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FOR THE THREE MONTHS ENDED

MARCH 31, 2007

TO THE SHARE OWNERS:

Canadian Utilities Limited reported increased earnings of $134.7 million ($1.07 per share) for the three months ended March 31, 2007, compared to earnings for the same three months in 2006 of $86.9 million ($0.68 per share).

Earnings for the three months ended March 31, 2007, increased primarily due to:

- the timing and demand of storage capacity sold and higher storage fees in ATCO Midstream. The majority of the storage earnings recognized in the first quarter of 2007 pertained to contracts entered into in the 2006/07 storage year which ended March 31, 2007;
- lower income tax rates; and
- higher earnings in ATCO Power's Alberta generating plants due to higher spark spreads realized on sales of electricity in the Alberta market.

Revenues for the three months ended March 31, 2007, increased by $55.6 million to $697.6 million, primarily due to:

- the timing and demand of storage capacity sold and higher storage fees in ATCO Midstream; and
- impact of 2007 interim customer rate increases for ATCO Electric approved by the Alberta Energy and Utilities Board ("AEUB") in December 2006. In November 2006, ATCO Electric filed a general tariff application with the AEUB for the 2007 and 2008 test years. On December 19, 2006, the AEUB approved interim refundable rate increases amounting to 50% of ATCO Electric's requested increases for transmission and distribution operations.

Funds generated by operations for the three months ended March 31, 2007, increased by $26.5 million to $232.2 million, primarily due to increased earnings.

Recent Highlights include:

- ATCO Pipelines was recognized as a Gold Champion Level Reporter by the Canadian Challenge Registry for the comprehensive reporting quality of the company's '2006 Action Plan for Reducing Greenhouse Gas Emissions'. This ranking represents the highest level of achievement for a voluntary reporting of greenhouse gas emissions in the country.
- ATCO Employees Participating in Communities raised a record $1.48 million for charities across Alberta in 2006. More than 450 communities and charities received support in 2006.
- On April 18, 2007, CU Inc., a wholly owned subsidiary of Canadian Utilities Limited issued 4,600,000 4.60% Cumulative Redeemable Preferred Share Series 1 at a price of $25.00 per share, for aggregate gross proceeds of $115 million. On April 13, 2007, Canadian Utilities Limited announced that it will redeem on May 18, 2007, all of its 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. $92 million of the CU Inc. issue will be used to redeem the Canadian Utilities Limited Preferred Shares.

Canadian Utilities Limited is part of the ATCO Group of Companies (www.atco.com). Canadian Utilities Limited is a Canadian based worldwide organization of companies with assets of approximately $7.1 billion and more than 6,000 employees, actively engaged in 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.

N.C. Southern	R.D. Southern
President & Chief Executive Officer	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 three months ended March 31, 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 March 31, 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 11 to the unaudited interim consolidated financial statements for the three months ended March 31, 2007). Transactions between Business Groups are eliminated in all reporting of the Corporation's consolidated financial information.

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 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.

For the three months ended March 31, 2007, the mark-to-market adjustment for the derivative asset and the corresponding adjustment for the associated power generation revenue contract liability increased earnings by $4.5 million, net of income taxes ("Mark-to-Market Adjustment").

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 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.

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)				
Revenues	697.6	....	....	....
Earnings attributable to Class A and Class B shares	134.7	....	....	....
Earnings per Class A and Class B share	1.07	....	....	....
Diluted earnings per Class A and Class B share	1.07	....	....	....
2006 (1) (2)				
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)				
Revenues	....	552.9	537.4	680.3
Earnings attributable to Class A and Class B shares	....	50.0	46.5	89.1
Earnings per Class A and Class B share	....	0.39	0.37	0.70
Diluted earnings per Class A and Class B share	....	0.39	0.37	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) *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.

Consolidated Operations

Revenues for the three months ended March 31, 2007, **increased** by $55.6 million to $697.6 million, primarily due to:

- the timing and demand of natural gas storage capacity sold and higher storage fees in ATCO Midstream. The majority of the storage revenues recognized in the first quarter of 2007 pertained to contracts entered into in the 2006/2007 storage year which ended March 31, 2007 (refer to Business Risks – Non-Regulated Operations – ATCO Midstream);
- impact of 2007 interim customer rate increases for ATCO Electric approved by the Alberta Energy and Utilities Board ("AEUB") in December 2006 (refer to Regulatory Matters – ATCO Electric section); and
- impact of higher United Kingdom ("U.K.") exchange rates on conversion of revenues to Canadian dollars in ATCO Power's U.K. operations.

This increase was partially offset by:

- lower natural gas fuel purchases recovered on a "no-margin" basis in ATCO Power's U.K. operations; and
- lower franchise fees collected by ATCO Gas on behalf of cities and municipalities.

Earnings attributable to Class A and Class B shares for the three months ended March 31, 2007, **increased** by $47.8 million ($0.39 per share) to $134.7 million ($1.07 per share), primarily due to:

- the timing and demand of storage capacity sold and higher storage fees in ATCO Midstream;
- lower income tax rates;
- higher earnings in ATCO Power's Alberta generating plants due to higher spark spreads realized on sales of electricity in the Alberta market; and
- Mark-to-Market Adjustment (refer to Natural Gas Purchase Contracts and Associated Power Generation Revenue Contract Liability section).

Operating expenses (consisting of natural gas supply, purchased power, operation and maintenance, selling and administrative and franchise fee costs) for the three months ended March 31, 2007, **decreased** by $1.2 million to $358.4 million, primarily due to:

- lower franchise fees collected by ATCO Gas on behalf of cities and municipalities.

Depreciation and amortization expenses for the three months ended March 31, 2007, **increased** by $4.2 million to $91.9 million, primarily due to:

- capital additions in 2007 and 2006.

Interest expense for the three months ended March 31, 2007, **increased** by $1.3 million to $54.6 million, primarily due to:

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

This increase was partially offset by:

- repayment of non-recourse financings in 2007 and 2006.

Interest and other income for the three months ended March 31, 2007, **increased** by $11.1 million to $20.2 million, primarily due to:

- higher short term interest rates; and
- Mark-to-Market Adjustment (refer to Natural Gas Purchase Contracts and Associated Power Generation Revenue Contract Liability section).

Income taxes for the three months ended March 31, 2007, **increased** by $14.7 million to $69.4 million, primarily due to:

- higher earnings.

This increase was partially offset by:

- lower income tax rates.

Segmented Information

Segmented revenues and earnings attributable to Class A and Class B shares for the three months ended March 31, 2007, were as follows:

	For the Three Months Ended March 31			
($ Millions)	Revenues		Earnings	
	2007	2006	**2007**	2006
	(unaudited)			
Utilities	**344.7**	328.7	**49.1**	40.4
Power Generation	**205.9**	189.8	**43.4**	27.4
Global Enterprises	**181.9**	154.1	**42.8**	23.0
Corporate and Other	**3.3**	3.0	**0.2**	(2.5)
Intersegment eliminations	**(38.2)**	(33.6)	**(0.8)**	(1.4)
Total	**697.6**	642.0	**134.7**	86.9

Utilities

Revenues from the Utilities Business Group for the three months ended March 31, 2007, **increased** by $16.0 million to $344.7 million, primarily due to:

- impact of 2007 interim customer rate increases for ATCO Electric approved by the AEUB in December 2006 (refer to Regulatory Matters – ATCO Electric section);
- customer growth in ATCO Gas; and
- colder temperatures in ATCO Gas.

This increase was partially offset by:

- lower franchise fees collected by ATCO Gas on behalf of cities and municipalities.

Temperatures in ATCO Gas for the three months ended March 31, 2007, were 5.1% warmer than normal, compared to 6.8% warmer than normal for the corresponding period in 2006.

Earnings for the three months ended March 31, 2007, **increased** by $8.7 million to $49.1 million, primarily due to:

- customer growth in ATCO Gas;
- reduced earnings recorded in the first quarter of 2006 as a result of the ATCO Electric GTA Decision (refer to Regulatory Matters – ATCO Electric section); and
- colder temperatures in ATCO Gas.

This increase was partially offset by:

- higher operating and maintenance and depreciation expenses in ATCO Gas.

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 March 31, 2007, **increased** by $16.1 million to $205.9 million, primarily due to:

- impact of higher U.K. exchange rates on conversion of revenues to Canadian dollars in ATCO Power's U.K operations;
- higher revenues in ATCO Power's Alberta generating plants due to higher Alberta Power Pool prices; and
- higher availability, improved performance and the impact of higher Australian exchange rates on conversion of revenues to Canadian dollars in ATCO Power's Australian operations.

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 March 31, 2007, **increased** by $16.0 million to $43.4 million, primarily due to:

- higher earnings in ATCO Power's Alberta generating plants due to higher spark spreads realized on sales of electricity in the Alberta market;
- Mark-to-Market Adjustment (refer to Natural Gas Purchase Contracts and Associated Power Generation Revenue Contract Liability section); and
- improved merchant performance and higher exchange rates on conversion of earnings to Canadian dollars in ATCO Power's U.K. operations.

Alberta Power Pool electricity prices for the three months ended March 31, 2007, averaged $63.29 per megawatt hour, compared to average prices of $56.85 per megawatt hour for the corresponding period in 2006. Natural gas prices for the three months ended March 31, 2007, averaged $7.00 per gigajoule, compared to average prices of $7.13 per gigajoule for the corresponding period in 2006. The consequence of these electricity and natural gas prices was an average spark spread of $10.76 per megawatt hour for the three months ended March 31, 2007, compared to $3.35 per megawatt hour for the corresponding period in 2006.

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 406 megawatts of plant capacity owned in Alberta by ATCO Power and Alberta Power (2000) out of a total Alberta owned capacity of approximately 1,709 megawatts and a world wide owned capacity of approximately 2,474 megawatts.

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 Power Purchase Arrangement ("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 which will result 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. As such, Alberta Power (2000) has withdrawn its application with the AEUB to decommission the plant.

The Piikani Nation of Brockett, Alberta has an option to purchase a 25% interest in ATCO Power's 32 megawatt hydroelectric generating plant at the Oldman River dam near Pincher Creek, Alberta. On February 26, 2007, this option was extended from February 28, 2007, to April 30, 2007.

During the three months ended March 31, 2007, Alberta Power (2000)'s **deferred availability incentive** account **increased** by $6.6 million to $46.2 million. The increase was due to additional availability incentives received for improved plant availability net of quarterly amortization. During the three months ended March 31, 2007, the amortization of deferred availability incentives, recorded in revenues, increased by $0.3 million to $2.9 million, compared to the same period in 2006.

Global Enterprises

Revenues from the Global Enterprises Business Group for the three months ended March 31, 2007, **increased** by $27.8 million to $181.9 million, primarily due to:

- the timing and demand of natural gas storage capacity sold and higher storage fees in ATCO Midstream. The majority of the storage revenues recognized in the first quarter of 2007 pertained to contracts entered into in the 2006/2007 storage year which ended March 31, 2007 (refer to Business Risks – Non-Regulated Operations – ATCO Midstream).

Earnings for the three months ended March 31, 2007, **increased** by $19.8 million to $42.8 million, primarily due to:

- the timing and demand of storage capacity sold and higher storage fees in ATCO Midstream.

Corporate and Other

Earnings for the three months ended March 31, 2007, **increased** by $2.7 million to $0.2 million, primarily due to:

- decreased 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; and
- higher short term interest rates.

REGULATORY MATTERS

Regulated operations are conducted by wholly owned subsidiaries of Canadian Utilities' 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.
- 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 an ongoing collaborative benchmarking process.

ATCO Electric

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

- 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 negatively impacted by $1.3 million, recorded in first quarter of 2006; and
- ATCO Electric's 2006 earnings reduced by an additional $1.6 million, compared to 2005 earnings, recorded throughout 2006.

In August 2006, the AEUB approved the first phase of the AESO's application for the need to improve transmission infrastructure in northwest Alberta:

- AEUB decision grants the AESO approval to assign approximately $300 million in projects to the Transmission Facility Owner, ATCO Electric;
- once assigned by the AESO, ATCO Electric will prepare and file facility applications with the AEUB. Construction will commence once approval to proceed is received from the AEUB; and
- the entire 725 kilometre project was originally intended to be completed by 2009, but now is anticipated to be completed by 2011. As a result of price escalation caused by the change in completion date, coupled with the increasing costs of construction in Alberta, the entire project is now estimated to cost $400 million. 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;
- a decision from the AEUB on the general tariff application is not expected until late 2007;
- 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.

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 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; and
- on February 15, 2007, the City of Calgary filed for leave to appeal this decision with the Alberta Court of Appeal.

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; and
- 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. A schedule for the hearing has not yet been determined.

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; and
- 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 Carbon facility including the lease of the entire storage 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).

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; and
- 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 with the Alberta Court of Appeal on April 13, 2007, the Court declined to consider Calgary's appeal and referred the jurisdictional question back to the AEUB.

ATCO Pipelines

In March 2007, the AEUB directed ATCO Pipelines to file its next General Rate Application by October 1, 2007. ATCO Pipelines anticipates that the filing will include the 2008 and 2009 test years:

- requesting, among other things, increased revenues to recover increased financing, depreciation and operating costs associated with increased rate base in Alberta; and
- a decision from the AEUB on the General Rate Application is not expected until the third quarter of 2008.

The AEUB has delayed its review of the competitive natural gas pipeline issues under AEUB jurisdiction until mid 2007. This review is expected to address competitive issues between ATCO Pipelines and NOVA Gas Transmission Ltd.

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 March 31, 2007, **increased** by $26.5 million to $232.2 million, primarily due to:

- increased earnings.

This increase was partially offset by:

- 2006 proceeds received from the TXU Europe Settlement (refer to TXU Europe Settlement section).

Investing for the three months ended March 31, 2007, **increased** by $20.7 million to $124.4 million, primarily due to:

- higher capital expenditures; and
- changes in non-cash working capital.

Purchase of property, plant and equipment for the three months ended March 31, 2007, **increased** by $11.5 million to $123.7 million, primarily due to:

- increased investment in regulated electric distribution and transmission projects and regulated natural gas distribution projects.

During the three months ended March 31, 2007, the Corporation **issued**:

- no long term debt.

During the three months ended March 31, 2007, the Corporation **redeemed**:

- $25.1 million of non-recourse long term debt.

This change resulted in a **net debt decrease** of $25.1 million.

Net issue of Class A shares for the three months ended March 31, 2007, **increased** by $0.6 million to $0.5 million, primarily due to stock options exercised.

Foreign currency translation for the three months ended March 31, 2007, **negatively** impacted the Corporation's cash position by $1.2 million, primarily as a result of:

- changes in U.K. 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 has been fixed at 4.60%. The net proceeds of the issue will be 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.

On April 13, 2007, Canadian Utilities Limited announced the redemption on May 18, 2007 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.

At March 31, 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	69.1	7.1	62.0
Total	995.1	64.5	930.6

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 March 31, 2007.

Net current and long term future income tax liabilities of $199.7 million at March 31, 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 20, 2005, the Corporation commenced a **normal course issuer bid** for the purchase of up to 3% of the outstanding Class A shares. The bid expired on May 19, 2006. Over the life of the bid, 348,100 shares were purchased, of which 195,600 were purchased in 2005 and 152,500 were purchased in 2006. On May 23, 2006, 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, 2007. From May 23, 2006, to April 24, 2007, 1,679,700 shares have been purchased, all of which were purchased in 2006.

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. 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 April 24, 2007, the Corporation had outstanding 81,525,886 Class A shares, 43,890,984 Class B shares and options to purchase 1,340,800 Class A shares.

BUSINESS RISKS

Environmental Matters

The Government of Canada is proposing to regulate greenhouse gas ("GHG") emissions under a new act, the Clean Air Act. The Corporation is unable to determine what impact the Clean Air Act may have on its operations, as the government has not provided industry with details.

In March 2007, the Government of Alberta introduced legislation (Bill 3, Climate Change and Emissions Management Amendment Act and the Specified Gas Emitters Regulation Amendment) that will require 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. While it is not certain, it is anticipated that the Corporation's coal-fired plant PPAs will allow the Corporation to recover most of the costs associated with the implementation of Bill 3. The estimated cost to ATCO Power and Alberta Power (2000) is approximately $1 million per year.

Alberta Environment implemented a mercury emission regulation in March 2006 for Alberta Power (2000)'s coal-fired generating plants. The regulation requires coal-fired plant operators 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 $10.0 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 an ongoing collaborative benchmarking process.

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.

Measurement Inaccuracies in Metering Facilities

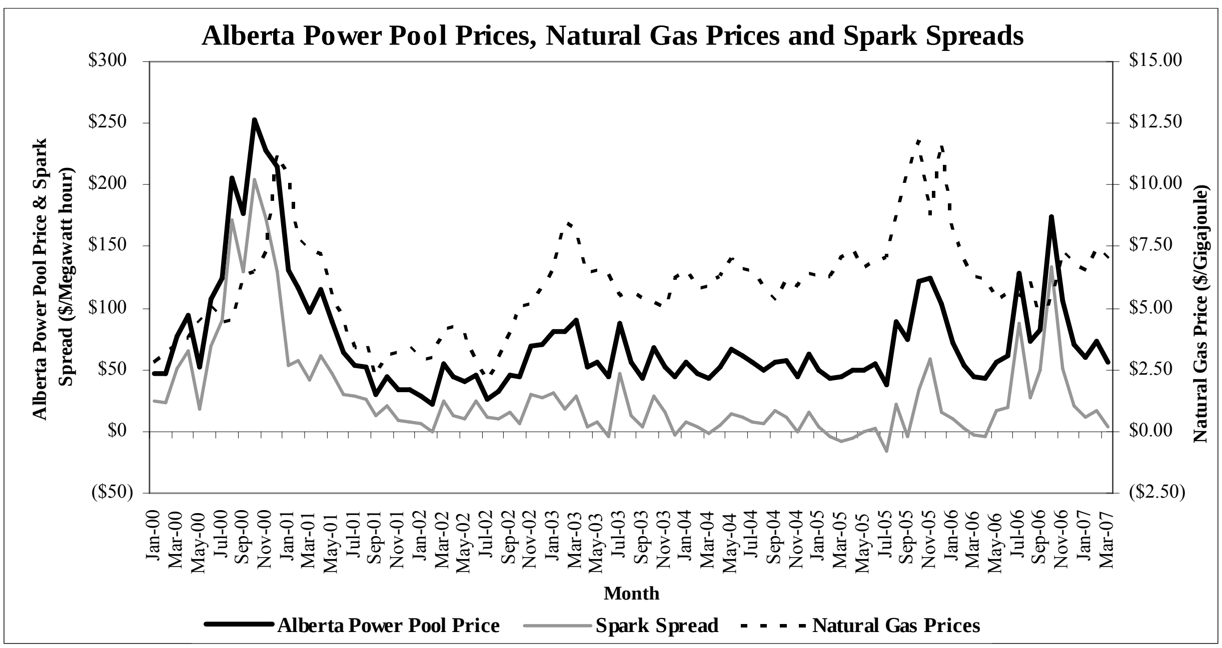
Measurement inaccuracies occur from time to time with respect to ATCO Electric's, ATCO Gas' and ATCO Pipelines' metering facilities. Measurement adjustments are settled between the parties based on the requirements of the Electricity and Gas Inspections Act (Canada) and applicable regulations issued 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.

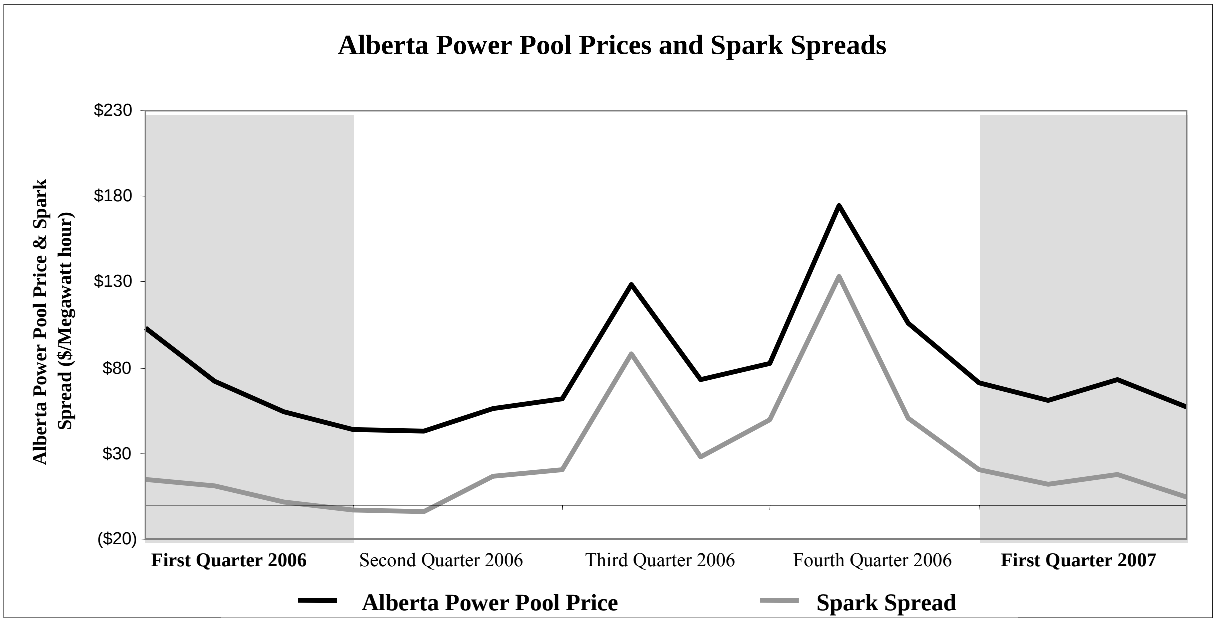
A recent AEUB decision applicable to ATCO Gas established a two year adjustment limitation period for inaccuracies in gas supply costs, including measurement inaccuracies in metering facilities. The AEUB stated that it will consider specific applications for adjustments beyond the two year limitation 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 January 2000 to March 2007.





Changes 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, and in 2006 the market experienced an increase in electricity prices due to the increased world prices for natural gas. Since then, natural gas prices have softened with additional natural gas infrastructure coming on stream and the slightly lower oil prices. Nevertheless, 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 natural gas liquids 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 natural gas liquids extraction operations.

ATCO Frontec

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

On December 23, 2005, the Government of Canada filed a claim in the amount of $70 million which alleges that the Corporation is liable for the destruction of property owned by the Governments of Canada and the United States. The Corporation believes that the claim is defensible and, in any event, has sufficient insurance coverage in place to cover any material amounts that might become payable as a result of the claim. Accordingly, the claim is not expected to have any material impact on the financial position of the Corporation.

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 March 31, 2007, the Corporation had recorded $46.2 million of deferred availability incentives. For the three months ended March 31, 2007, the amortization of deferred availability incentives, which was recorded in revenues, amounted to $2.9 million.

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 $1.1 million, whereas the low case scenario would have resulted in lower revenues of approximately $1.1 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 months ended March 31, 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 months ended March 31, 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 months ended March 31, 2007.

The assumed annual health care cost trend rate increases used in measuring the accumulated post employment benefit obligations in the three months ended March 31, 2007, are as follows: for drug costs, 7.8% starting in 2007 grading down over six 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 months ended March 31, 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 8 to the unaudited interim consolidated financial statements for the three months ended March 31, 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 8 to the unaudited interim consolidated financial statements for the three months ended March 31, 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 5 to the unaudited interim consolidated financial statements for the three months ended March 31, 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 4 to the unaudited interim consolidated financial statements for the three months ended March 31, 2007).
(e) Reclassification of deferred financing charges from other assets to long term debt and non-recourse long term debt (refer to Note 6 to the unaudited interim consolidated financial statements for the three months ended March 31, 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 months ended March 31, 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 9 to the unaudited interim consolidated financial statements for the three months ended March 31, 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 months ended March 31, 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.

April 25, 2007

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

	Note	Three Months Ended March 31 2007	2006
		(Unaudited)	
Revenues		**$ 697.6**	$ 642.0
Costs and expenses			
Natural gas supply		**3.1**	4.7
Purchased power		**13.8**	13.0
Operation and maintenance		**240.6**	236.1
Selling and administrative		**42.4**	43.9
Depreciation and amortization		**91.9**	87.7
Interest		**42.6**	40.9
Interest on non-recourse long term debt		**12.0**	12.4
Franchise fees		**58.5**	61.9
		504.9	500.6
		192.7	141.4
Interest and other income	5	**20.2**	9.1
Earnings before income taxes		**212.9**	150.5
Income taxes		**69.4**	54.7
		143.5	95.8
Dividends on equity preferred shares		**8.8**	8.9
Earnings attributable to Class A and Class B shares		**134.7**	86.9
Retained earnings at beginning of period as restated	4	**1,813.3**	1,721.9
		1,948.0	1,808.8
Dividends on Class A and Class B shares		**38.2**	36.2
Purchase of Class A shares		**-**	0.8
Retained earnings at end of period		**$1,909.8**	$1,771.8
Earnings per Class A and Class B share	7	**$ 1.07**	$ 0.68
Diluted earnings per Class A and Class B share	7	**$ 1.07**	$ 0.68
Dividends paid per Class A and Class B share	7	**$ 0.305**	$ 0.285

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

	Note	March 31 **2007**	March 31 2006	December 31 2006
		(Unaudited)		*(Audited)*
ASSETS				
Current assets				
Cash and short term investments	3	**$ 939.0**	$ 939.4	$ 798.8
Accounts receivable		**311.4**	289.3	362.3
Inventories		**94.4**	83.4	96.5
Regulatory assets		**8.3**	19.7	13.3
Derivative assets	8	**0.1**	-	-
Prepaid expenses		**22.3**	19.7	23.6
		1,375.5	1,351.5	1,294.5
Property, plant and equipment		**5,441.9**	5,209.4	5,426.1
Regulatory assets		**44.6**	29.4	43.2
Derivative assets	8	**82.2**	-	-
Other assets		**201.1**	253.8	229.7
		$7,145.3	$6,844.1	$6,993.5
LIABILITIES AND SHARE OWNERS' EQUITY				
Current liabilities				
Bank indebtedness		**$ 0.4**	$ -	$ -
Accounts payable and accrued liabilities		**343.0**	300.2	338.8
Income taxes payable		**34.6**	33.8	22.7
Future income taxes		**0.3**	4.1	0.3
Regulatory liabilities		**4.8**	2.6	0.5
Derivative liabilities	8	**2.1**	-	-
Non-recourse long term debt due within one year	6	**66.0**	53.7	59.3
		451.2	394.4	421.6
Future income taxes		**199.4**	199.6	194.7
Regulatory liabilities		**144.2**	155.5	148.8
Derivative liabilities	8	**4.6**	-	-
Deferred credits	8	**299.2**	259.2	229.0
Long term debt	6	**2,399.0**	2,266.5	2,411.5
Non-recourse long term debt	6	**586.8**	658.2	626.7
Equity preferred shares		**636.5**	636.5	636.5
Class A and Class B share owners' equity				
Class A and Class B shares	7	**516.6**	519.8	516.0
Contributed surplus		**1.4**	0.8	1.2
Retained earnings		**1,909.8**	1,771.8	1,804.4
Accumulated other comprehensive income	9	**(3.4)**	(18.2)	3.1
		2,424.4	2,274.2	2,324.7
		$7,145.3	$6,844.1	$6,993.5

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

		Three Months Ended March 31	
	Note	**2007**	2006
		(Unaudited)	
Operating activities			
Earnings attributable to Class A and Class B shares		**$ 134.7**	$ 86.9
Adjustments for:			
Depreciation and amortization		**91.9**	87.7
Future income taxes		**2.7**	2.9
Deferred availability incentives		**6.6**	12.4
TXU Europe settlement - net of income taxes	3	**(3.0)**	10.6
Other		**(0.7)**	5.2
Funds generated by operations		**232.2**	205.7
Changes in non-cash working capital		**94.2**	33.0
Cash flow from operations		**326.4**	238.7
Investing activities			
Purchase of property, plant and equipment		**(123.7)**	(112.2)
Costs on disposal of property, plant and equipment		**(0.5)**	(0.2)
Contributions by utility customers for extensions to plant		**19.8**	25.7
Non-current deferred electricity costs		**(1.4)**	5.3
Changes in non-cash working capital		**(14.2)**	(21.3)
Other		**(4.4)**	(1.0)
		(124.4)	(103.7)
Financing activities			
Issue of long term debt		**-**	35.5
Repayment of non-recourse long term debt		**(25.1)**	(19.8)
Net issue (purchase) of Class A shares		**0.5**	(0.1)
Dividends paid to Class A and Class B share owners		**(38.2)**	(36.2)
Other		**1.0**	(0.2)
		(61.8)	(20.8)
Foreign currency translation		**(0.4)**	0.8
Cash position (1)			
Increase		**139.8**	115.0
Beginning of period		**798.8**	824.4
End of period		**$ 938.6**	$ 939.4

(1) Cash position consists of cash and short term investments less current bank indebtedness, and includes $204.4 million (2006 - $144.1 million) which is only available for use in joint ventures (see Note 3).

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

		Three Months Ended March 31	
	Note	**2007**	2006
		(Unaudited)	
Earnings attributable to Class A and Class B shares		**$134.7**	$86.9
Other comprehensive income, net of income taxes:			
Cash flow hedges	9	**0.5**	-
Foreign currency translation adjustment	9	**0.3**	-
		0.8	-
Comprehensive income		**$135.5**	$86.9

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 months ended March 31, 2007:

(f) 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 8).
(g) Recognition of the fair value of a power generation revenue contract liability associated with the natural gas purchase contracts derivative asset (see Note 8).
(h) 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 5).
(i) 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 4).
(j) Reclassification of deferred financing charges from other assets to long term debt and non-recourse long term debt (see Note 6).

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 months ended March 31, 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 9). 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 months ended March 31, 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 months ended March 31, 2007 and March 31, 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.

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, which pertain solely 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 6).

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.

2. Regulatory matters

On March 17, 2006, ATCO Electric received a decision on its General Tariff Application for 2005 and 2006 which was filed with the Alberta Energy and Utilities Board ("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.

4. Retained earnings at beginning of period as restated

	March 31	
	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

5. Interest and other income

Interest and other income for the three months ended March 31, 2007 includes a gain of $22.9 million related to the change in fair value of the natural gas purchase contracts derivative asset (see Note 8). This increase is partially offset by an additional provision of $16.5 million for the associated power generation revenue contract liability.

6. 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.

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

Long term debt

	Effective Interest Rate	March 31 **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 December 2008, 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		**(12.5)**	-
		2,352.0	2,219.5
ATCO Midstream Ltd. credit facility, at BA rates, due June 2011, 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
		$2,399.0	$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 8). 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.

Project Financing	Effective Interest Rate	March 31 **2007**	2006
Barking Power Limited, payable in British pounds:			
Term loans, at fixed rates averaging 7.95%, due to 2010 (£20.5 million (2006 – £25.1 million))	7.95%	**$ 46.4**	$ 51.0
Term loan, at LIBOR, due to 2010 (1) (£33.5 million (2006 – £41.2 million))	Floating	**76.1**	83.5

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

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

Project Financing	Effective Interest Rate	March 31 **2007**	2006
Osborne Cogeneration Pty Ltd., payable in Australian dollars:			
Term loan, at Bank Bill rates, due to 2013 (1) ($35.1 million AUD (2006 – $39.4 million AUD))	Floating (2)	**32.8**	32.9
ATCO Power Alberta Limited Partnership (“APALP”):			
Term loan, at LIBOR, due to 2016 (1)	Floating (2)	**90.0**	96.7
Joffre:			
Term loan, at BA rates, due to 2012 (1)	Floating (2)	**3.1**	9.1
Term facility, at Canadian Prime Advances, due to 2012 (1)	Floating (2)	**0.1**	0.1
Term loan, at LIBOR, due to 2012 (1)	Floating (2)	**5.6**	16.3
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**	45.1
Term facility, at Canadian Prime Advances, due to 2014 (1)	Floating (2)	**0.2**	-
Term loan, at LIBOR, due to 2014 (1)	Floating (2)	**10.7**	11.3
Notes, at fixed rate of 7.93%, due to 2022	8.302%	**25.9**	26.7
Muskeg River:			
Term loan, at BA rates, due to 2014 (1)	Floating (2)	**32.5**	34.9
Term facility, at Canadian Prime Advances, due to 2014 (1)	Floating (2)	**0.2**	0.1
Term loan, at LIBOR, due to 2014 (1)	Floating (2)	**8.2**	8.8
Notes, at fixed rate of 7.56%, due to 2022	7.902%	**28.9**	30.8
Brighton Beach:			
Term loan, at BA rates, due to 2020 (1)	Floating (2)	**19.9**	20.8
Term loan, at LIBOR, due to 2020 (1)	Floating (2)	**18.0**	18.7
Construction overrun facility, at BA rates, due to 2020 (1)	Floating (2)	**4.9**	5.1
Construction overrun facility, at LIBOR, due to 2020 (1)	Floating (2)	**4.4**	4.6
Notes, at fixed rate of 6.924%, due to 2024	7.025%	**107.1**	109.9
Cory:			
Cost overrun facility, at BA rates, due to 2011 (1)	Floating (2)	**2.8**	3.4
Notes, at fixed rate of 7.586%, due to 2025	7.872%	**36.3**	37.2
Notes, at fixed rate of 7.601%, due to 2026	7.880%	**32.2**	32.9
Less: Deferred financing charges		**(8.0)**	-
		652.8	711.9
Less: Amounts due within one year		**66.0**	53.7
		$586.8	$658.2

BA – Bankers’ Acceptance
LIBOR – London Interbank Offered Rate

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

(2) *Floating interest rates have been partially or completely hedged with interest rate swaps (see Note 8).*

7. Class A and Class B shares

There were 81,486,886 (2006 – 82,916,986) Class A non-voting shares and 43,922,484 (2006 – 44,016,284) Class B common shares outstanding on March 31, 2007. In addition, there were 1,348,300 options to purchase Class A non-voting shares outstanding at March 31, 2007 under the Corporation's stock option plan. From April 1, 2007, to April 24, 2007, no stock options were granted or cancelled, 7,500 stock options were exercised, 31,500 Class B common shares were converted to Class A non-voting shares and no Class A non-voting shares have been purchased under the Corporation's normal course issuer bid.

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

	March 31	
	2007	2006
Weighted average shares outstanding	**125,390,433**	126,949,397
Effect of dilutive stock options	**499,458**	615,983
Weighted average diluted shares outstanding	**125,889,891**	127,565,380

8. 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 March 31, 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:

	March 31 2007
Derivative assets – current:	
Interest rate swap agreements	$ 0.1
Derivative assets – non-current:	
Natural gas purchase contracts	$81.9
Interest rate swap agreements	0.3
	$82.2
Derivative liabilities – current:	
Foreign currency forward contracts	$ 0.2
Interest rate swap agreements	1.9
	$ 2.1
Derivative liabilities – non-current:	
Interest rate swap agreements	$ 4.6

8. 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 March 31 **2007**	Notional Principal March 31 2006
Osborne: ($34.6 million AUD (2006 – $40.2 million AUD))	7.3325%	Bank Bill Rate in Australia	December 2013	**$ 32.4**	$ 33.6
APALP:	7.54%	90 day BA	November 2008	**2.6**	3.8
	7.317%	90 day BA	December 2008	**3.6**	5.4
	7.50%	6 month LIBOR	December 2011	**83.9**	87.5
Joffre:	7.286%	90 day BA	September 2012	**22.8**	27.0
Scotford:	5.212%	90 day BA	September 2008	**52.9**	58.0
Muskeg River:	5.287%	90 day BA	December 2007	**39.9**	43.6
Brighton Beach:	5.8367%	90 day BA	June 2009	**8.8**	9.3
	6.575%	90 day BA	March 2019	**35.6**	37.4
Cory:	6.346%	90 day BA	June 2011	**2.6**	3.2
				$285.1	$308.8

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 6).*

The Corporation has fixed interest rates, either directly or through interest rate swap agreements, on 96% (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 and Euros. At March 31, 2007, the contracts consist of purchases of $1.4 million U.S. (2006 – $3.0 million U.S.) and sales of 2.0 million Euros (2006 – 6.0 million Euros).

8. Risk management and financial instruments (continued)

Natural gas purchase contracts and associated power generation revenue contract liability

The Corporation has long term contracts for the supply of natural gas for certain of its power generation projects. Under the terms of certain of these contracts, the volume of natural gas that the Corporation is entitled to take is in excess of the natural gas required to generate power. As the excess volume of natural gas can be sold, the Corporation is required to designate these entire contracts as derivative instruments. The Corporation 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.

For the three months ended March 31, 2007, the mark-to-market adjustment for the derivative asset and the corresponding adjustment for the associated power generation revenue contract liability increased earnings by $4.5 million, net of income taxes.

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.

8. Risk management and financial instruments (continued)

Fair value of non-derivative financial instruments

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

	March 31			
	2007		2006	
	Carrying Value	**Fair Value**	Carrying Value	Fair Value
Assets				
Cash and short term investments (1)	**$ 939.0**	**$ 939.0**	$ 939.4	$ 939.4
Accounts receivable (1)	**311.4**	**311.4**	289.3	289.3
Liabilities				
Bank indebtedness (2)	**0.4**	**0.4**	-	-
Accounts payable and accrued liabilities (2)	**343.0**	**343.0**	300.2	300.2
Long term debt (3)	**2,399.0**	**2,773.8**	2,266.5	2,635.3
Non-recourse long term debt (3)	**652.8**	**691.1**	711.9	742.2

(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.*

Fair value of derivative financial instruments

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

	March 31					
	2007			2006		
	Notional Principal (1)	**Fair Value Receivable (Payable) (3)**	**Maturity**	Notional Principal (1)	Fair Value Receivable (Payable) (3)	Maturity
Interest rate swaps	**$285.1**	**$(6.1)**	**2007-2019**	$308.8	$(8.3)	2007-2019
Foreign currency forward contracts	**$ 4.6**	**$(0.2)**	**2007**	$ 11.7	$(0.4)	2006
Natural gas purchase contracts	**N/A (2)**	**$81.9**	**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 March 31.*

(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.*

9. 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.

Changes in the components of accumulated OCI are summarized below:

	Three Months Ended March 31	
	2007	2006
Accumulated OCI at beginning of period:		
Foreign currency translation adjustment	**$ 3.1**	$(18.2)
Adjustment to accumulated OCI at beginning of period due to change in method of accounting for:		
Cash flow hedge losses [1]	**(7.4)**	-
Financial assets available for sale [2]	**0.1**	-
	(7.3)	-
OCI for the period:		
Changes in fair values of cash flow hedges [3]	**0.4**	-
Transfers of cash flow hedge losses to earnings [4]	**0.1**	-
	0.5	-
Foreign currency translation adjustment	**0.3**	-
	0.8	-
Accumulated OCI at end of period:		
Cash flow hedge losses [5]	**(6.9)**	-
Financial assets available for sale [2]	**0.1**	-
Foreign currency translation adjustment	**3.4**	(18.2)
	$(3.4)	$(18.2)

(1) *Net of income taxes of $3.2 million.*
(2) *Net of income taxes of nil.*
(3) *Net of income taxes of $(0.1) million.*
(4) *Net of income taxes of nil.*
(5) *Net of income taxes of $3.1 million.*

10. Employee future benefits

In the three months ended March 31, 2007, net expense of $3.6 million (2006 – $3.9 million) was recognized for pension benefit plans and net expense of $1.3 million (2006 – $1.2 million) was recognized for other post employment benefit plans.

11. Segmented information

Segmented results – Three months ended March 31

2007 2006	Utilities	Power Generation	Global Enterprises	Corporate and Other	Intersegment Eliminations	Consolidated
(Unaudited)						
Revenues – external	**$ 338.4** $ 322.7	**$ 205.9** $ 189.8	**$152.9** $129.2	**$ 0.4** $ 0.3	**$ -** $ -	**$ 697.6** $ 642.0
Revenues – intersegment [(1)]	**6.3** 6.0	**-** -	**29.0** 24.9	**2.9** 2.7	**(38.2)** (33.6)	**-** -
Revenues	**$ 344.7** $ 328.7	**$ 205.9** $ 189.8	**$181.9** $154.1	**$ 3.3** $ 3.0	**$ (38.2)** $ (33.6)	**$ 697.6** $ 642.0
Earnings attributable to Class A and Class B shares	**$ 49.1** $ 40.4	**$ 43.4** $ 27.4	**$ 42.8** $ 23.0	**$ 0.2** $ (2.5)	**$ (0.8)** $ (1.4)	**$ 134.7** $ 86.9
Total assets	**$3,820.5** $3,546.2	**$2,311.4** $2,200.4	**$240.4** $295.7	**$679.3** $666.9	**$ 93.7** $134.9	**$7,145.3** $6,844.1

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

12. Subsequent event

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 will be 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.

On April 13, 2007, Canadian Utilities Limited announced the redemption on May 18, 2007 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.

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