ATCO
GROUP

Corporate Office

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07028100

SUPPL

November 7, 2007

Securities and Exchange Commissio
Judiciary Plaza
450 - 5 Street NW
Washington, DC 20549

Dear Sir or Madam:

Canadian Utilities Limited - File No.: 82-34744
Exemption Pursuant to Rule 12g3-2(b)

Pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934, as amended, enclosed is a copy of the following:

- Form 52-109FT2 – Certification of Interim Filings by President and CEO
- Form 52-109FT2 – Certification of Interim Filings by Senior Vice President and CFO
- Consolidated Financial Statements for the Nine Months Ended September 30, 2007
- Management's Discussion and Analysis for the Nine Months Ended September 30, 2007
- News Release dated October 18, 2007 – Third Quarter Results
- Interim Report for the Nine Months Ended September 30, 2007
- News Release dated October 25, 2007 – Third Quarter Operational Earnings
- News Release dated October 25, 2007 – Eligible Dividends
- News Release dated November 5, 2007 – Unplanned Outage at Barking Power Station

As required pursuant to Rule 12g3-2(b), the exemption number appears in the upper right-hand corner of each unbound page and of the first page of each bound document.

Please indicate your receipt of the enclosed by stamping the enclosed copy of this letter and returning it to the sender in the enclosed self-addressed, stamped envelope.

Regards,

Karen Sharp, Senior Administrative Assistant
Corporate Secretarial Department
ATCO Ltd. and Canadian Utilities Limited

dw 11/19

Encl.

ATCO 60 years 2007

Form 52-109F2 - Certification of Interim Filings

I, Nancy C. Southern, President & Chief Executive Officer of Canadian Utilities Limited, certify that:

1. I have reviewed the interim filings (as this term is defined in Multilateral Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings*) of **Canadian Utilities Limited,** (the issuer) for the interim period ending September 30, 2007;

2. Based on my knowledge, the interim filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the interim filings;

3. Based on my knowledge, the interim financial statements together with the other financial information included in the interim filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the interim filings;

4. The issuer's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures and internal control over financial reporting for the issuer, and we have:

(a) designed such disclosure controls and procedures, or caused them to be designed under our supervision, to provide reasonable assurance that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which the interim filings are being prepared; and

(b) designed such internal control over financial reporting, or caused it to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the issuer's GAAP; and

5. I have caused the issuer to disclose in the interim MD&A any change in the issuer's internal control over financial reporting that occurred during the issuer's most recent interim period that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting.

Date: October 25, 2007

Original signed by Nancy C. Southern

President & Chief Executive Officer

FILE NO. 82-34744

Form 52-109F2 - Certification of Interim Filings

I, Karen M. Watson, Senior Vice President & Chief Financial Officer of Canadian Utilities Limited, certify that:

1. I have reviewed the interim filings (as this term is defined in Multilateral Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings*) of **Canadian Utilities Limited,** (the issuer) for the interim period ending September 30, 2007;

2. Based on my knowledge, the interim filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the interim filings;

3. Based on my knowledge, the interim financial statements together with the other financial information included in the interim filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the interim filings;

4. The issuer's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures and internal control over financial reporting for the issuer, and we have:

(a) designed such disclosure controls and procedures, or caused them to be designed under our supervision, to provide reasonable assurance that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which the interim filings are being prepared; and

(b) designed such internal control over financial reporting, or caused it to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the issuer's GAAP; and

5. I have caused the issuer to disclose in the interim MD&A any change in the issuer's internal control over financial reporting that occurred during the issuer's most recent interim period that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting.

Date: October 25, 2007

Original signed by Karen M. Watson

Senior Vice President
& Chief Financial Officer

FILE NO. 82-34744

CANADIAN UTILITIES LIMITED

An ATCO Company

CONSOLIDATED FINANCIAL STATEMENTS

FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2007

CANADIAN UTILITIES LIMITED
CONSOLIDATED STATEMENT OF EARNINGS AND RETAINED EARNINGS
(Millions of Canadian Dollars except per share data)

		Three Months Ended September 30		Nine Months Ended September 30	
	Note	**2007**	2006	**2007**	2006
		(Unaudited)		*(Unaudited)*	
Revenues	2	**$ 489.9**	$ 553.9	**$1,747.8**	$1,759.3
Costs and expenses					
Natural gas supply		**8.0**	11.2	**17.3**	26.2
Purchased power		**11.1**	10.0	**36.3**	33.6
Operation and maintenance		**219.3**	238.3	**690.2**	706.8
Selling and administrative		**47.6**	45.7	**139.7**	132.6
Depreciation and amortization		**77.3**	73.3	**252.5**	252.9
Interest	4	**43.6**	42.2	**129.1**	131.9
Interest on non-recourse long term debt		**10.5**	12.1	**33.3**	36.4
Franchise fees		**20.6**	18.4	**113.8**	108.0
		438.0	451.2	**1,412.2**	1,428.4
		51.9	102.7	**335.6**	330.9
Interest and other income	6	**11.4**	17.3	**43.0**	39.6
Earnings before income taxes		**63.3**	120.0	**378.6**	370.5
Income taxes	2, 4	**(17.2)**	44.2	**64.6**	119.7
		80.5	75.8	**314.0**	250.8
Dividends on equity preferred shares		**8.3**	9.0	**26.0**	26.9
Earnings attributable to Class A and Class B shares		**72.2**	66.8	**288.0**	223.9
Retained earnings at beginning of period as restated	5	**1,951.4**	1,780.3	**1,813.3**	1,721.9
		2,023.6	1,847.1	**2,101.3**	1,945.8
Dividends on Class A and Class B shares		**39.5**	68.0	**117.2**	140.4
Purchase of Class A shares		**-**	38.0	**-**	64.3
Retained earnings at end of period		**$1,984.1**	$1,741.1	**$1,984.1**	$1,741.1
Earnings per Class A and Class B share	9	**$ 0.58**	$ 0.53	**$ 2.30**	$ 1.77
Diluted earnings per Class A and Class B share	9	**$ 0.58**	$ 0.53	**$ 2.29**	$ 1.76
Dividends paid per Class A and Class B share	9	**$ 0.315**	$ 0.54	**$ 0.935**	$ 1.11

CANADIAN UTILITIES LIMITED
CONSOLIDATED BALANCE SHEET
(Millions of Canadian Dollars)

		September 30		December 31
	Note	**2007**	2006	2006
		(Unaudited)		*(Audited)*
ASSETS				
Current assets				
Cash and short term investments	3	**$ 682.9**	$ 732.6	$ 798.8
Accounts receivable		**332.1**	264.7	362.3
Inventories		**98.2**	84.1	96.5
Future income taxes		**2.3**	0.2	-
Regulatory assets	2	**7.3**	12.2	13.3
Derivative assets	10	**0.3**	-	-
Prepaid expenses		**34.2**	26.2	23.6
		1,157.3	1,120.0	1,294.5
Property, plant and equipment		**5,587.3**	5,318.1	5,426.1
Regulatory assets	2	**64.0**	30.1	43.2
Derivative assets	10	**58.9**	-	-
Other assets		**194.3**	232.7	229.7
		$7,061.8	$6,700.9	$6,993.5
LIABILITIES AND SHARE OWNERS' EQUITY				
Current liabilities				
Accounts payable and accrued liabilities	2	**$ 380.0**	$ 272.5	$ 338.8
Income taxes payable	2, 4	**2.2**	13.8	22.7
Future income taxes		**-**	-	0.3
Regulatory liabilities		**9.7**	2.0	0.5
Derivative liabilities	10	**1.9**	-	-
Non-recourse long term debt due within one year	7	**61.2**	50.2	59.3
		455.0	338.5	421.6
Future income taxes	2, 4	**166.9**	177.9	194.7
Regulatory liabilities		**144.2**	149.6	148.8
Derivative liabilities	10	**2.9**	-	-
Deferred credits	2, 10	**295.7**	256.9	229.0
Long term debt	7	**2,399.4**	2,266.5	2,411.5
Non-recourse long term debt	7	**495.7**	633.8	626.7
Equity preferred shares	8	**625.0**	636.5	636.5
Class A and Class B share owners' equity				
Class A and Class B shares	9	**517.4**	514.0	516.0
Contributed surplus		**1.8**	1.1	1.2
Retained earnings		**1,984.1**	1,741.1	1,804.4
Accumulated other comprehensive income	11	**(26.3)**	(15.0)	3.1
		2,477.0	2,241.2	2,324.7
		$7,061.8	$6,700.9	$6,993.5

CANADIAN UTILITIES LIMITED
CONSOLIDATED STATEMENT OF CASH FLOWS
(Millions of Canadian Dollars)

		Three Months Ended September 30		Nine Months Ended September 30	
	Note	**2007**	2006	**2007**	2006
		(Unaudited)		*(Unaudited)*	
Operating activities					
Earnings attributable to Class A and Class B shares		**$ 72.2**	$ 66.8	**$ 288.0**	$ 223.9
Adjustments for:					
Depreciation and amortization		**77.3**	73.3	**252.5**	252.9
Future income taxes	2	**3.2**	4.0	**3.8**	(12.9)
Deferred availability incentives		**(5.3)**	12.2	**(2.3)**	20.8
TXU Europe settlement - net of income taxes	3	**(2.7)**	(3.6)	**(8.6)**	1.7
Other		**5.7**	(5.4)	**12.5**	2.7
Funds generated by operations		**150.4**	147.3	**545.9**	489.1
Changes in non-cash working capital		**(45.1)**	(37.1)	**33.9**	8.9
Cash flow from operations		**105.3**	110.2	**579.8**	498.0
Investing activities					
Purchase of property, plant and equipment		**(216.4)**	(143.0)	**(488.2)**	(383.7)
Proceeds (costs) on disposal of property, plant and equipment		**2.3**	(3.4)	**(1.5)**	(6.1)
Contributions by utility customers for extensions to plant		**28.7**	20.4	**65.4**	61.2
Non-current deferred electricity costs		**(2.7)**	(2.2)	**(5.1)**	13.2
Changes in non-cash working capital		**22.6**	(25.4)	**7.1**	(33.7)
Income tax reassessment	4	**-**	4.2	**-**	(12.8)
Other		**(6.1)**	(2.4)	**(17.9)**	(5.0)
		(171.6)	(151.8)	**(440.2)**	(366.9)
Financing activities					
Issue of long term debt		**-**	-	**-**	35.5
Repayment of non-recourse long term debt	3	**(19.3)**	(21.7)	**(110.5)**	(52.0)
Issue of equity preferred shares by subsidiary	8	**-**	-	**115.0**	-
Redemption of equity preferred shares	8	**-**	-	**(126.5)**	-
Net issue (purchase) of Class A shares		**0.2**	(41.7)	**1.3**	(69.4)
Dividends paid to Class A and Class B share owners		**(39.5)**	(68.0)	**(117.2)**	(140.4)
Other		**0.6**	(0.5)	**(2.7)**	(1.3)
		(58.0)	(131.9)	**(240.6)**	(227.6)
Foreign currency translation		**(5.8)**	2.1	**(14.9)**	4.7
Cash position [1]					
Decrease		**(130.1)**	(171.4)	**(115.9)**	(91.8)
Beginning of period		**813.0**	904.0	**798.8**	824.4
End of period		**$ 682.9**	$ 732.6	**$ 682.9**	$ 732.6

[1] Cash position includes $129.3 million (2006 - $146.9 million) which is only available for use in joint ventures.

CANADIAN UTILITIES LIMITED
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME
(Millions of Canadian Dollars)

		Three Months Ended September 30		Nine Months Ended September 30	
	Note	**2007**	2006	**2007**	2006
		(Unaudited)		*(Unaudited)*	
Earnings attributable to Class A and Class B shares		**$72.2**	$66.8	**$288.0**	$223.9
Other comprehensive income, net of income taxes:					
Cash flow hedges	11	**(1.3)**	-	**2.3**	-
Foreign currency translation adjustment	11	**(11.0)**	1.7	**(24.4)**	3.2
		(12.3)	1.7	**(22.1)**	3.2
Comprehensive income		**$59.9**	$68.5	**$265.9**	$227.1

CANADIAN UTILITIES LIMITED
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
SEPTEMBER 30, 2007

(Unaudited, Tabular Amounts in Millions of Canadian Dollars)

1. Summary of significant accounting policies

Financial statement presentation

The accompanying consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles and should be read in conjunction with the consolidated financial statements and related notes included in the Corporation's 2006 Annual Report. These interim financial statements have been prepared using the same accounting policies as used in the financial statements for the year ended December 31, 2006, except as described below.

Effective January 1, 2007, the Corporation prospectively adopted the Canadian Institute of Chartered Accountants ("CICA") recommendations pertaining to financial instruments, which establish standards for the recognition, measurement, disclosure and presentation of financial assets, financial liabilities and non-financial derivatives. These recommendations require that fair value be used to measure financial assets that are held for trading or available for sale, financial liabilities that are held for trading and all derivative financial instruments. Other financial assets, such as loans and receivables and investments that are held to maturity, and other financial liabilities are measured at their carrying value. This change in accounting had the following effect on the consolidated financial statements for the three and nine months ended September 30, 2007:

(a) Recognition of interest rate swaps, foreign currency forward contracts and certain natural gas purchase contracts as derivative assets and liabilities in the consolidated financial statements (see Note 10).
(b) Recognition of the fair value of a power generation revenue contract liability associated with the natural gas purchase contracts derivative asset (see Note 10).
(c) Recognition of a mark-to-market adjustment for the change in fair value of the natural gas purchase contracts derivative asset and recognition of an adjustment to the associated power generation revenue contract liability (see Note 6).
(d) Restatement of opening retained earnings at January 1, 2007 to recognize the prior years' earnings effect of the natural gas purchase contracts derivative asset and the associated power generation revenue contract liability, as well as the prior years' earnings effect of accounting for certain financial assets and financial liabilities at amortized cost using the effective interest method (see Note 5).
(e) Reclassification of deferred financing charges from other assets to long term debt and non-recourse long term debt (see Note 7).

Effective January 1, 2007, the Corporation prospectively adopted the CICA recommendations pertaining to hedges, which establish standards for the identification, designation, documentation and effectiveness of hedging relationships for the purpose of applying hedge accounting. The purpose of hedge accounting is to ensure that gains, losses, revenues and expenses from effective hedging relationships are recorded in earnings in the same period. This change in accounting had no effect on the consolidated financial statements for the three and nine months ended September 30, 2007.

Effective January 1, 2007, the Corporation prospectively adopted the CICA recommendations regarding the reporting and disclosure of comprehensive income. Comprehensive income consists of changes in the equity of the Corporation from sources other than the Corporation's share owners, and includes earnings of the Corporation, the foreign currency translation adjustment relating to self-sustaining foreign operations and unrealized gains and losses on changes in fair values of available-for-sale assets and effective cash flow hedging instruments. Other comprehensive income comprises revenues, expenses, gains and losses that are recognized in comprehensive income but are excluded from earnings of the period. Comprehensive income is disclosed in a separate statement in the consolidated financial statements.

Effective January 1, 2007, the Corporation prospectively adopted the CICA recommendations regarding the presentation of equity and changes in equity. These recommendations require separate presentation of the components of equity, including retained earnings, accumulated other comprehensive income, contributed surplus, share capital and reserves, and the changes therein. As a result of this change in accounting, the Corporation has

1. **Summary of significant accounting policies** (continued)

included a reconciliation of accumulated other comprehensive income in the notes to the consolidated financial statements (see Note 11). In accordance with the recommendations, comparative figures have been adjusted to incorporate the foreign currency translation adjustment into accumulated other comprehensive income.

Effective January 1, 2007, the Corporation adopted the CICA recommendations that prescribe the criteria for changing accounting policies, together with the accounting treatment and disclosure of changes in accounting policies, changes in accounting estimates and corrections of errors. Adoption of these recommendations had no effect on the consolidated financial statements for the three and nine months ended September 30, 2007, except for the disclosure of accounting changes that have been issued by the CICA but have not yet been adopted by the Corporation because they are not effective until a future date (see Future Accounting Changes below).

Due to the seasonal nature of the Corporation's operations, changes in electricity prices in Alberta, the timing and demand of natural gas storage capacity sold, changes in natural gas storage fees and the timing of rate decisions, the consolidated statements of earnings and retained earnings for the three and nine months ended September 30, 2007 and September 30, 2006 are not necessarily indicative of operations on an annual basis.

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

Cash and Short Term Investments

Short term investments consist of certificates of deposit and bankers' acceptances with maturities generally of 90 days or less at purchase.

Deferred Financing Charges

Issue costs of long term debt are amortized over the life of the debt using the effective interest method. Issue costs of preferred shares relating to regulated operations are amortized over the expected life of the issue and issue costs of preferred shares relating to other subsidiaries are charged to retained earnings. Unamortized premiums and issue costs of redeemed long term debt and preferred shares relating to regulated operations are amortized over the life of the issue funding the redemption. The Corporation's deferred financing charges pertaining to long term debt have been reclassified from other assets to long term debt and non-recourse long term debt in accordance with the CICA recommendations for financial instruments (see Note 7).

Derivative Financial Instruments

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

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

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

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

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

1. **Summary of significant accounting policies** (continued)

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

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

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

Hedge gains or losses that were recognized in other comprehensive income are added to the initial carrying amount of a non-financial asset or non-financial liability when:
(i) an anticipated transaction for a non-financial asset or non-financial liability becomes a specific firm commitment for which fair value hedge accounting is applied or,
(ii) a cash flow hedge of an anticipated transaction subsequently results in the recognition of the non-financial asset or non-financial liability.

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

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

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.

Foreign Currency Translation

Assets and liabilities of self-sustaining foreign operations are translated into Canadian dollars at the rate of exchange in effect at the balance sheet date and revenues and expenses are translated at the average monthly rates of exchange during the year. Gains or losses on translation of self-sustaining foreign operations are included in accumulated other comprehensive income in share owners' equity.

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

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

1. Summary of significant accounting policies (continued)

Future Accounting Changes

The CICA has issued new accounting recommendations for capital disclosures which require disclosure of both qualitative and quantitative information that enables users of financial statements to evaluate the Corporation's objectives, policies and processes for managing capital. These recommendations are effective for the Corporation beginning January 1, 2008.

The CICA has also issued new accounting recommendations for disclosure and presentation of financial instruments which require disclosures of both qualitative and quantitative information that enables users of financial statements to evaluate the nature and extent of risks arising from financial instruments to which the Corporation is exposed. These recommendations are effective for the Corporation beginning January 1, 2008.

The CICA has also issued new accounting recommendations for measurement and disclosure of inventories which provide guidance on the determination of cost and its subsequent recognition as an expense, including any writedown to net realizable value, and on the cost formulas that are used to assign costs to inventories. The Corporation is evaluating the effect of these recommendations on earnings and assets of the Corporation. These recommendations are effective for the Corporation beginning January 1, 2008.

The CICA has decided to remove 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. The CICA has also decided to amend its accounting recommendations pertaining to regulated income taxes to require the recognition of future regulated 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 Corporation is evaluating the possibility of using standards issued by the Financial Accounting Standards Board in the United States as another source of Canadian GAAP. Once issued, these recommendations will be effective for the Corporation beginning January 1, 2009, and are to be applied prospectively.

2. Regulatory matters

On September 22, 2007, ATCO Electric received a decision on its General Tariff Application for 2007 and 2008 which was filed with the Alberta Energy and Utilities Board ("AEUB") in November 2006. The decision established the amount of revenue ATCO Electric can recover through its rates for electric distribution and transmission service provided to its customers for 2007 and 2008. The effect of the decision on the earnings of ATCO Electric was not material, as higher revenues primarily resulting from increased investment in capital expenditures and previously approved interim customer rates were offset by lower allowed 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, whereby, effective January 1, 2007, ATCO Electric no longer recognizes future income taxes, and will refund to customers the $34.4 million of future income taxes collected under the previously allowed tax methodology.

The reversal of these recorded future income taxes as at January 1, 2007, was reflected in the third quarter of 2007. The adjustment does not affect earnings as ATCO Electric's revenues and income tax expense were reduced by similar amounts. The adjustment does not affect cash flow from operations for the three and nine months ended September 30, 2007. The timing of the cash refund to customers is subject to a further regulatory process at which time ATCO Electric intends to propose a five year repayment period. Accordingly, at September 30, 2007, ATCO Electric has recorded a reduction in future income tax liabilities of $34.4 million and a liability to customers of $49.3 million, offset by a regulatory asset of $14.9 million which represents current income tax savings to be realized in future periods. Unrecorded future income tax liabilities have increased by $34.4 million as a result of this decision.

2. Regulatory matters (continued)

On March 17, 2006, ATCO Electric received a decision on its General Tariff Application for 2005 and 2006 which was filed with the AEUB in May 2005. The decision established the amount of revenue ATCO Electric can recover through its rates for electric distribution and transmission service provided to its customers for 2005 and 2006. The impact of the decision for 2005 reduced ATCO Electric's earnings by $1.3 million and was recorded in the first quarter of 2006. The impact of the decision for the full year 2006, as compared to the decision for the full year 2005, further reduced ATCO Electric's earnings by $1.6 million. The decision also confirmed the return on common equity as determined by the AEUB's standardized rate of return methodology. The rate of return on common equity was 8.93% in 2006.

On January 27, 2006, ATCO Gas received a decision on its general rate application which was filed with the AEUB in May 2005 for the 2005, 2006 and 2007 test years. The decision established the amount of revenue ATCO Gas can recover through distribution rates for natural gas distribution service to its customers over the period of 2005 to 2007. The decision also approved the return on common equity as determined by the AEUB's standardized rate of return methodology. The rate of return on common equity was 8.93% in 2006 and is 8.51% for 2007. The final impact of the decision is subject to the outcome of an existing process regarding the pricing of services provided by ATCO I-Tek.

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

3. TXU Europe settlement

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

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

Based on the foreign currency exchange rate in effect at March 30, 2005, the Corporation's share of this settlement is expected to generate earnings after income taxes of approximately $69 million, which will be recognized over the remaining term of the TXU Europe contract to September 30, 2010, at approximately $11 million per year. These earnings will be dependent upon foreign currency exchange rates in effect at the time that the earnings are recognized.

On May 31, 2007, £95.0 million of the TXU proceeds, of which the Corporation's share is $52.7 million, were applied to Barking Power's non-recourse long term debt.

4. Income taxes

On June 15, 2007, an amendment to tax legislation pertaining to the taxation of preferred share dividends paid by corporations received third reading in the House of Commons. The Canada Revenue Agency ("CRA") has been assessing corporate tax returns based on this proposed change since January 1, 2003, resulting in a reduction of taxes paid to the CRA. As this change is now considered to have been substantively enacted, the Corporation recorded a reduction to current income tax expense of $16.4 million in the second quarter of 2007. Funds generated by operations increased by $16.4 million, offset by a similar reduction in changes in non-cash working capital, leaving the Corporation's cash position unchanged.

4. Income taxes (continued)

In the third quarter of 2006, the CRA issued a reassessment for Alberta Power (2000)'s 2001 taxation year. The CRA's reassessment treats the proceeds received from the sale of the H.R. Milner generating plant to the Alberta Balancing Pool as income rather than as a sale of an asset. The Corporation has appealed the reassessment to the Tax Court of Canada. The full impact of the reassessment was a $12.4 million increase in interest and income tax expense, a $12.4 million decrease in earnings ($8.0 million recorded in the second quarter of 2006 and $4.4 million recorded in the third quarter of 2006), and a $28.8 million payment associated with the tax and interest assessed, paid in the third quarter of 2006. It is expected that $16.4 million of this cash payment will be recovered by reducing income taxes payable through higher capital cost allowance claims in future years.

5. Retained earnings at beginning of period as restated

	January 1	
	2007	2006
Retained earnings at beginning of period as previously reported	**$1,804.4**	$1,721.9
Adjustments to retained earnings to recognize the prior years' effect of:		
(a) the fair value of the natural gas purchase contracts derivative asset (net of income taxes)	**41.6**	-
(b) the fair value of the power generation revenue contract liability associated with the natural gas purchase contracts derivative asset (net of income taxes)	**(31.6)**	-
(c) the change in method of accounting for long term debt and non-recourse long term debt at amortized cost using the effective interest method (net of income taxes)	**(0.6)**	-
(d) the fair value of receivables (net of income taxes)	**(0.5)**	-
Retained earnings at beginning of period as restated	**$1,813.3**	$1,721.9

6. Interest and other income

Interest and other income for the three months ended September 30, 2007 includes a loss of $10.7 million related to the change in fair value of the natural gas purchase contracts derivative asset (see Note 10). This loss is partially offset by a reduced provision of $7.4 million for the associated power generation revenue contract liability.

Interest and other income for the nine months ended September 30, 2007 includes a loss of $0.6 million related to the change in fair value of the natural gas purchase contracts derivative asset (see Note 10). This loss is offset by a reduced provision of $0.8 million for the associated power generation revenue contract liability.

7. Long term debt and non-recourse long term debt

The CICA recommendations regarding the measurement of financial liabilities require the financial liabilities to be measured at initial recognition, including transaction costs, minus principal repayments, plus or minus the cumulative amortization using the effective interest method of any difference between that initial amount and the maturity amount, minus any reduction for impairment. Accordingly, deferred financing charges have been recalculated using the effective interest method. Commencing January 1, 2007, in accordance with CICA recommendations regarding the presentation of financial liabilities, long term debt and non-recourse long term debt have been reduced by their respective cumulative unamortized balance of deferred financing charges.

7. Long term debt and non-recourse long term debt (continued)

Long term debt

	Effective Interest Rate	September 30 2007	September 30 2006
CU Inc. debentures – unsecured			
2001 4.84% due November 2006	4.977%	**$ -**	$ 175.0
2002 4.801% due November 2007	4.913%	**50.0**	50.0
2000 6.97% due June 2008	7.062%	**100.0**	100.0
1989 Series 10.20% due November 2009	10.331%	**125.0**	125.0
1990 Series 11.40% due August 2010	11.537%	**125.0**	125.0
2000 7.05% due June 2011	7.130%	**100.0**	100.0
2004 5.096% due November 2014	5.162%	**100.0**	100.0
2002 6.145% due November 2017	6.217%	**150.0**	150.0
2004 5.432% due January 2019	5.492%	**180.0**	180.0
1999 6.8% due August 2019	6.861%	**300.0**	300.0
1990 Second Series 11.77% due November 2020	11.903%	**100.0**	100.0
2006 4.801% due November 2021	4.854%	**160.0**	-
1991 Series 9.92% due April 2022	10.063%	**125.0**	125.0
1992 Series 9.40% due May 2023	9.511%	**100.0**	100.0
2004 5.896% due November 2034	5.939%	**200.0**	200.0
2005 5.183% due November 2035	5.226%	**185.0**	185.0
2006 5.032% due November 2036	5.072%	**160.0**	-
CU Inc. other long term obligation, due June 2009, unsecured	6.000%	**4.5**	4.5
Canadian Utilities Limited debentures – unsecured			
2002 6.14% due November 2012	6.228%	**100.0**	100.0
Less: Deferred financing charges		**(12.1)**	-
		2,352.4	2,219.5
ATCO Midstream Ltd. credit facility, at BA rates, due June 2012, unsecured (1)	Floating	**25.0**	25.0
ATCO Power Canada Ltd. credit facility, at BA rates, due August 2011, secured by a pledge of cash (1)	Floating	**22.0**	22.0
		$2,399.4	$2,266.5

Non-recourse long term debt

The CICA recommendations pertaining to financial instruments do not permit the presentation of interest rate swaps in combination with floating rate long term debt to emulate fixed rate long term debt. Consequently, any of the Corporation's floating rate non-recourse long term debt that had previously been presented in combination with interest rate swaps is now presented exclusive of the effect of the interest rate swaps (see Note 10). The comparative figures have been restated; this change in presentation had no effect on the amount of the Corporation's non-recourse long term debt.

7. Long term debt and non-recourse long term debt (continued)

Non-recourse long term debt (continued)

Project Financing	Effective Interest Rate	September 30 2007	2006
Barking Power Limited, payable in British pounds:			
Term loans, at fixed rates averaging 7.95%, due to 2010 (£17.9 million (2006 – £22.8 million))	7.95%	**$ 36.4**	$ 47.8
Term loan, at LIBOR, due to 2010 [1] (£5.2 million (2006 – £37.4 million))	Floating	**10.6**	78.3
Osborne Cogeneration Pty Ltd., payable in Australian dollars:			
Term loan, at Bank Bill rates, due to 2013 [1] ($31.9 million AUD (2006 – $36.5 million AUD))	Floating [2]	**28.1**	30.4
ATCO Power Alberta Limited Partnership ("APALP"):			
Term loan, at LIBOR, due to 2016 [1]	Floating [2]	**86.5**	93.4
Joffre:			
Term loan, at BA rates, due to 2012 [1]	Floating [2]	**0.5**	7.6
Term loan, at LIBOR, due to 2012 [1]	Floating [2]	**0.9**	13.6
Notes, at fixed rate of 8.59%, due to 2020	8.845%	**32.0**	32.0
Scotford:			
Term loan, at BA rates, due to 2014 [1]	Floating [2]	**42.5**	42.9
Term facility, at Canadian Prime Advances, due to 2014 [1]	Floating [2]	**0.1**	0.1
Term loan, at LIBOR, due to 2014 [1]	Floating [2]	**10.7**	10.7
Notes, at fixed rate of 7.93%, due to 2022	8.302%	**25.5**	26.3
Muskeg River:			
Term loan, at BA rates, due to 2014 [1]	Floating [2]	**32.5**	33.4
Term facility, at Canadian Prime Advances, due to 2014 [1]	Floating [2]	**0.1**	0.1
Term loan, at LIBOR, due to 2014 [1]	Floating [2]	**8.2**	8.4
Notes, at fixed rate of 7.56%, due to 2022	7.902%	**28.0**	29.9
Brighton Beach:			
Term loan, at BA rates, due to 2020 [1]	Floating [2]	**19.5**	20.4
Term loan, at LIBOR, due to 2020 [1]	Floating [2]	**17.5**	18.3
Construction overrun facility, at BA rates, due to 2020 [1]	Floating [2]	**4.8**	5.0
Construction overrun facility, at LIBOR, due to 2020 [1]	Floating [2]	**4.3**	4.5
Notes, at fixed rate of 6.924%, due to 2024	7.025%	**105.6**	108.5
Cory:			
Cost overrun facility, at BA rates, due to 2011 [1]	Floating [2]	**2.5**	3.1
Notes, at fixed rate of 7.586%, due to 2025	7.872%	**35.7**	36.7
Notes, at fixed rate of 7.601%, due to 2026	7.880%	**31.8**	32.6
Less: Deferred financing charges		**(7.4)**	-
		556.9	684.0
Less: Amounts due within one year		**61.2**	50.2
		$495.7	$633.8

BA – Bankers' Acceptance
LIBOR – London Interbank Offered Rate

(1) *The above interest rates have additional margin fees at a weighted average rate of 1.2% (2006 — 1.1%). The margin fees are subject to escalation.*

(2) *Floating interest rates have been partially or completely hedged with interest rate swaps (see Note 10).*

8. Equity preferred shares

CU Inc. equity preferred shares

Authorized and issued

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

Issued:

	Stated Value (dollars)	Redemption Dates	September 30 2007 Shares	2007 Amount	2006 Shares	2006 Amount
Cumulative Redeemable Preferred Shares						
4.60% Series 1	$25.00	See below	**4,600,000**	**$ 115.0**	-	$ -

On April 18, 2007, CU Inc., a subsidiary corporation, issued $115.0 million Cumulative Redeemable Preferred Shares Series 1 at a price of $25.00 per share for cash. The dividend rate has been fixed at 4.60%. The net proceeds of the issue were used in part to redeem $91.8 million of the outstanding Cumulative Redeemable Second Preferred Shares Series Q, R and S of ATCO Electric, ATCO Gas and ATCO Pipelines, subsidiary corporations of CU Inc., that are held by Canadian Utilities Limited.

Fair values

Fair values for preferred shares determined using quoted market prices for the same or similar issues are $99.3 million (2006 - nil).

Redemption privileges

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

Canadian Utilities Limited equity preferred shares

Authorized and issued

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

Issued:

	Stated Value (dollars)	Redemption Dates	September 30 2007 Shares	2007 Amount	2006 Shares	2006 Amount
Cumulative Redeemable Second Preferred Shares						
5.9% Series Q	$25.00	Open	-	$ -	2,277,675	$ 56.9
5.3% Series R	$25.00	Open	-	-	2,146,730	53.7
6.6% Series S	$25.00	Open	-	-	635,700	15.9
5.8% Series W	$25.00	See below	**6,000,000**	**150.0**	6,000,000	150.0
6.0% Series X	$25.00	See below	**6,000,000**	**150.0**	6,000,000	150.0
Perpetual Cumulative Second Preferred Shares						
4.35% Series O	$25.00	December 2, 2011	**1,600,000**	**40.0**	1,600,000	40.0
4.35% Series T	$25.00	December 2, 2011	**1,600,000**	**40.0**	1,600,000	40.0
4.35% Series U	$25.00	December 2, 2011	**800,000**	**20.0**	800,000	20.0
5.25% Series V	$25.00	October 3, 2007	**4,400,000**	**110.0**	4,400,000	110.0
				$510.0		$636.5

8. Equity preferred shares (continued)

On May 18, 2007, Canadian Utilities Limited redeemed $126.5 million of outstanding Cumulative Redeemable Second Preferred Shares Series Q, R and S at a price of $25.00 per share plus accrued and unpaid dividends per share.

The dividends payable on the Series O, T, U and V preferred shares are fixed until the redemption dates specified above, at which time a new dividend rate may be established by negotiations between Canadian Utilities Limited and the owners of the shares.

Effective October 3, 2007, the dividend rate on the Series V preferred shares has been reset to 4.70% with a redemption date of October 3, 2012.

Fair values

Fair values for preferred shares determined using quoted market prices for the same or similar issues are $519.8 million (2006 - $669.7 million).

Redemption privileges

The preferred shares, except for Series W and X, are redeemable on the dates specified above at the option of Canadian Utilities Limited at the stated value plus accrued and unpaid dividends.

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

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

9. Class A and Class B shares

There were 81,637,086 (2006 – 81,278,986) Class A non-voting shares and 43,806,584 (2006 – 44,009,284) Class B common shares outstanding on September 30, 2007. In addition, there were 1,313,000 options to purchase Class A non-voting shares outstanding at September 30, 2007 under the Corporation's stock option plan. From October 1, 2007, to October 23, 2007, no stock options were granted or cancelled, no stock options were exercised, 5,000 Class B common shares were converted to Class A non-voting shares and no Class A non-voting shares were purchased under the Corporation's normal course issuer bid.

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

	Three Months Ended September 30		Nine Months Ended September 30	
	2007	2006	**2007**	2006
Weighted average shares outstanding	**125,433,940**	125,802,286	**125,415,320**	126,502,915
Effect of dilutive stock options	**536,860**	542,011	**516,633**	532,422
Weighted average diluted shares outstanding	**125,970,800**	126,344,297	**125,931,953**	127,035,337

The Corporation paid a Special Dividend of $0.25 per Class A and Class B share on September 1, 2006.

10. Risk management and financial instruments

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

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

The derivative assets and liabilities comprise the following:

	September 30 2007
Derivative assets – current:	
Interest rate swap agreements	$ 0.3
Derivative assets – non-current:	
Natural gas purchase contracts	$58.4
Interest rate swap agreements	0.5
	$58.9
Derivative liabilities – current:	
Interest rate swap agreements	$ 1.2
Foreign currency forward contracts	0.7
	$ 1.9
Derivative liabilities – non-current:	
Interest rate swap agreements	$ 2.9

10. Risk management and financial instruments (continued)

Interest rate risk

The Corporation has converted variable rate non-recourse long term debt to fixed rate debt through the following interest rate swap agreements:

Project Financing	Swap Fixed Interest Rate [1]	Variable Debt Interest Rate	Maturity Date	Notional Principal September 30 2007	2006
Osborne: ($33.3 million AUD (2006 – $37.4 million AUD))	7.388%	Bank Bill Rate in Australia	December 2013	**$ 29.4**	$ 31.1
APALP:	7.727%	90 day BA	November 2008	**1.9**	3.2
	7.504%	90 day BA	December 2008	**2.7**	4.5
	7.687%	6 month LIBOR	December 2011	**79.0**	85.7
Joffre:	7.286%	90 day BA	September 2012	**21.0**	25.1
Scotford:	5.306%	90 day BA	September 2008	**51.4**	55.5
Muskeg River:	5.372%	90 day BA	December 2007	**39.9**	41.8
Brighton Beach:	5.8367%	90 day BA	June 2009	**8.6**	9.1
	6.575%	90 day BA	March 2019	**34.7**	36.6
Cory:	6.532%	90 day BA	June 2011	**2.2**	2.8
				$270.8	$295.4

BA – Bankers' Acceptance
LIBOR – London Interbank Offered Rate

(1) *The above swap fixed interest rates include any long term debt margin fees; the margin fees are subject to escalation (Note 7).*

The Corporation has fixed interest rates, either directly or through interest rate swap agreements, on 98% (2006 — 96%) of total long term debt and non-recourse long term debt.

Foreign currency exchange rate risk

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

The Corporation has entered into foreign currency forward contracts in order to fix the exchange rate on certain planned equipment expenditures and operational cash flows denominated in U.S. dollars, U.K. pounds sterling ("£") and Euros. At September 30, 2007, the contracts consist of purchases of $8.4 million U.S. and £1.4 million (2006 — purchases of $1.4 million U.S. and sales of 6.0 million Euros).

Natural gas purchase contracts and associated power generation revenue contract liability

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

10. Risk management and financial instruments (continued)

As all but the excess volume of natural gas is committed to the Corporation's power generation obligations, the Corporation could not recognize the entire fair values of these natural gas purchase contracts in its revenues. Consequently, on January 1, 2007, the Corporation recognized a provision for a power generation revenue contract in the amount of $44.8 million; thereafter, the Corporation will record adjustments to the power generation revenue contract liability concurrently with the mark-to-market adjustments for the natural gas purchase contracts derivative asset. This power generation revenue contract liability is included in deferred credits in the consolidated balance sheet.

The mark-to-market adjustment for the derivative asset and the corresponding adjustment for the associated power generation revenue contract liability decreased earnings by $2.4 million, net of income taxes, for the three months ended September 30, 2007 and increased earnings by $0.1 million, net of income taxes, for the nine months ended September 30, 2007. At September 30, 2007, the natural gas purchase contracts derivative asset is $58.4 million and the power generation revenue contract liability is $44.0 million.

Credit risk

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

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

Fair value of non-derivative financial instruments

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

	September 30			
	2007		2006	
	Carrying Value	**Fair Value**	Carrying Value	Fair Value
Assets				
Cash and short term investments [1]	**$ 682.9**	**$ 682.9**	$ 732.6	$ 732.6
Accounts receivable [1]	**332.1**	**332.1**	264.7	264.7
Liabilities				
Accounts payable and accrued liabilities [2]	**380.0**	**380.0**	272.5	272.5
Long term debt [3]	**2,399.4**	**2,650.5**	2,266.5	2,661.1
Non-recourse long term debt [3]	**556.9**	**587.3**	684.0	720.0

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

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

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

10. Risk management and financial instruments (continued)

Fair value of derivative financial instruments

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

	September 30					
	2007			2006		
	Notional Principal [(1)]	**Fair Value Receivable (Payable) [(3)]**	**Maturity**	Notional Principal [(1)]	Fair Value Receivable (Payable) [(3)]	Maturity
Interest rate swaps	**$270.8**	**$(3.3)**	**2007-2019**	$295.4	$(8.2)	2007-2019
Foreign currency forward contracts	**$ 11.7**	**$(0.7)**	**2007-2008**	$ 10.3	$ 0.1	2006-2007
Natural gas purchase contracts	**N/A [(2)]**	**$58.4**	**2014**	N/A [(4)]	N/A [(4)]	N/A [(4)]

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

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

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

[(4)] *In accordance with the CICA recommendations for financial instruments, disclosures not required in financial statements for periods prior to January 1, 2007 need not be provided on a comparative basis.*

11. Other comprehensive income

Other comprehensive income ("OCI") of the Corporation is comprised of three components: the unrealized gains and losses on effective cash flow hedging instruments, the unrealized gains and losses on financial assets that are available for sale, and the foreign currency translation adjustment relating to self-sustaining foreign operations.

11. Other comprehensive income (continued)

Changes in the components of accumulated OCI are summarized below:

	Three Months Ended September 30		Nine Months Ended September 30	
	2007	2006	**2007**	2006
Accumulated OCI at beginning of period:				
Cash flow hedge losses [1]	**$ (3.8)**	$ -	**$ -**	$ -
Financial assets available for sale [2]	**0.1**	-	**-**	-
Foreign currency translation adjustment	**(10.3)**	(16.7)	**3.1**	(18.2)
	(14.0)	$(16.7)	**3.1**	(18.2)
Adjustment to accumulated OCI at beginning of period due to change in method of accounting for:				
Cash flow hedge losses [3]	**-**	-	**(7.4)**	-
Financial assets available for sale [2]	**-**	-	**0.1**	-
	-	-	**(7.3)**	-
OCI for the period:				
Changes in fair values of cash flow hedges [4]	**(1.3)**	-	**2.2**	-
Transfers of cash flow hedge losses to earnings [2]	**-**	-	**0.1**	-
	(1.3)	-	**2.3**	-
Foreign currency translation adjustment	**(11.0)**	1.7	**(24.4)**	3.2
	(12.3)	1.7	**(22.1)**	3.2
Accumulated OCI at end of period:				
Cash flow hedge losses [5]	**(5.1)**	-	**(5.1)**	-
Financial assets available for sale [2]	**0.1**	-	**0.1**	-
Foreign currency translation adjustment	**(21.3)**	(15.0)	**(21.3)**	(15.0)
	$(26.3)	$(15.0)	**$(26.3)**	$(15.0)

(1) *Net of income taxes of $1.6 million.*
(2) *Net of income taxes of nil.*
(3) *Net of income taxes of $3.2 million.*
(4) *Net of income taxes of $0.6 million and $(1.0) million, respectively.*
(5) *Net of income taxes of $2.2 million and $2.2 million, respectively.*

12. Employee future benefits

In the three months ended September 30, 2007, net expense of $3.9 million (2006 – $4.0 million) was recognized for pension benefit plans and net expense of $0.6 million (2006 – $1.2 million) was recognized for other post employment benefit plans.

In the nine months ended September 30, 2007, net expense of $11.2 million (2006 – $11.7 million) was recognized for pension benefit plans and net expense of $3.3 million (2006 – $3.7 million) was recognized for other post employment benefit plans.

13. Segmented information

Segmented results – Three months ended September 30

2007 2006	Utilities	Power Generation	Global Enterprises	Corporate and Other	Intersegment Eliminations	Consolidated
(Unaudited)						
Revenues – external	**$ 181.6**	**$ 197.6**	**$110.2**	**$ 0.5**	**$ -**	**$ 489.9**
	$ 215.0	$ 202.5	$136.0	$ 0.4	$ -	$ 553.9
Revenues – intersegment [1]	**6.2**	**-**	**34.2**	**2.9**	**(43.3)**	**-**
	6.1	-	30.0	2.9	(39.0)	-
Revenues	**$ 187.8**	**$ 197.6**	**$144.4**	**$ 3.4**	**$ (43.3)**	**$ 489.9**
	$ 221.1	$ 202.5	$166.0	$ 3.3	$ (39.0)	$ 553.9
Earnings attributable to Class A and Class B shares	**$ 14.3**	**$ 38.6**	**$ 20.9**	**$ (0.8)**	**$ (0.8)**	**$ 72.2**
	$ 19.2	$ 29.3	$ 22.1	$ (2.3)	$ (1.5)	$ 66.8

Segmented results – Nine months ended September 30

2007 2006	Utilities	Power Generation	Global Enterprises	Corporate and Other	Intersegment Eliminations	Consolidated
(Unaudited)						
Revenues – external	**$ 784.6**	**$ 579.1**	**$382.8**	**$ 1.3**	**$ -**	**$1,747.8**
	$ 777.8	$ 572.8	$407.7	$ 1.0	$ -	$1,759.3
Revenues – intersegment [1]	**18.6**	**-**	**91.6**	**8.8**	**(119.0)**	**-**
	18.3	-	85.6	8.4	(112.3)	-
Revenues	**$ 803.2**	**$ 579.1**	**$474.4**	**$ 10.1**	**$(119.0)**	**$1,747.8**
	$ 796.1	$ 572.8	$493.3	$ 9.4	$(112.3)	$1,759.3
Earnings attributable to Class A and Class B shares	**$ 91.7**	**$ 109.2**	**$ 82.3**	**$ 7.2**	**$ (2.4)**	**$ 288.0**
	$ 77.5	$ 82.3	$ 73.7	$ (5.2)	$ (4.4)	$ 223.9
Total assets	**$3,968.2**	**$2,222.0**	**$308.5**	**$477.9**	**$ 85.2**	**$7,061.8**
	$3,646.6	$2,174.1	$295.3	$518.6	$ 66.3	$6,700.9

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

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CANADIAN UTILITIES LIMITED
An ATCO Company

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2007

CANADIAN UTILITIES LIMITED

MANAGEMENT'S DISCUSSION AND ANALYSIS
OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS ("MD&A")

The following discussion and analysis of financial condition and results of operations of Canadian Utilities Limited (the "Corporation") should be read in conjunction with the Corporation's unaudited interim consolidated financial statements for the nine months ended September 30, 2007, and the audited consolidated financial statements and management's discussion and analysis of financial condition and results of operations for the year ended December 31, 2006 ("2006 MD&A"). Information contained in the 2006 MD&A that is not discussed in this document remains substantially unchanged. Additional information relating to the Corporation, including the Corporation's Annual Information Form, is available on SEDAR at www.sedar.com.

The equity securities of the Corporation consist of Class A non-voting shares ("Class A shares") and Class B common shares ("Class B shares").

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FORWARD-LOOKING INFORMATION

Certain statements contained in this MD&A constitute forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "anticipate", "plan", "estimate", "expect", "may", "will", "intend", "should", and similar expressions. These statements involve 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 statements. The Corporation believes that the expectations reflected in the forward-looking statements are reasonable, but no assurance can be given that these expectations will prove to be correct and such forward-looking statements should not be unduly relied upon.

In particular, this MD&A contains forward-looking statements pertaining to contractual obligations, planned capital expenditures, the impact of changes in government regulation and non-regulated generating capacity subject to long term contracts. The Corporation's actual results could differ materially from those anticipated in these forward-looking statements as a result of regulatory decisions, competitive factors in the industries in which the Corporation operates, prevailing economic conditions, and other factors, many of which are beyond the control of the Corporation.

NON-GAAP FINANCIAL MEASURES

In this MD&A, reference is made to funds generated by operations, which is a measure that does not have a standardized meaning under Canadian generally accepted accounting principles ("GAAP"). Funds generated by operations is calculated on the Corporation's consolidated statement of cash flows from operating activities before changes in non-cash working capital. In the Corporation's opinion, funds generated by operations is a significant performance indicator of the Corporation's ability to generate cash flow to fund its capital expenditures.

INTERNAL CONTROL OVER FINANCIAL REPORTING

There were no changes in the Corporation's internal control over financial reporting that occurred during the three months ended September 30, 2007, that have materially affected, or are reasonably likely to materially affect, the Corporation's internal control over financial reporting.

BUSINESS OF THE CORPORATION

The Corporation's financial statements are consolidated from three Business Groups: Utilities, Power Generation and Global Enterprises. For the purposes of financial disclosure, corporate transactions are accounted for as Corporate and Other (refer to Note 13 to the unaudited interim consolidated financial statements for the nine months ended September 30, 2007). Transactions between Business Groups are eliminated in all reporting of the Corporation's consolidated financial information.

SIGNIFICANT NON-OPERATING FINANCIAL ITEMS

Natural Gas Purchase Contracts and Associated Power Generation Revenue Contract Liability

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

As all but the excess volume of natural gas is committed to the Corporation's power generation obligations, the Corporation could not recognize the entire fair values of these natural gas purchase contracts in its revenues. Consequently, on January 1, 2007, the Corporation recognized a provision for a power generation revenue contract in the amount of $44.8 million; thereafter, the Corporation will record adjustments to the power generation revenue contract liability concurrently with the mark-to-market adjustments for the natural gas purchase contracts derivative asset. This power generation revenue contract liability is included in deferred credits in the consolidated balance sheet.

The mark-to-market adjustment for the derivative asset and the corresponding adjustment for the associated power generation revenue contract liability **decreased** earnings by $2.4 million, net of income taxes, for the three months ended September 30, 2007, and **increased** earnings by $0.1 million, net of income taxes, for the nine months ended September 30, 2007 ("Mark-to-Market Adjustment"). At September 30, 2007, the natural gas purchase contracts derivative asset is $58.4 million and the power generation revenue contract liability is $44.0 million.

TXU Europe Settlement

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

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

Based on the foreign currency exchange rate in effect on March 30, 2005, the Corporation's share of this settlement is expected to generate earnings after income taxes of approximately $69 million, which will be recognized over the remaining term of the TXU Europe contract to September 30, 2010, at approximately $11 million per year. These earnings will be dependent upon foreign currency exchange rates in effect at the time that the earnings are recognized.

On May 31, 2007, £95.0 million of the TXU proceeds (of which the Corporation's share is $52.7 million), were applied to Barking Power's non-recourse long term debt.

H.R. Milner Income Tax Reassessment

In the third quarter of 2006, the Canada Revenue Agency ("CRA") issued a reassessment for Alberta Power (2000)'s 2001 taxation year. The CRA's reassessment treats the proceeds received from the sale of the H.R. Milner generating plant to the Alberta Balancing Pool as income rather than as a sale of an asset. The Corporation appealed the reassessment to the Tax Court of Canada. The full impact of the reassessment was a $12.4 million increase in interest and income tax expense, a $12.4 million decrease in earnings ($8.0 million recorded in the second quarter of 2006 and $4.4 million recorded in the third quarter of 2006), and a $28.8 million payment associated with the tax and interest assessed, paid in the third quarter of 2006. It is expected that $16.4 million of this cash payment will be recovered by reducing income taxes payable through higher capital cost allowance claims in future years.

2007 Change in the Taxation of Preferred Share Dividends

On June 15, 2007, an amendment to tax legislation pertaining to the taxation of preferred share dividends paid by corporations received third reading in the House of Commons. This change pertains to taxes paid by corporations that pay dividends on taxable preferred shares (Part VI.1 tax). Prior to this change, corporations that paid Part VI.1 tax were entitled to an income tax deduction equal to 9/4ths of the Part VI.1 tax paid. Effective January 1, 2003, this deduction was increased to 9/3rds of the Part VI.1 tax paid. The CRA has been assessing corporate tax returns based on this proposed change since January 1, 2003, resulting in a reduction of taxes paid to the CRA. As this change is now considered to have been substantively enacted, the Corporation recorded a reduction to current income tax expense of $16.4 million in the second quarter of 2007. Funds generated by operations increased by $16.4 million, offset by a similar reduction in changes in non-cash working capital, leaving the Corporation's cash position unchanged ("Part VI.1 Tax Adjustment").

The earnings impact of the Part VI.1 Tax Adjustment by Business Group is as follows:

($ Millions)	Years Prior to 2007	First Quarter of 2007	Total
Utilities	4.2	0.2	4.4
Power Generation	1.3	0.1	1.4
Global Enterprises	1.4	-	1.4
Corporate and Other	8.7	0.5	9.2
Total	15.6	0.8	16.4

2006 Changes in Income Taxes and Rates

In 2006, Federal and provincial governments announced a number of changes to income taxes and rates. As a result of these changes the Corporation made an adjustment to income taxes amounting to $11.8 million in the second quarter of 2006, most of which related to future income taxes. The adjustment increased 2006 earnings by $11.8 million, of which $1.9 million related to the Utilities Business Group, $7.2 million to the Power Generation Business Group, $2.3 million to the Global Enterprises Business Group and $0.4 million to Corporate and Other.

SELECTED QUARTERLY INFORMATION

	For the Three Months Ended			
($ Millions except per share data)	Mar. 31	Jun. 30	Sep. 30	Dec. 31
		(unaudited)		
2007 (1) (2) (3)				
Revenues	697.6	560.3	489.9	....
Earnings attributable to Class A and Class B shares	134.7	81.1	72.2	....
Earnings per Class A and Class B share	1.07	0.65	0.58	....
Diluted earnings per Class A and Class B share	1.07	0.64	0.58	....
2006 (1) (2) (3)				
Revenues	642.0	563.4	553.9	671.1
Earnings attributable to Class A and Class B shares	86.9	70.2	66.8	100.0
Earnings per Class A and Class B share	0.68	0.56	0.53	0.80
Diluted earnings per Class A and Class B share	0.68	0.55	0.53	0.80
2005 (1) (2) (3)				
Revenues	....	....	....	680.3
Earnings attributable to Class A and Class B shares	....	....	....	89.1
Earnings per Class A and Class B share	....	....	....	0.70
Diluted earnings per Class A and Class B share	....	....	....	0.69

Notes:

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

(2) Due to the seasonal nature of the Corporation's operations, changes in electricity prices in Alberta, the timing and demand of natural gas storage capacity sold, changes in natural gas storage fees and the timing of rate decisions, revenues and earnings for any quarter are not necessarily indicative of operations on an annual basis.

(3) Includes impact from Significant Non-Operating Financial Items (refer to Significant Non-Operating Financial Items section).

(4) The above data has been extracted from the financial statements which have been prepared in accordance with Canadian generally accepted accounting principles and the reporting currency is the Canadian dollar.

RESULTS OF OPERATIONS

The principal factors that have caused variations in **revenues** and **earnings** over the eight most recently completed quarters necessary to understand general trends that have developed and the seasonality of the businesses disclosed in the 2006 MD&A remain substantially unchanged, except for the impact of the 2007 change in the taxation of preferred share dividends.

Consolidated Operations

Revenues, earnings attributable to Class A and Class B shares, and earnings and diluted earnings per share were as follows:

	For the Three Months Ended September 30		For the Nine Months Ended September 30	
($ Millions, except per share data)	**2007**	2006	**2007**	2006
	(unaudited)			
Revenues (1) (2) (3)	**489.9**	553.9	**1,747.8**	1,759.3
Earnings attributable to Class A and Class B shares (1) (2) (3)	**72.2**	66.8	**288.0**	223.9
Earnings per Class A share and Class B share (1) (2) (3)	**0.58**	0.53	**2.30**	1.77
Diluted earnings per Class A share and Class B share (1) (2) (3)	**0.58**	0.53	**2.29**	1.76

Notes:

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

(2) Due to the seasonal nature of the Corporation's operations, changes in electricity prices in Alberta, the timing and demand of natural gas storage capacity sold, changes in natural gas storage fees and the timing of rate decisions, revenues and earnings for any quarter are not necessarily indicative of operations on an annual basis.

(3) Includes impact from Significant Non-Operating Financial Items (refer to Significant Non-Operating Financial Items section).

(4) The above data has been extracted from the financial statements which have been prepared in accordance with Canadian generally accepted accounting principles and the reporting currency is the Canadian dollar.

Revenues for the three months ended September 30, 2007, **decreased** by $64.0 million to $489.9 million, primarily due to:

- refund of future income tax balances resulting from the ATCO Electric GTA Decision (refer to Regulatory Matters – ATCO Electric section);
- lower natural gas fuel purchases recovered on a "no-margin" basis in ATCO Power's United Kingdom ("U.K.") operations;
- decreased business activity in ATCO Frontec's operations; and
- lower prices and volumes of natural gas processed for Natural Gas Liquids ("NGL") extraction in ATCO Midstream (refer to Business Risks – Non-Regulated Operations – ATCO Midstream section).

This decrease was partially offset by:

- impact of finalization of customer rates related to ATCO Gas GRA Decision (refer to Regulatory Matters – ATCO Gas section);
- colder temperatures and customer growth in ATCO Gas; and
- improved merchant performance in ATCO Power's Alberta generating plants.

Revenues for the nine months ended September 30, 2007, **decreased** by $11.5 million to $1,747.8 million, primarily due to:

- refund of future income tax balances resulting from the ATCO Electric GTA Decision (refer to Regulatory Matters – ATCO Electric section);
- lower prices and volumes of natural gas processed for NGL extraction in ATCO Midstream (refer to Business Risks – Non-Regulated Operations – ATCO Midstream section);
- lower natural gas fuel purchases recovered on a "no-margin" basis in ATCO Power's U.K. operations; and
- decreased business activity in ATCO Frontec's operations.

This decrease was partially offset by:

- colder temperatures, customer growth and higher sales per customer in ATCO Gas;
- the timing and demand of natural gas storage capacity sold and higher storage fees in ATCO Midstream (refer to Business Risks – Non-Regulated Operations – ATCO Midstream section); and
- impact of the ATCO Electric GTA Decision (refer to Regulatory Matters – ATCO Electric section).

Earnings attributable to Class A and Class B shares for the three months ended September 30, 2007, **increased** by $5.4 million ($0.05 per share) to $72.2 million ($0.58 per share), primarily due to:

- H.R. Milner Income Tax Reassessment in 2006 (refer to H.R. Milner Income Tax Reassessment section);
- reduced tax expense resulting from lower future corporate tax rates in ATCO Power's U.K. operations; and
- improved performance in ATCO Power's Alberta generating plants.

This increase was partially offset by:

- the timing and demand of natural gas storage capacity sold, lower storage fees and lower volumes for NGL in ATCO Midstream (refer to Business Risks – Non-Regulated Operations – ATCO Midstream section);
- higher operating and maintenance expenses and depreciation expenses in ATCO Gas due to customer growth and increased capital expenditures; and
- Calgary Stores Block decision in 2006 in ATCO Gas (refer to Regulatory Matters – ATCO Gas section).

Earnings attributable to Class A and Class B shares for the nine months ended September 30, 2007, **increased** by $64.1 million ($0.53 per share) to $288.0 million ($2.30 per share), primarily due to:

- $16.4 million Part VI.1 Tax Adjustment (refer to 2007 Change in the Taxation of Preferred Share Dividends section);
- improved merchant performance, increased availability, higher exchange rates on conversion of earnings to Canadian dollars and reduced tax resulting from lower future corporate tax rates in ATCO Power's U.K. operations;
- colder temperatures, customer growth and higher sales per customer in ATCO Gas; and
- H.R. Milner Income Tax Reassessment in 2006 (refer to H.R. Milner Income Tax Reassessment section).

This increase was partially offset by:

- $11.8 million adjustment in 2006 to reflect tax changes (refer to 2006 Changes in Income Taxes and Rates section);
- higher operating and maintenance expenses and depreciation expenses in ATCO Gas due to customer growth and increased capital expenditures; and
- increased share appreciation rights expense due to changes in Canadian Utilities Limited Class A non-voting share and ATCO Ltd. Class I share prices since December 2006.

Operating expenses (consisting of natural gas supply, purchased power, operation and maintenance, selling and administrative and franchise fee costs) for the three months ended September 30, 2007, **decreased** by $17.0 million to $306.6 million, primarily due to:

- lower operating and maintenance expenses in ATCO Frontec, due to decreased business activity;
- lower natural gas fuel purchases recovered on a "no-margin" basis in ATCO Power's U.K. operations; and
- lower prices and volumes of natural gas purchased for NGL extraction in ATCO Midstream.

This decrease was partially offset by:

- higher operating and maintenance expenses in ATCO Gas due to customer growth and increased capital expenditures; and
- higher operating and maintenance expenses in ATCO Electric, due to increased capital expenditures.

Operating expenses for the nine months ended September 30, 2007, **decreased** by $9.9 million to $997.3 million, primarily due to:

- lower natural gas fuel purchases recovered on a "no-margin" basis in ATCO Power's U.K. operations;
- lower operating and maintenance expenses in ATCO Frontec due to decreased business activity; and
- lower prices and volumes of natural gas purchased for NGL extraction in ATCO Midstream.

This decrease was partially offset by:

- higher operating and maintenance expenses in ATCO Electric due to increased capital expenditures; and
- higher operating and maintenance expenses in ATCO Gas due to customer growth and increased capital expenditures.

Depreciation and amortization expenses for the three months ended September 30, 2007, **increased** by $4.0 million to $77.3 million, primarily due to:

- capital additions in 2007 and 2006.

Depreciation and amortization expenses for the nine months ended September 30, 2007, were **substantially unchanged**, primarily due to:

- one-time amortization charge of certain deferred items approved by the Alberta Energy and Utilities Board ("AEUB") in the ATCO Gas GRA Decision recorded in the second quarter of 2006.

Partially offset by:

- capital additions in 2007 and 2006.

Interest expense for the three and nine months ended September 30, 2007, **decreased** by $0.2 million to $54.1 million, and by $5.9 million to $162.4 million, respectively, primarily due to:

- refinancing and repayment of higher cost financings in 2007 and 2006; and
- H.R. Milner Income Tax Reassessment in 2006 (refer to H.R. Milner Income Tax Reassessment section).

This decrease was partially offset by:

- interest on new financings issued in 2006 to fund capital expenditures in Utilities operations.

Interest and other income for the three months ended September 30, 2007, **decreased** by $5.9 million to $11.4 million, primarily due to:

- Calgary Stores Block decision in 2006 in ATCO Gas (refer to Regulatory Matters – ATCO Gas section); and
- Mark-to-Market Adjustment (refer to Natural Gas Purchase Contracts and Associated Power Generation Revenue Contract Liability section).

Interest and other income for the nine months ended September 30, 2007, **increased** by $3.4 million to $43.0 million, primarily due to:

- higher short term interest rates on cash investments.

This increase was partially offset by:

- Calgary Stores Block decision in 2006 in ATCO Gas (refer to Regulatory Matters – ATCO Gas section).

Income taxes for the three months ended September 30, 2007, **decreased** by $61.4 million to $(17.2) million, primarily due to:

- refund of future income tax balances and lower current income tax expense resulting from the ATCO Electric GTA Decision (refer to Regulatory Matters – ATCO Electric section); and
- H.R. Milner Income Tax Reassessment in 2006 (refer to H.R. Milner Income Tax Reassessment section).

Income taxes for the nine months ended September 30, 2007, **decreased** by $55.1 million to $64.6 million, primarily due to:

- refund of future income tax balances and lower current income tax expense resulting from the ATCO Electric GTA Decision (refer to Regulatory Matters – ATCO Electric section);
- $16.4 million Part VI.1 Tax Adjustment (refer to 2007 Change in the Taxation of Preferred Share Dividends section; and
- H.R. Milner Income Tax Reassessment in 2006 (refer to H.R. Milner Income Tax Reassessment section).

This decrease was partially offset by:

- $11.8 million adjustment in 2006 to reflect tax changes (refer to 2006 Changes in Income Taxes and Rates section).

Segmented Information

Segmented revenues for the three and nine months ended September 30, 2007, were as follows:

	For the Three Months Ended September 30		**For the Nine Months Ended September 30**	
($ Millions)	**2007**	2006	**2007**	2006
		(unaudited)		
Utilities	**187.8**	221.1	**803.2**	796.1
Power Generation	**197.6**	202.5	**579.1**	572.8
Global Enterprises	**144.4**	166.0	**474.4**	493.3
Corporate and Other	**3.4**	3.3	**10.1**	9.4
Intersegment eliminations	**(43.3)**	(39.0)	**(119.0)**	(112.3)
Total	**489.9**	553.9	**1,747.8**	1,759.3

Note:

(1) Includes impact from Significant Non-Operating Financial Items (refer to Significant Non-Operating Financial Items section).

Segmented earnings attributable to Class A and Class B shares for the three and nine months ended September 30, 2007, were as follows:

	For the Three Months Ended September 30		**For the Nine Months Ended September 30**	
($ Millions)	**2007**	2006	**2007**	2006
		(unaudited)		
Utilities	**14.3**	19.2	**91.7**	77.5
Power Generation	**38.6**	29.3	**109.2**	82.3
Global Enterprises	**20.9**	22.1	**82.3**	73.7
Corporate and Other	**(0.8)**	(2.3)	**7.2**	(5.2)
Intersegment eliminations	**(0.8)**	(1.5)	**(2.4)**	(4.4)
Total	**72.2**	66.8	**288.0**	223.9

Note:

(1) Includes impact from Significant Non-Operating Financial Items (refer to Significant Non-Operating Financial Items section).

Utilities

Revenues from the Utilities Business Group for the three months ended September 30, 2007, **decreased** by $33.3 million to $187.8 million, primarily due to:

- refund of future income tax balances resulting from the ATCO Electric GTA Decision (refer to Regulatory Matters – ATCO Electric section).

This decrease was partially offset by:

- impact of finalization of customer rates in the ATCO Gas GRA Decision (refer to Regulatory Matters – ATCO Gas section); and
- colder temperatures and customer growth in ATCO Gas.

Temperatures in ATCO Gas for the three months ended September 30, 2007, were 9.9% colder than normal, compared to 3.8% warmer than normal for the corresponding period in 2006.

Revenues for the nine months ended September 30, 2007, **increased** by $7.1 million to $803.2 million, primarily due to:

- colder temperatures, customer growth and higher sales per customer in ATCO Gas; and
- impact of the ATCO Electric GTA Decision (refer to Regulatory Matters – ATCO Electric section).

This increase was partially offset by:

- refund of future income tax balances resulting from the ATCO Electric GTA Decision (refer to Regulatory Matters – ATCO Electric section).

Temperatures in ATCO Gas for the nine months ended September 30, 2007, were 2.0% warmer than normal, compared to 12.4% warmer than normal for the corresponding period in 2006.

Earnings for the three months ended September 30, 2007, **decreased** by $4.9 million to $14.3 million, primarily due to:

- higher operating and maintenance expenses and depreciation expenses in ATCO Gas due to customer growth and increased capital expenditures; and
- Calgary Stores Block decision in 2006 in ATCO Gas (refer to Regulatory Matters – ATCO Gas section).

Earnings for the nine months ended September 30, 2007, **increased** by $14.2 million to $91.7 million, primarily due to:

- colder temperatures, customer growth and higher sales per customer in ATCO Gas; and
- $4.4 million Part VI.1 Tax Adjustment (refer to 2007 Change in the Taxation of Preferred Share Dividends section).

This increase was partially offset by:

- higher operating and maintenance expenses and depreciation expenses in ATCO Gas due to customer growth and increased capital expenditures.

Utilities Business Group capital expenditures to maintain capacity and meet planned growth are expected to be approximately $600 million in 2007. The total three year (2007-2009) anticipated capital expenditures in the Utilities Business Group are expected to be approximately $2.1 billion.

Power Generation

Revenues from the Power Generation Business Group for the three months ended September 30, 2007, **decreased** by $4.9 million to $197.6 million, primarily due to:

- lower natural gas fuel purchases recovered on a "no-margin" basis in ATCO Power's U.K. operations; and
- lower merchant revenues in ATCO Power's U.K. operations.

This decrease was partially offset by:

- improved merchant performance in ATCO Power's Alberta generating plants; and
- increased generation at Alberta Power (2000)'s Battle River generating plant due to improved plant performance.

Revenues for the nine months ended September 30, 2007, **increased** by $6.3 million to $579.1 million, primarily due to:

- impact of higher U.K. and Australian exchange rates on conversion of revenues to Canadian dollars in ATCO Power's U.K and Australian operations;
- improved merchant performance in ATCO Power's Alberta generating plants;
- increased generation at Alberta Power (2000)'s Battle River generating plant due to improved plant performance; and
- higher revenues in ATCO Power's Australian operations due to higher power prices.

This increase was partially offset by:

- lower natural gas fuel purchases recovered on a "no-margin" basis in ATCO Power's U.K. operations.

Earnings for the three months ended September 30, 2007, **increased** by $9.3 million to $38.6 million, primarily due to:

- H.R. Milner Income Tax Reassessment in 2006 (refer to H.R. Milner Income Tax Reassessment section);
- reduced tax expense resulting from lower future corporate tax rates in ATCO Power's U.K. operations; and
- improved performance in ATCO Power's Alberta generating plants.

Earnings for the nine months ended September 30, 2007, **increased** by $26.9 million to $109.2 million, primarily due to:

- improved merchant performance, increased availability, higher exchange rates on conversion of earnings to Canadian dollars and reduced tax resulting from lower future corporate tax rates in ATCO Power's U.K. operations;
- H.R. Milner Income Tax Reassessment in 2006 (refer to H.R. Milner Income Tax Reassessment section); and
- improved performance in ATCO Power's Alberta generating plants.

This increase was partially offset by:

- $7.2 million adjustment in 2006 to reflect tax changes (refer to 2006 Changes in Income Taxes and Rates section).

Impacting Alberta Power (2000)'s revenues and earnings for the three and nine months ended September 30, 2007, were lower Power Purchase Arrangement ("PPA") tariffs due to declining rate bases at the Battle River and Sheerness generating plants and a decline in the return on common equity rate (2007 – 8.65%, 2006 – 8.75%). These return on common equity rates are based on long term Government of Canada bond yields plus 4.5%.

Alberta Power Pool Electricity Prices

Spark spread is related to the difference between Alberta Power Pool electricity prices and the marginal cost of producing electricity from natural gas. These spark spreads are based on an approximate industry heat rate of 7.5 gigajoules per megawatt hour.

Changes in spark spread affect the results of approximately 408 megawatts of plant capacity owned in Alberta by ATCO Power and Alberta Power (2000) out of a total Alberta owned capacity of approximately 1,703 megawatts and a worldwide owned capacity of approximately 2,468 megawatts.

Alberta Power Pool electricity prices for the three months ended September 30, 2007, averaged $92.88 per megawatt hour, compared to average prices of $95.31 per megawatt hour for the corresponding period in 2006. Natural gas prices for the three months ended September 30, 2007, averaged $4.86 per gigajoule, compared to average prices of $5.33 per gigajoule for the corresponding period in 2006. The consequence of these electricity and natural gas prices was an average spark spread of $56.47 per megawatt hour for the three months ended September 30, 2007, compared to $55.37 per megawatt hour for the corresponding period in 2006.

Alberta Power Pool electricity prices for the nine months ended September 30, 2007, averaged $68.68 per megawatt hour, compared to average prices of $68.59 per megawatt hour for the corresponding period in 2006. Natural gas prices for the nine months ended September 30, 2007, averaged $6.20 per gigajoule, compared to average prices of $6.05 per gigajoule for the corresponding period in 2006. The consequence of these electricity and natural gas prices was an average spark spread of $22.20 per megawatt hour for the nine months ended September 30, 2007, compared to $23.24 per megawatt hour for the corresponding period in 2006.

Deferred Availability Incentives

During the three months ended September 30, 2007, Alberta Power (2000)'s **deferred availability incentive** account decreased by $5.3 million to $37.3 million. The decrease was due to planned outages and the quarterly amortization of deferred availability incentives. During the three months ended September 30, 2007, the amortization of deferred availability incentives, recorded in revenues, increased by $0.4 million to $3.0 million, compared to the same period in 2006.

During the nine months ended September 30, 2007, Alberta Power (2000)'s **deferred availability incentive** account decreased by $2.3 million to $37.3 million. The decrease was due to planned outages and the quarterly amortization of deferred availability incentives offset by incentive billings received. During the nine months ended September 30, 2007, the amortization of deferred availability incentives, recorded in revenues, increased by $1.0 million to $8.9 million, compared to the same period in 2006.

Recent Developments

Alberta Power (2000) operated the Rainbow generating plant during 2006 and the electricity generated was sold to the Alberta Power Pool. Alberta Power (2000) had one year after the expiry of the PPA for the Rainbow generating plant (December 31, 2005) to determine whether to decommission the plant in order to fully recover plant decommissioning costs or to continue to operate the plant. In the first quarter of 2007 the Alberta Electric System Operator ("AESO") and Alberta Power (2000) executed a contract resulting in Alberta Power (2000) continuing to operate the plant and thus be responsible for future decommissioning costs. These costs are included in Alberta Power (2000)'s asset retirement obligation liability.

On May 10, 2007, ATCO Power announced that it will construct a 45 megawatt natural gas-fired unit for its Valleyview generating plant in Valleyview, Alberta. All of the electricity produced by the unit will be sold to the Alberta Power Pool. Construction of the unit is scheduled for completion in 2008.

On July 1, 2007, the Piikani Nation of Brockett, Alberta, exercised its option to purchase a 25% interest in ATCO Power's and ATCO Resources' 32 megawatt hydroelectric generating plant at the Oldman River dam near Pincher Creek, Alberta.

Global Enterprises

Revenues from the Global Enterprises Business Group for the three months ended September 30, 2007, **decreased** by $21.6 million to $144.4 million, primarily due to:

- decreased business activity in ATCO Frontec's operations;
- lower prices and volumes of natural gas processed for NGL extraction in ATCO Midstream (refer to Business Risks – Non-Regulated Operations – ATCO Midstream section); and
- the timing and demand of natural gas storage capacity sold and lower storage fees in ATCO Midstream (refer to Business Risks – Non-Regulated Operations – ATCO Midstream section).

Revenues for the nine months ended September 30, 2007, **decreased** by $18.9 million to $474.4 million, primarily due to:

- lower prices and volumes of natural gas processed for NGL extraction in ATCO Midstream (refer to Business Risks – Non-Regulated Operations – ATCO Midstream section); and
- decreased business activity in ATCO Frontec's operations.

This decrease was partially offset by:

- the timing and demand of natural gas storage capacity sold and higher storage fees in ATCO Midstream (refer to Business Risks – Non-Regulated Operations – ATCO Midstream section).

Earnings for the three months ended September 30, 2007, were **substantially unchanged.**

Earnings for the nine months ended September 30, 2007, **increased** by $8.6 million to $82.3 million, primarily due to:

- the timing and demand of natural gas storage capacity sold and higher storage fees in ATCO Midstream (refer to Business Risks – Non-Regulated Operations – ATCO Midstream section).

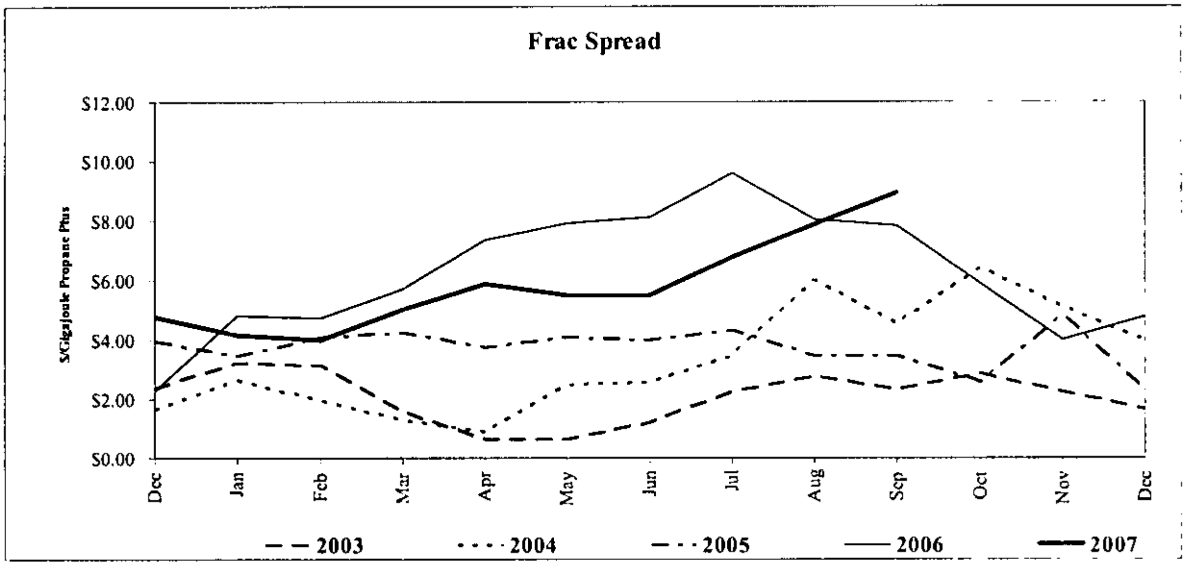
This increase was partially offset by:

- lower volumes and margins for NGL in ATCO Midstream (refer to Business Risks – Non-Regulated Operations – ATCO Midstream section).

ATCO Midstream

ATCO Midstream provides natural gas producers with gathering, processing and natural gas liquids extraction services and natural gas storage services.

ATCO Midstream's natural gas liquids extraction operations involve the extraction of natural gas liquids (ethane, propane, butane, pentane and certain other hydrocarbons) from natural gas and the replacement (on a heat content equivalent basis) of the natural gas liquids extracted with natural gas ("shrinkage gas"). For propane, butane, pentane and the other hydrocarbons ("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 January 2003 to September 2007.



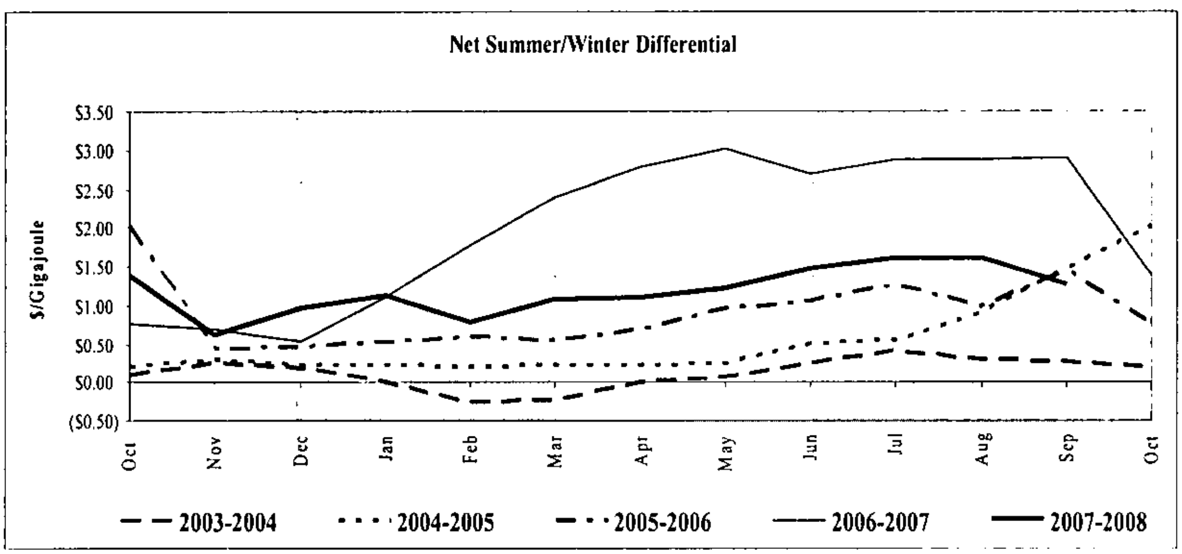
The above table represents measurements of frac spreads as reported by an independent consultant and does not necessarily represent the frac spreads received by ATCO Midstream.

The frac spread can also vary with the proportion of each liquid in the Propane Plus extracted which is dependent on the quantity of natural gas liquids in the natural gas and the performance of the plant.

Fluctuations in frac spreads may have a significant impact on ATCO Midstream's earnings and cash flow from operations in the future. A $1.00 change in the average annual frac spread may impact annual earnings by as much as $7 million. Total net ownership capacity of ATCO Midstream's natural gas liquids plants is 411 million cubic feet per day.

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

Summer/winter natural gas storage differential can be very volatile, as shown in the following graph, which illustrates a range of differentials experienced during the storage periods from 2003-2004 to 2007-2008.



On October 5, 2007, ATCO Midstream announced that it had entered into an agreement to purchase a 50% interest in a joint venture which owns and operates a 2.5 million cubic feet per day natural gas processing plant near Kisbey, Saskatchewan and 22 kilometers of pipeline serving four regional natural gas producers. Bayhurst Energy Services Corporation ("Bayhurst Energy"), a subsidiary of SaskEnergy Incorporated, owns the remaining interest in the joint venture. Bayhurst Energy will be the operator of the plant, with ATCO Midstream providing both operational and marketing support.

ATCO Frontec

In June 2007, the Corporation was awarded five NATO support contracts at the Kandahar Airfield in Afghanistan for up to five years. Specific sectors of responsibility will include fire and crash rescue, visiting aircraft cross-servicing services, roads and grounds maintenance, facility maintenance, construction, engineering, equipment and vehicle maintenance, aircraft movement control and terminal transport, accommodation services, supply operations, airfield mechanical transport, delivery of potable water, sewage management, and waste management and disposal.

In June 2007, UQSUQ Corporation, a joint venture between ATCO Frontec and Nunavut Petroleum Corporation, was awarded a five year contract renewal to lease and operate the 79 million litre bulk fuel storage facility, the pipeline distribution system and the municipal fuel distribution system in Iqaluit, Nunavut.

On October 17, 2007, ATCO Frontec announced that it had entered into a limited partnership with the Fort McKay First Nation to construct, own and operate a new 500-room lodge in Fort McMurray, Alberta. The Creeburn Lodge, which will be primarily assembled using modules built by ATCO Structures Inc., is scheduled for Phase one completion in February 2008, with full operations scheduled for July 2008. The lodge has been designed to allow for future expansion to 1,000 rooms.

Corporate and Other

Earnings for the three months ended September 30, 2007, **increased** by $1.5 million to $(0.8) million, primarily due to:

- higher short term interest rates on cash investments.

This increase was partially offset by:

- increased share appreciation rights expense due to changes in Canadian Utilities Limited Class A share and ATCO Ltd. Class I Non-Voting share prices since June 30, 2007.

Earnings for the nine months ended September 30, 2007, **increased** by $12.4 million to $7.2 million, primarily due to:

- $9.2 million Part VI.1 Tax Adjustment (refer to 2007 Change in the Taxation of Preferred Share Dividends section); and
- higher short term interest rates on cash investments.

This increase was partially offset by:

- increased share appreciation rights expense due to changes in Canadian Utilities Limited Class A share and ATCO Ltd. Class I Non-Voting share prices since December 31, 2006.

REGULATORY MATTERS

Regulated operations are conducted by wholly owned subsidiaries of the Corporation's wholly owned subsidiary, CU Inc.

- ATCO Electric and its subsidiaries Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical;
- the ATCO Gas and ATCO Pipelines divisions of ATCO Gas and Pipelines Ltd.; and
- the Battle River and Sheerness generating plants of Alberta Power (2000).

Regulated operations in Alberta (except for the generating plants of Alberta Power (2000)) are subject to a generic cost of capital regime:

- in July 2004, the AEUB issued the generic cost of capital decision which established, among other things:
  - a standardized approach for each utility company regulated by the AEUB for determining the rate of return on common equity;
    - rate of return adjusted annually by 75% of the change in long term Government of Canada bond yield as forecast; and
    - adjustment mechanism similar to the method the National Energy Board uses in determining its formula based rate of return;
  - the capital structure for each utility regulated by the AEUB; and
- in November 2005, the AEUB announced a generic return on common equity of 8.93% for 2006;
- in January 2006, the AEUB clarified that the generic return on equity determined on an annual basis in accordance with the generic cost of capital decision should apply to each year of the test period in the companies' applications. 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; and
- in November 2006, the AEUB announced a generic return on common equity of 8.51% for 2007.

ATCO Electric, ATCO Gas and ATCO Pipelines purchase information technology services, and 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 AEUB approval. Since 2003, the costs have been approved on a placeholder basis, and are subject to final AEUB approval after completion of the collaborative benchmarking process. The benchmarking report is expected in the fourth quarter of 2007, at which time an application will be made to the AEUB to finalize the placeholder costs. An AEUB decision is expected in early 2008.

ATCO Electric

In March 2006, the AEUB issued a decision on ATCO Electric's 2005 and 2006 General Tariff Application:

- which established, among other things, the amount of revenue to be collected in 2005 and 2006 from customers for transmission and distribution services and approved a return on common equity as determined by the AEUB's standardized rate of return methodology – 9.5% in 2005 and 8.93% in 2006;
- ATCO Electric's 2005 earnings were negatively impacted by $1.3 million, recorded in first quarter of 2006; and
- ATCO Electric's 2006 earnings were reduced by an additional $1.6 million, compared to 2005 earnings, recorded throughout 2006.

In August 2006, the AEUB approved the AESO application for the need to improve transmission infrastructure in northwest Alberta:

- AEUB decision grants the AESO approval to assign to the Transmission Facility Owner, ATCO Electric, work consisting of several distinct projects which will result in 725 kilometres of new transmission line to be constructed by 2011;
  - in June 2007, the first of these distinct projects was assigned to ATCO Electric by the AESO. This project consists of a 235 kilometre transmission line with an estimated cost of $210 million, and is anticipated to be completed by 2010. ATCO Electric has applied to the AEUB for approval to build and operate this project; and
  - as a result of price escalation caused by the change in completion date of the remaining distinct projects (post 2010), coupled with the increasing costs of construction in Alberta, ATCO Electric is unable, at this time, to estimate the cost of the entire project; and
- ATCO Electric anticipates that an additional 180 kilometres of transmission line projects will be required in its service area over the next five years.

In November 2006, ATCO Electric filed a general tariff application with the AEUB for the 2007 and 2008 test years:

- requesting, among other things, increased revenues to recover increased financing, depreciation and operating costs associated with increased rate base in Alberta;
- in November 2006, ATCO Electric filed an application requesting interim refundable rates for transmission and distribution operations, pending the AEUB's decision on the general tariff application; and
- on December 19, 2006, ATCO Electric received a decision from the AEUB approving interim refundable rate increases amounting to 50% of ATCO Electric's requested increases for transmission and distribution operations.

In September 2007, the AEUB issued a decision on ATCO Electric's general tariff application for the 2007 and 2008 test years ("ATCO Electric GTA Decision"):

- which established, among other things, the amount of revenue to be collected in 2007 and 2008 from customers for transmission and distribution services and approved a return on common equity as determined by the AEUB's standardized rate of return methodology – 8.51% in 2007. A final rate for 2008 will be determined in November 2007, in accordance with the AEUB standardized 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 lower approved rate of return on common equity (8.51% in 2007 versus 8.93% in 2006) and other adjustments; and
- the decision directed ATCO Electric to change its income tax methodology for federal purposes, whereby, effective January 1, 2007, ATCO Electric no longer recognizes future income taxes, and will refund to customers the future income taxes collected under the previously allowed tax methodology of $34.4 million. The reversal of these recorded future income taxes was reflected in the third quarter of 2007. Unrecorded future income tax liabilities have increased by $34.4 million as a result of this decision. The adjustment does not affect cash flow from operations for the three and nine months ended September 30, 2007. The timing of the cash refund to customers is subject to a further regulatory process at which time ATCO Electric intends to propose a five year repayment period.

ATCO Gas

In January 2006, the AEUB issued a decision on ATCO Gas' 2005, 2006 and 2007 General Rate Application ("ATCO Gas GRA Decision"):

- which, among other things, established the amount of revenue to be collected over the period 2005 to 2007 from customers for natural gas distribution service and approved a return on common equity as determined by the AEUB's standardized rate of return methodology – 9.5% in 2005, 8.93% in 2006 and 8.51% in 2007;
- in August 2007, final customer rates were confirmed by the AEUB.

In May 2006, the City of Calgary filed a Review and Variance application with the AEUB for the ATCO Gas GRA Decision:

- the application alleges that the AEUB made errors in the ATCO Gas GRA Decision related to the calculation of working capital needed by ATCO Gas to operate its Carbon natural gas storage facility;
- the AEUB issued its 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;
- the appeal was heard on June 19, 2007; and
- on August 31, 2007, the Alberta Court of Appeal granted the City of Calgary's leave to appeal. A date for the hearing has not yet been determined.

In October 2006, ATCO Gas also filed a Review and Variance application with the AEUB for the ATCO Gas GRA Decision:

- the application alleges that the AEUB made errors in the ATCO Gas GRA Decision related to the approved level of administrative expenses;
- in December 2006, the AEUB issued a decision in which it acknowledged an error for a portion of the administrative expenses in question;
- on April 18, 2007, ATCO Gas was advised by the AEUB that it would grant ATCO Gas' request to hear its Review and Variance application; and
- on May 30, 2007, the AEUB issued a written process which was completed on September 5, 2007. A final AEUB decision is not expected until the fourth quarter of 2007.

In October 2001, the AEUB approved the sale by ATCO Gas of certain properties in the City of Calgary, known as the Calgary Stores Block, for $6.6 million (excluding costs of disposition). As a result of this decision:

- $4.1 million of the proceeds were allocated by the AEUB to customers and $1.8 million to ATCO Gas;
- ATCO Gas appealed the decision to the Alberta Court of Appeal which overturned the decision and directed the AEUB to allocate $5.4 million of the proceeds to ATCO Gas;
- City of Calgary appealed this decision to the Supreme Court of Canada, which also granted ATCO Gas leave to cross-appeal the decision;
- the Supreme Court of Canada rendered its decision on February 9, 2006, dismissing the City of Calgary's appeal and allowing ATCO Gas' cross-appeal. The AEUB was directed to issue a new decision in accordance with the Supreme Court's ruling;
- ATCO Gas requested that the AEUB address the Supreme Court of Canada decision; and
- The AEUB complied with the Supreme Court of Canada decision on August 11, 2006 and ATCO Gas recorded additional net proceeds totaling $4.1 million from the sale and increased earnings of $3.7 million after income taxes in the third quarter of 2006.

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 AEUB approval, the following events are significant:

- in July 2004, the AEUB initiated a written process to consider its role in regulating the operations of the facility;
- in June 2005, the AEUB issued a decision with respect to this process. In addition to addressing other matters, the decision found that the AEUB 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 AEUB 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 AEUB 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 has filed a leave to appeal and a Review and Variance application of this decision;
- on February 5, 2007, the AEUB 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 requires 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 (refer to Business Risks – Regulated Operations – Carbon Natural Gas Storage Facility section); and
- the Alberta Court of Appeal heard ATCO Gas' leave to appeal with respect to the facility on September 18, 2007. On October 24, 2007, the Alberta Court of Appeal granted ATCO Gas' leave to appeal. A date for the hearing has not yet been determined.

ATCO Gas has filed an application with the AEUB 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 Corporation's pipelines) that have impacted ATCO Gas' deferred gas account:

- in April 2005, the AEUB issued a decision resulting in a 15% decrease in the transportation imbalance adjustments sought by ATCO Gas. The decision resulted in a decrease to ATCO Gas' 2005 revenues and earnings of $1.8 million and $1.2 million, respectively;
- the City of Calgary filed for leave to appeal the AEUB's decision. ATCO Gas filed a cross appeal of the AEUB's decision. The leave to appeal was heard by the Alberta Court of Appeal on April 18, 2006. 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 AEUB erred in law or jurisdiction in assuming that it had the authority to allow recovery in 2005, for costs relating to prior years. ATCO Gas' cross appeal was denied. 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 AEUB; and
- on September 5, 2007, the AEUB commenced proceedings to address the above mentioned jurisdictional questions.

ATCO Pipelines

On October 1, 2007, ATCO Pipelines filed a general rate application for the 2008 and 2009 test years ("ATCO Pipelines GRA") requesting:

- increased revenues to recover increased financing, depreciation and operating costs associated with increased rate base in Alberta.

A decision from the AEUB on the ATCO Pipelines GRA is not expected until the third quarter of 2008. On October 5, 2007, the AEUB approved ATCO Pipelines' request to negotiate revenue requirements with customers, allowing until January 11, 2008, to reach a settlement.

The AEUB has refocused attention to its review of the competitive natural gas pipeline issues under AEUB jurisdiction. This review will address competitive issues between ATCO Pipelines and NOVA Gas Transmission Ltd. ("NGTL"). On July 31, 2007, the AEUB issued a process letter that split the Competitive Proceeding into two parts:

- Part A – Competitive Boundaries Proceeding commenced on September 5, 2007 with the filing of evidence from ATCO Pipelines and NGTL. These proceedings will address market segmentation and obligation to serve. The AEUB will assess the proceedings in the fourth quarter of 2007 and determine the next steps for this process; and
- Part B – Competitive Guidelines Proceeding will address lowest cost alternative, with a date yet to be determined upon the completion of Part A.

Other Matters

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

LIQUIDITY AND CAPITAL RESOURCES

Funds generated by operations provide a substantial portion of the Corporation's cash requirements. Additional cash requirements are met externally through bank borrowings and the issuance of long term and non-recourse long term debt and preferred shares. Commercial paper borrowings and short term bank loans are used to provide flexibility in the timing and amounts of long term financing.

Funds generated by operations for the three months ended September 30, 2007, **increased** by $3.1 million to $150.4 million, primarily due to:

- increased cash flow after removal of non-cash items.

This increase was partially offset by:

- decreased deferred availability incentives in Alberta Power (2000).

Funds generated by operations for the nine months ended September 30, 2007, **increased** by $56.8 million to $545.9 million, primarily due to:

- increased earnings.

This increase was partially offset by:

- decreased deferred availability incentives in Alberta Power (2000); and
- 2006 proceeds received from the TXU Europe Settlement (refer to TXU Europe Settlement section).

Investing for the three months ended September 30, 2007, **increased** by $19.8 million to $171.6 million, primarily due to:

- higher capital expenditures.

This increase was partially offset by:

- changes in non-cash working capital.

Purchase of property, plant and equipment for the three months ended September 30, 2007, **increased** by $73.4 million to $216.4 million, primarily due to:

- increased investment in ATCO Frontec's projects: and
- increased investment in regulated electric distribution and transmission projects.

Investing for the nine months ended September 30, 2007, **increased** by $73.3 million to $440.2 million, primarily due to:

- higher capital expenditures; and
- changes in non-current deferred electricity costs.

This increase was partially offset by:

- changes in non-cash working capital; and
- H.R. Milner Income Tax Reassessment in 2006 (refer to H.R. Milner Income Tax Reassessment section).

Purchase of property, plant and equipment for the nine months ended September 30, 2007, **increased** by $104.5 million to $488.2 million, primarily due to:

- increased investment in regulated electric distribution and transmission projects; and
- increased investment in ATCO Frontec's projects.

This increase was partially offset by:

- decreased investment in regulated natural gas distribution projects.

During the three months ended September 30, 2007, the Corporation **issued**:

- no long term debt.

During the three months ended September 30, 2007, the Corporation **redeemed**:

- $19.3 million of non-recourse long term debt.

These changes resulted in a **net debt decrease** of $19.3 million.

During the nine months ended September 30, 2007, the Corporation **issued**:

- no long term debt.

During the nine months ended September 30, 2007, the Corporation **redeemed**:

- $110.5 million of non-recourse long term debt.

These changes resulted in a **net debt decrease** of $110.5 million.

During the nine months ended September 30, 2007, the Corporation **issued**:

- $115.0 million of equity preferred shares.

During the nine months ended September 30, 2007, the Corporation **redeemed**:

- $126.5 million of equity preferred shares.

These changes resulted in a **net equity preferred share decrease** of $11.5 million.

Net purchase of Class A shares for the three months ended September 30, 2007, **decreased** by $41.9 million, primarily due to:

- share purchases in 2006.

Net purchase of Class A shares for the nine months ended September 30, 2007, **decreased** by $70.7 million, primarily due to:

- share purchases in 2006.

Foreign currency translation for the three and nine months ended September 30, 2007, **negatively** impacted the Corporation's cash position by $7.9 million, and by $19.6 million, respectively, primarily due to:

- changes in U.K. and Australian exchange rates.

On April 18, 2007, CU Inc., a subsidiary corporation, issued $115.0 million Cumulative Redeemable Preferred Shares Series 1 at a price of $25.00 per share for cash. The dividend rate was fixed at 4.60%. The net proceeds of the issue were used in part to redeem, on May 18, 2007, $91.8 million of the outstanding Cumulative Redeemable Second Preferred Shares Series Q, R and S of ATCO Electric, ATCO Gas and ATCO Pipelines, subsidiary corporations of CU Inc., that were held by the Corporation.

On May 18, 2007, the Corporation redeemed all of the $126.5 million of outstanding Cumulative Redeemable Second Preferred Shares Series Q, R and S at a price of $25.00 per share plus accrued and unpaid dividends per share.

Effective October 3, 2007, the dividend rate on the Corporation's $110 million Perpetual Cumulative Second Preferred Shares Series V has been reset to 4.70% with a redemption date of October 3, 2012.

On October 18, 2007, Standard and Poor's announced that it had upgraded its rating on the Corporation's unsecured long term debt from A- to A.

At September 30, 2007, the Corporation had the following credit lines that enable it to obtain funding for general corporate purposes.

($ Millions)	Total	Used	Available
Long term committed	326.0	47.4	278.6
Short term committed	600.0	10.0	590.0
Uncommitted	74.1	10.7	63.4
Total	1,000.1	68.1	932.0

It is the Corporation's policy not to invest any of its cash balances in asset backed commercial paper.

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

Contractual obligations disclosed in the 2006 MD&A remain substantially unchanged as at September 30, 2007.

Net current and long term future income tax liabilities of $164.6 million at September 30, 2007, 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.

On May 23, 2006, the Corporation 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, 2007. Over the life of the bid 1,679,700 shares were purchased, all of which were purchased in 2006. On May 23, 2007, the Corporation commenced a new normal course issuer bid for the purchase of up to 5% of the outstanding Class A shares. The bid will expire on May 22, 2008. From May 23, 2007, to October 23, 2007, no shares have been purchased to date.

For the first quarter of 2007, the **quarterly dividend** payment on the Corporation's Class A and Class B shares was **increased** by $0.015 to $0.305 per share. For the second quarter of 2007, the quarterly dividend on the Corporation's Class A and Class B shares was **increased** by $0.01 to $0.315 per share. The quarterly dividend payment for the third quarter remained unchanged at $0.315 per share. The Corporation has increased its annual common share dividend each year since its inception as a holding company in 1972. The payment of any dividend is at the discretion of the Board of Directors and depends on the financial condition of the Corporation and other factors.

OUTSTANDING SHARE DATA

At October 23, 2007, the Corporation had outstanding 81,642,086 Class A shares, 43,801,584 Class B shares and options to purchase 1,313,000 Class A shares.

BUSINESS RISKS

Environmental Matters

On April 26, 2007, the federal government released a plan that proposes mandatory greenhouse gas ("GHG") emission targets on industry. The proposed plan requires an initial reduction in 2010 of 18% from 2006 levels followed thereafter by annual reductions of an additional 2%. 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. 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. Specific details on the regulations have yet to be released and will be required to assess the financial impact of the federal framework. While it is not certain, it is anticipated that the PPAs will allow the Corporation to recover most of the costs associated with complying with the new regulations.

On April 20, 2007 and June 27, 2007, respectively, the Government of Alberta approved Bill 3, Climate Change and Emissions Management Amendment Act and the Specified Gas Emitters Regulation Amendment that requires Alberta facilities that emit 100,000 tonnes or more of GHG to reduce facility emission intensities by 12% starting July 1, 2007. Units commissioned before January 1, 2000, or that have less than nine years of commercial operation are required to reduce their emission intensity by 2% per year starting in the fourth year of commercial operation to a maximum of 12% in the ninth year of commercial operation. Cogeneration units with emissions less than a deemed emission target based on a stand-alone natural gas combined cycle unit and conventional boiler will be eligible for credits. While it is not certain, it is anticipated that the PPAs will allow the Corporation to recover most of the costs associated with complying with the new regulations.

Alberta Environment implemented a mercury emission regulation in March 2006. The regulation requires coal-fired plant operators, including Alberta Power (2000), to monitor mercury emissions and capture at least 70% of the mercury in the coal starting January 1, 2011. While it is not certain, it is anticipated that the PPAs will allow the Corporation to recover most of the costs associated with complying with the new regulation.

Regulated Operations

ATCO Electric, ATCO Gas and ATCO Pipelines are regulated primarily by the AEUB, which administers acts and regulations covering such matters as rates, financing, accounting, construction, operation and service area. The AEUB may approve interim rates or approve the recovery of costs, including capital and operating costs, on a placeholder basis, subject to final determination. These subsidiaries are subject to the normal risks faced by companies that are regulated. These risks include the approval by the AEUB 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. The Corporation'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 AEUB approved placeholder rates. On February 5, 2007, the AEUB issued a decision to ATCO Gas that leaves in question these placeholder rates and the effect that these placeholder rates will have on future ATCO Gas revenues (refer to Regulatory Matters – ATCO Gas section).

Weather

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

ATCO I-Tek Services

ATCO Electric, ATCO Gas and ATCO Pipelines purchase information technology services, and 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 AEUB approval. Since 2003, the costs have been approved on a placeholder basis, and are subject to final AEUB approval after completion of the collaborative benchmarking process. The benchmarking report is expected in the fourth quarter of 2007, at which time an application will be made to the AEUB to finalize the placeholder costs. An AEUB decision is expected in early 2008.

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 Marketing Limited and one of its affiliates (collectively "DEML"), a subsidiary of Centrica plc.

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

Centrica plc, DEML's parent, has provided a $300 million guarantee, supported by a $235 million letter of credit in respect of DEML's obligations to ATCO Gas, ATCO Electric and ATCO I-Tek Business Services 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.

The Corporation has provided a guarantee of ATCO Gas', ATCO Electric's and ATCO I-Tek Business Services' payment and indemnity obligations to DEML 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. The Corporation is unable to determine at this time the impact, if any, that these decisions will have on the Corporation.

Alberta Power (2000)

Included in regulated operations are the Battle River and Sheerness generating plants of Alberta Power (2000), which were regulated by the AEUB until December 31, 2000, but are now governed by legislatively mandated PPA's that were approved by the AEUB. These plants are included in regulated operations primarily because the PPA's are designed to allow the owners of generating plants constructed before January 1, 1996, to recover their forecast fixed and variable costs and to earn a return at the rate specified in the PPA's. 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 PPA's expiring prior to 2019, Alberta Power (2000) has one year after the expiry of a PPA to determine whether to decommission the generating plant in order to fully recover plant decommissioning costs or to continue to operate the plant. 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.

Substantially all the electricity generated by Alberta Power (2000) is sold pursuant to PPA's. Under the PPA's, 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 PPA's were based.

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

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

At September 30, 2007, the Corporation had recorded $37.3 million of deferred availability incentives.

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.

Measurement Inaccuracies in Metering Facilities

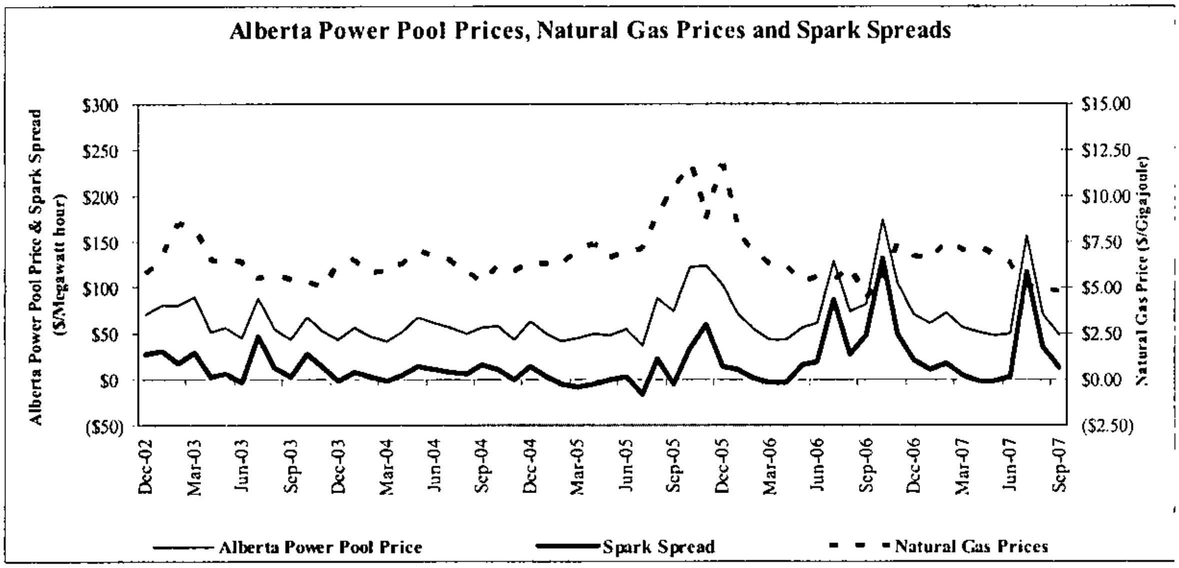
Measurement inaccuracies occur from time to time with respect to ATCO Electric's, ATCO Gas' and ATCO Pipelines' metering facilities. Measurement adjustments are settled between the parties based on the requirements of the Electricity and Gas Inspections Act (Canada) and applicable regulations issued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

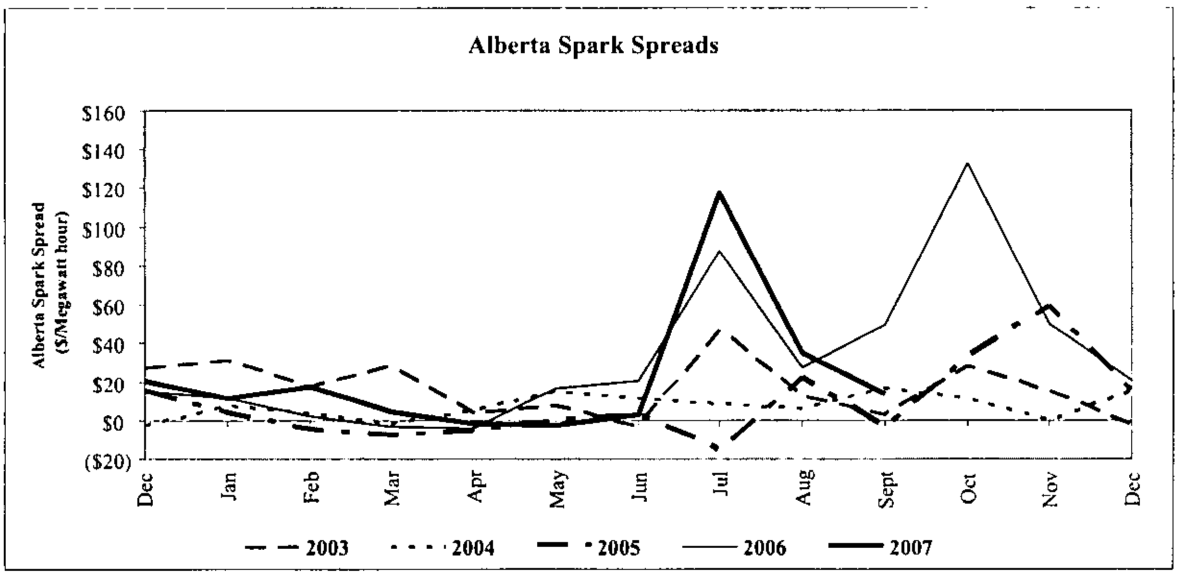
A recent AEUB decision applicable to ATCO Gas established a two year adjustment limitation period for inaccuracies in gas supply costs, including measurement inaccuracies in metering facilities. The AEUB stated that it will consider specific applications for adjustments beyond the two year limitation period.

Non-Regulated Operations

ATCO Power

Alberta Power Pool electricity prices, natural gas prices and related spark spreads can be very volatile, as shown in the following graph, which illustrates a range of prices experienced during the period December 2002 to September 2007.





Changes and volatility in Alberta Power Pool electricity prices, natural gas prices and related spark spreads may have a significant impact on the Corporation's earnings and cash flow from operations in the future. It is the Corporation's policy to continually monitor the status of its non-regulated electrical generating capacity that is not subject to long term commitments.

Since October 2004, the output from ATCO Power's Barking generating plant previously sold to TXU Europe (refer to TXU Europe Settlement section) has been sold into the U.K. power exchange market. In the U.K., electricity generators, on average, sell over 90% of their output to electricity suppliers in bilateral contracts, use power exchanges for approximately 7% of their output, and sell the remaining 2-3% via the Balancing Mechanism. Approximately 40% of the electricity generated is supplied from natural gas-fired generating plants. The Barking generating plant has a long term, fixed price gas purchase agreement and, as a result, has been able to experience increased margins due to the high market prices for electricity. Changes in the U.K. market electricity prices may have an impact on the Corporation's earnings and cash flow from operations in the future.

ATCO Midstream

Timing, capacity and demand of ATCO Midstream's storage business as well as changes in market conditions may impact the Corporation's earnings and cash flow from storage operations (refer to Results of Operations – Consolidated Operations section).

ATCO Midstream extracts ethane and other NGL from natural gas streams at its extraction plants. These products are sold under either long term cost of service arrangements or market based arrangements. Changes in market conditions may impact the Corporation's earnings and cash flow from NGL extraction operations.

ATCO Frontec

ATCO Frontec's operations include providing support to military agencies in foreign locations which may be subject to political risk.

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. The Corporation believes that it 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 financial position of the Corporation.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the Corporation's consolidated financial statements in accordance with generally accepted accounting principles 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 and employee future benefits, using currently available information. Changes in facts and circumstances may result in revised estimates, and actual results could differ from those estimates. The Corporation'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. As at September 30, 2007, the Corporation had recorded $37.3 million of deferred availability incentives. For the three and nine months ended September 30, 2007, the amortization of deferred availability incentives, which was recorded in revenues, amounted to $3.0 million and $8.9 million, respectively.

The amount to be amortized is dependent upon estimates of future generating unit availability and future electricity prices over the term of the PPA's. Each quarter, the Corporation uses these estimates to forecast 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 PPA to arrive at the amortization for the quarter.

Compared to the most likely scenario recorded in revenues for the year to date, the high case scenario would have resulted in higher revenues of approximately $3.9 million, whereas the low case scenario would have resulted in lower revenues of approximately $3.9 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 5.1% at the beginning of 2007, resulted in an expected long term rate of return of 6.6% for 2007. This methodology is supported by actuarial guidance on long term asset return assumptions for the Corporation'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 five years, from 8.1% in 2001 to 6.1% in the year ended December 31, 2006; the rate for the three and nine months ended September 30, 2007, was increased to 6.6%. 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.

The liability discount rate that is used to calculate the cost of benefit obligations reflects market interest rates on high quality corporate bonds that match the timing and amount of expected benefit payments. The liability discount rate has also declined over the same period, from 6.9% at the end of 2001 to 5.1% at the end of 2006; the rate has remained at 5.1% in the three and nine months ended September 30, 2007. The result has been an increase in benefit obligations (i.e., an experience loss), which is contributing to an increase in the cost of pension benefits as losses are amortized to earnings.

In accordance with the Corporation's accounting policy to amortize cumulative experience gains and losses in excess of 10 percent of the greater of the accrued benefit obligations or the market value of plan assets, the Corporation 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 during the three and nine months ended September 30, 2007.

The assumed annual health care cost trend rate increases used in measuring the accumulated post employment benefit obligations in the three and nine months ended September 30, 2007, are as follows: for drug costs, 7.8% starting in 2007 grading down over nine years to 4.5%, and for other medical and dental costs, 4.0% for 2007 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 AEUB 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).

CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2007, the Corporation prospectively adopted the Canadian Institute of Chartered Accountants ("CICA") recommendations pertaining to financial instruments, which establish standards for the recognition, measurement, disclosure and presentation of financial assets, financial liabilities and non-financial derivatives. These recommendations require that fair value be used to measure financial assets that are held for trading or available for sale, financial liabilities that are held for trading and all derivative financial instruments. Other financial assets, such as loans and receivables and investments that are held to maturity, and other financial liabilities are measured at their carrying value. This change in accounting had the following effect on the consolidated financial statements for the three and nine months ended September 30, 2007:

(a) Recognition of interest rate swaps, foreign currency forward contracts and certain natural gas purchase contracts as derivative assets and liabilities in the consolidated financial statements (refer to Note 10 to the unaudited interim consolidated financial statements for the nine months ended September 30, 2007).
(b) Recognition of the fair value of a power generation revenue contract liability associated with the natural gas purchase contracts derivative asset (refer to Note 10 to the unaudited interim consolidated financial statements for the nine months ended September 30, 2007).
(c) Recognition of a mark-to-market adjustment for the change in fair value of the natural gas purchase contracts derivative asset and recognition of an adjustment to the associated power generation revenue contract liability (refer to Note 6 to the unaudited interim consolidated financial statements for the nine months ended September 30, 2007).
(d) Restatement of opening retained earnings at January 1, 2007, to recognize the prior years' earnings effect of the natural gas purchase contracts derivative asset and the associated power generation revenue contract liability, as well as the prior years' earnings effect of accounting for certain financial assets and financial liabilities at amortized cost using the effective interest method (refer to Note 5 to the unaudited interim consolidated financial statements for the nine months ended September 30, 2007).
(e) Reclassification of deferred financing charges from other assets to long term debt and non-recourse long term debt (refer to Note 7 to the unaudited interim consolidated financial statements for the nine months ended September 30, 2007).

Effective January 1, 2007, the Corporation prospectively adopted the CICA recommendations pertaining to hedges, which establish standards for the identification, designation, documentation and effectiveness of hedging relationships for the purpose of applying hedge accounting. The purpose of hedge accounting is to ensure that gains, losses, revenues and expenses from effective hedging relationships are recorded in earnings in the same period. This change in accounting had no effect on the consolidated financial statements for the three and nine months ended September 30, 2007.

Effective January 1, 2007, the Corporation prospectively adopted the CICA recommendations regarding the reporting and disclosure of comprehensive income. Comprehensive income consists of changes in the equity of the Corporation from sources other than the Corporation's share owners, and includes earnings of the Corporation, the foreign currency translation adjustment relating to self-sustaining foreign operations and unrealized gains and losses on changes in fair values of available-for-sale assets and effective cash flow hedging instruments. Other comprehensive income comprises revenues, expenses, gains and losses that are recognized in comprehensive income but are excluded from earnings of the period. Comprehensive income is disclosed in a separate statement in the consolidated financial statements.

Effective January 1, 2007, the Corporation prospectively adopted the CICA recommendations regarding the presentation of equity and changes in equity. These recommendations require separate presentation of the components of equity, including retained earnings, accumulated other comprehensive income, contributed surplus, share capital and reserves, and the changes therein. As a result of this change in accounting, the Corporation has included a reconciliation of accumulated other comprehensive income in the notes to the consolidated financial statements (refer to Note 11 to the unaudited interim consolidated financial statements for the nine months ended September 30, 2007). In accordance with the recommendations, comparative figures have been adjusted to incorporate the foreign currency translation adjustment into accumulated other comprehensive income.

Effective January 1, 2007, the Corporation adopted the CICA recommendations that prescribe the criteria for changing accounting policies, together with the accounting treatment and disclosure of changes in accounting policies, changes in accounting estimates and corrections of errors. Adoption of these recommendations had no effect on the consolidated financial statements for the three and nine months ended September 30, 2007, except for the disclosure of accounting changes that have been issued by the CICA but have not yet been adopted by the Corporation because they are not effective until a future date (refer to Future Accounting Changes below).

Future Accounting Changes

The CICA has issued new accounting recommendations for capital disclosures which require disclosure of both qualitative and quantitative information that enables users of financial statements to evaluate the Corporation's objectives, policies and processes for managing capital. These recommendations are effective for the Corporation beginning January 1, 2008.

The CICA has also issued new accounting recommendations for disclosure and presentation of financial instruments which require disclosures of both qualitative and quantitative information that enables users of financial statements to evaluate the nature and extent of risks arising from financial instruments to which the Corporation is exposed. These recommendations are effective for the Corporation beginning January 1, 2008.

The CICA has also issued new accounting recommendations for measurement and disclosure of inventories which provide guidance on the determination of cost and its subsequent recognition as an expense, including any writedown to net realizable value, and on the cost formulas that are used to assign costs to inventories.. The Corporation is evaluating the effect of these recommendations on earnings and assets of the Corporation. These recommendations are effective for the Corporation beginning January 1, 2008.

The CICA has decided to remove 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. The CICA has also decided to amend its accounting recommendations pertaining to regulated income taxes to require the recognition of future regulated 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 Corporation is evaluating the possibility of using standards issued by the Financial Accounting Standards Board in the United States as another source of Canadian GAAP. Once issued, these recommendations will be effective for the Corporation beginning January 1, 2009, and are to be applied prospectively.

October 24, 2007

FILE NO. 82-34744

CANADIAN UTILITIES LIMITED
An ATCO Company

News Release

CANADIAN UTILITIES LIMITED
Corporate Head Office: 1400, 909 - 11 Avenue S.W., Calgary, Alberta T2R 1N6 Tel: (403) 292-7500

For Immediate Release
October 18, 2007

Canadian Utilities Limited to Release Third Quarter Results Thursday, October 25, 2007

CALGARY, Alberta – Canadian Utilities Limited (TSX: CU, CU.X) will release its financial results for the third quarter ended September 30, 2007 on Thursday, October 25, 2007. The news release will be distributed via www.marketwire.com and the results, including Financial Statements and Management's Discussion & Analysis will be posted on www.canadian-utilities.com.

Canadian Utilities Limited is part of the ATCO Group of Companies. ATCO Group, an Alberta based worldwide organization of companies with assets of approximately $7.8 billion and more than 7,000 employees, is comprised of three main business divisions: Power Generation; Utilities (natural gas and electricity transmission and distribution) and Global Enterprises, with companies active in industrial manufacturing, technology, logistics and energy services. More information about Canadian Utilities Limited can be found on its website www.canadian-utilities.com.

For further information, please contact:

K.M. (Karen) Watson
Senior Vice President & Chief Financial Officer
Canadian Utilities Limited
(403) 292-7502

Forward-Looking Information:

Certain statements contained in this news release may constitute forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "anticipate", "plan", "expect", "may", "will", "intend", "should", and similar expressions. These statements involve 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 statements. The Corporation believes that the expectations reflected in the forward-looking statements are reasonable, but no assurance can be given that these expectations will prove to be correct and such forward-looking statements should not be unduly relied upon.

The Corporation's actual results could differ materially from those anticipated in these forward-looking statements as a result of regulatory decisions, competitive factors in the industries in which the Corporation operates, prevailing economic conditions, and other factors, many of which are beyond the control of the Corporation.

The forward-looking statements contained in this news release represent the Corporations' expectations as of the date hereof, and are subject to change after such date. The Corporation disclaims any intention or obligation to update or revise any forward-looking statements whether as a result of new information, future events or otherwise, except as required under applicable securities regulations.

Corporate Head Office: 1400, 909 - 11th Ave S.W., Calgary, AB, Canada T2R 1N6 Tel (403) 292-7500 Fax (403) 292-7532 www.canadian-utilities.com

FILE NO. 82-34744

FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2007

TO THE SHARE OWNERS:

Canadian Utilities Limited reported earnings of $72.2 million ($0.58 per share) for the three months ended September 30, 2007, compared to earnings of $66.8 million ($0.53 per share) for the same three months of 2006. Earnings for the nine months ended September 30, 2007, were $288.0 million ($2.30 per share) compared to earnings of $223.9 million ($1.77 per share) for the same nine months in 2006.

Financial Summary	**For the Three Months Ended September 30**		**For the Nine Months Ended September 30**	
	2007	2006	**2007**	2006
	($ Millions except per share data) *(unaudited)*			
Earnings	**72.2**	66.8	**288.0**	223.9
Earnings per Class A and B share	**0.58**	0.53	**2.30**	1.77
Revenues	**489.9**	553.9	**1,747.8**	1,759.3
Funds generated by operations (1)	**150.4**	147.3	**545.9**	489.1

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

Earnings for the three months ended September 30, 2007, increased primarily due to:

- a $4.4 million income tax expense that was recorded by Alberta Power (2000) in the third quarter of 2006. This adjustment, which reduced earnings by $12.4 million in 2006, of which $8.0 million was recorded in the second quarter of 2006, pertained to a Canada Revenue Agency assessment on the taxation of proceeds received from the sale of the H.R. Milner generating plan in 2001. ("H.R. Milner Income Tax Reassessment");
- reduced tax expense resulting from lower future corporate tax rates in ATCO Power's U.K. operations; and
- improved performance in ATCO Power's Alberta generating plants.

This increase was partially offset by:

- the timing and demand of natural gas storage capacity sold, lower storage fees and lower volumes for natural gas liquids ("NGL") in ATCO Midstream; and
- higher operating and maintenance expenses and depreciation expenses in ATCO Gas due to customer growth and increased capital expenditures.

Earnings for the nine months ended September 30, 2007, increased primarily due to:

- $16.4 million adjustment relating to the 2007 change in the taxation of preferred share dividends. In the second quarter of 2007, the federal government amended legislation on the taxation of preferred share dividends paid. This change, which was retroactive to 2003, resulted in a reduction in income tax expense that was recorded in the second quarter of 2007;
- improved merchant performance, increased availability, higher exchange rates on conversion of earnings to Canadian dollars and reduced tax resulting from lower future corporate tax rates in ATCO Power's U.K. operations;
- colder temperatures, customer growth and higher sales per customer in ATCO Gas; and
- H.R. Milner Income Tax Reassessment in 2006.

This increase was partially offset by:

- $11.8 million adjustment in 2006 to reflect decreased federal and provincial taxes and rates; and
- higher operating and maintenance expenses and depreciation expenses in ATCO Gas due to customer growth and increased capital expenditures.

Revenues for the three months ended September 30, 2007, decreased primarily due to:

- impact of the ATCO Electric 2007/2008 General Tariff Application decision received from the Alberta Energy and Utilities Board ("AEUB") in the third quarter of 2007. The decision directed ATCO Electric to change its income tax methodology for federal purposes whereby, effective January 1, 2007, ATCO Electric no longer recognizes future income taxes. ("ATCO Electric Decision");
- lower natural gas fuel purchases recovered on a "no-margin" basis in ATCO Power's U.K. operations; and
- decreased business activity in ATCO Frontec's operations.

This decrease was partially offset by:

- impact of finalization of customer rates in the ATCO Gas 2005, 2006 and 2007 General Rate Application confirmed by the AEUB in August 2007;
- colder temperatures and customer growth in ATCO Gas; and
- improved merchant performance in ATCO Power's Alberta generating plants.

Revenues for the nine months ended September 30, 2007, decreased primarily due to:

- impact of the ATCO Electric Decision; and
- lower prices and volumes of natural gas processed for NGL extraction in ATCO Midstream.

This decrease was partially offset by:

- colder temperatures, customer growth and higher sales per customer in ATCO Gas; and
- the timing and demand of natural gas storage capacity sold and higher storage fees in ATCO Midstream.

Funds generated by operations for the three months ended September 30, 2007, increased primarily due to increased cash flow after removal of non-cash items.

This increase was partially offset by decreased deferred availability incentives in Alberta Power (2000).

Funds generated by operations for the nine months ended September 30, 2007, increased primarily due to increased earnings.

This increase was partially offset by decreased deferred availability incentives in Alberta Power (2000).

Other Recent Highlights include:

- ATCO Frontec entered into a limited partnership with the Fort McKay First Nation to construct, own and operate a new 500-room lodge in the Alberta oilsands region north of Fort McMurray, Alberta.
- ATCO Midstream Ltd. entered into an agreement to purchase a 50% interest in a joint venture which operates a 2.5 million cubic feet per day natural gas processing plant near the town of Kisbey, Saskatchewan.
- A record number of ATCO companies were honoured for safety. Four ATCO Group companies were honoured as "Best Safety Performers" in the province by Alberta's Occupational Health and Safety Council.
- ATCO Gas and its partners officially opened a new solar powered community in Okotoks in September. Incorporating the most advanced thermal technology, the Drake Landing project supplies 52 homes with 90 percent of their yearly space heating needs.

Canadian Utilities Limited is part of the ATCO Group of Companies. ATCO Group, an Alberta based worldwide organization of companies with assets of approximately $7.8 billion and more than 7,000 employees, is comprised of three main business divisions: Power Generation; Utilities (natural gas and electricity transmission and distribution) and Global Enterprises, with companies active in industrial manufacturing, technology, logistics and energy services. More information about Canadian Utilities Limited can be found on its website www.canadian-utilities.com.

N.C. Southern
President & Chief Executive Officer

R.D. Southern
Chairman of the Board

CANADIAN UTILITIES LIMITED

MANAGEMENT'S DISCUSSION AND ANALYSIS
OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS ("MD&A")

The following discussion and analysis of financial condition and results of operations of Canadian Utilities Limited (the "Corporation") should be read in conjunction with the Corporation's unaudited interim consolidated financial statements for the nine months ended September 30, 2007, and the audited consolidated financial statements and management's discussion and analysis of financial condition and results of operations for the year ended December 31, 2006 ("2006 MD&A"). Information contained in the 2006 MD&A that is not discussed in this document remains substantially unchanged. Additional information relating to the Corporation, including the Corporation's Annual Information Form, is available on SEDAR at www.sedar.com.

The equity securities of the Corporation consist of Class A non-voting shares ("Class A shares") and Class B common shares ("Class B shares").

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FORWARD-LOOKING INFORMATION

Certain statements contained in this MD&A constitute forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "anticipate", "plan", "estimate", "expect", "may", "will", "intend", "should", and similar expressions. These statements involve 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 statements. The Corporation believes that the expectations reflected in the forward-looking statements are reasonable, but no assurance can be given that these expectations will prove to be correct and such forward-looking statements should not be unduly relied upon.

In particular, this MD&A contains forward-looking statements pertaining to contractual obligations, planned capital expenditures, the impact of changes in government regulation and non-regulated generating capacity subject to long term contracts. The Corporation's actual results could differ materially from those anticipated in these forward-looking statements as a result of regulatory decisions, competitive factors in the industries in which the Corporation operates, prevailing economic conditions, and other factors, many of which are beyond the control of the Corporation.

NON-GAAP FINANCIAL MEASURES

In this MD&A, reference is made to funds generated by operations, which is a measure that does not have a standardized meaning under Canadian generally accepted accounting principles ("GAAP"). Funds generated by operations is calculated on the Corporation's consolidated statement of cash flows from operating activities before changes in non-cash working capital. In the Corporation's opinion, funds generated by operations is a significant performance indicator of the Corporation's ability to generate cash flow to fund its capital expenditures.

INTERNAL CONTROL OVER FINANCIAL REPORTING

There were no changes in the Corporation's internal control over financial reporting that occurred during the three months ended September 30, 2007, that have materially affected, or are reasonably likely to materially affect, the Corporation's internal control over financial reporting.

BUSINESS OF THE CORPORATION

The Corporation's financial statements are consolidated from three Business Groups: Utilities, Power Generation and Global Enterprises. For the purposes of financial disclosure, corporate transactions are accounted for as Corporate and Other (refer to Note 13 to the unaudited interim consolidated financial statements for the nine months ended September 30, 2007). Transactions between Business Groups are eliminated in all reporting of the Corporation's consolidated financial information.

SIGNIFICANT NON-OPERATING FINANCIAL ITEMS

Natural Gas Purchase Contracts and Associated Power Generation Revenue Contract Liability

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

As all but the excess volume of natural gas is committed to the Corporation's power generation obligations, the Corporation could not recognize the entire fair values of these natural gas purchase contracts in its revenues. Consequently, on January 1, 2007, the Corporation recognized a provision for a power generation revenue contract in the amount of $44.8 million; thereafter, the Corporation will record adjustments to the power generation revenue contract liability concurrently with the mark-to-market adjustments for the natural gas purchase contracts derivative asset. This power generation revenue contract liability is included in deferred credits in the consolidated balance sheet.

The mark-to-market adjustment for the derivative asset and the corresponding adjustment for the associated power generation revenue contract liability **decreased** earnings by $2.4 million, net of income taxes, for the three months ended September 30, 2007, and **increased** earnings by $0.1 million, net of income taxes, for the nine months ended September 30, 2007 ("Mark-to-Market Adjustment"). At September 30, 2007, the natural gas purchase contracts derivative asset is $58.4 million and the power generation revenue contract liability is $44.0 million.

TXU Europe Settlement

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

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

Based on the foreign currency exchange rate in effect on March 30, 2005, the Corporation's share of this settlement is expected to generate earnings after income taxes of approximately $69 million, which will be recognized over the remaining term of the TXU Europe contract to September 30, 2010, at approximately $11 million per year. These earnings will be dependent upon foreign currency exchange rates in effect at the time that the earnings are recognized.

On May 31, 2007, £95.0 million of the TXU proceeds (of which the Corporation's share is $52.7 million), were applied to Barking Power's non-recourse long term debt.

H.R. Milner Income Tax Reassessment

In the third quarter of 2006, the Canada Revenue Agency ("CRA") issued a reassessment for Alberta Power (2000)'s 2001 taxation year. The CRA's reassessment treats the proceeds received from the sale of the H.R. Milner generating plant to the Alberta Balancing Pool as income rather than as a sale of an asset. The Corporation appealed the reassessment to the Tax Court of Canada. The full impact of the reassessment was a $12.4 million increase in interest and income tax expense, a $12.4 million decrease in earnings ($8.0 million recorded in the second quarter of 2006 and $4.4 million recorded in the third quarter of 2006), and a $28.8 million payment associated with the tax and interest assessed, paid in the third quarter of 2006. It is expected that $16.4 million of this cash payment will be recovered by reducing income taxes payable through higher capital cost allowance claims in future years.

2007 Change in the Taxation of Preferred Share Dividends

On June 15, 2007, an amendment to tax legislation pertaining to the taxation of preferred share dividends paid by corporations received third reading in the House of Commons. This change pertains to taxes paid by corporations that pay dividends on taxable preferred shares (Part VI.1 tax). Prior to this change, corporations that paid Part VI.1 tax were entitled to an income tax deduction equal to 9/4ths of the Part VI.1 tax paid. Effective January 1, 2003, this deduction was increased to 9/3rds of the Part VI.1 tax paid. The CRA has been assessing corporate tax returns based on this proposed change since January 1, 2003, resulting in a reduction of taxes paid to the CRA. As this change is now considered to have been substantively enacted, the Corporation recorded a reduction to current income tax expense of $16.4 million in the second quarter of 2007. Funds generated by operations increased by $16.4 million, offset by a similar reduction in changes in non-cash working capital, leaving the Corporation's cash position unchanged ("Part VI.1 Tax Adjustment").

The earnings impact of the Part VI.1 Tax Adjustment by Business Group is as follows:

($ Millions)	Years Prior to 2007	First Quarter of 2007	Total
Utilities	4.2	0.2	4.4
Power Generation	1.3	0.1	1.4
Global Enterprises	1.4	-	1.4
Corporate and Other	8.7	0.5	9.2
Total	15.6	0.8	16.4

2006 Changes in Income Taxes and Rates

In 2006, Federal and provincial governments announced a number of changes to income taxes and rates. As a result of these changes the Corporation made an adjustment to income taxes amounting to $11.8 million in the second quarter of 2006, most of which related to future income taxes. The adjustment increased 2006 earnings by $11.8 million, of which $1.9 million related to the Utilities Business Group, $7.2 million to the Power Generation Business Group, $2.3 million to the Global Enterprises Business Group and $0.4 million to Corporate and Other.

SELECTED QUARTERLY INFORMATION

	For the Three Months Ended			
($ Millions except per share data)	Mar. 31	Jun. 30	Sep. 30	Dec. 31
		(unaudited)		
2007 (1) (2) (3)				
Revenues	697.6	560.3	489.9	....
Earnings attributable to Class A and Class B shares	134.7	81.1	72.2	....
Earnings per Class A and Class B share	1.07	0.65	0.58	....
Diluted earnings per Class A and Class B share	1.07	0.64	0.58	....
2006 (1) (2) (3)				
Revenues	642.0	563.4	553.9	671.1
Earnings attributable to Class A and Class B shares	86.9	70.2	66.8	100.0
Earnings per Class A and Class B share	0.68	0.56	0.53	0.80
Diluted earnings per Class A and Class B share	0.68	0.55	0.53	0.80
2005 (1) (2) (3)				
Revenues	....	....	....	680.3
Earnings attributable to Class A and Class B shares	....	....	....	89.1
Earnings per Class A and Class B share	....	....	....	0.70
Diluted earnings per Class A and Class B share	....	....	....	0.69

Notes:

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

(2) Due to the seasonal nature of the Corporation's operations, changes in electricity prices in Alberta, the timing and demand of natural gas storage capacity sold, changes in natural gas storage fees and the timing of rate decisions, revenues and earnings for any quarter are not necessarily indicative of operations on an annual basis.

(3) Includes impact from Significant Non-Operating Financial Items (refer to Significant Non-Operating Financial Items section).

(4) The above data has been extracted from the financial statements which have been prepared in accordance with Canadian generally accepted accounting principles and the reporting currency is the Canadian dollar.

RESULTS OF OPERATIONS

The principal factors that have caused variations in **revenues** and **earnings** over the eight most recently completed quarters necessary to understand general trends that have developed and the seasonality of the businesses disclosed in the 2006 MD&A remain substantially unchanged, except for the impact of the 2007 change in the taxation of preferred share dividends.

Consolidated Operations

Revenues, earnings attributable to Class A and Class B shares, and earnings and diluted earnings per share were as follows:

	For the Three Months Ended September 30		**For the Nine Months Ended September 30**	
($ Millions, except per share data)	**2007**	2006	**2007**	2006
		(unaudited)		
Revenues (1) (2) (3)	**489.9**	553.9	**1,747.8**	1,759.3
Earnings attributable to Class A and Class B shares (1) (2) (3)	**72.2**	66.8	**288.0**	223.9
Earnings per Class A share and Class B share (1) (2) (3)	**0.58**	0.53	**2.30**	1.77
Diluted earnings per Class A share and Class B share (1) (2) (3)	**0.58**	0.53	**2.29**	1.76

Notes:

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

(2) Due to the seasonal nature of the Corporation's operations, changes in electricity prices in Alberta, the timing and demand of natural gas storage capacity sold, changes in natural gas storage fees and the timing of rate decisions, revenues and earnings for any quarter are not necessarily indicative of operations on an annual basis.

(3) Includes impact from Significant Non-Operating Financial Items (refer to Significant Non-Operating Financial Items section).

(4) The above data has been extracted from the financial statements which have been prepared in accordance with Canadian generally accepted accounting principles and the reporting currency is the Canadian dollar.

Revenues for the three months ended September 30, 2007, **decreased** by $64.0 million to $489.9 million, primarily due to:

- refund of future income tax balances resulting from the ATCO Electric GTA Decision (refer to Regulatory Matters – ATCO Electric section);
- lower natural gas fuel purchases recovered on a "no-margin" basis in ATCO Power's United Kingdom ("U.K.") operations;
- decreased business activity in ATCO Frontec's operations; and
- lower prices and volumes of natural gas processed for Natural Gas Liquids ("NGL") extraction in ATCO Midstream (refer to Business Risks – Non-Regulated Operations – ATCO Midstream section).

This decrease was partially offset by:

- impact of finalization of customer rates related to ATCO Gas GRA Decision (refer to Regulatory Matters – ATCO Gas section);
- colder temperatures and customer growth in ATCO Gas; and
- improved merchant performance in ATCO Power's Alberta generating plants.

Revenues for the nine months ended September 30, 2007, **decreased** by $11.5 million to $1,747.8 million, primarily due to:

- refund of future income tax balances resulting from the ATCO Electric GTA Decision (refer to Regulatory Matters – ATCO Electric section);
- lower prices and volumes of natural gas processed for NGL extraction in ATCO Midstream (refer to Business Risks – Non-Regulated Operations – ATCO Midstream section);
- lower natural gas fuel purchases recovered on a "no-margin" basis in ATCO Power's U.K. operations; and
- decreased business activity in ATCO Frontec's operations.

This decrease was partially offset by:

- colder temperatures, customer growth and higher sales per customer in ATCO Gas;
- the timing and demand of natural gas storage capacity sold and higher storage fees in ATCO Midstream (refer to Business Risks – Non-Regulated Operations – ATCO Midstream section); and
- impact of the ATCO Electric GTA Decision (refer to Regulatory Matters – ATCO Electric section).

Earnings attributable to Class A and Class B shares for the three months ended September 30, 2007, **increased** by $5.4 million ($0.05 per share) to $72.2 million ($0.58 per share), primarily due to:

- H.R. Milner Income Tax Reassessment in 2006 (refer to H.R. Milner Income Tax Reassessment section);
- reduced tax expense resulting from lower future corporate tax rates in ATCO Power's U.K. operations; and
- improved performance in ATCO Power's Alberta generating plants.

This increase was partially offset by:

- the timing and demand of natural gas storage capacity sold, lower storage fees and lower volumes for NGL in ATCO Midstream (refer to Business Risks – Non-Regulated Operations – ATCO Midstream section);
- higher operating and maintenance expenses and depreciation expenses in ATCO Gas due to customer growth and increased capital expenditures; and
- Calgary Stores Block decision in 2006 in ATCO Gas (refer to Regulatory Matters – ATCO Gas section).

Earnings attributable to Class A and Class B shares for the nine months ended September 30, 2007, **increased** by $64.1 million ($0.53 per share) to $288.0 million ($2.30 per share), primarily due to:

- $16.4 million Part VI.1 Tax Adjustment (refer to 2007 Change in the Taxation of Preferred Share Dividends section);
- improved merchant performance, increased availability, higher exchange rates on conversion of earnings to Canadian dollars and reduced tax resulting from lower future corporate tax rates in ATCO Power's U.K. operations;
- colder temperatures, customer growth and higher sales per customer in ATCO Gas; and
- H.R. Milner Income Tax Reassessment in 2006 (refer to H.R. Milner Income Tax Reassessment section).

This increase was partially offset by:

- $11.8 million adjustment in 2006 to reflect tax changes (refer to 2006 Changes in Income Taxes and Rates section);
- higher operating and maintenance expenses and depreciation expenses in ATCO Gas due to customer growth and increased capital expenditures; and
- increased share appreciation rights expense due to changes in Canadian Utilities Limited Class A non-voting share and ATCO Ltd. Class I share prices since December 2006.

Operating expenses (consisting of natural gas supply, purchased power, operation and maintenance, selling and administrative and franchise fee costs) for the three months ended September 30, 2007, **decreased** by $17.0 million to $306.6 million, primarily due to:

- lower operating and maintenance expenses in ATCO Frontec, due to decreased business activity;
- lower natural gas fuel purchases recovered on a "no-margin" basis in ATCO Power's U.K. operations; and
- lower prices and volumes of natural gas purchased for NGL extraction in ATCO Midstream.

This decrease was partially offset by:

- higher operating and maintenance expenses in ATCO Gas due to customer growth and increased capital expenditures; and
- higher operating and maintenance expenses in ATCO Electric, due to increased capital expenditures.

Operating expenses for the nine months ended September 30, 2007, **decreased** by $9.9 million to $997.3 million, primarily due to:

- lower natural gas fuel purchases recovered on a "no-margin" basis in ATCO Power's U.K. operations;
- lower operating and maintenance expenses in ATCO Frontec due to decreased business activity; and
- lower prices and volumes of natural gas purchased for NGL extraction in ATCO Midstream.

This decrease was partially offset by:

- higher operating and maintenance expenses in ATCO Electric due to increased capital expenditures; and
- higher operating and maintenance expenses in ATCO Gas due to customer growth and increased capital expenditures.

Depreciation and amortization expenses for the three months ended September 30, 2007, **increased** by $4.0 million to $77.3 million, primarily due to:

- capital additions in 2007 and 2006.

Depreciation and amortization expenses for the nine months ended September 30, 2007, were **substantially unchanged**, primarily due to:

- one-time amortization charge of certain deferred items approved by the Alberta Energy and Utilities Board ("AEUB") in the ATCO Gas GRA Decision recorded in the second quarter of 2006.

Partially offset by:

- capital additions in 2007 and 2006.

Interest expense for the three and nine months ended September 30, 2007, **decreased** by $0.2 million to $54.1 million, and by $5.9 million to $162.4 million, respectively, primarily due to:

- refinancing and repayment of higher cost financings in 2007 and 2006; and
- H.R. Milner Income Tax Reassessment in 2006 (refer to H.R. Milner Income Tax Reassessment section).

This decrease was partially offset by:

- interest on new financings issued in 2006 to fund capital expenditures in Utilities operations.

Interest and other income for the three months ended September 30, 2007, **decreased** by $5.9 million to $11.4 million, primarily due to:

- Calgary Stores Block decision in 2006 in ATCO Gas (refer to Regulatory Matters – ATCO Gas section); and
- Mark-to-Market Adjustment (refer to Natural Gas Purchase Contracts and Associated Power Generation Revenue Contract Liability section).

Interest and other income for the nine months ended September 30, 2007, **increased** by $3.4 million to $43.0 million, primarily due to:

- higher short term interest rates on cash investments.

This increase was partially offset by:

- Calgary Stores Block decision in 2006 in ATCO Gas (refer to Regulatory Matters – ATCO Gas section).

Income taxes for the three months ended September 30, 2007, **decreased** by $61.4 million to $(17.2) million, primarily due to:

- refund of future income tax balances and lower current income tax expense resulting from the ATCO Electric GTA Decision (refer to Regulatory Matters – ATCO Electric section); and
- H.R. Milner Income Tax Reassessment in 2006 (refer to H.R. Milner Income Tax Reassessment section).

Income taxes for the nine months ended September 30, 2007, **decreased** by $55.1 million to $64.6 million, primarily due to:

- refund of future income tax balances and lower current income tax expense resulting from the ATCO Electric GTA Decision (refer to Regulatory Matters – ATCO Electric section);
- $16.4 million Part VI.1 Tax Adjustment (refer to 2007 Change in the Taxation of Preferred Share Dividends section; and
- H.R. Milner Income Tax Reassessment in 2006 (refer to H.R. Milner Income Tax Reassessment section).

This decrease was partially offset by:

- $11.8 million adjustment in 2006 to reflect tax changes (refer to 2006 Changes in Income Taxes and Rates section).

Segmented Information

Segmented revenues for the three and nine months ended September 30, 2007, were as follows:

	For the Three Months Ended September 30		**For the Nine Months Ended September 30**	
($ Millions)	**2007**	2006	**2007**	2006
	(unaudited)			
Utilities	**187.8**	221.1	**803.2**	796.1
Power Generation	**197.6**	202.5	**579.1**	572.8
Global Enterprises	**144.4**	166.0	**474.4**	493.3
Corporate and Other	**3.4**	3.3	**10.1**	9.4
Intersegment eliminations	**(43.3)**	(39.0)	**(119.0)**	(112.3)
Total	**489.9**	553.9	**1,747.8**	1,759.3

Note:

(1) Includes impact from Significant Non-Operating Financial Items (refer to Significant Non-Operating Financial Items section).

Segmented earnings attributable to Class A and Class B shares for the three and nine months ended September 30, 2007, were as follows:

	For the Three Months Ended September 30		**For the Nine Months Ended September 30**	
($ Millions)	**2007**	2006	**2007**	2006
	(unaudited)			
Utilities	**14.3**	19.2	**91.7**	77.5
Power Generation	**38.6**	29.3	**109.2**	82.3
Global Enterprises	**20.9**	22.1	**82.3**	73.7
Corporate and Other	**(0.8)**	(2.3)	**7.2**	(5.2)
Intersegment eliminations	**(0.8)**	(1.5)	**(2.4)**	(4.4)
Total	**72.2**	66.8	**288.0**	223.9

Note:

(1) Includes impact from Significant Non-Operating Financial Items (refer to Significant Non-Operating Financial Items section).

Utilities

Revenues from the Utilities Business Group for the three months ended September 30, 2007, **decreased** by $33.3 million to $187.8 million, primarily due to:

- refund of future income tax balances resulting from the ATCO Electric GTA Decision (refer to Regulatory Matters – ATCO Electric section).

This decrease was partially offset by:

- impact of finalization of customer rates in the ATCO Gas GRA Decision (refer to Regulatory Matters – ATCO Gas section); and
- colder temperatures and customer growth in ATCO Gas.

Temperatures in ATCO Gas for the three months ended September 30, 2007, were 9.9% colder than normal, compared to 3.8% warmer than normal for the corresponding period in 2006.

Revenues for the nine months ended September 30, 2007, **increased** by $7.1 million to $803.2 million, primarily due to:

- colder temperatures, customer growth and higher sales per customer in ATCO Gas; and
- impact of the ATCO Electric GTA Decision (refer to Regulatory Matters – ATCO Electric section).

This increase was partially offset by:

- refund of future income tax balances resulting from the ATCO Electric GTA Decision (refer to Regulatory Matters – ATCO Electric section).

Temperatures in ATCO Gas for the nine months ended September 30, 2007, were 2.0% warmer than normal, compared to 12.4% warmer than normal for the corresponding period in 2006.

Earnings for the three months ended September 30, 2007, **decreased** by $4.9 million to $14.3 million, primarily due to:

- higher operating and maintenance expenses and depreciation expenses in ATCO Gas due to customer growth and increased capital expenditures; and
- Calgary Stores Block decision in 2006 in ATCO Gas (refer to Regulatory Matters – ATCO Gas section).

Earnings for the nine months ended September 30, 2007, **increased** by $14.2 million to $91.7 million, primarily due to:

- colder temperatures, customer growth and higher sales per customer in ATCO Gas; and
- $4.4 million Part VI.1 Tax Adjustment (refer to 2007 Change in the Taxation of Preferred Share Dividends section).

This increase was partially offset by:

- higher operating and maintenance expenses and depreciation expenses in ATCO Gas due to customer growth and increased capital expenditures.

Utilities Business Group capital expenditures to maintain capacity and meet planned growth are expected to be approximately $600 million in 2007. The total three year (2007-2009) anticipated capital expenditures in the Utilities Business Group are expected to be approximately $2.1 billion.

Power Generation

Revenues from the Power Generation Business Group for the three months ended September 30, 2007, **decreased** by $4.9 million to $197.6 million, primarily due to:

- lower natural gas fuel purchases recovered on a "no-margin" basis in ATCO Power's U.K. operations; and
- lower merchant revenues in ATCO Power's U.K. operations.

This decrease was partially offset by:

- improved merchant performance in ATCO Power's Alberta generating plants; and
- increased generation at Alberta Power (2000)'s Battle River generating plant due to improved plant performance.

Revenues for the nine months ended September 30, 2007, **increased** by $6.3 million to $579.1 million, primarily due to:

- impact of higher U.K. and Australian exchange rates on conversion of revenues to Canadian dollars in ATCO Power's U.K and Australian operations;
- improved merchant performance in ATCO Power's Alberta generating plants;
- increased generation at Alberta Power (2000)'s Battle River generating plant due to improved plant performance; and
- higher revenues in ATCO Power's Australian operations due to higher power prices.

This increase was partially offset by:

- lower natural gas fuel purchases recovered on a "no-margin" basis in ATCO Power's U.K. operations.

Earnings for the three months ended September 30, 2007, **increased** by $9.3 million to $38.6 million, primarily due to:

- H.R. Milner Income Tax Reassessment in 2006 (refer to H.R. Milner Income Tax Reassessment section);
- reduced tax expense resulting from lower future corporate tax rates in ATCO Power's U.K. operations; and
- improved performance in ATCO Power's Alberta generating plants.

Earnings for the nine months ended September 30, 2007, **increased** by $26.9 million to $109.2 million, primarily due to:

- improved merchant performance, increased availability, higher exchange rates on conversion of earnings to Canadian dollars and reduced tax resulting from lower future corporate tax rates in ATCO Power's U.K. operations;
- H.R. Milner Income Tax Reassessment in 2006 (refer to H.R. Milner Income Tax Reassessment section); and
- improved performance in ATCO Power's Alberta generating plants.

This increase was partially offset by:

- $7.2 million adjustment in 2006 to reflect tax changes (refer to 2006 Changes in Income Taxes and Rates section).

Impacting Alberta Power (2000)'s revenues and earnings for the three and nine months ended September 30, 2007, were lower Power Purchase Arrangement ("PPA") tariffs due to declining rate bases at the Battle River and Sheerness generating plants and a decline in the return on common equity rate (2007 – 8.65%, 2006 – 8.75%). These return on common equity rates are based on long term Government of Canada bond yields plus 4.5%.

Alberta Power Pool Electricity Prices

Spark spread is related to the difference between Alberta Power Pool electricity prices and the marginal cost of producing electricity from natural gas. These spark spreads are based on an approximate industry heat rate of 7.5 gigajoules per megawatt hour.

Changes in spark spread affect the results of approximately 408 megawatts of plant capacity owned in Alberta by ATCO Power and Alberta Power (2000) out of a total Alberta owned capacity of approximately 1,703 megawatts and a worldwide owned capacity of approximately 2,468 megawatts.

Alberta Power Pool electricity prices for the three months ended September 30, 2007, averaged $92.88 per megawatt hour, compared to average prices of $95.31 per megawatt hour for the corresponding period in 2006. Natural gas prices for the three months ended September 30, 2007, averaged $4.86 per gigajoule, compared to average prices of $5.33 per gigajoule for the corresponding period in 2006. The consequence of these electricity and natural gas prices was an average spark spread of $56.47 per megawatt hour for the three months ended September 30, 2007, compared to $55.37 per megawatt hour for the corresponding period in 2006.

Alberta Power Pool electricity prices for the nine months ended September 30, 2007, averaged $68.68 per megawatt hour, compared to average prices of $68.59 per megawatt hour for the corresponding period in 2006. Natural gas prices for the nine months ended September 30, 2007, averaged $6.20 per gigajoule, compared to average prices of $6.05 per gigajoule for the corresponding period in 2006. The consequence of these electricity and natural gas prices was an average spark spread of $22.20 per megawatt hour for the nine months ended September 30, 2007, compared to $23.24 per megawatt hour for the corresponding period in 2006.

Deferred Availability Incentives

During the three months ended September 30, 2007, Alberta Power (2000)'s **deferred availability incentive** account decreased by $5.3 million to $37.3 million. The decrease was due to planned outages and the quarterly amortization of deferred availability incentives. During the three months ended September 30, 2007, the amortization of deferred availability incentives, recorded in revenues, increased by $0.4 million to $3.0 million, compared to the same period in 2006.

During the nine months ended September 30, 2007, Alberta Power (2000)'s **deferred availability incentive** account decreased by $2.3 million to $37.3 million. The decrease was due to planned outages and the quarterly amortization of deferred availability incentives offset by incentive billings received. During the nine months ended September 30, 2007, the amortization of deferred availability incentives, recorded in revenues, increased by $1.0 million to $8.9 million, compared to the same period in 2006.

Recent Developments

Alberta Power (2000) operated the Rainbow generating plant during 2006 and the electricity generated was sold to the Alberta Power Pool. Alberta Power (2000) had one year after the expiry of the PPA for the Rainbow generating plant (December 31, 2005) to determine whether to decommission the plant in order to fully recover plant decommissioning costs or to continue to operate the plant. In the first quarter of 2007 the Alberta Electric System Operator ("AESO") and Alberta Power (2000) executed a contract resulting in Alberta Power (2000) continuing to operate the plant and thus be responsible for future decommissioning costs. These costs are included in Alberta Power (2000)'s asset retirement obligation liability.

On May 10, 2007, ATCO Power announced that it will construct a 45 megawatt natural gas-fired unit for its Valleyview generating plant in Valleyview, Alberta. All of the electricity produced by the unit will be sold to the Alberta Power Pool. Construction of the unit is scheduled for completion in 2008.

On July 1, 2007, the Piikani Nation of Brockett, Alberta, exercised its option to purchase a 25% interest in ATCO Power's and ATCO Resources' 32 megawatt hydroelectric generating plant at the Oldman River dam near Pincher Creek, Alberta.

Global Enterprises

Revenues from the Global Enterprises Business Group for the three months ended September 30, 2007, **decreased** by $21.6 million to $144.4 million, primarily due to:

- decreased business activity in ATCO Frontec's operations;
- lower prices and volumes of natural gas processed for NGL extraction in ATCO Midstream (refer to Business Risks – Non-Regulated Operations – ATCO Midstream section); and
- the timing and demand of natural gas storage capacity sold and lower storage fees in ATCO Midstream (refer to Business Risks – Non-Regulated Operations – ATCO Midstream section).

Revenues for the nine months ended September 30, 2007, **decreased** by $18.9 million to $474.4 million, primarily due to:

- lower prices and volumes of natural gas processed for NGL extraction in ATCO Midstream (refer to Business Risks – Non-Regulated Operations – ATCO Midstream section); and
- decreased business activity in ATCO Frontec's operations.

This decrease was partially offset by:

- the timing and demand of natural gas storage capacity sold and higher storage fees in ATCO Midstream (refer to Business Risks – Non-Regulated Operations – ATCO Midstream section).

Earnings for the three months ended September 30, 2007, were **substantially unchanged.**

Earnings for the nine months ended September 30, 2007, **increased** by $8.6 million to $82.3 million, primarily due to:

- the timing and demand of natural gas storage capacity sold and higher storage fees in ATCO Midstream (refer to Business Risks – Non-Regulated Operations – ATCO Midstream section).

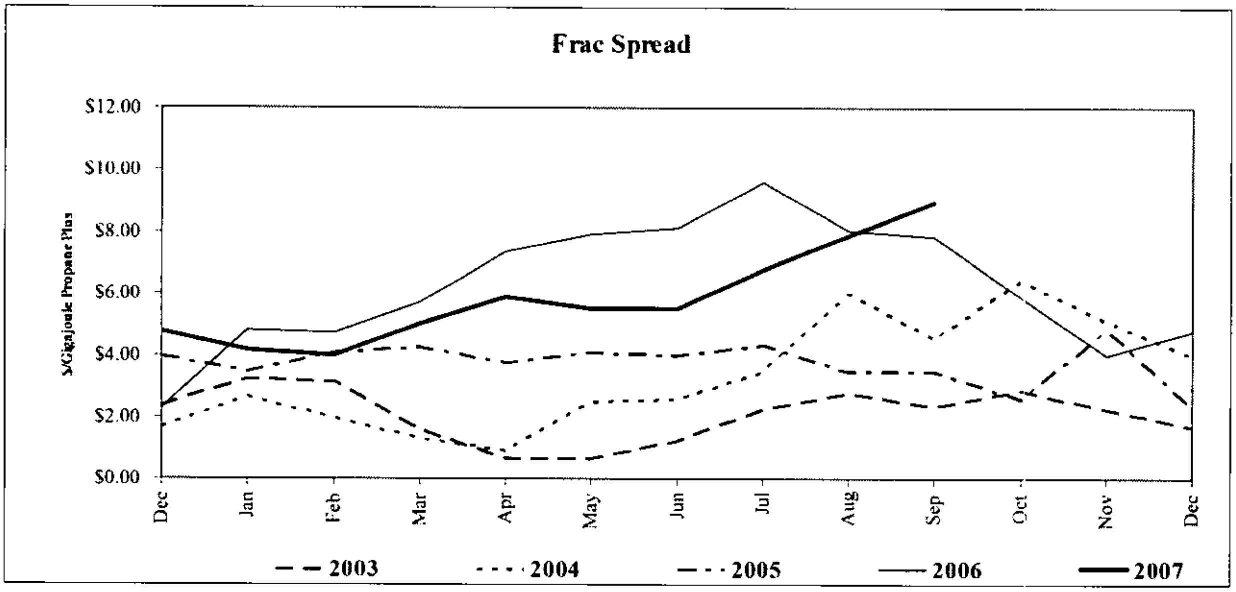
This increase was partially offset by:

- lower volumes and margins for NGL in ATCO Midstream (refer to Business Risks – Non-Regulated Operations – ATCO Midstream section).

ATCO Midstream

ATCO Midstream provides natural gas producers with gathering, processing and natural gas liquids extraction services and natural gas storage services.

ATCO Midstream's natural gas liquids extraction operations involve the extraction of natural gas liquids (ethane, propane, butane, pentane and certain other hydrocarbons) from natural gas and the replacement (on a heat content equivalent basis) of the natural gas liquids extracted with natural gas ("shrinkage gas"). For propane, butane, pentane and the other hydrocarbons ("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 January 2003 to September 2007.



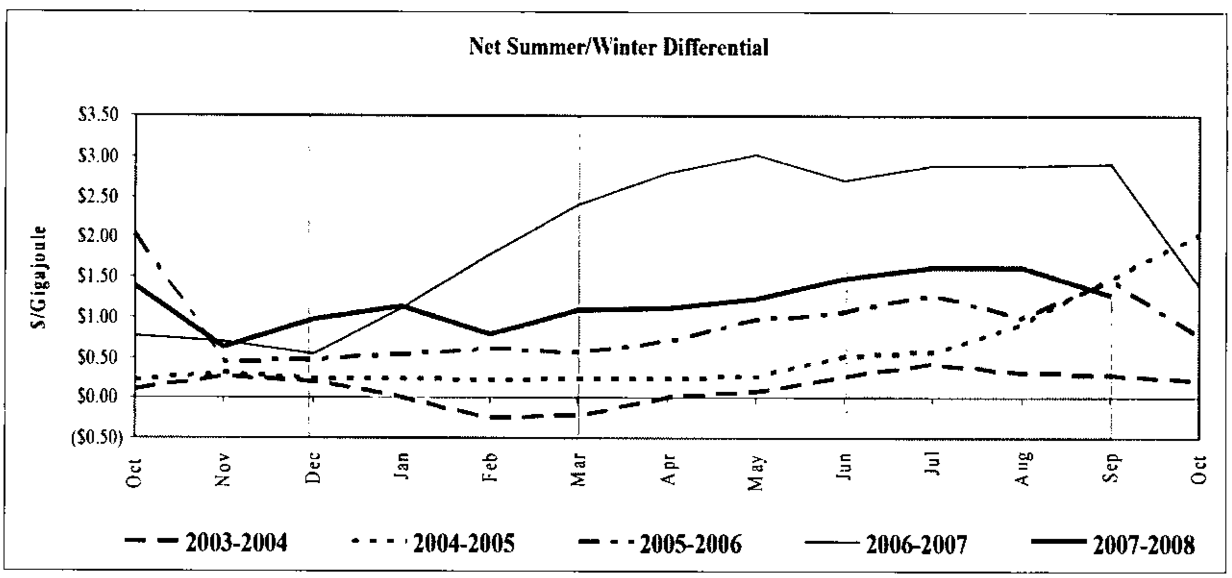
The above table represents measurements of frac spreads as reported by an independent consultant and does not necessarily represent the frac spreads received by ATCO Midstream.

The frac spread can also vary with the proportion of each liquid in the Propane Plus extracted which is dependent on the quantity of natural gas liquids in the natural gas and the performance of the plant.

Fluctuations in frac spreads may have a significant impact on ATCO Midstream's earnings and cash flow from operations in the future. A $1.00 change in the average annual frac spread may impact annual earnings by as much as $7 million. Total net ownership capacity of ATCO Midstream's natural gas liquids plants is 411 million cubic feet per day.

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

Summer/winter natural gas storage differential can be very volatile, as shown in the following graph, which illustrates a range of differentials experienced during the storage periods from 2003-2004 to 2007-2008.



On October 5, 2007, ATCO Midstream announced that it had entered into an agreement to purchase a 50% interest in a joint venture which owns and operates a 2.5 million cubic feet per day natural gas processing plant near Kisbey, Saskatchewan and 22 kilometers of pipeline serving four regional natural gas producers. Bayhurst Energy Services Corporation ("Bayhurst Energy"), a subsidiary of SaskEnergy Incorporated, owns the remaining interest in the joint venture. Bayhurst Energy will be the operator of the plant, with ATCO Midstream providing both operational and marketing support.

ATCO Frontec

In June 2007, the Corporation was awarded five NATO support contracts at the Kandahar Airfield in Afghanistan for up to five years. Specific sectors of responsibility will include fire and crash rescue, visiting aircraft cross-servicing services, roads and grounds maintenance, facility maintenance, construction, engineering, equipment and vehicle maintenance, aircraft movement control and terminal transport, accommodation services, supply operations, airfield mechanical transport, delivery of potable water, sewage management, and waste management and disposal.

In June 2007, UQSUQ Corporation, a joint venture between ATCO Frontec and Nunavut Petroleum Corporation, was awarded a five year contract renewal to lease and operate the 79 million litre bulk fuel storage facility, the pipeline distribution system and the municipal fuel distribution system in Iqaluit, Nunavut.

On October 17, 2007, ATCO Frontec announced that it had entered into a limited partnership with the Fort McKay First Nation to construct, own and operate a new 500-room lodge in Fort McMurray, Alberta. The Creeburn Lodge, which will be primarily assembled using modules built by ATCO Structures Inc., is scheduled for Phase one completion in February 2008, with full operations scheduled for July 2008. The lodge has been designed to allow for future expansion to 1,000 rooms.

Corporate and Other

Earnings for the three months ended September 30, 2007, **increased** by $1.5 million to $(0.8) million, primarily due to:

- higher short term interest rates on cash investments.

This increase was partially offset by:

- increased share appreciation rights expense due to changes in Canadian Utilities Limited Class A share and ATCO Ltd. Class I Non-Voting share prices since June 30, 2007.

Earnings for the nine months ended September 30, 2007, **increased** by $12.4 million to $7.2 million, primarily due to:

- $9.2 million Part VI.1 Tax Adjustment (refer to 2007 Change in the Taxation of Preferred Share Dividends section); and
- higher short term interest rates on cash investments.

This increase was partially offset by:

- increased share appreciation rights expense due to changes in Canadian Utilities Limited Class A share and ATCO Ltd. Class I Non-Voting share prices since December 31, 2006.

REGULATORY MATTERS

Regulated operations are conducted by wholly owned subsidiaries of the Corporation's wholly owned subsidiary, CU Inc.

- ATCO Electric and its subsidiaries Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical;
- the ATCO Gas and ATCO Pipelines divisions of ATCO Gas and Pipelines Ltd.; and
- the Battle River and Sheerness generating plants of Alberta Power (2000).

Regulated operations in Alberta (except for the generating plants of Alberta Power (2000)) are subject to a generic cost of capital regime:

- in July 2004, the AEUB issued the generic cost of capital decision which established, among other things:
  - a standardized approach for each utility company regulated by the AEUB for determining the rate of return on common equity;
    - rate of return adjusted annually by 75% of the change in long term Government of Canada bond yield as forecast; and
    - adjustment mechanism similar to the method the National Energy Board uses in determining its formula based rate of return;
  - the capital structure for each utility regulated by the AEUB; and
- in November 2005, the AEUB announced a generic return on common equity of 8.93% for 2006;
- in January 2006, the AEUB clarified that the generic return on equity determined on an annual basis in accordance with the generic cost of capital decision should apply to each year of the test period in the companies' applications. 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; and
- in November 2006, the AEUB announced a generic return on common equity of 8.51% for 2007.

ATCO Electric, ATCO Gas and ATCO Pipelines purchase information technology services, and 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 AEUB approval. Since 2003, the costs have been approved on a placeholder basis, and are subject to final AEUB approval after completion of the collaborative benchmarking process. The benchmarking report is expected in the fourth quarter of 2007, at which time an application will be made to the AEUB to finalize the placeholder costs. An AEUB decision is expected in early 2008.

ATCO Electric

In March 2006, the AEUB issued a decision on ATCO Electric's 2005 and 2006 General Tariff Application:

- which established, among other things, the amount of revenue to be collected in 2005 and 2006 from customers for transmission and distribution services and approved a return on common equity as determined by the AEUB's standardized rate of return methodology – 9.5% in 2005 and 8.93% in 2006;
- ATCO Electric's 2005 earnings were negatively impacted by \$1.3 million, recorded in first quarter of 2006; and
- ATCO Electric's 2006 earnings were reduced by an additional \$1.6 million, compared to 2005 earnings, recorded throughout 2006.

In August 2006, the AEUB approved the AESO application for the need to improve transmission infrastructure in northwest Alberta:

- AEUB decision grants the AESO approval to assign to the Transmission Facility Owner, ATCO Electric, work consisting of several distinct projects which will result in 725 kilometres of new transmission line to be constructed by 2011;
  - in June 2007, the first of these distinct projects was assigned to ATCO Electric by the AESO. This project consists of a 235 kilometre transmission line with an estimated cost of \$210 million, and is anticipated to be completed by 2010. ATCO Electric has applied to the AEUB for approval to build and operate this project; and
  - as a result of price escalation caused by the change in completion date of the remaining distinct projects (post 2010), coupled with the increasing costs of construction in Alberta, ATCO Electric is unable, at this time, to estimate the cost of the entire project; and
- ATCO Electric anticipates that an additional 180 kilometres of transmission line projects will be required in its service area over the next five years.

In November 2006, ATCO Electric filed a general tariff application with the AEUB for the 2007 and 2008 test years:

- requesting, among other things, increased revenues to recover increased financing, depreciation and operating costs associated with increased rate base in Alberta;
- in November 2006, ATCO Electric filed an application requesting interim refundable rates for transmission and distribution operations, pending the AEUB's decision on the general tariff application; and
- on December 19, 2006, ATCO Electric received a decision from the AEUB approving interim refundable rate increases amounting to 50% of ATCO Electric's requested increases for transmission and distribution operations.

In September 2007, the AEUB issued a decision on ATCO Electric's general tariff application for the 2007 and 2008 test years ("ATCO Electric GTA Decision"):

- which established, among other things, the amount of revenue to be collected in 2007 and 2008 from customers for transmission and distribution services and approved a return on common equity as determined by the AEUB's standardized rate of return methodology – 8.51% in 2007. A final rate for 2008 will be determined in November 2007, in accordance with the AEUB standardized 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 lower approved rate of return on common equity (8.51% in 2007 versus 8.93% in 2006) and other adjustments; and
- the decision directed ATCO Electric to change its income tax methodology for federal purposes, whereby, effective January 1, 2007, ATCO Electric no longer recognizes future income taxes, and will refund to customers the future income taxes collected under the previously allowed tax methodology of $34.4 million. The reversal of these recorded future income taxes was reflected in the third quarter of 2007. Unrecorded future income tax liabilities have increased by $34.4 million as a result of this decision. The adjustment does not affect cash flow from operations for the three and nine months ended September 30, 2007. The timing of the cash refund to customers is subject to a further regulatory process at which time ATCO Electric intends to propose a five year repayment period.

ATCO Gas

In January 2006, the AEUB issued a decision on ATCO Gas' 2005, 2006 and 2007 General Rate Application ("ATCO Gas GRA Decision"):

- which, among other things, established the amount of revenue to be collected over the period 2005 to 2007 from customers for natural gas distribution service and approved a return on common equity as determined by the AEUB's standardized rate of return methodology – 9.5% in 2005, 8.93% in 2006 and 8.51% in 2007;
- in August 2007, final customer rates were confirmed by the AEUB.

In May 2006, the City of Calgary filed a Review and Variance application with the AEUB for the ATCO Gas GRA Decision:

- the application alleges that the AEUB made errors in the ATCO Gas GRA Decision related to the calculation of working capital needed by ATCO Gas to operate its Carbon natural gas storage facility;
- the AEUB issued its 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;
- the appeal was heard on June 19, 2007; and
- on August 31, 2007, the Alberta Court of Appeal granted the City of Calgary's leave to appeal. A date for the hearing has not yet been determined.

In October 2006, ATCO Gas also filed a Review and Variance application with the AEUB for the ATCO Gas GRA Decision:

- the application alleges that the AEUB made errors in the ATCO Gas GRA Decision related to the approved level of administrative expenses;
- in December 2006, the AEUB issued a decision in which it acknowledged an error for a portion of the administrative expenses in question;
- on April 18, 2007, ATCO Gas was advised by the AEUB that it would grant ATCO Gas' request to hear its Review and Variance application; and
- on May 30, 2007, the AEUB issued a written process which was completed on September 5, 2007. A final AEUB decision is not expected until the fourth quarter of 2007.

In October 2001, the AEUB approved the sale by ATCO Gas of certain properties in the City of Calgary, known as the Calgary Stores Block, for $6.6 million (excluding costs of disposition). As a result of this decision:

- $4.1 million of the proceeds were allocated by the AEUB to customers and $1.8 million to ATCO Gas;
- ATCO Gas appealed the decision to the Alberta Court of Appeal which overturned the decision and directed the AEUB to allocate $5.4 million of the proceeds to ATCO Gas;
- City of Calgary appealed this decision to the Supreme Court of Canada, which also granted ATCO Gas leave to cross-appeal the decision;
- the Supreme Court of Canada rendered its decision on February 9, 2006, dismissing the City of Calgary's appeal and allowing ATCO Gas' cross-appeal. The AEUB was directed to issue a new decision in accordance with the Supreme Court's ruling;
- ATCO Gas requested that the AEUB address the Supreme Court of Canada decision; and
- The AEUB complied with the Supreme Court of Canada decision on August 11, 2006 and ATCO Gas recorded additional net proceeds totaling $4.1 million from the sale and increased earnings of $3.7 million after income taxes in the third quarter of 2006.

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 AEUB approval, the following events are significant:

- in July 2004, the AEUB initiated a written process to consider its role in regulating the operations of the facility;
- in June 2005, the AEUB issued a decision with respect to this process. In addition to addressing other matters, the decision found that the AEUB 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 AEUB 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 AEUB 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 has filed a leave to appeal and a Review and Variance application of this decision;
- on February 5, 2007, the AEUB 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 requires 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 (refer to Business Risks – Regulated Operations – Carbon Natural Gas Storage Facility section); and
- the Alberta Court of Appeal heard ATCO Gas' leave to appeal with respect to the facility on September 18, 2007. On October 24, 2007, the Alberta Court of Appeal granted ATCO Gas' leave to appeal. A date for the hearing has not yet been determined.

ATCO Gas has filed an application with the AEUB 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 Corporation's pipelines) that have impacted ATCO Gas' deferred gas account:

- in April 2005, the AEUB issued a decision resulting in a 15% decrease in the transportation imbalance adjustments sought by ATCO Gas. The decision resulted in a decrease to ATCO Gas' 2005 revenues and earnings of $1.8 million and $1.2 million, respectively;
- the City of Calgary filed for leave to appeal the AEUB's decision. ATCO Gas filed a cross appeal of the AEUB's decision. The leave to appeal was heard by the Alberta Court of Appeal on April 18, 2006. 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 AEUB erred in law or jurisdiction in assuming that it had the authority to allow recovery in 2005, for costs relating to prior years. ATCO Gas' cross appeal was denied. 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 AEUB; and
- on September 5, 2007, the AEUB commenced proceedings to address the above mentioned jurisdictional questions.

ATCO Pipelines

On October 1, 2007, ATCO Pipelines filed a general rate application for the 2008 and 2009 test years ("ATCO Pipelines GRA") requesting:

- increased revenues to recover increased financing, depreciation and operating costs associated with increased rate base in Alberta.

A decision from the AEUB on the ATCO Pipelines GRA is not expected until the third quarter of 2008. On October 5, 2007, the AEUB approved ATCO Pipelines' request to negotiate revenue requirements with customers, allowing until January 11, 2008, to reach a settlement.

The AEUB has refocused attention to its review of the competitive natural gas pipeline issues under AEUB jurisdiction. This review will address competitive issues between ATCO Pipelines and NOVA Gas Transmission Ltd. ("NGTL"). On July 31, 2007, the AEUB issued a process letter that split the Competitive Proceeding into two parts:

- Part A – Competitive Boundaries Proceeding commenced on September 5, 2007 with the filing of evidence from ATCO Pipelines and NGTL. These proceedings will address market segmentation and obligation to serve. The AEUB will assess the proceedings in the fourth quarter of 2007 and determine the next steps for this process; and
- Part B – Competitive Guidelines Proceeding will address lowest cost alternative, with a date yet to be determined upon the completion of Part A.

Other Matters

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

LIQUIDITY AND CAPITAL RESOURCES

Funds generated by operations provide a substantial portion of the Corporation's cash requirements. Additional cash requirements are met externally through bank borrowings and the issuance of long term and non-recourse long term debt and preferred shares. Commercial paper borrowings and short term bank loans are used to provide flexibility in the timing and amounts of long term financing.

Funds generated by operations for the three months ended September 30, 2007, **increased** by $3.1 million to $150.4 million, primarily due to:

- increased cash flow after removal of non-cash items.

This increase was partially offset by:

- decreased deferred availability incentives in Alberta Power (2000).

Funds generated by operations for the nine months ended September 30, 2007, **increased** by $56.8 million to $545.9 million, primarily due to:

- increased earnings.

This increase was partially offset by:

- decreased deferred availability incentives in Alberta Power (2000); and
- 2006 proceeds received from the TXU Europe Settlement (refer to TXU Europe Settlement section).

Investing for the three months ended September 30, 2007, **increased** by $19.8 million to $171.6 million, primarily due to:

- higher capital expenditures.

This increase was partially offset by:

- changes in non-cash working capital.

Purchase of property, plant and equipment for the three months ended September 30, 2007, **increased** by $73.4 million to $216.4 million, primarily due to:

- increased investment in ATCO Frontec's projects; and
- increased investment in regulated electric distribution and transmission projects.

Investing for the nine months ended September 30, 2007, **increased** by $73.3 million to $440.2 million, primarily due to:

- higher capital expenditures; and
- changes in non-current deferred electricity costs.

This increase was partially offset by:

- changes in non-cash working capital; and
- H.R. Milner Income Tax Reassessment in 2006 (refer to H.R. Milner Income Tax Reassessment section).

Purchase of property, plant and equipment for the nine months ended September 30, 2007, **increased** by $104.5 million to $488.2 million, primarily due to:

- increased investment in regulated electric distribution and transmission projects; and
- increased investment in ATCO Frontec's projects.

This increase was partially offset by:

- decreased investment in regulated natural gas distribution projects.

During the three months ended September 30, 2007, the Corporation **issued**:

- no long term debt.

During the three months ended September 30, 2007, the Corporation **redeemed**:

- $19.3 million of non-recourse long term debt.

These changes resulted in a **net debt decrease** of $19.3 million.

During the nine months ended September 30, 2007, the Corporation **issued**:

- no long term debt.

During the nine months ended September 30, 2007, the Corporation **redeemed**:

- $110.5 million of non-recourse long term debt.

These changes resulted in a **net debt decrease** of $110.5 million.

During the nine months ended September 30, 2007, the Corporation **issued**:

- $115.0 million of equity preferred shares.

During the nine months ended September 30, 2007, the Corporation **redeemed**:

- $126.5 million of equity preferred shares.

These changes resulted in a **net equity preferred share decrease** of $11.5 million.

Net purchase of Class A shares for the three months ended September 30, 2007, **decreased** by $41.9 million, primarily due to:

- share purchases in 2006.

Net purchase of Class A shares for the nine months ended September 30, 2007, **decreased** by $70.7 million, primarily due to:

- share purchases in 2006.

Foreign currency translation for the three and nine months ended September 30, 2007, **negatively** impacted the Corporation's cash position by $7.9 million, and by $19.6 million, respectively, primarily due to:

- changes in U.K. and Australian exchange rates.

On April 18, 2007, CU Inc., a subsidiary corporation, issued $115.0 million Cumulative Redeemable Preferred Shares Series 1 at a price of $25.00 per share for cash. The dividend rate was fixed at 4.60%. The net proceeds of the issue were used in part to redeem, on May 18, 2007, $91.8 million of the outstanding Cumulative Redeemable Second Preferred Shares Series Q, R and S of ATCO Electric, ATCO Gas and ATCO Pipelines, subsidiary corporations of CU Inc., that were held by the Corporation.

On May 18, 2007, the Corporation redeemed all of the $126.5 million of outstanding Cumulative Redeemable Second Preferred Shares Series Q, R and S at a price of $25.00 per share plus accrued and unpaid dividends per share.

Effective October 3, 2007, the dividend rate on the Corporation's $110 million Perpetual Cumulative Second Preferred Shares Series V has been reset to 4.70% with a redemption date of October 3, 2012.

On October 18, 2007, Standard and Poor's announced that it had upgraded its rating on the Corporation's unsecured long term debt from A- to A.

At September 30, 2007, the Corporation had the following credit lines that enable it to obtain funding for general corporate purposes.

($ Millions)	**Total**	**Used**	**Available**
Long term committed	326.0	47.4	278.6
Short term committed	600.0	10.0	590.0
Uncommitted	74.1	10.7	63.4
Total	1,000.1	68.1	932.0

It is the Corporation's policy not to invest any of its cash balances in asset backed commercial paper.

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

Contractual obligations disclosed in the 2006 MD&A remain substantially unchanged as at September 30, 2007.

Net current and long term future income tax liabilities of $164.6 million at September 30, 2007, 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.

On May 23, 2006, the Corporation 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, 2007. Over the life of the bid 1,679,700 shares were purchased, all of which were purchased in 2006. On May 23, 2007, the Corporation commenced a new normal course issuer bid for the purchase of up to 5% of the outstanding Class A shares. The bid will expire on May 22, 2008. From May 23, 2007, to October 23, 2007, no shares have been purchased to date.

For the first quarter of 2007, the **quarterly dividend** payment on the Corporation's Class A and Class B shares was **increased** by $0.015 to $0.305 per share. For the second quarter of 2007, the quarterly dividend on the Corporation's Class A and Class B shares was **increased** by $0.01 to $0.315 per share. The quarterly dividend payment for the third quarter remained unchanged at $0.315 per share. The Corporation has increased its annual common share dividend each year since its inception as a holding company in 1972. The payment of any dividend is at the discretion of the Board of Directors and depends on the financial condition of the Corporation and other factors.

OUTSTANDING SHARE DATA

At October 23, 2007, the Corporation had outstanding 81,642,086 Class A shares, 43,801,584 Class B shares and options to purchase 1,313,000 Class A shares.

BUSINESS RISKS

Environmental Matters

On April 26, 2007, the federal government released a plan that proposes mandatory greenhouse gas ("GHG") emission targets on industry. The proposed plan requires an initial reduction in 2010 of 18% from 2006 levels followed thereafter by annual reductions of an additional 2%. 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. 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. Specific details on the regulations have yet to be released and will be required to assess the financial impact of the federal framework. While it is not certain, it is anticipated that the PPAs will allow the Corporation to recover most of the costs associated with complying with the new regulations.

On April 20, 2007 and June 27, 2007, respectively, the Government of Alberta approved Bill 3, Climate Change and Emissions Management Amendment Act and the Specified Gas Emitters Regulation Amendment that requires Alberta facilities that emit 100,000 tonnes or more of GHG to reduce facility emission intensities by 12% starting July 1, 2007. Units commissioned before January 1, 2000, or that have less than nine years of commercial operation are required to reduce their emission intensity by 2% per year starting in the fourth year of commercial operation to a maximum of 12% in the ninth year of commercial operation. Cogeneration units with emissions less than a deemed emission target based on a stand-alone natural gas combined cycle unit and conventional boiler will be eligible for credits. While it is not certain, it is anticipated that the PPAs will allow the Corporation to recover most of the costs associated with complying with the new regulations.

Alberta Environment implemented a mercury emission regulation in March 2006. The regulation requires coal-fired plant operators, including Alberta Power (2000), to monitor mercury emissions and capture at least 70% of the mercury in the coal starting January 1, 2011. While it is not certain, it is anticipated that the PPAs will allow the Corporation to recover most of the costs associated with complying with the new regulation.

Regulated Operations

ATCO Electric, ATCO Gas and ATCO Pipelines are regulated primarily by the AEUB, which administers acts and regulations covering such matters as rates, financing, accounting, construction, operation and service area. The AEUB may approve interim rates or approve the recovery of costs, including capital and operating costs, on a placeholder basis, subject to final determination. These subsidiaries are subject to the normal risks faced by companies that are regulated. These risks include the approval by the AEUB 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. The Corporation'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 AEUB approved placeholder rates. On February 5, 2007, the AEUB issued a decision to ATCO Gas that leaves in question these placeholder rates and the effect that these placeholder rates will have on future ATCO Gas revenues (refer to Regulatory Matters – ATCO Gas section).

Weather

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

ATCO I-Tek Services

ATCO Electric, ATCO Gas and ATCO Pipelines purchase information technology services, and 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 AEUB approval. Since 2003, the costs have been approved on a placeholder basis, and are subject to final AEUB approval after completion of the collaborative benchmarking process. The benchmarking report is expected in the fourth quarter of 2007, at which time an application will be made to the AEUB to finalize the placeholder costs. An AEUB decision is expected in early 2008.

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 Marketing Limited and one of its affiliates (collectively "DEML"), a subsidiary of Centrica plc.

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

Centrica plc, DEML's parent, has provided a $300 million guarantee, supported by a $235 million letter of credit in respect of DEML's obligations to ATCO Gas, ATCO Electric and ATCO I-Tek Business Services 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.

The Corporation has provided a guarantee of ATCO Gas', ATCO Electric's and ATCO I-Tek Business Services' payment and indemnity obligations to DEML 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. The Corporation is unable to determine at this time the impact, if any, that these decisions will have on the Corporation.

Alberta Power (2000)

Included in regulated operations are the Battle River and Sheerness generating plants of Alberta Power (2000), which were regulated by the AEUB until December 31, 2000, but are now governed by legislatively mandated PPA's that were approved by the AEUB. These plants are included in regulated operations primarily because the PPA's are designed to allow the owners of generating plants constructed before January 1, 1996, to recover their forecast fixed and variable costs and to earn a return at the rate specified in the PPA's. 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 PPA's expiring prior to 2019, Alberta Power (2000) has one year after the expiry of a PPA to determine whether to decommission the generating plant in order to fully recover plant decommissioning costs or to continue to operate the plant. 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.

Substantially all the electricity generated by Alberta Power (2000) is sold pursuant to PPA's. Under the PPA's, 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 PPA's were based.

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

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

At September 30, 2007, the Corporation had recorded $37.3 million of deferred availability incentives.

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.

Measurement Inaccuracies in Metering Facilities

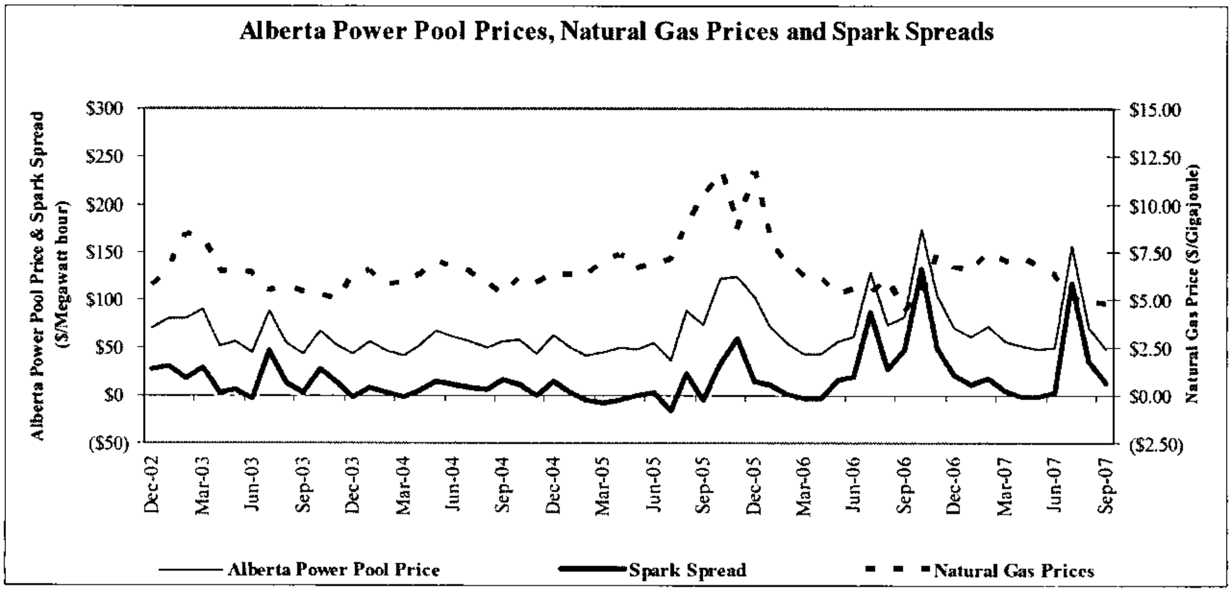
Measurement inaccuracies occur from time to time with respect to ATCO Electric's, ATCO Gas' and ATCO Pipelines' metering facilities. Measurement adjustments are settled between the parties based on the requirements of the Electricity and Gas Inspections Act (Canada) and applicable regulations issued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

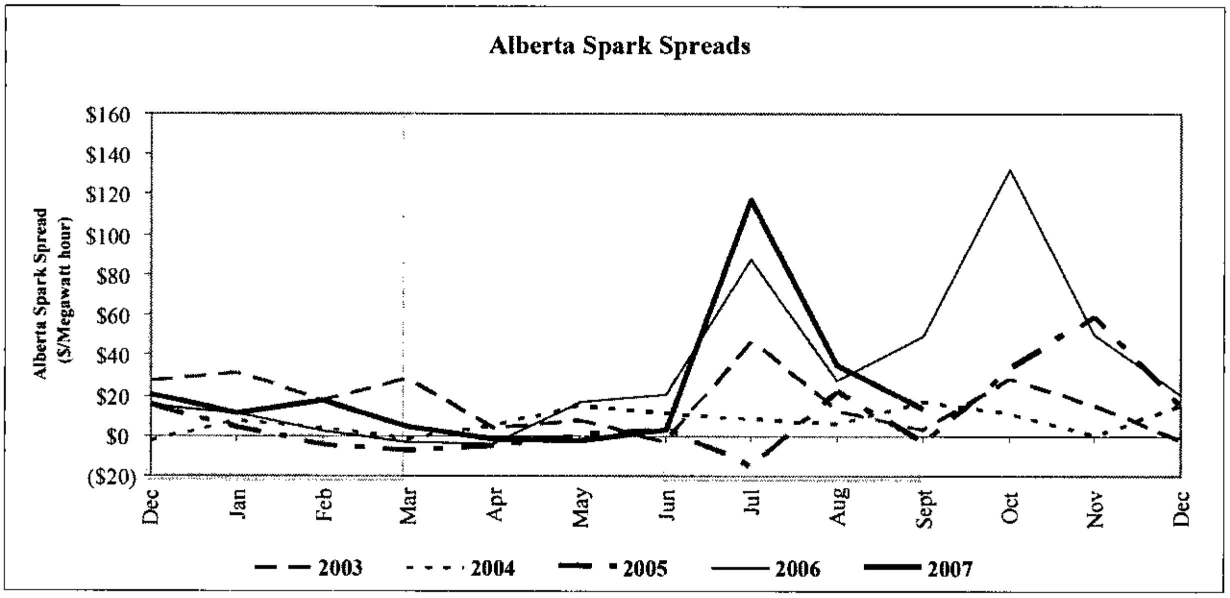
A recent AEUB decision applicable to ATCO Gas established a two year adjustment limitation period for inaccuracies in gas supply costs, including measurement inaccuracies in metering facilities. The AEUB stated that it will consider specific applications for adjustments beyond the two year limitation period.

Non-Regulated Operations

ATCO Power

Alberta Power Pool electricity prices, natural gas prices and related spark spreads can be very volatile, as shown in the following graph, which illustrates a range of prices experienced during the period December 2002 to September 2007.





Changes and volatility in Alberta Power Pool electricity prices, natural gas prices and related spark spreads may have a significant impact on the Corporation's earnings and cash flow from operations in the future. It is the Corporation's policy to continually monitor the status of its non-regulated electrical generating capacity that is not subject to long term commitments.

Since October 2004, the output from ATCO Power's Barking generating plant previously sold to TXU Europe (refer to TXU Europe Settlement section) has been sold into the U.K. power exchange market. In the U.K., electricity generators, on average, sell over 90% of their output to electricity suppliers in bilateral contracts, use power exchanges for approximately 7% of their output, and sell the remaining 2-3% via the Balancing Mechanism. Approximately 40% of the electricity generated is supplied from natural gas-fired generating plants. The Barking generating plant has a long term, fixed price gas purchase agreement and, as a result, has been able to experience increased margins due to the high market prices for electricity. Changes in the U.K. market electricity prices may have an impact on the Corporation's earnings and cash flow from operations in the future.

ATCO Midstream

Timing, capacity and demand of ATCO Midstream's storage business as well as changes in market conditions may impact the Corporation's earnings and cash flow from storage operations (refer to Results of Operations – Consolidated Operations section).

ATCO Midstream extracts ethane and other NGL from natural gas streams at its extraction plants. These products are sold under either long term cost of service arrangements or market based arrangements. Changes in market conditions may impact the Corporation's earnings and cash flow from NGL extraction operations.

ATCO Frontec

ATCO Frontec's operations include providing support to military agencies in foreign locations which may be subject to political risk.

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. The Corporation believes that it 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 financial position of the Corporation.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the Corporation's consolidated financial statements in accordance with generally accepted accounting principles 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 and employee future benefits, using currently available information. Changes in facts and circumstances may result in revised estimates, and actual results could differ from those estimates. The Corporation'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. As at September 30, 2007, the Corporation had recorded $37.3 million of deferred availability incentives. For the three and nine months ended September 30, 2007, the amortization of deferred availability incentives, which was recorded in revenues, amounted to $3.0 million and $8.9 million, respectively.

The amount to be amortized is dependent upon estimates of future generating unit availability and future electricity prices over the term of the PPA's. Each quarter, the Corporation uses these estimates to forecast 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 PPA to arrive at the amortization for the quarter.

Compared to the most likely scenario recorded in revenues for the year to date, the high case scenario would have resulted in higher revenues of approximately $3.9 million, whereas the low case scenario would have resulted in lower revenues of approximately $3.9 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 5.1% at the beginning of 2007, resulted in an expected long term rate of return of 6.6% for 2007. This methodology is supported by actuarial guidance on long term asset return assumptions for the Corporation'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 five years, from 8.1% in 2001 to 6.1% in the year ended December 31, 2006; the rate for the three and nine months ended September 30, 2007, was increased to 6.6%. 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.

The liability discount rate that is used to calculate the cost of benefit obligations reflects market interest rates on high quality corporate bonds that match the timing and amount of expected benefit payments. The liability discount rate has also declined over the same period, from 6.9% at the end of 2001 to 5.1% at the end of 2006; the rate has remained at 5.1% in the three and nine months ended September 30, 2007. The result has been an increase in benefit obligations (i.e., an experience loss), which is contributing to an increase in the cost of pension benefits as losses are amortized to earnings.

In accordance with the Corporation's accounting policy to amortize cumulative experience gains and losses in excess of 10 percent of the greater of the accrued benefit obligations or the market value of plan assets, the Corporation 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 during the three and nine months ended September 30, 2007.

The assumed annual health care cost trend rate increases used in measuring the accumulated post employment benefit obligations in the three and nine months ended September 30, 2007, are as follows: for drug costs, 7.8% starting in 2007 grading down over nine years to 4.5%, and for other medical and dental costs, 4.0% for 2007 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 AEUB 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).

CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2007, the Corporation prospectively adopted the Canadian Institute of Chartered Accountants ("CICA") recommendations pertaining to financial instruments, which establish standards for the recognition, measurement, disclosure and presentation of financial assets, financial liabilities and non-financial derivatives. These recommendations require that fair value be used to measure financial assets that are held for trading or available for sale, financial liabilities that are held for trading and all derivative financial instruments. Other financial assets, such as loans and receivables and investments that are held to maturity, and other financial liabilities are measured at their carrying value. This change in accounting had the following effect on the consolidated financial statements for the three and nine months ended September 30, 2007:

(a) Recognition of interest rate swaps, foreign currency forward contracts and certain natural gas purchase contracts as derivative assets and liabilities in the consolidated financial statements (refer to Note 10 to the unaudited interim consolidated financial statements for the nine months ended September 30, 2007).
(b) Recognition of the fair value of a power generation revenue contract liability associated with the natural gas purchase contracts derivative asset (refer to Note 10 to the unaudited interim consolidated financial statements for the nine months ended September 30, 2007).
(c) Recognition of a mark-to-market adjustment for the change in fair value of the natural gas purchase contracts derivative asset and recognition of an adjustment to the associated power generation revenue contract liability (refer to Note 6 to the unaudited interim consolidated financial statements for the nine months ended September 30, 2007).
(d) Restatement of opening retained earnings at January 1, 2007, to recognize the prior years' earnings effect of the natural gas purchase contracts derivative asset and the associated power generation revenue contract liability, as well as the prior years' earnings effect of accounting for certain financial assets and financial liabilities at amortized cost using the effective interest method (refer to Note 5 to the unaudited interim consolidated financial statements for the nine months ended September 30, 2007).
(e) Reclassification of deferred financing charges from other assets to long term debt and non-recourse long term debt (refer to Note 7 to the unaudited interim consolidated financial statements for the nine months ended September 30, 2007).

Effective January 1, 2007, the Corporation prospectively adopted the CICA recommendations pertaining to hedges, which establish standards for the identification, designation, documentation and effectiveness of hedging relationships for the purpose of applying hedge accounting. The purpose of hedge accounting is to ensure that gains, losses, revenues and expenses from effective hedging relationships are recorded in earnings in the same period. This change in accounting had no effect on the consolidated financial statements for the three and nine months ended September 30, 2007.

Effective January 1, 2007, the Corporation prospectively adopted the CICA recommendations regarding the reporting and disclosure of comprehensive income. Comprehensive income consists of changes in the equity of the Corporation from sources other than the Corporation's share owners, and includes earnings of the Corporation, the foreign currency translation adjustment relating to self-sustaining foreign operations and unrealized gains and losses on changes in fair values of available-for-sale assets and effective cash flow hedging instruments. Other comprehensive income comprises revenues, expenses, gains and losses that are recognized in comprehensive income but are excluded from earnings of the period. Comprehensive income is disclosed in a separate statement in the consolidated financial statements.

Effective January 1, 2007, the Corporation prospectively adopted the CICA recommendations regarding the presentation of equity and changes in equity. These recommendations require separate presentation of the components of equity, including retained earnings, accumulated other comprehensive income, contributed surplus, share capital and reserves, and the changes therein. As a result of this change in accounting, the Corporation has included a reconciliation of accumulated other comprehensive income in the notes to the consolidated financial statements (refer to Note 11 to the unaudited interim consolidated financial statements for the nine months ended September 30, 2007). In accordance with the recommendations, comparative figures have been adjusted to incorporate the foreign currency translation adjustment into accumulated other comprehensive income.

Effective January 1, 2007, the Corporation adopted the CICA recommendations that prescribe the criteria for changing accounting policies, together with the accounting treatment and disclosure of changes in accounting policies, changes in accounting estimates and corrections of errors. Adoption of these recommendations had no effect on the consolidated financial statements for the three and nine months ended September 30, 2007, except for the disclosure of accounting changes that have been issued by the CICA but have not yet been adopted by the Corporation because they are not effective until a future date (refer to Future Accounting Changes below).

Future Accounting Changes

The CICA has issued new accounting recommendations for capital disclosures which require disclosure of both qualitative and quantitative information that enables users of financial statements to evaluate the Corporation's objectives, policies and processes for managing capital. These recommendations are effective for the Corporation beginning January 1, 2008.

The CICA has also issued new accounting recommendations for disclosure and presentation of financial instruments which require disclosures of both qualitative and quantitative information that enables users of financial statements to evaluate the nature and extent of risks arising from financial instruments to which the Corporation is exposed. These recommendations are effective for the Corporation beginning January 1, 2008.

The CICA has also issued new accounting recommendations for measurement and disclosure of inventories which provide guidance on the determination of cost and its subsequent recognition as an expense, including any writedown to net realizable value, and on the cost formulas that are used to assign costs to inventories. The Corporation is evaluating the effect of these recommendations on earnings and assets of the Corporation. These recommendations are effective for the Corporation beginning January 1, 2008.

The CICA has decided to remove 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. The CICA has also decided to amend its accounting recommendations pertaining to regulated income taxes to require the recognition of future regulated 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 Corporation is evaluating the possibility of using standards issued by the Financial Accounting Standards Board in the United States as another source of Canadian GAAP. Once issued, these recommendations will be effective for the Corporation beginning January 1, 2009, and are to be applied prospectively.

October 24, 2007

CANADIAN UTILITIES LIMITED
CONSOLIDATED STATEMENT OF EARNINGS AND RETAINED EARNINGS
(Millions of Canadian Dollars except per share data)

		Three Months Ended September 30		Nine Months Ended September 30	
	Note	**2007**	2006	**2007**	2006
		(Unaudited)		*(Unaudited)*	
Revenues	2	**$ 489.9**	$ 553.9	**$1,747.8**	$1,759.3
Costs and expenses					
Natural gas supply		**8.0**	11.2	**17.3**	26.2
Purchased power		**11.1**	10.0	**36.3**	33.6
Operation and maintenance		**219.3**	238.3	**690.2**	706.8
Selling and administrative		**47.6**	45.7	**139.7**	132.6
Depreciation and amortization		**77.3**	73.3	**252.5**	252.9
Interest	4	**43.6**	42.2	**129.1**	131.9
Interest on non-recourse long term debt		**10.5**	12.1	**33.3**	36.4
Franchise fees		**20.6**	18.4	**113.8**	108.0
		438.0	451.2	**1,412.2**	1,428.4
		51.9	102.7	**335.6**	330.9
Interest and other income	6	**11.4**	17.3	**43.0**	39.6
Earnings before income taxes		**63.3**	120.0	**378.6**	370.5
Income taxes	2, 4	**(17.2)**	44.2	**64.6**	119.7
		80.5	75.8	**314.0**	250.8
Dividends on equity preferred shares		**8.3**	9.0	**26.0**	26.9
Earnings attributable to Class A and Class B shares		**72.2**	66.8	**288.0**	223.9
Retained earnings at beginning of period as restated	5	**1,951.4**	1,780.3	**1,813.3**	1,721.9
		2,023.6	1,847.1	**2,101.3**	1,945.8
Dividends on Class A and Class B shares		**39.5**	68.0	**117.2**	140.4
Purchase of Class A shares		**-**	38.0	**-**	64.3
Retained earnings at end of period		**$1,984.1**	$1,741.1	**$1,984.1**	$1,741.1
Earnings per Class A and Class B share	9	**$ 0.58**	$ 0.53	**$ 2.30**	$ 1.77
Diluted earnings per Class A and Class B share	9	**$ 0.58**	$ 0.53	**$ 2.29**	$ 1.76
Dividends paid per Class A and Class B share	9	**$ 0.315**	$ 0.54	**$ 0.935**	$ 1.11

CANADIAN UTILITIES LIMITED
CONSOLIDATED BALANCE SHEET
(Millions of Canadian Dollars)

	Note	September 30 2007	September 30 2006	December 31 2006
		(Unaudited)		*(Audited)*
ASSETS				
Current assets				
Cash and short term investments	3	**$ 682.9**	$ 732.6	$ 798.8
Accounts receivable		**332.1**	264.7	362.3
Inventories		**98.2**	84.1	96.5
Future income taxes		**2.3**	0.2	-
Regulatory assets	2	**7.3**	12.2	13.3
Derivative assets	10	**0.3**	-	-
Prepaid expenses		**34.2**	26.2	23.6
		1,157.3	1,120.0	1,294.5
Property, plant and equipment		**5,587.3**	5,318.1	5,426.1
Regulatory assets	2	**64.0**	30.1	43.2
Derivative assets	10	**58.9**	-	-
Other assets		**194.3**	232.7	229.7
		$7,061.8	$6,700.9	$6,993.5
LIABILITIES AND SHARE OWNERS' EQUITY				
Current liabilities				
Accounts payable and accrued liabilities	2	**$ 380.0**	$ 272.5	$ 338.8
Income taxes payable	2, 4	**2.2**	13.8	22.7
Future income taxes		**-**	-	0.3
Regulatory liabilities		**9.7**	2.0	0.5
Derivative liabilities	10	**1.9**	-	-
Non-recourse long term debt due within one year	7	**61.2**	50.2	59.3
		455.0	338.5	421.6
Future income taxes	2, 4	**166.9**	177.9	194.7
Regulatory liabilities		**144.2**	149.6	148.8
Derivative liabilities	10	**2.9**	-	-
Deferred credits	2, 10	**295.7**	256.9	229.0
Long term debt	7	**2,399.4**	2,266.5	2,411.5
Non-recourse long term debt	7	**495.7**	633.8	626.7
Equity preferred shares	8	**625.0**	636.5	636.5
Class A and Class B share owners' equity				
Class A and Class B shares	9	**517.4**	514.0	516.0
Contributed surplus		**1.8**	1.1	1.2
Retained earnings		**1,984.1**	1,741.1	1,804.4
Accumulated other comprehensive income	11	**(26.3)**	(15.0)	3.1
		2,477.0	2,241.2	2,324.7
		$7,061.8	$6,700.9	$6,993.5

CANADIAN UTILITIES LIMITED
CONSOLIDATED STATEMENT OF CASH FLOWS
(Millions of Canadian Dollars)

	Note	Three Months Ended September 30		Nine Months Ended September 30	
		2007	2006	**2007**	2006
		(Unaudited)		*(Unaudited)*	
Operating activities					
Earnings attributable to Class A and Class B shares		**$ 72.2**	$ 66.8	**$ 288.0**	$ 223.9
Adjustments for:					
Depreciation and amortization		**77.3**	73.3	**252.5**	252.9
Future income taxes	2	**3.2**	4.0	**3.8**	(12.9)
Deferred availability incentives		**(5.3)**	12.2	**(2.3)**	20.8
TXU Europe settlement - net of income taxes	3	**(2.7)**	(3.6)	**(8.6)**	1.7
Other		**5.7**	(5.4)	**12.5**	2.7
Funds generated by operations		**150.4**	147.3	**545.9**	489.1
Changes in non-cash working capital		**(45.1)**	(37.1)	**33.9**	8.9
Cash flow from operations		**105.3**	110.2	**579.8**	498.0
Investing activities					
Purchase of property, plant and equipment		**(216.4)**	(143.0)	**(488.2)**	(383.7)
Proceeds (costs) on disposal of property, plant and equipment		**2.3**	(3.4)	**(1.5)**	(6.1)
Contributions by utility customers for extensions to plant		**28.7**	20.4	**65.4**	61.2
Non-current deferred electricity costs		**(2.7)**	(2.2)	**(5.1)**	13.2
Changes in non-cash working capital		**22.6**	(25.4)	**7.1**	(33.7)
Income tax reassessment	4	**-**	4.2	**-**	(12.8)
Other		**(6.1)**	(2.4)	**(17.9)**	(5.0)
		(171.6)	(151.8)	**(440.2)**	(366.9)
Financing activities					
Issue of long term debt		**-**	-	**-**	35.5
Repayment of non-recourse long term debt	3	**(19.3)**	(21.7)	**(110.5)**	(52.0)
Issue of equity preferred shares by subsidiary	8	**-**	-	**115.0**	-
Redemption of equity preferred shares	8	**-**	-	**(126.5)**	-
Net issue (purchase) of Class A shares		**0.2**	(41.7)	**1.3**	(69.4)
Dividends paid to Class A and Class B share owners		**(39.5)**	(68.0)	**(117.2)**	(140.4)
Other		**0.6**	(0.5)	**(2.7)**	(1.3)
		(58.0)	(131.9)	**(240.6)**	(227.6)
Foreign currency translation		**(5.8)**	2.1	**(14.9)**	4.7
Cash position [(1)]					
Decrease		**(130.1)**	(171.4)	**(115.9)**	(91.8)
Beginning of period		**813.0**	904.0	**798.8**	824.4
End of period		**$ 682.9**	$ 732.6	**$ 682.9**	$ 732.6

[(1)] Cash position includes $129.3 million (2006 - $146.9 million) which is only available for use in joint ventures.

CANADIAN UTILITIES LIMITED
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME
(Millions of Canadian Dollars)

		Three Months Ended September 30		Nine Months Ended September 30	
	Note	**2007**	2006	**2007**	2006
		(Unaudited)		*(Unaudited)*	
Earnings attributable to Class A and Class B shares		**$72.2**	$66.8	**$288.0**	$223.9
Other comprehensive income, net of income taxes:					
Cash flow hedges	11	**(1.3)**	-	**2.3**	-
Foreign currency translation adjustment	11	**(11.0)**	1.7	**(24.4)**	3.2
		(12.3)	1.7	**(22.1)**	3.2
Comprehensive income		**$59.9**	$68.5	**$265.9**	$227.1

CANADIAN UTILITIES LIMITED
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
SEPTEMBER 30, 2007
(Unaudited, Tabular Amounts in Millions of Canadian Dollars)

1. Summary of significant accounting policies

Financial statement presentation

The accompanying consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles and should be read in conjunction with the consolidated financial statements and related notes included in the Corporation's 2006 Annual Report. These interim financial statements have been prepared using the same accounting policies as used in the financial statements for the year ended December 31, 2006, except as described below.

Effective January 1, 2007, the Corporation prospectively adopted the Canadian Institute of Chartered Accountants ("CICA") recommendations pertaining to financial instruments, which establish standards for the recognition, measurement, disclosure and presentation of financial assets, financial liabilities and non-financial derivatives. These recommendations require that fair value be used to measure financial assets that are held for trading or available for sale, financial liabilities that are held for trading and all derivative financial instruments. Other financial assets, such as loans and receivables and investments that are held to maturity, and other financial liabilities are measured at their carrying value. This change in accounting had the following effect on the consolidated financial statements for the three and nine months ended September 30, 2007:
(a) Recognition of interest rate swaps, foreign currency forward contracts and certain natural gas purchase contracts as derivative assets and liabilities in the consolidated financial statements (see Note 10).
(b) Recognition of the fair value of a power generation revenue contract liability associated with the natural gas purchase contracts derivative asset (see Note 10).
(c) Recognition of a mark-to-market adjustment for the change in fair value of the natural gas purchase contracts derivative asset and recognition of an adjustment to the associated power generation revenue contract liability (see Note 6).
(d) Restatement of opening retained earnings at January 1, 2007 to recognize the prior years' earnings effect of the natural gas purchase contracts derivative asset and the associated power generation revenue contract liability, as well as the prior years' earnings effect of accounting for certain financial assets and financial liabilities at amortized cost using the effective interest method (see Note 5).
(e) Reclassification of deferred financing charges from other assets to long term debt and non-recourse long term debt (see Note 7).

Effective January 1, 2007, the Corporation prospectively adopted the CICA recommendations pertaining to hedges, which establish standards for the identification, designation, documentation and effectiveness of hedging relationships for the purpose of applying hedge accounting. The purpose of hedge accounting is to ensure that gains, losses, revenues and expenses from effective hedging relationships are recorded in earnings in the same period. This change in accounting had no effect on the consolidated financial statements for the three and nine months ended September 30, 2007.

Effective January 1, 2007, the Corporation prospectively adopted the CICA recommendations regarding the reporting and disclosure of comprehensive income. Comprehensive income consists of changes in the equity of the Corporation from sources other than the Corporation's share owners, and includes earnings of the Corporation, the foreign currency translation adjustment relating to self-sustaining foreign operations and unrealized gains and losses on changes in fair values of available-for-sale assets and effective cash flow hedging instruments. Other comprehensive income comprises revenues, expenses, gains and losses that are recognized in comprehensive income but are excluded from earnings of the period. Comprehensive income is disclosed in a separate statement in the consolidated financial statements.

Effective January 1, 2007, the Corporation prospectively adopted the CICA recommendations regarding the presentation of equity and changes in equity. These recommendations require separate presentation of the components of equity, including retained earnings, accumulated other comprehensive income, contributed surplus, share capital and reserves, and the changes therein. As a result of this change in accounting, the Corporation has

1. **Summary of significant accounting policies** (continued)

included a reconciliation of accumulated other comprehensive income in the notes to the consolidated financial statements (see Note 11). In accordance with the recommendations, comparative figures have been adjusted to incorporate the foreign currency translation adjustment into accumulated other comprehensive income.

Effective January 1, 2007, the Corporation adopted the CICA recommendations that prescribe the criteria for changing accounting policies, together with the accounting treatment and disclosure of changes in accounting policies, changes in accounting estimates and corrections of errors. Adoption of these recommendations had no effect on the consolidated financial statements for the three and nine months ended September 30, 2007, except for the disclosure of accounting changes that have been issued by the CICA but have not yet been adopted by the Corporation because they are not effective until a future date (see Future Accounting Changes below).

Due to the seasonal nature of the Corporation's operations, changes in electricity prices in Alberta, the timing and demand of natural gas storage capacity sold, changes in natural gas storage fees and the timing of rate decisions, the consolidated statements of earnings and retained earnings for the three and nine months ended September 30, 2007 and September 30, 2006 are not necessarily indicative of operations on an annual basis.

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

Cash and Short Term Investments

Short term investments consist of certificates of deposit and bankers' acceptances with maturities generally of 90 days or less at purchase.

Deferred Financing Charges

Issue costs of long term debt are amortized over the life of the debt using the effective interest method. Issue costs of preferred shares relating to regulated operations are amortized over the expected life of the issue and issue costs of preferred shares relating to other subsidiaries are charged to retained earnings. Unamortized premiums and issue costs of redeemed long term debt and preferred shares relating to regulated operations are amortized over the life of the issue funding the redemption. The Corporation's deferred financing charges pertaining to long term debt have been reclassified from other assets to long term debt and non-recourse long term debt in accordance with the CICA recommendations for financial instruments (see Note 7).

Derivative Financial Instruments

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

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

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

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

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

1. **Summary of significant accounting policies** (continued)

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

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

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

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

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

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

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

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

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.

Foreign Currency Translation

Assets and liabilities of self-sustaining foreign operations are translated into Canadian dollars at the rate of exchange in effect at the balance sheet date and revenues and expenses are translated at the average monthly rates of exchange during the year. Gains or losses on translation of self-sustaining foreign operations are included in accumulated other comprehensive income in share owners' equity.

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

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

1. Summary of significant accounting policies (continued)

Future Accounting Changes

The CICA has issued new accounting recommendations for capital disclosures which require disclosure of both qualitative and quantitative information that enables users of financial statements to evaluate the Corporation's objectives, policies and processes for managing capital. These recommendations are effective for the Corporation beginning January 1, 2008.

The CICA has also issued new accounting recommendations for disclosure and presentation of financial instruments which require disclosures of both qualitative and quantitative information that enables users of financial statements to evaluate the nature and extent of risks arising from financial instruments to which the Corporation is exposed. These recommendations are effective for the Corporation beginning January 1, 2008.

The CICA has also issued new accounting recommendations for measurement and disclosure of inventories which provide guidance on the determination of cost and its subsequent recognition as an expense, including any writedown to net realizable value, and on the cost formulas that are used to assign costs to inventories. The Corporation is evaluating the effect of these recommendations on earnings and assets of the Corporation. These recommendations are effective for the Corporation beginning January 1, 2008.

The CICA has decided to remove 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. The CICA has also decided to amend its accounting recommendations pertaining to regulated income taxes to require the recognition of future regulated 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 Corporation is evaluating the possibility of using standards issued by the Financial Accounting Standards Board in the United States as another source of Canadian GAAP. Once issued, these recommendations will be effective for the Corporation beginning January 1, 2009, and are to be applied prospectively.

2. Regulatory matters

On September 22, 2007, ATCO Electric received a decision on its General Tariff Application for 2007 and 2008 which was filed with the Alberta Energy and Utilities Board ("AEUB") in November 2006. The decision established the amount of revenue ATCO Electric can recover through its rates for electric distribution and transmission service provided to its customers for 2007 and 2008. The effect of the decision on the earnings of ATCO Electric was not material, as higher revenues primarily resulting from increased investment in capital expenditures and previously approved interim customer rates were offset by lower allowed 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, whereby, effective January 1, 2007, ATCO Electric no longer recognizes future income taxes, and will refund to customers the $34.4 million of future income taxes collected under the previously allowed tax methodology.

The reversal of these recorded future income taxes as at January 1, 2007, was reflected in the third quarter of 2007. The adjustment does not affect earnings as ATCO Electric's revenues and income tax expense were reduced by similar amounts. The adjustment does not affect cash flow from operations for the three and nine months ended September 30, 2007. The timing of the cash refund to customers is subject to a further regulatory process at which time ATCO Electric intends to propose a five year repayment period. Accordingly, at September 30, 2007, ATCO Electric has recorded a reduction in future income tax liabilities of $34.4 million and a liability to customers of $49.3 million, offset by a regulatory asset of $14.9 million which represents current income tax savings to be realized in future periods. Unrecorded future income tax liabilities have increased by $34.4 million as a result of this decision.

2. Regulatory matters (continued)

On March 17, 2006, ATCO Electric received a decision on its General Tariff Application for 2005 and 2006 which was filed with the AEUB in May 2005. The decision established the amount of revenue ATCO Electric can recover through its rates for electric distribution and transmission service provided to its customers for 2005 and 2006. The impact of the decision for 2005 reduced ATCO Electric's earnings by $1.3 million and was recorded in the first quarter of 2006. The impact of the decision for the full year 2006, as compared to the decision for the full year 2005, further reduced ATCO Electric's earnings by $1.6 million. The decision also confirmed the return on common equity as determined by the AEUB's standardized rate of return methodology. The rate of return on common equity was 8.93% in 2006.

On January 27, 2006, ATCO Gas received a decision on its general rate application which was filed with the AEUB in May 2005 for the 2005, 2006 and 2007 test years. The decision established the amount of revenue ATCO Gas can recover through distribution rates for natural gas distribution service to its customers over the period of 2005 to 2007. The decision also approved the return on common equity as determined by the AEUB's standardized rate of return methodology. The rate of return on common equity was 8.93% in 2006 and is 8.51% for 2007. The final impact of the decision is subject to the outcome of an existing process regarding the pricing of services provided by ATCO I-Tek.

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

3. TXU Europe settlement

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

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

Based on the foreign currency exchange rate in effect at March 30, 2005, the Corporation's share of this settlement is expected to generate earnings after income taxes of approximately $69 million, which will be recognized over the remaining term of the TXU Europe contract to September 30, 2010, at approximately $11 million per year. These earnings will be dependent upon foreign currency exchange rates in effect at the time that the earnings are recognized.

On May 31, 2007, £95.0 million of the TXU proceeds, of which the Corporation's share is $52.7 million, were applied to Barking Power's non-recourse long term debt.

4. Income taxes

On June 15, 2007, an amendment to tax legislation pertaining to the taxation of preferred share dividends paid by corporations received third reading in the House of Commons. The Canada Revenue Agency ("CRA") has been assessing corporate tax returns based on this proposed change since January 1, 2003, resulting in a reduction of taxes paid to the CRA. As this change is now considered to have been substantively enacted, the Corporation recorded a reduction to current income tax expense of $16.4 million in the second quarter of 2007. Funds generated by operations increased by $16.4 million, offset by a similar reduction in changes in non-cash working capital, leaving the Corporation's cash position unchanged.

4. Income taxes (continued)

In the third quarter of 2006, the CRA issued a reassessment for Alberta Power (2000)'s 2001 taxation year. The CRA's reassessment treats the proceeds received from the sale of the H.R. Milner generating plant to the Alberta Balancing Pool as income rather than as a sale of an asset. The Corporation has appealed the reassessment to the Tax Court of Canada. The full impact of the reassessment was a $12.4 million increase in interest and income tax expense, a $12.4 million decrease in earnings ($8.0 million recorded in the second quarter of 2006 and $4.4 million recorded in the third quarter of 2006), and a $28.8 million payment associated with the tax and interest assessed, paid in the third quarter of 2006. It is expected that $16.4 million of this cash payment will be recovered by reducing income taxes payable through higher capital cost allowance claims in future years.

5. Retained earnings at beginning of period as restated

	January 1	
	2007	2006
Retained earnings at beginning of period as previously reported	**$1,804.4**	$1,721.9
Adjustments to retained earnings to recognize the prior years' effect of:		
(a) the fair value of the natural gas purchase contracts derivative asset (net of income taxes)	**41.6**	-
(b) the fair value of the power generation revenue contract liability associated with the natural gas purchase contracts derivative asset (net of income taxes)	**(31.6)**	-
(c) the change in method of accounting for long term debt and non-recourse long term debt at amortized cost using the effective interest method (net of income taxes)	**(0.6)**	-
(d) the fair value of receivables (net of income taxes)	**(0.5)**	-
Retained earnings at beginning of period as restated	**$1,813.3**	$1,721.9

6. Interest and other income

Interest and other income for the three months ended September 30, 2007 includes a loss of $10.7 million related to the change in fair value of the natural gas purchase contracts derivative asset (see Note 10). This loss is partially offset by a reduced provision of $7.4 million for the associated power generation revenue contract liability.

Interest and other income for the nine months ended September 30, 2007 includes a loss of $0.6 million related to the change in fair value of the natural gas purchase contracts derivative asset (see Note 10). This loss is offset by a reduced provision of $0.8 million for the associated power generation revenue contract liability.

7. Long term debt and non-recourse long term debt

The CICA recommendations regarding the measurement of financial liabilities require the financial liabilities to be measured at initial recognition, including transaction costs, minus principal repayments, plus or minus the cumulative amortization using the effective interest method of any difference between that initial amount and the maturity amount, minus any reduction for impairment. Accordingly, deferred financing charges have been recalculated using the effective interest method. Commencing January 1, 2007, in accordance with CICA recommendations regarding the presentation of financial liabilities, long term debt and non-recourse long term debt have been reduced by their respective cumulative unamortized balance of deferred financing charges.

7. **Long term debt and non-recourse long term debt** (continued)

Long term debt

	Effective Interest Rate	September 30 **2007**	2006
CU Inc. debentures – unsecured			
2001 4.84% due November 2006	4.977%	**$ -**	$ 175.0
2002 4.801% due November 2007	4.913%	**50.0**	50.0
2000 6.97% due June 2008	7.062%	**100.0**	100.0
1989 Series 10.20% due November 2009	10.331%	**125.0**	125.0
1990 Series 11.40% due August 2010	11.537%	**125.0**	125.0
2000 7.05% due June 2011	7.130%	**100.0**	100.0
2004 5.096% due November 2014	5.162%	**100.0**	100.0
2002 6.145% due November 2017	6.217%	**150.0**	150.0
2004 5.432% due January 2019	5.492%	**180.0**	180.0
1999 6.8% due August 2019	6.861%	**300.0**	300.0
1990 Second Series 11.77% due November 2020	11.903%	**100.0**	100.0
2006 4.801% due November 2021	4.854%	**160.0**	-
1991 Series 9.92% due April 2022	10.063%	**125.0**	125.0
1992 Series 9.40% due May 2023	9.511%	**100.0**	100.0
2004 5.896% due November 2034	5.939%	**200.0**	200.0
2005 5.183% due November 2035	5.226%	**185.0**	185.0
2006 5.032% due November 2036	5.072%	**160.0**	-
CU Inc. other long term obligation, due June 2009, unsecured	6.000%	**4.5**	4.5
Canadian Utilities Limited debentures – unsecured			
2002 6.14% due November 2012	6.228%	**100.0**	100.0
Less: Deferred financing charges		**(12.1)**	-
		2,352.4	2,219.5
ATCO Midstream Ltd. credit facility, at BA rates, due June 2012, unsecured (1)	Floating	**25.0**	25.0
ATCO Power Canada Ltd. credit facility, at BA rates, due August 2011, secured by a pledge of cash (1)	Floating	**22.0**	22.0
		$2,399.4	$2,266.5

Non-recourse long term debt

The CICA recommendations pertaining to financial instruments do not permit the presentation of interest rate swaps in combination with floating rate long term debt to emulate fixed rate long term debt. Consequently, any of the Corporation's floating rate non-recourse long term debt that had previously been presented in combination with interest rate swaps is now presented exclusive of the effect of the interest rate swaps (see Note 10). The comparative figures have been restated; this change in presentation had no effect on the amount of the Corporation's non-recourse long term debt.

7. Long term debt and non-recourse long term debt (continued)

Non-recourse long term debt (continued)

Project Financing	Effective Interest Rate	September 30 2007	September 30 2006
Barking Power Limited, payable in British pounds:			
Term loans, at fixed rates averaging 7.95%, due to 2010 (£17.9 million (2006 – £22.8 million))	7.95%	**$ 36.4**	$ 47.8
Term loan, at LIBOR, due to 2010 (1) (£5.2 million (2006 – £37.4 million))	Floating	**10.6**	78.3
Osborne Cogeneration Pty Ltd., payable in Australian dollars:			
Term loan, at Bank Bill rates, due to 2013 (1) ($31.9 million AUD (2006 – $36.5 million AUD))	Floating (2)	**28.1**	30.4
ATCO Power Alberta Limited Partnership ("APALP"):			
Term loan, at LIBOR, due to 2016 (1)	Floating (2)	**86.5**	93.4
Joffre:			
Term loan, at BA rates, due to 2012 (1)	Floating (2)	**0.5**	7.6
Term loan, at LIBOR, due to 2012 (1)	Floating (2)	**0.9**	13.6
Notes, at fixed rate of 8.59%, due to 2020	8.845%	**32.0**	32.0
Scotford:			
Term loan, at BA rates, due to 2014 (1)	Floating (2)	**42.5**	42.9
Term facility, at Canadian Prime Advances, due to 2014 (1)	Floating (2)	**0.1**	0.1
Term loan, at LIBOR, due to 2014 (1)	Floating (2)	**10.7**	10.7
Notes, at fixed rate of 7.93%, due to 2022	8.302%	**25.5**	26.3
Muskeg River:			
Term loan, at BA rates, due to 2014 (1)	Floating (2)	**32.5**	33.4
Term facility, at Canadian Prime Advances, due to 2014 (1)	Floating (2)	**0.1**	0.1
Term loan, at LIBOR, due to 2014 (1)	Floating (2)	**8.2**	8.4
Notes, at fixed rate of 7.56%, due to 2022	7.902%	**28.0**	29.9
Brighton Beach:			
Term loan, at BA rates, due to 2020 (1)	Floating (2)	**19.5**	20.4
Term loan, at LIBOR, due to 2020 (1)	Floating (2)	**17.5**	18.3
Construction overrun facility, at BA rates, due to 2020 (1)	Floating (2)	**4.8**	5.0
Construction overrun facility, at LIBOR, due to 2020 (1)	Floating (2)	**4.3**	4.5
Notes, at fixed rate of 6.924%, due to 2024	7.025%	**105.6**	108.5
Cory:			
Cost overrun facility, at BA rates, due to 2011 (1)	Floating (2)	**2.5**	3.1
Notes, at fixed rate of 7.586%, due to 2025	7.872%	**35.7**	36.7
Notes, at fixed rate of 7.601%, due to 2026	7.880%	**31.8**	32.6
Less: Deferred financing charges		**(7.4)**	-
		556.9	684.0
Less: Amounts due within one year		**61.2**	50.2
		$495.7	$633.8

BA – Bankers' Acceptance
LIBOR – London Interbank Offered Rate

(1) *The above interest rates have additional margin fees at a weighted average rate of 1.2% (2006 — 1.1%). The margin fees are subject to escalation.*

(2) *Floating interest rates have been partially or completely hedged with interest rate swaps (see Note 10).*

8. Equity preferred shares

CU Inc. equity preferred shares

Authorized and issued

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

Issued:

	Stated Value (dollars)	Redemption Dates	September 30 2007 Shares	2007 Amount	2006 Shares	2006 Amount
Cumulative Redeemable Preferred Shares						
4.60% Series 1	$25.00	See below	**4,600,000**	**$ 115.0**	-	$ -

On April 18, 2007, CU Inc., a subsidiary corporation, issued $115.0 million Cumulative Redeemable Preferred Shares Series 1 at a price of $25.00 per share for cash. The dividend rate has been fixed at 4.60%. The net proceeds of the issue were used in part to redeem $91.8 million of the outstanding Cumulative Redeemable Second Preferred Shares Series Q, R and S of ATCO Electric, ATCO Gas and ATCO Pipelines, subsidiary corporations of CU Inc., that are held by Canadian Utilities Limited.

Fair values

Fair values for preferred shares determined using quoted market prices for the same or similar issues are $99.3 million (2006 - nil).

Redemption privileges

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

Canadian Utilities Limited equity preferred shares

Authorized and issued

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

Issued:

	Stated Value (dollars)	Redemption Dates	September 30 2007 Shares	2007 Amount	2006 Shares	2006 Amount
Cumulative Redeemable Second Preferred Shares						
5.9% Series Q	$25.00	Open	-	$ -	2,277,675	$ 56.9
5.3% Series R	$25.00	Open	-	-	2,146,730	53.7
6.6% Series S	$25.00	Open	-	-	635,700	15.9
5.8% Series W	$25.00	See below	**6,000,000**	**150.0**	6,000,000	150.0
6.0% Series X	$25.00	See below	**6,000,000**	**150.0**	6,000,000	150.0
Perpetual Cumulative Second Preferred Shares						
4.35% Series O	$25.00	December 2, 2011	**1,600,000**	**40.0**	1,600,000	40.0
4.35% Series T	$25.00	December 2, 2011	**1,600,000**	**40.0**	1,600,000	40.0
4.35% Series U	$25.00	December 2, 2011	**800,000**	**20.0**	800,000	20.0
5.25% Series V	$25.00	October 3, 2007	**4,400,000**	**110.0**	4,400,000	110.0
				$510.0		$636.5

8. Equity preferred shares (continued)

On May 18, 2007, Canadian Utilities Limited redeemed $126.5 million of outstanding Cumulative Redeemable Second Preferred Shares Series Q, R and S at a price of $25.00 per share plus accrued and unpaid dividends per share.

The dividends payable on the Series O, T, U and V preferred shares are fixed until the redemption dates specified above, at which time a new dividend rate may be established by negotiations between Canadian Utilities Limited and the owners of the shares.

Effective October 3, 2007, the dividend rate on the Series V preferred shares has been reset to 4.70% with a redemption date of October 3, 2012.

Fair values

Fair values for preferred shares determined using quoted market prices for the same or similar issues are $519.8 million (2006 - $669.7 million).

Redemption privileges

The preferred shares, except for Series W and X, are redeemable on the dates specified above at the option of Canadian Utilities Limited at the stated value plus accrued and unpaid dividends.

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

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

9. Class A and Class B shares

There were 81,637,086 (2006 – 81,278,986) Class A non-voting shares and 43,806,584 (2006 – 44,009,284) Class B common shares outstanding on September 30, 2007. In addition, there were 1,313,000 options to purchase Class A non-voting shares outstanding at September 30, 2007 under the Corporation's stock option plan. From October 1, 2007, to October 23, 2007, no stock options were granted or cancelled, no stock options were exercised, 5,000 Class B common shares were converted to Class A non-voting shares and no Class A non-voting shares were purchased under the Corporation's normal course issuer bid.

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

	Three Months Ended September 30		Nine Months Ended September 30	
	2007	2006	**2007**	2006
Weighted average shares outstanding	**125,433,940**	125,802,286	**125,415,320**	126,502,915
Effect of dilutive stock options	**536,860**	542,011	**516,633**	532,422
Weighted average diluted shares outstanding	**125,970,800**	126,344,297	**125,931,953**	127,035,337

The Corporation paid a Special Dividend of $0.25 per Class A and Class B share on September 1, 2006.

10. Risk management and financial instruments

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

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

The derivative assets and liabilities comprise the following:

	September 30 2007
Derivative assets – current:	
Interest rate swap agreements	$ 0.3
Derivative assets – non-current:	
Natural gas purchase contracts	$58.4
Interest rate swap agreements	0.5
	$58.9
Derivative liabilities – current:	
Interest rate swap agreements	$ 1.2
Foreign currency forward contracts	0.7
	$ 1.9
Derivative liabilities – non-current:	
Interest rate swap agreements	$ 2.9

10. Risk management and financial instruments (continued)

Interest rate risk

The Corporation has converted variable rate non-recourse long term debt to fixed rate debt through the following interest rate swap agreements:

Project Financing	Swap Fixed Interest Rate [1]	Variable Debt Interest Rate	Maturity Date	Notional Principal September 30 2007	2006
Osborne: ($33.3 million AUD (2006 – $37.4 million AUD))	7.388%	Bank Bill Rate in Australia	December 2013	**$ 29.4**	$ 31.1
APALP:	7.727%	90 day BA	November 2008	**1.9**	3.2
	7.504%	90 day BA	December 2008	**2.7**	4.5
	7.687%	6 month LIBOR	December 2011	**79.0**	85.7
Joffre:	7.286%	90 day BA	September 2012	**21.0**	25.1
Scotford:	5.306%	90 day BA	September 2008	**51.4**	55.5
Muskeg River:	5.372%	90 day BA	December 2007	**39.9**	41.8
Brighton Beach:	5.8367%	90 day BA	June 2009	**8.6**	9.1
	6.575%	90 day BA	March 2019	**34.7**	36.6
Cory:	6.532%	90 day BA	June 2011	**2.2**	2.8
				$270.8	$295.4

BA – Bankers' Acceptance
LIBOR – London Interbank Offered Rate

[1] *The above swap fixed interest rates include any long term debt margin fees; the margin fees are subject to escalation (Note 7).*

The Corporation has fixed interest rates, either directly or through interest rate swap agreements, on 98% (2006 – 96%) of total long term debt and non-recourse long term debt.

Foreign currency exchange rate risk

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

The Corporation has entered into foreign currency forward contracts in order to fix the exchange rate on certain planned equipment expenditures and operational cash flows denominated in U.S. dollars, U.K. pounds sterling ("£") and Euros. At September 30, 2007, the contracts consist of purchases of $8.4 million U.S. and £1.4 million (2006 – purchases of $1.4 million U.S. and sales of 6.0 million Euros).

Natural gas purchase contracts and associated power generation revenue contract liability

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

10. Risk management and financial instruments (continued)

As all but the excess volume of natural gas is committed to the Corporation's power generation obligations, the Corporation could not recognize the entire fair values of these natural gas purchase contracts in its revenues. Consequently, on January 1, 2007, the Corporation recognized a provision for a power generation revenue contract in the amount of $44.8 million; thereafter, the Corporation will record adjustments to the power generation revenue contract liability concurrently with the mark-to-market adjustments for the natural gas purchase contracts derivative asset. This power generation revenue contract liability is included in deferred credits in the consolidated balance sheet.

The mark-to-market adjustment for the derivative asset and the corresponding adjustment for the associated power generation revenue contract liability decreased earnings by $2.4 million, net of income taxes, for the three months ended September 30, 2007 and increased earnings by $0.1 million, net of income taxes, for the nine months ended September 30, 2007. At September 30, 2007, the natural gas purchase contracts derivative asset is $58.4 million and the power generation revenue contract liability is $44.0 million.

Credit risk

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

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

Fair value of non-derivative financial instruments

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

	September 30			
	2007		2006	
	Carrying Value	**Fair Value**	Carrying Value	Fair Value
Assets				
Cash and short term investments [1]	**$ 682.9**	**$ 682.9**	$ 732.6	$ 732.6
Accounts receivable [1]	**332.1**	**332.1**	264.7	264.7
Liabilities				
Accounts payable and accrued liabilities [2]	**380.0**	**380.0**	272.5	272.5
Long term debt [3]	**2,399.4**	**2,650.5**	2,266.5	2,661.1
Non-recourse long term debt [3]	**556.9**	**587.3**	684.0	720.0

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

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

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

10. Risk management and financial instruments (continued)

Fair value of derivative financial instruments

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

	September 30					
	2007			2006		
	Notional Principal [1]	**Fair Value Receivable (Payable)** [3]	**Maturity**	Notional Principal [1]	Fair Value Receivable (Payable) [3]	Maturity
Interest rate swaps	**$270.8**	**$(3.3)**	**2007-2019**	$295.4	$(8.2)	2007-2019
Foreign currency forward contracts	**$ 11.7**	**$(0.7)**	**2007-2008**	$ 10.3	$ 0.1	2006-2007
Natural gas purchase contracts	**N/A** [2]	**$58.4**	**2014**	N/A [4]	N/A [4]	N/A [4]

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

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

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

(4) *In accordance with the CICA recommendations for financial instruments, disclosures not required in financial statements for periods prior to January 1, 2007 need not be provided on a comparative basis.*

11. Other comprehensive income

Other comprehensive income ("OCI") of the Corporation is comprised of three components: the unrealized gains and losses on effective cash flow hedging instruments, the unrealized gains and losses on financial assets that are available for sale, and the foreign currency translation adjustment relating to self-sustaining foreign operations.

11. Other comprehensive income (continued)

Changes in the components of accumulated OCI are summarized below:

	Three Months Ended September 30		Nine Months Ended September 30	
	2007	2006	**2007**	2006
Accumulated OCI at beginning of period:				
Cash flow hedge losses [1]	**$ (3.8)**	$ -	**$ -**	$ -
Financial assets available for sale [2]	**0.1**	-	**-**	-
Foreign currency translation adjustment	**(10.3)**	(16.7)	**3.1**	(18.2)
	(14.0)	$(16.7)	**3.1**	(18.2)
Adjustment to accumulated OCI at beginning of period due to change in method of accounting for:				
Cash flow hedge losses [3]	**-**	-	**(7.4)**	-
Financial assets available for sale [2]	**-**	-	**0.1**	-
	-	-	**(7.3)**	-
OCI for the period:				
Changes in fair values of cash flow hedges [4]	**(1.3)**	-	**2.2**	-
Transfers of cash flow hedge losses to earnings [2]	**-**	-	**0.1**	-
	(1.3)	-	**2.3**	-
Foreign currency translation adjustment	**(11.0)**	1.7	**(24.4)**	3.2
	(12.3)	1.7	**(22.1)**	3.2
Accumulated OCI at end of period:				
Cash flow hedge losses [5]	**(5.1)**	-	**(5.1)**	-
Financial assets available for sale [2]	**0.1**	-	**0.1**	-
Foreign currency translation adjustment	**(21.3)**	(15.0)	**(21.3)**	(15.0)
	$(26.3)	$(15.0)	**$(26.3)**	$(15.0)

(1) *Net of income taxes of $1.6 million.*
(2) *Net of income taxes of nil.*
(3) *Net of income taxes of $3.2 million.*
(4) *Net of income taxes of $0.6 million and $(1.0) million, respectively.*
(5) *Net of income taxes of $2.2 million and $2.2 million, respectively.*

12. Employee future benefits

In the three months ended September 30, 2007, net expense of $3.9 million (2006 – $4.0 million) was recognized for pension benefit plans and net expense of $0.6 million (2006 – $1.2 million) was recognized for other post employment benefit plans.

In the nine months ended September 30, 2007, net expense of $11.2 million (2006 – $11.7 million) was recognized for pension benefit plans and net expense of $3.3 million (2006 – $3.7 million) was recognized for other post employment benefit plans.

13. Segmented information

Segmented results – Three months ended September 30

2007 2006 *(Unaudited)*	Utilities	Power Generation	Global Enterprises	Corporate and Other	Intersegment Eliminations	Consolidated
Revenues – external	**$ 181.6**	**$ 197.6**	**$110.2**	**$ 0.5**	**$ -**	**$ 489.9**
	$ 215.0	$ 202.5	$136.0	$ 0.4	$ -	$ 553.9
Revenues – intersegment [1]	**6.2**	**-**	**34.2**	**2.9**	**(43.3)**	**-**
	6.1	-	30.0	2.9	(39.0)	-
Revenues	**$ 187.8**	**$ 197.6**	**$144.4**	**$ 3.4**	**$ (43.3)**	**$ 489.9**
	$ 221.1	$ 202.5	$166.0	$ 3.3	$ (39.0)	$ 553.9
Earnings attributable to Class A and Class B shares	**$ 14.3**	**$ 38.6**	**$ 20.9**	**$ (0.8)**	**$ (0.8)**	**$ 72.2**
	$ 19.2	$ 29.3	$ 22.1	$ (2.3)	$ (1.5)	$ 66.8

Segmented results – Nine months ended September 30

2007 2006 *(Unaudited)*	Utilities	Power Generation	Global Enterprises	Corporate and Other	Intersegment Eliminations	Consolidated
Revenues – external	**$ 784.6**	**$ 579.1**	**$382.8**	**$ 1.3**	**$ -**	**$1,747.8**
	$ 777.8	$ 572.8	$407.7	$ 1.0	$ -	$1,759.3
Revenues – intersegment [1]	**18.6**	**-**	**91.6**	**8.8**	**(119.0)**	**-**
	18.3	-	85.6	8.4	(112.3)	-
Revenues	**$ 803.2**	**$ 579.1**	**$474.4**	**$ 10.1**	**$(119.0)**	**$1,747.8**
	$ 796.1	$ 572.8	$493.3	$ 9.4	$(112.3)	$1,759.3
Earnings attributable to Class A and Class B shares	**$ 91.7**	**$ 109.2**	**$ 82.3**	**$ 7.2**	**$ (2.4)**	**$ 288.0**
	$ 77.5	$ 82.3	$ 73.7	$ (5.2)	$ (4.4)	$ 223.9
Total assets	**$3,968.2**	**$2,222.0**	**$308.5**	**$477.9**	**$ 85.2**	**$7,061.8**
	$3,646.6	$2,174.1	$295.3	$518.6	$ 66.3	$6,700.9

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

Printed in Canada

CANADIAN UTILITIES LIMITED
An ATCO Company

News Release

CANADIAN UTILITIES LIMITED
Corporate Head Office: 1400, 909 - 11 Avenue S.W., Calgary, Alberta T2R 1N6 Tel: (403) 292-7500

For Immediate Release

October 25, 2007

Canadian Utilities Reports Increased Third Quarter Earnings

CALGARY, Alberta – **Canadian Utilities Limited (TSX: CU, CU.X) reported earnings of $72.2 million ($0.58 per share) for the three months ended September 30, 2007,** compared to earnings of $66.8 million ($0.53 per share) for the same three months of 2006. Earnings for the nine months ended September 30, 2007, were $288.0 million ($2.30 per share) compared to earnings of $223.9 million ($1.77 per share) for the same nine months in 2006.

Financial Summary	**For the Three Months Ended September 30**		**For the Nine Months Ended September 30**	
	2007	2006	**2007**	2006
	($ Millions except per share data) *(unaudited)*			
Earnings	**72.2**	66.8	**288.0**	223.9
Earnings per Class A and B share	**0.58**	0.53	**2.30**	1.77
Revenues	**489.9**	553.9	**1,747.8**	1,759.3
Funds generated by operations [1]	**150.4**	147.3	**545.9**	489.1

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

Earnings for the three months ended September 30, 2007, increased primarily due to:
- a $4.4 million income tax expense that was recorded by Alberta Power (2000) in the third quarter of 2006. This adjustment, which reduced earnings by $12.4 million in 2006, of which $8.0 million was recorded in the second quarter of 2006, pertained to a Canada Revenue Agency assessment on the taxation of proceeds received from the sale of the H.R. Milner generating plan in 2001. ("H.R. Milner Income Tax Reassessment");
- reduced tax expense resulting from lower future corporate tax rates in ATCO Power's U.K. operations; and
- improved performance in ATCO Power's Alberta generating plants.

This increase was partially offset by:
- the timing and demand of natural gas storage capacity sold, lower storage fees and lower volumes for natural gas liquids ("NGL") in ATCO Midstream; and
- higher operating and maintenance expenses and depreciation expenses in ATCO Gas due to customer growth and increased capital expenditures.

[continued]

Earnings for the nine months ended September 30, 2007, increased primarily due to:

- $16.4 million adjustment relating to the 2007 change in the taxation of preferred share dividends. In the second quarter of 2007, the federal government amended legislation on the taxation of preferred share dividends paid. This change, which was retroactive to 2003, resulted in a reduction in income tax expense that was recorded in the second quarter of 2007;
- improved merchant performance, increased availability, higher exchange rates on conversion of earnings to Canadian dollars and reduced tax resulting from lower future corporate tax rates in ATCO Power's U.K. operations;
- colder temperatures, customer growth and higher sales per customer in ATCO Gas; and
- H.R. Milner Income Tax Reassessment in 2006.

This increase was partially offset by:

- $11.8 million adjustment in 2006 to reflect decreased federal and provincial taxes and rates; and
- higher operating and maintenance expenses and depreciation expenses in ATCO Gas due to customer growth and increased capital expenditures.

Revenues for the three months ended September 30, 2007, decreased primarily due to:

- impact of the ATCO Electric 2007/2008 General Tariff Application decision received from the Alberta Energy and Utilities Board ("AEUB") in the third quarter of 2007. The decision directed ATCO Electric to change its income tax methodology for federal purposes whereby, effective January 1, 2007, ATCO Electric no longer recognizes future income taxes. ("ATCO Electric Decision");
- lower natural gas fuel purchases recovered on a "no-margin" basis in ATCO Power's U.K. operations; and
- decreased business activity in ATCO Frontec's operations.

This decrease was partially offset by:

- impact of finalization of customer rates in the ATCO Gas 2005, 2006 and 2007 General Rate Application confirmed by the AEUB in August 2007;
- colder temperatures and customer growth in ATCO Gas; and
- improved merchant performance in ATCO Power's Alberta generating plants.

Revenues for the nine months ended September 30, 2007, decreased primarily due to:

- impact of the ATCO Electric Decision; and
- lower prices and volumes of natural gas processed for NGL extraction in ATCO Midstream.

This decrease was partially offset by:

- colder temperatures, customer growth and higher sales per customer in ATCO Gas; and
- the timing and demand of natural gas storage capacity sold and higher storage fees in ATCO Midstream.

Funds generated by operations for the three months ended September 30, 2007, increased primarily due to increased cash flow after removal of non-cash items.

This increase was partially offset by decreased deferred availability incentives in Alberta Power (2000).

Funds generated by operations for the nine months ended September 30, 2007, increased primarily due to increased earnings.

This increase was partially offset by decreased deferred availability incentives in Alberta Power (2000).

[continued]

Other Recent Highlights include:

- ATCO Frontec entered into a limited partnership with the Fort McKay First Nation to construct, own and operate a new 500-room lodge in the Alberta oilsands region north of Fort McMurray, Alberta.
- ATCO Midstream Ltd. entered into an agreement to purchase a 50% interest in a joint venture which operates a 2.5 million cubic feet per day natural gas processing plant near the town of Kisbey, Saskatchewan.
- A record number of ATCO companies were honoured for safety. Four ATCO Group companies were honoured as "Best Safety Performers" in the province by Alberta's Occupational Health and Safety Council.
- ATCO Gas and its partners officially opened a new solar powered community in Okotoks in September. Incorporating the most advanced thermal technology, the Drake Landing project supplies 52 homes with 90 percent of their yearly space heating needs.

Canadian Utilities Limited's consolidated financial statements and management's discussion and analysis of financial condition and results of operations for the three and nine months ended September 30, 2007, will be available on Canadian Utilities' website (www.canadian-utilities.com) or via SEDAR (www.sedar.com) or can be requested from the Corporation.

Canadian Utilities Limited is part of the ATCO Group of Companies. ATCO Group, an Alberta based worldwide organization of companies with assets of approximately $7.8 billion and more than 7,000 employees, is comprised of three main business divisions: Power Generation; Utilities (natural gas and electricity transmission and distribution) and Global Enterprises, with companies active in industrial manufacturing, technology, logistics and energy services. More information about Canadian Utilities Limited can be found on its website www.canadian-utilities.com.

For further information, please contact:

K.M. (Karen) Watson
Senior Vice President & Chief Financial Officer
Canadian Utilities Limited
(403) 292-7502

Forward-Looking Information:

Certain statements contained in this news release may constitute forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "anticipate", "plan", "expect", "may", "will", "intend", "should", and similar expressions. These statements involve 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 statements. The Corporation believes that the expectations reflected in the forward-looking statements are reasonable, but no assurance can be given that these expectations will prove to be correct and such forward-looking statements should not be unduly relied upon.

The Corporation's actual results could differ materially from those anticipated in these forward-looking statements as a result of regulatory decisions, competitive factors in the industries in which the Corporation operates, prevailing economic conditions, and other factors, many of which are beyond the control of the Corporation.

The forward-looking statements contained in this news release represent the Corporations' expectations as of the date hereof, and are subject to change after such date. The Corporation disclaims any intention or obligation to update or revise any forward-looking statements whether as a result of new information, future events or otherwise, except as required under applicable securities regulations.

CANADIAN UTILITIES LIMITED
An ATCO Company

News Release

CANADIAN UTILITIES LIMITED
Corporate Head Office: 1400, 909 - 11 Avenue S.W., Calgary, Alberta T2R 1N6 Tel: (403) 292-7500

For Immediate Release
October 25, 2007

Canadian Utilities Limited Eligible Dividends

CALGARY, Alberta – The Board of Directors of Canadian Utilities Limited has declared the following quarterly dividends.

Shares	TSX Stock Symbol	Dividend Per Share ($)	Record Date (2007)	Payment Date (2007)
Class A non-voting	CU	0.315	07-Nov	01-Dec
Class B common	CU.X	0.315	07-Nov	01-Dec
Series W 5.80%	CU.PR.A	0.3625	07-Nov	01-Dec
Series X 6.00%	CU.PR.B	0.3750	07-Nov	01-Dec

These dividends are eligible dividends for Canadian income tax purposes.

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For further information, please contact:

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CANADIAN UTILITIES LIMITED
An ATCO Company

News Release

CANADIAN UTILITIES LIMITED
Corporate Head Office: 1400, 909 - 11 Avenue S.W., Calgary, Alberta T2R 1N6 Tel: (403) 292-7500

For Immediate Release
November 5, 2007

ATCO Power Reports Unplanned Outage at Barking Power Station in London, England

CALGARY, Alberta – ATCO Power reported today that the 1,000 megawatt Barking Power Station in East London, England has experienced an unplanned outage that is expected to last for at least 45 days on 60% of the plant capacity. ATCO Power owns 25.5% of the Barking Power Plant.

The outage involves a steam turbine generator and the cause of the failure will become clearer as the machine is disassembled.

The financial impact of the failure has not been fully determined, but is estimated to decrease Canadian Utilities Limited's earnings for the three months ended December 31, 2007, and the 12 months ended December 31, 2007 by approximately $5 million to $10 million Canadian.

ATCO Power, a wholly owned subsidiary of Canadian Utilities Limited, is a world-class developer, construction manager, owner and operator of technologically advanced independent power generation facilities. Canadian Utilities Limited is an Alberta based worldwide organization of companies with more than 6,000 employees and $7.1 billion in assets, comprised of three main business divisions: Power Generation; Utilities (natural gas and electricity transmission and distribution) and Global Enterprises, with companies active in technology, logistics and energy services. More information about Canadian Utilities Limited can be found on its website www.canadian-utilities.com.

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The Corporation's actual results could differ materially from those anticipated in these forward-looking statements as a result of regulatory decisions, competitive factors in the industries in which the Corporation operates, prevailing economic conditions, and other factors, many of which are beyond the control of the Corporation.

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