capital expenditures rose by $280.5 million from 2007 as a result of the rapid growth of the Alberta economy, customer growth, and safety and reliability enhancements. Capital expenditures for 2009 to 2011 are expected to be $2.0 billion and, depending on infrastructure spending, could be as much as $4.0 billion.

Regulatory Developments

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 in 2008 was 8.75% and for 2009 has been set at a placeholder rate of 8.75%. The rate of return in 2007 was 8.51%. 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.

Generic Cost of Capital

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 rescheduled for May 19, 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 filed a general rate application 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, as inclusion of these issues was removed from its 2008/2009 general rate application. The changes for 2008 and 2009 will not apply to ATCO Pipelines if its negotiated settlement for 2008 and 2009 revenue requirements is approved by the AUC. Approval of the negotiated settlement is expected in the first quarter of 2009.

Benchmarking

ATCO Electric, ATCO Gas, and ATCO Pipelines (the ATCO Utilities) 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 has established a further process for the 2003 – 2007 period with a hearing scheduled for the second quarter of 2009 to review the issues related to the application and subsequent agreement with the customer group.

For the 2008 and 2009 period, a separate regulatory process will occur to approve rates for information technology and customer care and billing services provided by ATCO I-Tek that can be included in customer rates. The 2008-2009 proceeding will commence after the completion of the 2003-2007 process. In 2009, the ATCO Utilities will continue to utilize placeholder rates for information technology and customer care and billing services until final rates are determined by the AUC.

A further regulatory process to deal with rates for information technology and customer care and billing services provided by ATCO I-Tek for 2010 and beyond has been established and the AUC is expected to set a schedule for this regulatory process in the second quarter of 2009.

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 decision discussed below). The AUC has stated that it 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. On November 28, 2008, the AUC suspended the utility asset disposition rate review proceeding until further notice to allow for various related matters currently before the courts to be addressed.

ATCO Electric

2007 and 2008 General Tariff Application

In September 2007, the AUC issued a decision on ATCO Electric's general tariff application for 2007 and 2008. The decision established, among other things, the amount of revenue to be collected in 2007 and 2008 from customers for transmission and distribution services. The AUC also approved a rate of return on common equity of 8.51% for 2007, as determined by its standardized rate of return methodology. The effect of this decision on the earnings of ATCO Electric was not material as higher revenues primarily resulting from increased capital expenditures and previously approved interim customer rates were offset by a lower approved rate of return on common equity (8.51% in 2007 versus 8.93% in 2006) and other adjustments.

The decision also directed ATCO Electric to change its income tax methodology for federal purposes. This change in tax methodology does not affect earnings as ATCO Electric's revenues and income tax expense were reduced by similar amounts. Accordingly, in 2007, ATCO Electric recorded a reduction in future income tax liabilities of $34.4 million and a liability to customers of $48.6 million, offset by a regulatory asset of $14.2 million which represents current income tax savings to be realized in future periods. Unrecorded future income tax liabilities increased by $34.4 million as a result of this decision. In December 2007, ATCO Electric refunded $16.1 million of the liability to transmission customers reducing the liability to customers to $32.5 million. In addition, the $16.1 million refund resulted in current income tax savings of $5.2 million, reducing the regulatory asset to $9.0 million. The total reduction in revenues and income taxes in 2007 was $39.6 million. ATCO Electric began refunding the remaining $32.5 million to distribution customers over a five year period commencing in 2008. ATCO Electric will realize the regulatory asset of $9.0 million over the same 5 year period with no effect on earnings as current income tax savings will be offset by this reduction in revenues.

Transmission Infrastructure Projects

In August 2006, the AUC approved the AESO application for increased transmission infrastructure in northwest Alberta. The AESO has approval to assign to the transmission facility owner, ATCO Electric, work consisting of several distinct projects that is expected to result in 725 kilometres of new transmission lines to be constructed by 2011.

To date, three of these projects have been assigned by the AESO with final approval having been received from the AUC for two projects relating to the construction of 516 kilometres of transmission line with an estimated cost of $390 million and an anticipated completion by March 31, 2010.

As a result of changing economic conditions and completion dates of the remaining distinct projects (post 2010), ATCO Electric is unable to estimate the cost of the entire project at this time.

In addition to the increased transmission infrastructure in northwestern Alberta, ATCO Electric anticipates that an additional 200 - 500 kilometres of transmission line projects will be required in its service area over the next five years.

2009 and 2010 General Tariff Application

In July 2008, ATCO Electric filed a general tariff application with the AUC for 2009 and 2010 requesting, among other things, increased revenues to recover increased financing, depreciation and operating costs associated with increased rate base in Alberta. ATCO Electric filed an application requesting interim refundable rates pending the AUC's decision on the application. In December 2008, ATCO Electric received a decision from the AUC approving interim refundable rate increases amounting to 50% of the requested increase for transmission operations and 25% of the requested increase for distribution operations. A hearing is scheduled for February 2009, with a decision expected by the third quarter in 2009.

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 court decided to postpone addressing the appeal, allowing the AUC time to address the Alberta Court of Appeal decision related to the removal of the Carbon assets from regulation.

In October 2006, ATCO Gas filed a review and variance application with the AUC for the ATCO Gas 2005, 2006 and 2007 general rate application decision. The application alleges that the AUC made errors in the decision related to the approved level of administrative expense. In December 2006, the AUC issued a decision which acknowledged an error for a portion of the administrative expense in question. On April 18, 2007, the AUC agreed to review its original decision. On November 27, 2007, a decision on this matter was received granting ATCO Gas $4.7 million in costs to be collected during the first two quarters of 2008, with a total increase to ATCO Gas' 2007 earnings of $3.2 million.

2008 and 2009 General Rate Application

In November 2007, ATCO Gas filed a general rate application with the AUC for 2008 and 2009 requesting, among other things, increased revenues to recover increased financing, depreciation and operating costs associated with increased rate base in Alberta. ATCO Gas also filed an application requesting interim adjustable rates pending the AUC's decision on the general rate application. In December 2007, ATCO Gas received a decision from the AUC approving interim adjustable rate increases amounting to 50% of ATCO Gas' requested revenue increase. On November 13, 2008, the AUC issued a decision on ATCO Gas' 2008 and 2009 general rate application. The effect of the decision on ATCO Gas' 2008 earnings was not materially different from the impact of the interim rates approved in December 2007. In the decision, the AUC used placeholders for common equity capitalization ratios, 2009 information and technology and customer care and billing costs and income tax amounts. The final amounts for these placeholders will be determined by the AUC in subsequent proceedings. The decision also approved the establishment of deferral accounts to defer the impact of temperature fluctuations on ATCO Gas' revenues after January 1, 2008 (refer to Business Risks – Temperatures section).

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 November 3, 2008, the AUC denied the City of Calgary's request that it review and vary its decision that the facility is no longer required for utility service with respect to the use of the facility for load balancing purposes.

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 facility 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. On December 4, 2008, the Supreme Court of Canada dismissed the City of Calgary's application for leave to appeal, thus upholding the Alberta Court of Appeal's May 27, 2008 decision.

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 $6.3 million and earnings of $4.4 million in 2008 for the period July 1, 2008, to December 31, 2008. Due to certain factors, revenues and earnings from this matter for this period are not necessarily indicative of revenues or earnings on an annual basis.

On July 11, 2008, ATCO Gas 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. Certain aspects of the application were updated on January 15, 2009. This application, in addition to the amounts recognized above, is seeking to recover from customers an additional $30.3 million, excluding interest, related to those amounts refunded to customers over the April 1, 2005, to June 30, 2008, period. This additional $30.3 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 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. ATCO Gas has withdrawn its October 15, 2008, application to the Alberta Court of Appeal as a result of the AUC recommencing the Carbon proceeding. A pre-hearing conference occurred on December 16, 2008, and on January 9, 2009, the AUC issued a decision establishing a final issues list to remove the Carbon facility from rate base. The AUC has set a proceeding schedule with a hearing currently scheduled to commence on March 16, 2009. 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).

As part of the 2008-2009 general rate application, in a compliance application submitted to the AUC on January 19, 2009, ATCO Gas reduced its rate increase applicable to its south customers by $7.6 million related to the production and storage charge that was included in ATCO Gas' rates from January through June 2008 as a result of excluding any costs for the Carbon facility in its general rate application. The impact of this $7.6 million reduction to revenues will be a $5.3 million decrease to ATCO Gas' earnings when a decision on the 2008-2009 general rate application compliance filing is ultimately received.

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 and 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 for this leave to appeal occurred on December 16, 2008 and a decision is expected in the first quarter of 2009.

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 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. In November 2008, the AUC approved ATCO Pipelines application for revised rates effective December 1, 2008, to collect 60% of ATCO Pipelines requested revenue increase.

In November 2008, ATCO Pipelines filed an application requesting the AUC approve a negotiated settlement with its customers of ATCO Pipelines' 2008 and 2009 revenue requirements. A decision on the application is expected in the first quarter of 2009.

Competitive Proceedings

During 2007, the AUC reinstituted its review of the competitive natural gas pipeline issues under its jurisdiction. This review will address competitive issues between ATCO Pipelines and NOVA Gas Transmission Ltd. (NOVA). This review process is currently suspended to allow ATCO Pipelines and NOVA time to progress their proposed agreement (see below) and to submit the required applications.

Recent Developments

On September 8, 2008, ATCO Pipelines and NOVA announced a proposed agreement to provide natural gas transmission service to their customers. The proposal will allow ATCO Pipelines and NOVA 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 2008 **revenues increased** by $116.6 million (15%) over 2007, primarily as a result of higher natural gas fuel purchases recovered on a "no-margin" basis, improved operations and the recognition of insurance proceeds from the Barking outage in ATCO Power's U.K. operations and improved merchant performance in ATCO Power's Alberta generating plants. These increases were partially offset by the impact of lower exchange rates on conversion of revenues to Canadian dollars in ATCO Power's U.K. operations.

Earnings for 2008 were $151.0 million, an **increase** of $16.3 million (12%) over 2007 including the impact of the adjustments identified in the Significant Non-Operating Financial Items section.

Adjusted Earnings were $149.5 million, an **increase** of $31.2 million (26%) over 2007. The primary reasons for the higher Adjusted Earnings were increased availability and the recognition of insurance proceeds from the Barking outage in ATCO Power's U.K. operations and improved merchant performance in ATCO Power's Alberta generating plants. These increases were partially offset by lower exchange rates on conversion of U.K. earnings to Canadian dollars.

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

	For the Year Ended December 31		
	2008	2007	Change to 2008 (2008-2007)
ATCO Power [(1)]:			
Canada	**94.9%**	96.3%	(1.4%)
U.K.[(2)]	**87.8%**	83.2%	4.6%
Australia	**98.7%**	94.6%	4.1%
Alberta Power (2000) [(1)]:			
Canada	**91.8%**	90.2%	1.6%

Notes:

(1) *Generating plant availability will fluctuate due to the timing and duration of outages.*

(2) *The higher availability for 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 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.

TXU Europe Settlement

On November 19, 2002, an administration order was issued by an English Court against TXU Europe Energy Trading Limited (TXU Europe) which had a long term "off take" agreement for 27.5% of the power produced by the 1,000 megawatt Barking generating plant in London, England, in which the Company, through Barking Power, has a 25.5% equity interest. Barking Power had filed a claim for damages for breach of contract related to TXU Europe's obligations to purchase 27.5% of the power produced by the Barking generating plant. Following negotiations with the administrators, an agreement was reached with respect to Barking Power's claim.

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

The Company's share of this settlement is being recognized in earnings in equal monthly amounts over the remaining term of the TXU Europe contract to September 30, 2010. Based on the foreign currency exchange rate in effect at December 31, 2008, earnings after income taxes $9.0 million per year have yet to be recognized. These earnings will be dependent upon foreign currency exchange rates in effect at the time that the earnings are recognized.

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. 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 disagreed 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 a 45 MW natural 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 sold to the Alberta Power Pool. ATCO Power owns an 80% interest in the plant and ATCO Resources owns 20%.

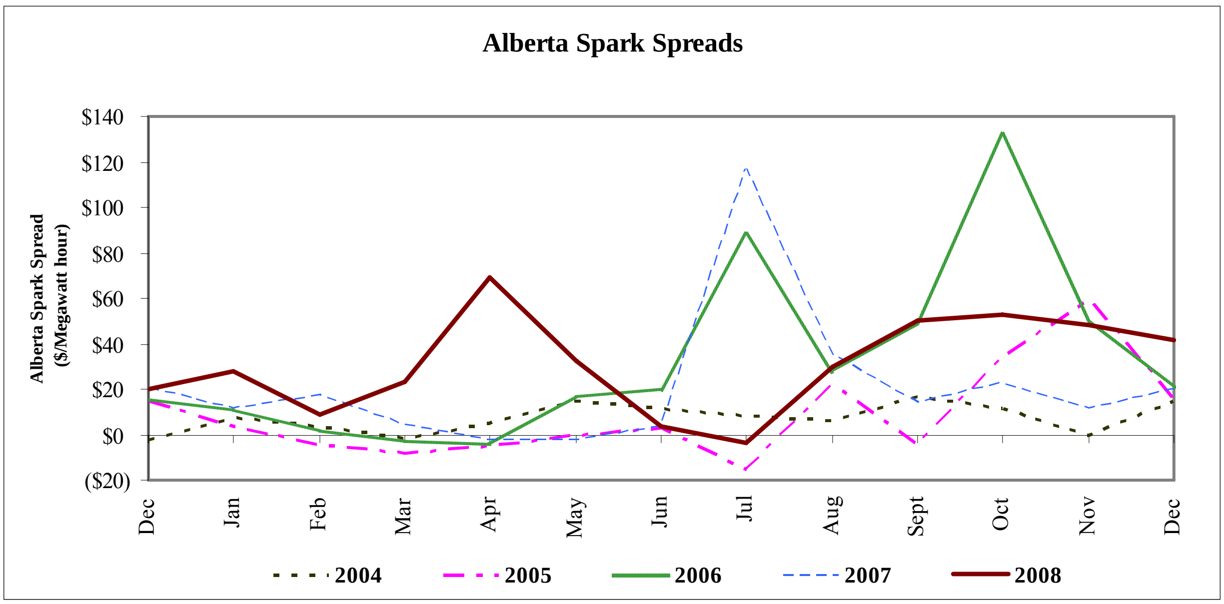
On November 24, 2008, ATCO Power announced it will design, build, own and operate a two unit 86 MW natural gas-fired simple cycle generating plant in Karratha, Western Australia (the Karratha generating plant). All of the electricity generated will be sold under a 20-year power purchase agreement with Horizon Power, a company owned by the State of Western Australia. The first unit is expected to be completed in the first quarter of 2010. ATCO Power owns a 100% interest in the plant.

On January 28, 2009, ATCO Power entered into an Australian $100 million credit facility with the Commonwealth Bank of Australia. The facility term is for construction plus five years. The interest rate during construction will be 5.71% and the rate during operation will be 6.16%. The funds will be used to finance the design and construction of the Karratha generating plant.

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 $89.95 per MWh in 2008, compared to average prices of $66.95 per MWh in 2007. Natural gas prices averaged $7.73 per GJ, compared to average prices of $6.10 per GJ in 2007. These electricity and natural gas prices resulted in an average spark spread of $32.00 per MWh in 2008, compared to $21.22 per MWh in 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 December 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)

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

Over 99% of the electricity generated by Alberta Power (2000) is sold pursuant to PPAs. Under the PPAs, Alberta Power (2000) is required to make the generating capacity for each generating unit available to the purchaser of the PPA for that unit. In return, Alberta Power (2000) is entitled to recover its forecast fixed and variable costs for that unit from the PPA purchaser, including a rate of return on common equity equal to the long term Government of Canada bond rate plus 4.5% based on a deemed common equity ratio of 45%. Many of the forecast costs will be determined by indices, formulae or other means for the entire period of the PPA. Alberta Power (2000)'s actual results will vary and depend on performance compared to the forecasts on which the PPAs were based. The return on common equity rate used in its PPA tariff calculations for Alberta Power (2000) was 8.88% in 2008 and 8.65% for 2007. The rate of return on common equity for 2009 is 8.64%.

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.

Accumulated incentives in excess of accumulated penalties are deferred. For any of the individual PPAs, should accumulated incentives plus estimated future incentives exceed accumulated penalties plus estimated future penalties, the excess will be amortized to revenues on a straight-line basis over the remaining term of the PPAs. Should accumulated penalties plus estimated future penalties exceed accumulated incentives plus estimated future incentives, the shortfall will be expensed in the year the shortfall occurs.

During 2008, the deferred availability incentive account increased by $19.5 million to $61.3 million at December 31, 2008, due to additional availability incentives received for plant availability in excess of amortization and planned outages. During 2008, the amortization of deferred availability incentives, recorded in revenues, increased by $0.8 million to $12.6 million.

H.R. Milner Generating Plant

In 2001, Alberta Power (2000) and the Balancing Pool entered into an agreement which gave the Balancing Pool control of the 150 megawatt, coal-fired H.R. Milner generating plant effective January 1, 2001 and the right to sell it until September 30, 2003, failing which the rights to control the generating plant would revert to Alberta Power (2000). In return, Alberta Power (2000) was paid $63.5 million, the net book value of the generating plant and coal inventory. Alberta Power (2000) operated the generating plant under a cost of service contract with the Balancing Pool. On August 6, 2003, the Balancing Pool announced that it had entered into an agreement for the sale of plant. Alberta Power (2000) extended its cost of service contract until January 29, 2004, when the plant was sold by the Balancing Pool to a third party.

In 2006, the CRA issued a reassessment for Alberta Power (2000)'s 2001 taxation year which treated the proceeds received from the sale of the H.R. Milner generating plant to the Balancing Pool as income rather than as a sale of an asset. The impact of the reassessment was a $12.4 million increase in interest and income tax expense, a $12.4 million decrease in earnings and a $28.8 million payment associated with the tax and interest assessed. The Company disagreed with the CRA's position and appealed the reassessment to the Tax Court of Canada. Due to the uncertainty as to whether the reassessment would ultimately be resolved in the Company's favour, the Company made the $28.8 million payment and reduced earnings by $12.4 million in 2006. The Tax Court of Canada is scheduled to hear the Company's appeal in March 2009. The Company is unable to predict the outcome at this time.

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).

In the fourth quarter of 2008, the Company recognized $3.0 million in earnings from carbon offsets generated by ATCO Power's Oldman River hydro generating plant during the period from July 1, 2003, to December 31, 2008. The offsets were determined in accordance with the government of Alberta's protocol for hydro generating plants.

Global Enterprises

Global Enterprises **revenues increased** by $118.1 million (18%) from 2007. Items that increased revenues include increased business activity in ATCO Frontec's operations and higher volumes of natural gas purchased for others 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 for 2008 were $126.9 million, an **increase** of $16.9 million (15%) over 2007, including the impact of the adjustments identified in the Significant Non-Operating Financial Items section.

In 2008, **Adjusted Earnings** were $122.7 million, an **increase** of $14.1 million (13%) over 2007. The primary reasons for the higher Adjusted Earnings were 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.

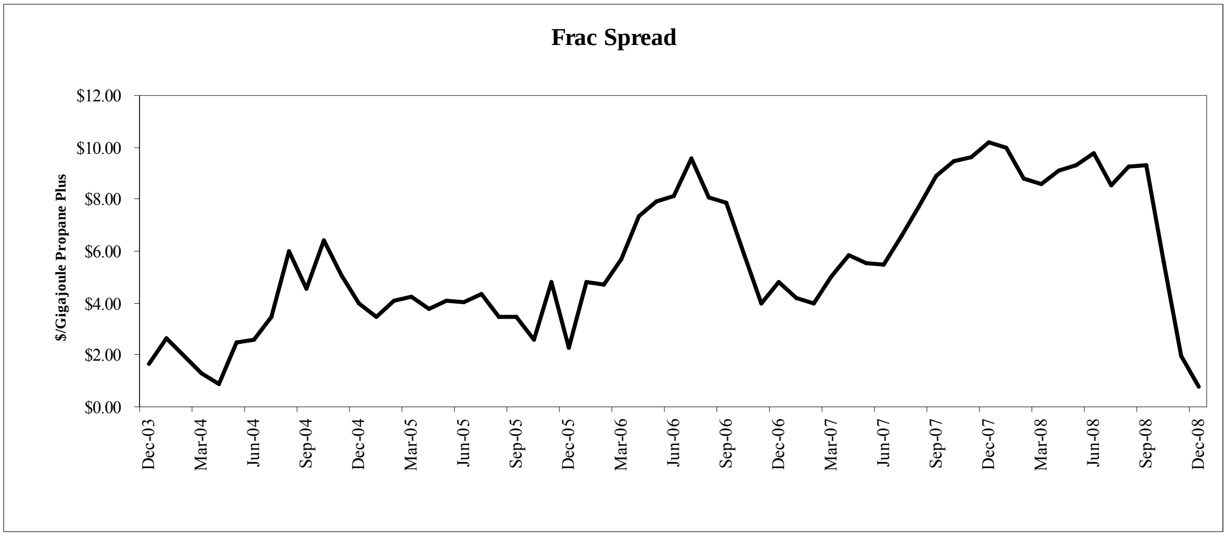
ATCO Midstream

ATCO Midstream provides non-regulated natural gas gathering and processing, NGL extraction, and natural gas storage services to natural gas producers.

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 December 2008.



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

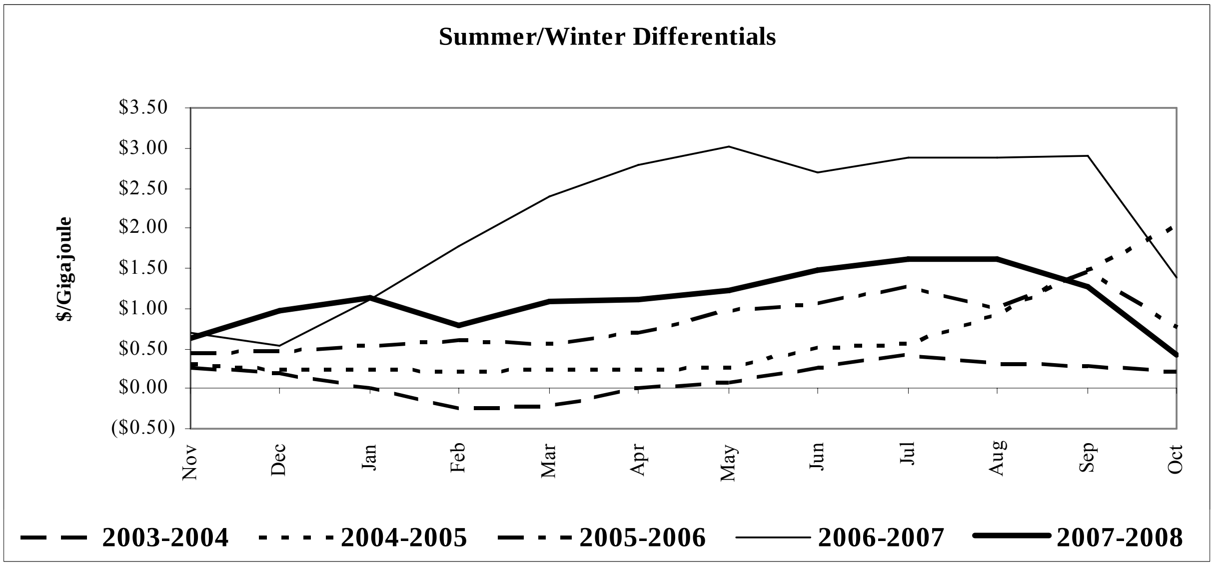
Lower prices for natural gas liquids were the primary cause of the decreased frac spread in the fourth quarter of 2008. Natural gas liquids prices are impacted by oil prices and the significant decrease in oil prices was the primary cause for lower NGL prices.

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.

Recent Developments

On Nov. 17, 2008, ATCO Midstream announced the purchase of IPL Holdings Inc. (IPLH). IPLH, Inuvialuit Petroleum Corporation and AltaGas Utility Group Inc. are partners in the Ikhil joint venture and each owns a one-third interest in Inuvik Gas Ltd. The Ikhil joint venture owns and operates two producing natural gas wells and gas gathering and processing facilities in the Mackenzie delta region of the Northwest Territories and a 50 kilometre pipeline connecting the facilities to the town of Inuvik. Inuvik Gas Ltd., the sole distributor of natural gas in Inuvik, serves more than 850 customers.

ATCO Frontec

ATCO Frontec, through its own operations and through a number of joint ventures, provides project management and technical services for customers in the resource, defence and telecommunications sectors.

Activities include:

- the operation and maintenance of the North Warning System, Alaska Radar System and various remote sites for Northwestel Inc. in northern Canada;
- accommodations for oil sands workers at the Creeburn Lake and Barge Landing Lodges north of Fort McMurray, Alberta;
- construction and support services for NATO, United Nations and the Swedish Armed Forces in Afghanistan and eastern Europe;
- airport operation and maintenance in Canada and Afghanistan;
- operation and maintenance of a bulk fuel storage and distribution facility in Iqaluit, Nunavut; and
- a wide variety of services and business activities in numerous locations across Canada.

A number of the Canadian operations are conducted with aboriginal partners.

The following is a summary of the principal contracts which provide significant contributions to ATCO Frontec's earnings:

Contract	Customer	Start Date	Completion Date	Possible Extension [1]
Alaska Radar System [2]	U.S. Department of Defense	Oct. 2004	Sep. 2009	2014
North Warning System [2]	Department of National Defense	Sep. 2001	Sep. 2011	-
Iqaluit Fuel Contract [2]	Government of Nunavut	Jun. 2007	Nov. 2012	2017
Stabilization Force Organization	NATO	Feb. 2004	Dec. 2009	-
Kabul International Airport	NATO	Feb. 2005	Aug. 2009	Dec. 2009
NATO Flight Training	NATO	Jun. 2000	May 2020	-
Kandahar Projects	NATO	Sep. 2007	Sep. 2010	2012
Creeburn Lake Lodge [2]		April 2008	-	-
Barge Landing Lodge [2]	Suncor Energy Inc.	July 2008	Jun. 2009	-
	Albian Sands Energy Inc.	Oct. 2008	Mar. 2010	Mar. 2011

Notes:
(1) *The contract may be extended at the option of the customer.*
(2) *Joint venture with aboriginal partners.*

Recent Developments

On April 14, 2008, ATCO Frontec announced that the first phase of the 500-room Creeburn Lake Lodge north of Fort McMurray, Alberta had commenced operations. The Creeburn Lake Lodge accepts clients on a nightly, weekly or monthly basis. Due to recent declines in world oil prices and the cancellation and delay of a number of oil sands projects in Alberta, ATCO Frontec has decided not to proceed with the expansion of the Creeburn Lake Lodge at this time.

On April 28, 2008, ATCO Frontec and its partner, the Fort McKay First Nation, announced that they had been selected by Suncor Energy Inc. (Suncor) to create and operate the Barge Landing Lodge, a 1,148-room accommodation complex to support oil sands development north of Fort McMurray. ATCO Structures supplied the rooms in modular units. Operations commenced in July 2008. On August 18, 2008, a 603-room expansion was announced under the existing joint venture with the Fort McKay First Nation for Albian Sands Energy Inc. (Albian). Operations for the expansion commenced in October 2008. The Albian contract will expire in March 2010 unless extended for an additional 12 months at the option of Albian, and the Suncor contract will expire in June 2009.

ATCO I-Tek

ATCO I-Tek is engaged in the development, operation and support of information systems and technologies.

ATCO I-Tek provides billing services, payment processing, credit, collection and call centre services to its clients. ATCO I-Tek currently provides such services to Direct Energy for its regulated retail and competitive energy supply businesses in Alberta. In addition, ATCO I-Tek also supplies distribution-related billing and customer care services to ATCO Gas and ATCO Electric. In 2008, ATCO I-Tek's call centre was named the top customer service provider in the North American energy sector by Service Quality Measurement Group Inc. for the third year in a row.

Direct Energy has entered into a 10 year contract effective May 4, 2004, with ATCO I-Tek to provide billing and call centre services to ensure continued quality customer service. Direct Energy has the ability to terminate this contract after the fifth anniversary upon immediate payment of termination fees which decline over the remaining term of the contract. Based upon current customer counts and service levels and a 10 year contract, revenues are estimated to be between $400-$500 million over the term of the contract.

Corporate and Other

Earnings for 2008 were $(12.7) million, a **decrease** of $15.8 million (510%) over 2007, including the impact of the adjustments identified in the Significant Non-Operating Financial Items section.

In 2008, **Adjusted Earnings** were $(12.8) million, a **decrease** of $7.2 million (129%) over 2007. The primary reasons for the lower Adjusted Earnings in 2008 were lower rates of interest earned on lower cash balances.

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

($ millions)	For the Year Ended December 31		
	2008	2007	Change to 2008 (2008-2007)
Cash position, beginning of period	**747.2**	798.8	(6%)
Cash provided by (used in)			
Operating activities	**791.8**	706.9	12%
Investing activities	**(813.1)**	(642.1)	27%
Financing activities	**12.0**	(98.8)	112%
Foreign currency impact on cash balances	**(11.3)**	(17.6)	36%
Cash position, end of period	**726.6**	747.2	(3%)

OPERATING ACTIVITIES

Cash flow from operations increased by 12% in 2008, primarily due to increases in funds generated by operations, partially offset by changes in non-cash working capital. **Funds generated by operations increased** by 11% in 2008, primarily due to higher cash earnings and increased deferred availability incentives in Alberta Power (2000).

INVESTING ACTIVITIES

In 2008, **cash used in investing activities increased** 27%, primarily due to higher capital expenditures in 2008, partially offset by higher contributions by utility customers for extensions to plant, changes in non-cash working capital and non-current deferred electricity costs. **Capital expenditures increased** by $310.1 million, primarily due to increased investment in regulated electric and natural gas distribution and transmission projects.

Capital Expenditures	**For the Year Ended December 31**		
($ millions)	**2008**	2007	Change to 2008 (2008-2007)
Utilities	**869.4**	588.9	48%
Power Generation	**75.8**	49.2	54%
Global Enterprises	**56.2**	62.7	(10%)
Corporate and Other	**9.5**	-	-
	1,010.9	700.8	44%

Capital expenditures to maintain capacity, meet planned growth, and fund future development activities are expected to be approximately $1.1 billion in 2009, an increase of 9% from 2008. The majority of these expenditures relate to the Utilities segment. For the 2009 to 2011 period, capital expenditures in the Utilities segment are expected to be $2.0 billion and, depending on infrastructure spending, could be as much as $4.0 billion over the next three years.

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 provide these services for required capital projects in the extremely tight labour market for such services available in Alberta. Individual projects assigned pursuant to this agreement will be jointly estimated and a target project cost agreed to before construction commences. The agreement provides ATCO Electric full discretion to assign or remove projects on an individual basis. Projects will be undertaken with a full disclosure to the AUC of actual costs, with any savings or overruns relative to target project costs shared equally.

FINANCING ACTIVITIES

In 2008, the Company had **net debt increases** of $173.5 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 $45.7 million of other long term debt. **Redemptions** were comprised of $100.0 million of 6.97% Debentures which matured in June 2008, $12.0 million of other long term debt and $85.2 million of non-recourse long term debt.

In 2008, the Company had **no issues or redemptions** of equity preferred shares, 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.

In 2008, there were **no purchases** of Class A Shares under its normal course issuer bids, a decrease of $8.0 million from 2007. In 2008, **issues** of Class A Shares due to stock option exercises were $5.0 million, an increase of $3.4 million over 2007. In 2008, **net issues** were $5.0 million, an increase of $11.4 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 were 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. No shares have been purchased from May 23, 2008 to February 13, 2009.

Total **dividends paid to Class A and Class B share owners increased** by 6% to $166.8 million over 2007. At their meeting in the first quarter of 2008, the Board of Directors increased the quarterly dividend 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. At their meeting in the first quarter of 2009, the Board of Directors increased the quarterly dividend by $0.02 to $0.3525. 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 impacted the Company's cash position by $(11.3) million 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 December 31, 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	326.0	48.2	277.8
Short term committed	600.0	54.1	545.9
Uncommitted	99.1	28.1	71.0
Total	1,025.1	130.4	894.7

The Company's long term committed lines of credit include:

- A $200 million unsecured revolving extendible term credit facility of Canadian Utilities established in 1999 with a syndicate of Canadian chartered banks. This facility will expire in June 2013, unless extended at the option of the lenders; and
- A $100 million unsecured revolving extendible term credit facility of ATCO Midstream established in 1999 with a syndicate of Canadian chartered banks and financial institutions. The facility will expire in August 2013, unless extended at the option of the lenders.

The Company's short term committed lines of credit consist of:

- A $300 million unsecured revolving extendible credit facility of CU Inc. established in 1999 with a syndicate of Canadian chartered banks. This facility is used as a backstop for CU Inc.'s commercial paper program and for occasional issues of letters of credit. The facility will expire in June 2009, unless extended at the option of the lenders; and
- A $300 million unsecured revolving extendible credit facility of Canadian Utilities established in 1999 with a syndicate of Canadian chartered banks. This facility is used as a backstop for Canadian Utilities' commercial paper program. This facility will expire in June 2009, unless extended at the option of the lenders.

The Company's uncommitted lines of credit are primarily used by its subsidiaries for liquidity purposes and for issues of letters of credit. Most of these facilities are unsecured, but some are secured by charges over assets of particular subsidiaries.

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

CONTRACTUAL OBLIGATIONS

Contractual obligations for the next five years and thereafter are as follows:

	Payments Due by Period				
	Total	**Less than 1 Year**	**1-3 Years**	**4-5 Years**	**After 5 Years**
($ millions)					
Long term debt	2,877.0	142.7	247.3	182.0	2,305.0
Non-recourse long term debt	462.4	44.8	91.4	82.2	244.0
Interest expense [(1)]	2,852.3	220.9	385.3	340.7	1,905.4
Operating leases	132.5	21.6	37.2	24.3	49.4
Purchase obligations:					
ATCO Gas natural gas purchase contracts [(2)]	2.0	0.4	0.8	0.8	-
Alberta Power (2000) coal purchase contracts [(3)]	606.9	50.2	104.0	144.0	308.7
ATCO Power natural gas fuel supply contracts [(4)]	99.6	46.3	47.9	5.4	-
Alberta Power (2000), ATCO Power operating and maintenance agreements [(5)]	136.0	18.2	35.8	33.1	48.9
Capital Expenditures [(6)]	137.8	133.5	4.3	-	-
Derivatives[(7)]	22.7	5.1	7.8	4.3	5.5
Other	2.9	0.9	1.2	0.6	0.2
Total	7,332.1	684.6	963.0	817.4	4,867.1

Notes:

(1) *Interest payments on floating rate debt that has not been hedged have been estimated using rates in effect at December 31, 2008. Interest payments on debt that has been hedged have been estimated using the hedged rates.*

(2) *ATCO Gas has ongoing obligations to purchase fixed quantities of natural gas from various gas producers at market prices that are in effect at the time the quantities are purchased. These obligations relate primarily to operational contracts pertaining to the Carbon natural gas storage facility, which continues to be subject to AUC regulation. Some of these obligations are for the life of the gas reserves. The estimated value of these purchase obligations is based on the market price of natural gas in effect on December 31, 2008, and assumes a remaining life of 10 years for the gas reserves commencing January 1, 2004. Direct Energy has agreed to purchase the natural gas purchased under these contracts at the prices paid by ATCO Gas.*

(3) *Alberta Power (2000) has fixed price long term contracts to purchase coal for its coal-fired generating plants. These costs are recoverable pursuant to the PPAs.*

(4) *ATCO Power has various contracts to purchase natural gas for certain of its natural gas-fired generating plants. ATCO Power has long term offtake agreements with the purchasers of the electricity to recover 78% of these costs. The balance of 22%, related to ATCO Power's Barking generating plant, is recovered through merchant sales in the U.K. electricity market. The ATCO Power merchant component of its generating plants in Alberta do not have any long term contracts to purchase natural gas.*

(5) *Alberta Power (2000) and ATCO Power have various contracts with suppliers to provide operating and maintenance services at certain of their generating plants.*

(6) *Various contracts to purchase goods and services with respect to capital expenditure programs.*

(7) *Payments on outstanding derivatives have been estimated using rates in effect at December 31, 2008.*

NET CURRENT AND LONG TERM FUTURE INCOME TAXES

Net current and long term future income taxes of $158.6 million at December 31, 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 December 31, 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 February 13, 2009, the Company had outstanding 83,757,894 Class A Shares, 41,756,926 Class B Shares and options to purchase 1,233,550 Class A Shares.

CLASS A NON-VOTING SHARES AND CLASS B COMMON SHARES

The owners of the Class A shares and the Class B shares are entitled to share equally, on a share for share basis, in all dividends declared by the Company on either of such classes of shares as well as the remaining property of the Company upon dissolution. The owners of the Class B shares are entitled to vote and to exchange at any time each share held for one Class A share.

If a take-over bid is made for the Class B shares which would result in the offeror owning more than 50% of the outstanding Class B shares and which would constitute a change in control of the Company, owners of Class A shares are entitled, for the duration of the bid, to exchange their Class A shares for Class B shares and to tender such Class B shares pursuant to the terms of the take-over bid. Such right of exchange is conditional upon the completion of the take-over bid giving rise to the right of exchange, and if the take-over bid is not completed, then the right of exchange shall be deemed never to have existed. In addition, owners of the Class A shares are entitled to exchange their shares for Class B shares of the Company if ATCO Ltd., the present controlling share owner of the Company, ceases to own or control, directly or indirectly, more than 10,000,000 of the issued and outstanding Class B shares of the Company. In either case, each Class A share is exchangeable for one Class B share, subject to changes in the exchange ratio for certain events such as a stock split or rights offering.

Of the 6,400,000 Class A non-voting shares authorized for grant in respect of options under Canadian Utilities Limited's stock option plan, 2,972,700 Class A non-voting shares are available for issuance at December 31, 2008. Options may be granted to directors, officers and key employees of Canadian Utilities Limited and its subsidiaries at an exercise price equal to the weighted average of the trading price of the shares on the Toronto Stock Exchange for the five trading days immediately preceding the date of grant. The vesting provisions and exercise period (which cannot exceed 10 years) are determined at the time of grant. As of February 13, 2009, options to purchase 1,233,550 Class A shares were outstanding.

Business Risks

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. As discussed elsewhere in this MD&A, the Utilities Business Group has a capital program of $2.0 billion and, depending on infrastructure spending, could be as much as $4.0 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. On January 28, 2009, ATCO Power entered into an Australian $100 million credit facility with the Commonwealth Bank of Australia to finance the design and construction of the Karratha generating plant located in Western Australia. In addition, the Company has cash balances of approximately $0.7 billion and available committed and uncommitted lines of credit of approximately $0.9 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 equity capital. The Company is unable to determine what future changes in the financial markets could occur and how these changes could affect the Company. In addition, the deterioration in the domestic and international economic activity may impact the operations of the Company.

COMMODITY PRICES

Commodity prices, particularly oil and natural gas prices, have fallen significantly since September 2008. These lower prices have had an impact on the Company's operations, particularly the lower frac spreads on ATCO Midstream's NGL business. The Company is unable to determine what future changes in commodity markets could occur and how these changes could affect the Company.

PENSION PLANS

Recent declines in stock and bond markets have resulted in a reduction in the value of the Company's defined benefit pension plans, creating a pension plan deficit that may require the Company to make contributions to the pension plans commencing in 2009.

Employees are required to contribute a percentage of their salary to the registered defined benefit pension plans. The Company is required to provide the balance of the funding, based on triennial actuarial valuations, necessary to ensure that benefits will be fully provided for at retirement. Based on the most recent actuarial valuation for funding purposes as of December 31, 2006 the Company is continuing a contribution holiday that began on April 1, 1996 for all but one of the registered pension plans; commencing in 2007, the Company is required to make annual contributions of approximately $0.7 million to cover the unfunded liability of that plan. The next actuarial valuation for funding purposes is required as of December 31, 2009. The government of Alberta has issued a white paper which, if it becomes law, would require an actuarial valuation to be filed as at December 31, 2008, for those plans that wish to continue their contribution holidays in 2009. Depending on the outcome of the full actuarial valuation, current service contributions may be required to resume in 2009.

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 draft 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 intends to implement fixed emission caps in the 2020 to 2025 time period. A draft regulation has yet to be released.

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 target a capture of 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.

In November 2008, the federal government signaled its intention to pursue a North America wide emissions trading program. The government has not released details of this proposed emissions trading system and it has remained non-committal as to whether it will continue with the implementation of the legislation. ATCO Power continues to monitor these developments and the impact of complying with the federal regulations.

REGULATED OPERATIONS

Regulated operations are conducted by Canadian Utilities' wholly owned subsidiary CU Inc., which in turn has the following subsidiaries: ATCO Electric and its subsidiaries, ATCO Gas, ATCO Pipelines, and CU Water. Alberta Power (2000)'s two largest generating plants are also considered regulated operations because they are governed by legislatively mandated PPAs, approved by the AUC.

ATCO Electric, ATCO Gas, ATCO Pipelines and CU Water 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 by the AUC, of costs incurred. The Company's ability to recover the actual costs of providing service and to earn the approved rates of return depends on achieving the forecasts established in the rate-setting process.

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

ATCO Gas, pursuant to the AUC decision on its 2008-2009 general rate application issued on November 13, 2008, has received approval to establish deferral accounts deferring the impact of temperature fluctuations on ATCO Gas' revenues commencing January 1, 2008. The deferral account mechanism largely eliminates the impact of temperature on ATCO Gas' earnings.

Benchmarking

ATCO Electric, ATCO Gas, and ATCO Pipelines (the ATCO Utilities) 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 has established a further process for the 2003 – 2007 period with a hearing scheduled for the second quarter of 2009 to review the issues related to the application and subsequent agreement with the customer group.

For the 2008 and 2009 period, a separate regulatory process will occur to approve rates for information technology and customer care and billing services provided by ATCO I-Tek that can be included in customer rates. The 2008-2009 proceeding will commence after the completion of the 2003-2007 process.

In 2009, the ATCO Utilities will continue to utilize placeholder rates for information technology and customer care and billing services until final rates are determined by the AUC.

A further regulatory process to deal with rates for information technology and customer care and billing services provided by ATCO I-Tek for 2010 and beyond has been established and the AUC is expected to set a schedule for this regulatory process in the second quarter of 2009.

Transfer of the Retail Energy Supply Businesses

On May 4, 2004, ATCO Gas and ATCO Electric transferred their retail energy supply businesses to Direct Energy and one of its affiliates (collectively Direct Energy), a subsidiary of Centrica plc. ATCO Gas and ATCO Electric continue to own and operate the natural gas and electricity distribution systems used to deliver energy.

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

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

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

Late Payment Penalties on Utility Bills

As a result of decisions of the Supreme Court of Canada in Garland vs. Consumers' Gas Co., the imposition of late payment penalties on utility bills has been called into question. ATCO is unable to determine at this time the impact, if any, that these decisions will have on the Company.

Measurement Inaccuracies in Metering Facilities

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

Alberta Power (2000)

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

Over 99% of the electricity generated by Alberta Power (2000) is sold pursuant to PPAs. Under the PPAs, Alberta Power (2000) is required to make the generating capacity for each generating unit available to the purchaser of the PPA for that unit. In return, Alberta Power (2000) is entitled to recover its forecast fixed and variable costs for that unit from the PPA purchaser, including a return on common equity equal to the long term Government of Canada bond rate plus 4.5% based on a deemed common equity ratio of 45%. Many of the forecast costs will be determined by indices, formulae or other means for the entire period of the PPA. Alberta Power (2000)'s actual results will vary and depend on performance compared to the forecasts on which the PPAs were based.

Fuel costs in Alberta Power (2000) are mostly for coal supply. To protect against volatility in coal prices, Alberta Power (2000) owns or has sufficient coal supplies under long term contracts for the anticipated lives of its Battle River and Sheerness coal-fired generating plants. These contracts are at prices that are either fixed or indexed to inflation.

NON-REGULATED OPERATIONS

ATCO Power

The Company's portfolio of non-regulated electric generating plants is made up of gas-fired cogeneration, gas-fired combined cycle, gas-fired simple cycle, and small hydro plants. The majority of operating income from power generation operations is derived through long term power, steam and transmission support agreements. Where long term agreements are in place, the purchaser assumes the fuel supply and price risks and the Company, under these agreements, assumes the operating risks.

ATCO Power's generating plants include high efficiency gas-fired cogeneration plants, with associated on-site steam and power tolling arrangements, and gas-fired peaking and hydroelectric plants with underlying transmission support agreements. In 2008, sales from approximately 70% of ATCO Power's generating capacity were subject to long term agreements, while the remaining 30% consisted primarily of sales to the Alberta Power Pool and the U.K. merchant power market. In 2009, these percentages are expected to be approximately the same. These sales are dependent on prices in the Alberta electricity spot market and in the U.K. merchant power market. The majority of the electricity sales to the Alberta Power Pool are from gas-fired generating plants, and as a result operating income is affected by natural gas prices. During peak electricity usage hours in Alberta, a good correlation exists between electricity spot prices and natural gas spot prices. During off-peak hours, there is less correlation. The correlation is expected to increase in the future as customer load grows and older plants are decommissioned.

Changes and volatility in Alberta Power Pool electricity prices, natural gas prices and related spark spreads may have a significant impact on the Company's earnings and cash flow from operations in the future. The Company has adopted asset optimization strategies for bidding its merchant power into the Alberta and U.K. power markets.

Since October 2004, 27.5% of the power generated at ATCO Power's Barking generating plant has been sold into the U.K. power exchange market. A substantial proportion of the UK electricity market is comprised of vertically integrated companies whose operations include both generation and supply. Market participants trade primarily through structured bilateral contracts and wholesale markets, with smaller volumes traded on a power exchange. Approximately 40% of the electricity generated is supplied from natural gas-fired generating plants. The Barking generating plant has a fixed price gas purchase agreement which expires in September 2010 and, as a result, has been able to experience strong margins due to the high market prices for electricity. Changes in the U.K. market electricity prices may have an impact on the Company's earnings and cash flow from operations in the future.

ATCO Power has financed the majority of its non-regulated electrical generating capacity on a non-recourse basis. In these projects, the lender's recourse in the event of default is limited to the business and assets of the project in question, which includes the Company's equity therein. Canadian Utilities has provided a number of guarantees related to ATCO Power's and ATCO Resources' obligations under their respective non-recourse loans associated with certain of their projects. ATCO Power (80%) and ATCO Resources (20%) have a joint venture in these projects subject to guarantees, excluding Barking Power. ATCO Ltd. has indemnified and agreed to reimburse Canadian Utilities for any amounts it may be required to pay under these guarantees in respect of ATCO Resources' 20% interest. The guarantees outstanding at December 31, 2008, are described in Note 11 to the consolidated financial statements. To date, Canadian Utilities has not been required to make any payments related to its guaranteed obligations.

The Company's generating plants are exposed to operational risks which may cause outages due to such issues as boiler, turbine, and generator failures. In order to mitigate this risk, a proactive maintenance program is carried out on a regular basis with scheduled outages for major overhauls and other maintenance issues. In addition, the Company carries property and business interruption insurance to protect against the risk of extended outages.

ATCO Midstream

ATCO Midstream is exposed to the difference between the selling prices of the NGL produced and the purchase price of shrinkage gas. The amount of profit made from ATCO Midstream's NGL extraction operations will increase or decrease as the difference between the price of NGL and natural gas commodities increases or decreases.

ATCO Midstream is exposed to seasonal natural gas price spreads. The amount of earnings and cash flow from the storage business will vary as the differences between the price of natural gas in the summer and the following winter fluctuates. To mitigate this risk ATCO Midstream maintains portfolios of varied contracts, delivery terms, capacities and customers for its storage operations.

In June 2007, the AUC initiated an industry wide review of NGL extraction rights in anticipation of the existing industry agreement expiring in 2008. On February 4, 2009, the AUC issued a decision with respect to NOVA's natural gas transmission system that, in most situations, transfers ownership of the NGL extraction rights to the producer from the NOVA delivery service customer. The implementation of this decision is expected to occur in three years time. The earnings and cash flow impact on certain of ATCO Midstream's NGL extraction facilities is uncertain at this time.

ATCO Frontec

ATCO Frontec's operations include providing support to military agencies in foreign locations which may be subject to war risk. ATCO Frontec maintains insurance, including war risks, to mitigate the risk associated with the nature of these contracts. Additionally, in areas where the risk of injury is considered to be severe, ATCO Frontec confines its staff to specific military compounds and all employees are given pre-deployment orientation and ongoing safety training.

A fuel spill occurred in January 2007 at the Brevoort Island, Northwest Territories, radar site maintained by Nasittuq Corporation, a corporation jointly owned by ATCO Frontec and Pan Arctic Inuit Logistics Corporation. ATCO has sufficient insurance coverage in place to cover any material amounts that might become payable as a result of the fuel spill. Accordingly, this spill is not expected to have any material impact on the Company's financial position.

ATCO I-Tek

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. A benchmarking report was received on January 23, 2008.

Adjustments to ATCO I-Tek's fees as a result of the benchmarking report for information technology services will be retroactive to January 1, 2008. Price changes relating to ATCO I-Tek's customer care and billing contract services for ATCO Gas and ATCO Electric will be applied following renegotiation of a new fee schedule. The benchmarking report has resulted in reduced revenues for ATCO I-Tek in 2008 and will result in reduced revenues in 2009 and beyond for services provided to ATCO Electric, ATCO Gas, and ATCO Pipelines.

Derivative Financial Instruments

In conducting its business, the Company uses various instruments, including forward contracts, swaps and options, to manage the risks arising from fluctuations in exchange rates, interest rates and commodity prices. All such instruments are used only to manage risk and not for trading purposes. For details on the financial instruments in place at December 31, 2008, see Note 21 to the consolidated financial statements.

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

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

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

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

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

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

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

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

(i) an anticipated transaction for a non-financial asset or non-financial liability becomes a specific firm commitment for which fair value hedge accounting is applied or,

(ii) a cash flow hedge of an anticipated transaction subsequently results in the recognition of the non-financial asset or non-financial liability.

(b) A non-hedge derivative instrument is recorded on the consolidated balance sheet at fair value and subsequent changes in fair value are recorded in earnings.

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

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

Transactions with Related Parties

In transactions with ATCO Ltd. and its wholly owned subsidiary corporations, the Company sold fuel in the amount of $2.6 million (2007 – $2.0 million), provided computer operations and systems development services totaling $14.1 million (2007 – $6.7 million), recovered administrative expenses totaling $1.5 million (2007 – $1.6 million) and incurred administrative expenses and corporate signature rights totaling $8.9 million (2007 – $8.3 million). The Company also incurred capital expenditures of $10.3 million (2007 – $9.4 million) that were recorded in property, plant and equipment.

In transactions with entities related through common control, the Company provided security services and recovered administrative expenses totaling nil (2007 – $0.3 million) and incurred advertising, promotion and administrative expenses totaling $1.4 million (2007 – $1.5 million).

At December 31, 2008, accounts receivable due from related parties amounted to $3.3 million (2007 – $0.8 million) and accounts payable due to related parties amounted to $6.6 million (2007 – $8.3 million).

The Company's transactions with related parties are in the normal course of business and under normal commercial terms, and did not have a material impact on earnings.

Off-Balance Sheet Arrangements

At December 31, 2008, unrecorded future income tax liabilities of the regulated operations amounted to $192.2 million. The liabilities include $1.6 million in respect of Alberta Power (2000)'s generating plants, which will be recovered through future payments received in respect of the PPA's. There are tax loss carryforwards of $0.3 million for Canadian subsidiary corporations for which no benefit has been recorded. The losses for the Canadian subsidiary corporations begin to expire in 2015. For additional information on the Company's unrecorded future income tax liabilities, refer to Note 6 to the consolidated financial statements.

Other than the financial instruments discussed under the Derivative Financial Instruments section, the Company does not have any off-balance sheet arrangements that have, or are reasonably likely to have, a current or future effect on the results of operations or financial condition, including, without limitation, such considerations as liquidity and capital resources.

Contingencies

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

Critical Accounting Estimates

The preparation of the Company's consolidated financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the year. On an on-going basis, management reviews its estimates, particularly those related to depreciation and amortization methods, useful lives and impairment of long-lived assets, amortization of deferred availability incentives, asset retirement obligations, employee future benefits and the fair values of financial instruments, using currently available information. Changes in facts and circumstances may result in revised estimates, and actual results could differ from those estimates. The Company's critical accounting estimates are discussed below.

DEFERRED AVAILABILITY INCENTIVES

Alberta Power (2000) is subject to an incentive/penalty regime related to generating unit availability. The amount to be amortized is dependent upon estimates of future generating unit availability and future electricity prices over the term of the PPAs. Each quarter, management uses these estimates to forecast high case, low case and most likely scenarios for the incentives to be received from, less penalties to be paid to, the PPA counterparties. These forecasts are added to the accumulated unamortized deferred availability incentives outstanding at the end of the quarter; the resulting total is divided by the remaining term of the PPAs to arrive at the amortization for the quarter. As at December 31, 2008, the Company had recorded $61.3 million of deferred availability incentives. The amortization of deferred availability incentives recorded in revenues amounted to $12.6 million in 2008.

Compared to the most likely scenario recorded in revenues for the year, the high case scenario would have resulted in higher revenues of approximately $5.2 million, whereas the low case scenario would have resulted in lower revenues of approximately $5.9 million.

EMPLOYEE FUTURE BENEFITS

The expected long term rate of return on pension plan assets is determined at the beginning of the year on the basis of the long bond yield rate plus an equity and management premium that reflects the plan asset mix. Actual balanced fund performance over a longer period suggests that this premium is about 1.5%, which, when added to the long bond yield rate of 5.5% at the beginning of 2008, resulted in an expected long term rate of return of 7.0% for 2008. This methodology is supported by actuarial guidance on long term asset return assumptions for the Company's defined benefit pension plans, taking into account asset class returns, normal equity risk premiums, and asset diversification effect on portfolio returns.

Expected return on plan assets for the year is calculated by applying the expected long term rate of return to the market related value of plan assets, which is the average of the market value of plan assets at the end of the preceding three years. The expected long term rate of return has declined over the past seven years, from 8.1% in 2001 to 7.0% in the year ended December 31, 2008. The result has been a decrease in the expected return on plan assets and a corresponding increase in the cost of pension benefits. In addition, the actual return on plan assets over the same period has been lower than expected (i.e., an experience loss), which is also contributing to an increase in the cost of pension benefits as losses are amortized to earnings.

Accrued benefit obligations at the end of the year are determined using a discount rate that reflects market interest rates that match the timing and amount of expected benefit payments. Due to the recent, unprecedented events in the financial markets associated with the current credit environment which has resulted in significantly higher yields than normal, the current discount rate selection methodology has been refined to include high quality corporate bonds and quasi-government organizations. The liability discount rate has also declined over the same period, from 6.9% at the end of 2001 to 5.5% at the end of 2007, but has since increased to 7.0% for 2008. The result has been a decrease in benefit obligations (i.e., an experience gain), which is contributing to a decrease in the cost of pension benefits as gains are amortized to earnings.

In accordance with the Company's accounting policy to amortize cumulative experience gains and losses in excess of 10% of the greater of the accrued benefit obligations or the market value of plan assets, the Company began amortizing a portion of the net cumulative experience losses on plan assets and accrued benefit obligations in 2003 for both pension benefit plans and other post employment benefit plans and continued this amortization in 2008.

The assumed annual health care cost trend rate increases used in measuring the accumulated post employment benefit obligations in the year ended December 31, 2008, are as follows: for drug costs, 7.2% starting in 2008 grading down over five years to 4.5%, and for other medical and dental costs, 4.0% for 2008 and thereafter. Combined with lower recent claims experience, the effect of these changes has been to decrease the costs of other post employment benefits.

The effect of changes in these estimates and assumptions is mitigated by an AUC decision to record the costs of employee future benefits when paid rather than accrued. Therefore, a significant portion of the benefit plans expense or income is unrecognized by the regulated operations, excluding Alberta Power (2000).

The sensitivities of key assumptions used in measuring accrued benefit obligations and benefit plan cost (income) for 2008 are outlined in the following table. The sensitivities of each key assumption have been calculated independently of changes in other key assumptions. Actual experience may result in changes in a number of assumptions simultaneously.

($ millions)	2008 Pension Benefit Plans		2008 Other Post Employment Benefit Plans	
	Accrued Benefit Obligation	Benefit Plan Cost	Accrued Benefit Obligation	Benefit Plan Cost
Expected long term rate of return on plan assets				
1% increase [(1)]	-	(4.3)	-	-
1% decrease [(1)]	-	4.3	-	-
Liability discount rate				
1% increase [(1)]	(80.9)	(4.6)	(3.2)	(0.2)
1% decrease [(1)]	102.0	8.0	4.0	0.2
Future compensation rate				
1% increase [(1)]	20.1	2.7	-	-
1% decrease [(1)]	(18.5)	(2.5)	-	-
Long term inflation rate				
1% increase [(1) (2) (3)]	36.8	4.5	3.0	0.2
1% decrease [(1) (3)]	(64.4)	(6.8)	(2.5)	(0.2)

Notes:

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

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

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

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 15 to the consolidated financial statements). 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 21 to the consolidated financial statements). The recommendation requires additional disclosure in the notes to the financial statements.

Effective January 1, 2008, the Company 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 consolidated financial statements).

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, 2008, was $461.2 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, 2008 was $192.2 million. Upon adoption of the new standard, the Company expects to record an increase in future income tax liabilities and non-current regulatory assets of approximately $255 million. The additional amount reflects the future income tax effects of the settlement mechanism of the regulatory assets through customer rates that would occur in the future periods. 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

The Canadian Accounting Standards Board confirmed in 2008 that the use of International Financial Reporting Standards ("IFRS") by publicly accountable enterprises will be required in 2011. The Company will need to 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. Education sessions have been, and will continue to be, provided for employees, senior management and the Audit Committee 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 and the impact on financial reporting computer systems. These position papers are being reviewed with the Company's auditors. 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 is also evaluating the potential impact of IFRS on financial covenants, business contracts and internal controls over financial reporting.

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 the Company's accounting: property, plant and equipment, joint arrangements, leases, rate regulated operations, deferred availability incentives 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 and the impact on and implementation of financial reporting computer systems will be completed in 2009.

Quarterly Results of Operations

SELECTED INFORMATION

	For the Three Months Ended (1) (2) (3)				
($ millions except per share data)	**Mar. 31**	**Jun. 30**	**Sep. 30**	**Dec. 31**	**Total**
			(unaudited)		
2008					
Revenues	740.6	655.6	638.4	744.3	2,778.9
Earnings attributable to Class A and Class B Shares	150.0	82.2	66.7	114.2	413.1
Earnings per Class A and Class B Share	1.20	0.65	0.53	0.91	3.29
Diluted earnings per Class A and Class B Share	1.19	0.65	0.53	0.91	3.28
Adjusted Earnings (4)	149.7	70.3	71.3	110.5	401.8
Adjusted Earnings per Class A and Class B Share (4)	1.19	0.56	0.57	0.88	3.20
2007					
Revenues	697.6	560.3	489.9	657.1	2,404.9
Earnings attributable to Class A and Class B Shares	134.7	81.1	72.2	98.7	386.7
Earnings per Class A and Class B Share	1.07	0.65	0.58	0.78	3.08
Diluted earnings per Class A and Class B Share	1.07	0.64	0.58	0.78	3.07
Adjusted Earnings (4)	130.2	67.5	70.6	75.5	343.8
Adjusted Earnings per Class A and Class B Share (4)	1.04	0.54	0.56	0.60	2.74

Notes:

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

(2) *Due to certain factors, revenues 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 were:

- unplanned and planned outages affecting availability in ATCO Power's and Alberta Power (2000)'s generating plants;
- the timing of utility rate decisions;
- amount of franchise fees collected by ATCO Gas on behalf of cities and municipalities;
- fluctuations in temperatures, natural gas prices, electricity prices and related spark spreads in Alberta and the U.K.;
- changes in market conditions in ATCO Midstream's NGL and storage operations;
- changes in business activity in ATCO Frontec;
- exchange rates;
- changes in the quarterly depreciation expense allocation in ATCO Gas;
- mark to market adjustments in ATCO Power;
- Other Post Employment Benefits;
- Federal Court of Appeal Decision - Mining Assets;
- 2008 Tax Assessment;
- 2007 Changes in Income Taxes and Rates;
- 2007 Changes in the Taxation of Preferred Share Dividends;
- ATCO Gas Tax Reassessments; and
- changes in share appreciation rights expense due to changes in ATCO Class I non-voting share and Canadian Utilities' Class A non-voting share prices.

Fourth Quarter 2008

All quarterly information in this document is unaudited and has been shaded to differentiate it from the annual information.

SEGMENTED REVENUE

($ millions)	For the Three Months Ended December 31		
	2008	2007	Change to 2008 (2008-2007)
		(unaudited)	
Utilities	**331.3**	313.3	6%
Power Generation	**249.1**	193.9	28%
Global Enterprises	**209.0**	198.2	5%
Corporate and Other	**3.6**	3.5	3%
Intersegment eliminations	**(48.7)**	(51.8)	6%
Revenues	**744.3**	657.1	13%

Notes:

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

(2) *Due to certain factors, revenues 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 has been extracted from the financial statements, which have been prepared in accordance with GAAP and the reporting currency is the Canadian dollar.*

Fourth quarter **revenues increased** by $87.2 million primarily due to higher natural gas fuel purchases recovered on a "no-margin" basis, improved merchant operations and increased availability in ATCO Power's U.K. operations and improved merchant performance in ATCO Power's Alberta generating plants. In addition, increased business activity in ATCO Frontec's operations and the ATCO Gas GRA contributed to the increase in revenues. These increases were partially offset by lower prices for NGL extraction in ATCO Midstream.

Temperatures in ATCO Gas for the three months ended December 31, 2008, were 0.8% colder than normal, compared to 0.8% colder than normal in 2007. ATCO Gas, pursuant to the AUC decision on its 2008-2009 general rate application issued on November 13, 2008, has received approval to establish deferral accounts deferring the impact of temperature fluctuations on ATCO Gas' revenues commencing January 1, 2008. The deferral account mechanism largely eliminates the impact of temperature on ATCO Gas' earnings.

SEGMENTED EARNINGS ATTRIBUTABLE TO CLASS A AND CLASS B SHARES

($ millions)	For the Three Months Ended December 31 (1) (2) (3) 2008	2007	Change to 2008 (2008-2007)
		(unaudited)	
Utilities	**45.8**	48.0	(5%)
Power Generation	**46.0**	25.5	80%
Global Enterprises	**31.9**	27.7	15%
Corporate and Other	**(9.3)**	(4.1)	127%
Intersegment eliminations	**(0.2)**	1.6	113%
Earnings attributable to Class A and Class B Shares	**114.2**	98.7	16%
Earnings per Class A and Class B Share	**0.91**	0.78	17%
Diluted earnings per Class A and Class B Share	**0.91**	0.78	17%
Adjusted earnings per Class A and Class B Share	**0.88**	0.60	46%

Notes:

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

(2) *Due to certain factors, 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.*

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

For the Three Months Ended December 31

($ millions)	Utilities	Power Generation	Global Enterprises	Corporate & Other	Intersegment Eliminations	Total
2008						
Earnings attributable to Class A and Class B Shares	**45.8**	**46.0**	**31.9**	**(9.3)**	**(0.2)**	**114.2**
Mark-to-Market Adjustment (1)	-	**1.1**	-	-	-	**1.1**
2008 Tax Assessment (1)	**(3.3)**	-	-	-	-	**(3.3)**
Other Post Employment Benefits (1)	-	**(1.5)**	-	-	-	**(1.5)**
Adjusted Earnings	**42.5**	**45.6**	**31.9**	**(9.3)**	**(0.2)**	**110.5**
2007						
Earnings attributable to Class A and Class B Shares	48.0	25.5	27.7	(4.1)	1.6	98.7
2007 Changes in Income Taxes and Rates (1)	(0.3)	(8.2)	-	-	(2.4)	(10.9)
Mark-to-Market Adjustment (1)	-	(2.8)	-	-	-	(2.8)
ATCO Gas Tax Reassessments (1)	(9.5)	-	-	-	-	(9.5)
Adjusted Earnings	38.2	14.5	27.7	(4.1)	(0.8)	75.5

Note:
(1) *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.*

Fourth quarter **earnings increased** by $15.5 million (16%) over 2007, including the impact of adjustments identified in the Significant Non-Operating Financial Items section.

Fourth quarter **Adjusted Earnings increased** by $35.0 million (46%) over 2007 primarily due to improved merchant performance in ATCO Power's Alberta generating plants, improved merchant performance and increased availability in ATCO Power's U.K. operations, and increased earnings of $3.5 million due to the change in quarterly depreciation expense allocation in ATCO Gas (ATCO Gas Depreciation Expense Adjustment, refer to Other Expenses - Depreciation Expense Adjustment section). These increases were partially offset by reduced activity in NGL extraction operations in ATCO Midstream.

Alberta Power Pool electricity prices for the three months ended December 31, 2008, averaged $95.20 per MWh, compared to average prices of $61.77 per MWh for the corresponding period in 2007. Natural gas prices for the three months ended December 31, 2008, averaged $6.35 per GJ, compared to average prices of $5.83 per GJ for the corresponding period in 2007. The consequence of these changes in electricity and natural gas prices was an average spark spread of $47.59 per MWh for the three months ended December 31, 2008, compared to $18.02 per MWh for the corresponding period in 2007.

During the three months ended December 31, 2008, the **deferred availability incentive** account **increased** by $16.1 million to $61.3 million, mainly due to reduced outages in the quarter, compared to the corresponding period in 2007. During the three months ended December 31, 2008, the amortization of deferred availability incentives, recorded in revenues, increased by $0.6 million to $3.5 million, compared to the corresponding period in 2007.

Interest and other income for the fourth quarter **decreased** by $6.7 million to $14.6 million primarily as a result of the mark-to-market adjustment in ATCO Power and lower rates of interest earned on lower cash balances.

OTHER EXPENSES

($ millions)	For the Three Months Ended December 31		
	2008	2007	Change to 2008 (2008-2007)
		(unaudited)	
Operating expenses:			
Natural gas supply	**3.6**	24.8	(85%)
Purchased power	**14.9**	13.6	10%
Operation and maintenance	**300.4**	251.4	19%
Selling and administrative	**87.2**	77.1	13%
Franchise fees	**42.5**	37.4	14%
	448.6	404.3	11%
Depreciation and amortization expenses	**100.5**	99.0	2%
Interest	**60.3**	55.0	10%
Income taxes	**27.1**	13.1	107%
Dividends on equity preferred shares	**8.2**	8.3	(1%)

Fourth quarter **operating expenses increased** by $44.3 million (11%) over 2007. Natural gas supply expense decreased primarily as a result of lower business activity in NGL extraction operations in

ATCO Midstream. Operation and maintenance expenses were higher, primarily due to the Barking outage in ATCO Power, and increased business activity in ATCO Frontec. 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 in ATCO Power. Increased franchise fees due to higher natural gas prices, recovered on a flow through basis, were paid in ATCO Gas.

Fourth quarter **depreciation and amortization expenses increased** by $1.5 million, primarily as a result of increased capital additions in 2007 and 2008, mainly in the Utilities segment and in ATCO Frontec, partially offset by the ATCO Gas Depreciation Expense Adjustment.

Interest expense for the fourth quarter **increased** by $5.3 million (10%) over the same period 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.

Income taxes in the fourth quarter **increased** by $14.0 million (107%) over the same period in 2007, mainly due to an increase in earnings before taxes, the 2007 Changes in Income Taxes and Rates and the 2007 ATCO Gas Tax Reassessments. These increases were partially offset by the impact of the higher tax deductions in the Utilities Business Group due to the use of the flow-through tax methodology, lower corporate income tax rates in 2008 and favorable tax decisions received in the Utilities Business Group in the fourth quarter to treat certain previously reported capital outlays as current expenditures for tax purposes.

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 a decrease to ATCO Gas' depreciation and amortization expense for the three months ended December 31, 2008, of $4.9 million, as compared to the methodology used for the depreciation and amortization expense recorded in the corresponding period 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 an increase to the Company's earnings for the three months ended December 31, 2008, of $3.5 million as compared to the methodology used in the corresponding period of 2007.

LIQUIDITY AND CAPITAL RESOURCES

SUMMARY OF CASH FLOW	For the Three Months Ended December 31		
($ millions)	**2008**	2007	Change to 2008 (2008-2007)
		(unaudited)	
Cash position, beginning of period	**946.1**	682.9	39%
Cash provided by (used in):			
Operating activities	**145.3**	127.1	14%
Investing activities	**(290.3)**	(201.9)	44%
Financing activities	**(71.3)**	141.8	(150%)
Foreign currency impact on cash balances	**(3.2)**	(2.7)	(19%)
Cash position, end of period	**726.6**	747.2	(3%)

OPERATING ACTIVITIES

Cash flow from operations for the fourth quarter **increased** by 14% primarily due to increases in funds generated by operations, partially offset by changes in non-cash working capital. **Funds generated by operations increased** by 25%, primarily due to higher cash earnings and increased deferred availability incentives in Alberta Power (2000).

INVESTING ACTIVITIES

Investing in the fourth quarter **increased** by 44% primarily as a result of higher capital expenditures, partially offset by increased non-current deferred electricity costs, changes in non-cash working capital and higher contributions by utility customers for extensions to plant. **Increases** in **capital expenditures** reflect increased investment in regulated electric and natural gas distribution and transmission projects and in the Karratha generating plant in ATCO Power.

FINANCING ACTIVITIES

In the fourth quarter, the Company had **net debt decreases** of $28.4 million. **Issuance** of debt included $4.0 million of long term debt. **Redemptions** were comprised of $3.8 million of long term debt and $28.6 million of non-recourse long term debt.

In the fourth quarter, the Company had **no issues or redemptions** of equity preferred shares.

In the fourth quarter, there were **no purchases** of Class A Shares under its normal course issuer bids, a decrease of $8.0 million from the corresponding period in 2007. In the fourth quarter, **issues** of Class A Shares due to stock option exercises were $0.1 million, a decrease of $0.2 million over the corresponding period in 2007. In the fourth quarter, **net issues** were $0.1 million, a decrease of $7.8 million from the corresponding period in 2007.

In the fourth quarter, total **dividends paid to Class A and Class B share owners increased** by 5% to $41.7 million over the same period in 2007. In the fourth quarter, the **quarterly dividend** payment on the Company's Class A and Class B Shares **increased** by $0.0175 to $0.3325 per share.

FOREIGN CURRENCY TRANSLATION

Changes in U.K. and Australian exchange rates used for balance sheet translations impacted the Company’s cash position by $(3.2) million.