ATCO
GROUP

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October 28, 2003

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

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

Dear Sir or Madam:

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

- Corporation's Press Release, issued October 24, 2003

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

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

Regards,

The ATCO Group of Companies

S C Mitchell

Sharlene C. Mitchell, STI
Corporate Secretarial Department

Enclosure(s)

dlw 11/14

CU Release

CANADIAN UTILITIES LIMITED
An ATCO Company

CORPORATE OFFICE
1500, 909 - 11 AVENUE SW, CALGARY, ALBERTA T2R 1N6
TELEPHONE (403) 292-7500

For Immediate Release

October 24, 2003

Canadian Utilities Reports September 2003 Earnings

CALGARY, Alberta – Canadian Utilities Limited reported earnings for the nine months ended September 30, 2003 of $172.6 million ($2.72 per share). Earnings for the same nine months in 2002 were $164.8 million ($2.60 per share), excluding the after-tax gain on the sale of the Viking-Kinsella property of $66.7 million ($1.05 per share). 2002 earnings in total were $231.5 million ($3.65 per share).

Earnings in the first nine months of 2003 were higher than 2002, excluding the Viking-Kinsella gain, due to stronger operational results which more than offset the carrying costs, net of investment income, of $10.0 million in respect of the $400 million of preferred shares and debentures issued between November 2002 and April 2003. These preferred shares and debentures were issued during a low interest rate environment to strengthen the Corporation's Balance Sheet and allow for future growth. When the carrying costs, net of investment income, are excluded, earnings are $182.6 million ($2.88 per share) compared to $164.8 million ($2.60 per share) in 2002. Operations in the Utilities and Technologies Business Groups, as well as Alberta Power (2000) and ATCO Midstream, provided stronger results year over year, but were partially offset by weaker results in ATCO Power, ATCO Frontec and ATCO Pipelines and the impact of warmer temperatures in ATCO Gas.

Revenues for the nine months ended September 30, 2003 were $2,792.3 million compared to $2,045.2 million in 2002 primarily due to the higher price of natural gas and electricity purchased for customers on a "no margin" basis by ATCO Gas and ATCO Electric, higher prices received for electricity sold to the Alberta Electric System Operator (formerly the Alberta Power Pool) by ATCO Power and higher natural gas prices on gas sales by ATCO Midstream.

Cash flow from operations was $367.0 million for the nine months ended September 30, 2003 compared to $336.1 million in 2002. The higher cash flow from operations was due to increased earnings, excluding the Viking-Kinsella gain. In addition, in the first quarter of 2002, ATCO Gas refunded to customers a total of $405.6 million related to the sale of the Viking-Kinsella property, of which $20.6 million had reduced cash flow from operations.

Earnings for the three months ended September 30, 2003 were $43.4 million ($0.68 per share) compared to $44.4 million ($0.70 per share) in the same period of 2002 due to weaker operational results in ATCO Power and ATCO Pipelines, the impact of warmer temperatures in ATCO Gas, and higher preferred share dividends and interest expense related to the issue of preferred shares, $150.0 million in December 2002 and $150.0 million in April 2003, and $100.0 million of debentures issued in November 2002, net of investment income. This decrease was partially offset by stronger operational results in the Utilities and Technologies Business Groups, and Alberta Power (2000) and ATCO Midstream. Temperatures for the three months ended September 30, 2003 were 16.0% warmer than normal compared to 16.3% colder than normal for 2002.

Revenues for the three months ended September 30, 2003 were $622.6 million compared to $542.7 million in 2002 primarily due to the higher price of natural gas purchased for customers on a "no margin" basis by ATCO Gas and higher natural gas prices on gas sales by ATCO Midstream.

Cash flow from operations was $105.3 million for the three months ended September 30, 2003 compared to $101.8 million in 2002.

Canadian Utilities Limited is a part of the ATCO Group of companies. ATCO Group is an Alberta based corporation with a worldwide organization of companies engaged in Power Generation, Utilities, Logistics and Energy Services, Technologies and Industrials. More information about Canadian Utilities can be found on its website, www.canadian-utilities.com.

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

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 comparative interim financial statements for the nine months ended September 30, 2003, and Management's Discussion and Analysis of Financial Condition and Results of Operations and the comparative financial statements for the year ended December 31, 2002. This discussion and analysis of financial condition and results of operations may contain forward-looking statements. These statements are not guarantees of future performance and are subject to risks and uncertainties that could cause actual results to differ materially from those in the forward-looking statements.

The Corporation's financial statements are consolidated from four Business Groups: Utilities, Power Generation, Logistics and Energy Services, and Technologies. For the purposes of financial disclosure, the Technologies Business Group is included in Technologies and Other Businesses and corporate transactions are accounted for as Corporate. (Refer to Note 7 of the comparative interim financial statements). Transactions between Business Groups are eliminated in all reporting of the Corporation's consolidated financial information.

RESULTS OF OPERATIONS

Consolidated Operations

Revenues, earnings attributable to Class A non-voting shares ("Class A shares") and Class B common shares ("Class B shares"), and earnings and diluted earnings per Class A and Class B share were as follows:

	Three Months Ended September 30		**Nine Months Ended September 30**	
	2003	2002	**2003**	2002
	($ Millions except per share data) (unaudited)			
Revenues	**622.6**	542.7	**2,792.3**	2,045.2
Earnings attributable to Class A and Class B shares (1) (2) (3)	**43.4**	44.4	**172.6**	231.5
Earnings per Class A and Class B share (1) (2) (3)	**0.68**	0.70	**2.72**	3.65
Diluted earnings per Class A and Class B share (1) (2) (3)	**0.68**	0.70	**2.71**	3.64

Notes:
(1) There were no discontinued operations or extraordinary items during these periods.
(2) Due to the seasonal nature of the Corporation's operations and the timing of rate decisions, earnings for any quarter are not necessarily indicative of operations on an annual basis.
(3) The results for the nine months ended September 30, 2002, include earnings of $66.7 million ($1.05 per share) on the sale of the Viking-Kinsella natural gas producing property.

Revenues for the three months ended September 30, 2003, increased by $79.9 million to $622.6 million. This increase was primarily due to the higher price of natural gas purchased for customers on a "no-margin" basis by ATCO Gas and higher natural gas prices on gas sales by ATCO Midstream. Revenues for the nine months ended September 30, 2003, increased by $747.1 million to $2,792.3 million. This increase was primarily due to the higher price of natural gas and electricity purchased for customers on a "no-margin" basis by ATCO Gas and ATCO Electric, higher prices received for electricity sold by ATCO Power to the Alberta Electric System Operator ("AESO"), formerly the Alberta Power Pool, and higher natural gas prices on gas sales by ATCO Midstream.

Earnings attributable to Class A and Class B shares for the three months ended September 30, 2003, decreased by $1.0 million ($0.02 per share) to $43.4 million ($0.68 per share). This decrease was primarily due to weaker operational results in ATCO Power and ATCO Pipelines, the impact of warmer temperatures in ATCO Gas, and higher preferred share dividends and interest expense related to the issue of preferred shares, $150.0 million in December 2002 and $150.0 million in April 2003, and $100.0 million of debentures issued in November 2002, net of investment income. This decrease was partially offset by stronger operational results in the Utilities and Technologies Business Groups, and Alberta Power (2000) and ATCO Midstream. Temperatures for the three months ended September 30, 2003 were 16.0% warmer than normal compared to 16.3% colder than normal for 2002.

Earnings attributable to Class A and Class B shares for the nine months ended September 30, 2003, were $172.6 million ($2.72 per share). Earnings for the corresponding period in 2002 were $164.8 million ($2.60 per share), excluding the after-tax gain on the sale of the Viking-Kinsella natural gas producing property (the "Viking property") of $66.7 million ($1.05 per share). 2002 earnings in total were $231.5 million ($3.65 per share). Earnings for the nine months ended September 30, 2003, were $7.8 million ($0.12 per share) higher than for the corresponding period in 2002, excluding the impact of the sale of the Viking property. This increase was primarily due to stronger operational results, which more than offset the carrying costs, net of investment income, of $10.0 million in respect of the $400.0 million of preferred shares and debentures issued between November 2002 and April 2003. These preferred shares and debentures were issued during a low interest rate environment to strengthen the Corporation's Balance Sheet and allow for future growth. When the carrying costs, net of investment income, are excluded, earnings are $182.6 million ($2.88 per share) compared to $164.8 million ($2.60 per share) in 2002. Operations in the Utilities and Technologies Business Groups, as well as Alberta Power (2000) and ATCO Midstream, provided stronger results year over year, but were partially offset by weaker results in ATCO Power, ATCO Frontec and ATCO Pipelines and the impact of warmer temperatures in ATCO Gas.

Operating expenses (consisting of natural gas supply costs, purchased power costs, operation and maintenance expenses, selling and administrative expenses and franchise fee costs) for the three months ended September 30, 2003, increased by $68.6 million to $434.1 million. This increase was largely the result of higher natural gas and purchased power costs and higher operation and maintenance expenses associated with increased business activity in 2003. Operating expenses for the nine months ended September 30, 2003, increased by $687.4 million to $2,154.0 million. This increase was largely the result of higher natural gas and purchased power costs and higher operation and maintenance expenses associated with increased business activity in 2003.

Depreciation and amortization expenses for the three and nine months ended September 30, 2003, increased by $3.5 million to $62.1 million, and by $19.7 million to $196.2 million, respectively. These increases were primarily due to capital additions in 2003 and 2002 and depreciation adjustments associated with the sale of the Viking property in the nine months ended September 30, 2002.

Interest expense for the three and nine months ended September 30, 2003, increased by $1.1 million to $47.7 million, and by $4.4 million to $143.2 million, respectively. These increases were principally due to increased amounts of long term debt outstanding, partially offset by lower interest rates associated with higher cost long term debt refinanced in 2002.

In January 2002, the Corporation sold its Viking property, having a net book value of approximately $40 million, for $550 million. In accordance with an Alberta Energy and Utilities Board ("AEUB") decision, $385 million plus related adjustments for future abandonment and future income taxes of $20.6 million, for a total of $405.6 million, was distributed to customers by way of lump sum payments. The Corporation's share of the net proceeds was $148.7 million, after adjustments, resulting in a gain of $108.5 million before income taxes of $41.8 million. This sale increased earnings for the nine months ended September 30, 2002, by $66.7 million, earnings per share by $1.05 and diluted earnings per share by $1.04.

Interest and other income for the three and nine months ended September 30, 2003, increased by $2.1 million to $8.7 million, and by $5.6 million to $23.9 million, respectively. These increases were primarily due to higher interest income on higher cash balances.

Income taxes for the three months ended September 30, 2003, increased by $5.1 million to $35.0 million. This increase was largely due to higher earnings, partially offset by lower income tax rates. Income taxes for the nine months ended September 30, 2003, excluding the $41.8 million of income taxes on the sale of the Viking property in 2002, increased by $22.2 million to $126.0 million. This increase was largely due to higher earnings and the impact of a 2002 refund to customers of amounts previously recovered from customers for future income taxes related to the Viking property, partially offset by lower income tax rates. Income taxes for the nine months ended September 30, 2002, including the impact of the sale of the Viking property, were $145.6 million.

Dividends on equity preferred shares for the three and nine months ended September 30, 2003, increased by $4.7 million to $9.0 million, and by $11.2 million to $24.2 million, respectively. These increases were primarily due to the issue of $150.0 million of 5.80% Cumulative Redeemable Second Preferred Shares Series W ("Series W Preferred Shares") on December 3, 2002, and to the issue of $150.0 million of 6.00% Cumulative Redeemable Second Preferred Shares Series X ("Series X Preferred Shares") on April 17, 2003.

Segmented revenues for the three and nine months ended September 30, 2003, were as follows:

Business Groups	**Three Months Ended September 30**		**Nine Months Ended September 30**	
	2003	2002	**2003**	2002
	($ Millions) (unaudited)			
Utilities	**331.4**	251.1	**1,830.4**	1,240.1
Power Generation	**146.1**	141.0	**471.5**	418.8
Logistics and Energy Services	**247.7**	218.3	**947.9**	669.4
Technologies and Other Businesses	**32.6**	26.3	**92.6**	75.9
Corporate	**2.9**	2.8	**8.6**	8.3
Intersegment eliminations	**(138.1)**	(96.8)	**(558.7)**	(367.3)
Total	**622.6**	542.7	**2,792.3**	2,045.2

Segmented earnings attributable to Class A and Class B shares for the three and nine months ended September 30, 2003, were as follows:

Business Groups	Three Months Ended September 30		Nine Months Ended September 30	
	2003	2002	**2003**	2002
	($ Millions) (unaudited)			
Utilities	**5.5**	1.1	**61.5**	120.9
Power Generation	**17.8**	18.9	**57.0**	51.9
Logistics and Energy Services	**17.7**	17.6	**46.5**	45.0
Technologies and Other Businesses	**5.2**	3.9	**14.0**	8.3
Corporate	**(3.8)**	0.7	**(10.0)**	(0.9)
Intersegment eliminations	**1.0**	2.2	**3.6**	6.3
Total	**43.4**	44.4	**172.6**	231.5

Utilities

Revenues from the Utilities Business Group for the three and nine months ended September 30, 2003, increased by $80.3 million to $331.4 million and by $590.3 million to $1,830.4 million, respectively. These increases were primarily the result of higher natural gas supply and purchased power costs.

Natural gas supply and purchased power costs are recovered in customer rates. As a consequence, changes in natural gas supply and purchased power costs have no effect on the Corporation's earnings. Effective April 1, 2003, all of ATCO Electric's customers are now billed on a flow-through of market prices for electric energy. The "flow-through" rate is based on the actual spot market price for the energy that customers use during each billing period.

Earnings for the three months ended September 30, 2003, increased by $4.4 million to $5.5 million. This increase was primarily the result of improved operating results in ATCO Electric, higher interim rates approved by the AEUB and customer additions in ATCO Gas and the impact in 2002 of the AEUB decisions regarding affiliated party transactions and the Carbon gas storage facility, partially offset by warmer temperatures and higher operation and maintenance costs in ATCO Gas.

Earnings for the nine months ended September 30, 2003, increased by $7.3 million to $61.5 million, excluding the $66.7 million in 2002 earnings on the sale of the Viking property. This increase was primarily the result of improved operating results in ATCO Electric, higher interim rates approved by the AEUB and customer additions in ATCO Gas and the impact in 2002 of the AEUB decisions regarding affiliated party transactions and the Carbon gas storage facility, partially offset by warmer temperatures and higher operation and maintenance costs in ATCO Gas. Earnings for the nine months ended September 30, 2002, including the impact of the sale of the Viking property, were $120.9 million.

ATCO Gas commenced in the first quarter of 2003 the first phase of a major project to relocate natural gas meters currently inside homes to the outside. The target was to move 22,000 meters in 2003 in order to relocate and replace aging infrastructure and facilitate efficient meter reading. On October 1, 2003, the AEUB issued a decision regarding ATCO Gas' 2003 and 2004 general rate application, in which the AEUB directed ATCO Gas to extend the timeframe over which the project is to be completed.

Power Generation

Revenues from the Power Generation Business Group for the three and nine months ended September 30, 2003, increased by $5.1 million to $146.1 million, and by $52.7 million to $471.5 million, respectively. These increases were primarily due to higher prices received for electricity sold to the AESO, the commencement of commercial operations in the first quarter of 2003 at the new Cory and Muskeg River generating plants and higher capacity and energy charges and improved operating results in Alberta Power (2000). These increases were partially offset by reduced revenues from the Barking generating plant in the United Kingdom, due to the loss of the TXU Europe long term offtake agreement arising from the issuance of an administration order in late 2002 by a United Kingdom court for TXU Europe, resulting in 275 megawatts of power previously supplied to TXU Europe now being sold under short term bilateral agreements. AESO prices for the three and nine months ended September 30, 2003, averaged $64.35 and $65.75 per megawatt hour, respectively, compared to average prices of $34.58 and $38.06 for the corresponding periods in 2002. Natural gas prices for the three and nine months ended September 30, 2003, averaged $5.52 and $6.58 per gigajoule, respectively, compared to average prices of $2.97 and $3.33 for the corresponding periods in 2002.

Earnings for the three months ended September 30, 2003, decreased by $1.1 million to $17.8 million. This decrease was primarily due to higher fuel costs arising from higher natural gas prices in Canada and reduced earnings from the Barking generating plant in the United Kingdom, due to the loss of the TXU Europe long term offtake agreement arising from the issuance of an administration order in late 2002 by a United Kingdom court for TXU Europe, resulting in 275 megawatts of power previously supplied to TXU Europe now being sold under short term bilateral agreements, partially offset by higher prices received for electricity sold to the AESO and improved operating results in Alberta Power (2000). Earnings for the nine months ended September 30, 2003, increased by $5.1 million to $57.0 million. This increase was primarily due to higher prices received for electricity sold to the AESO and improved operating results in Alberta Power (2000), partially offset by higher fuel costs arising from higher natural gas prices and reduced earnings from the Barking generating plant in the United Kingdom related to TXU Europe.

In 2001, Alberta Power (2000) and the Alberta Balancing Pool entered into an agreement which gave the Alberta Balancing Pool control of the 150 megawatt, coal-fired H.R. Milner generating plant effective January 1, 2001 and the right to sell it until September 30, 2003, failing which the rights to control the generating plant would revert to Alberta Power (2000). In return, Alberta Power (2000) was paid $63.5 million, the net book value of the station and coal inventory. Alberta Power (2000) operated the plant on a cost of service basis on behalf of the Alberta Balancing Pool under a contract scheduled to expire on September 30, 2003. On August 6, 2003, the Alberta Balancing Pool announced that it had entered into an agreement for the sale of the plant. Alberta Power (2000) has entered into an agreement with the Alberta Balancing Pool to continue operating the plant from September 30, 2003, to the closing date of the sale, anticipated to be January 31, 2004.

On September 8, 2003, SaskPower International Inc. announced that it had selected ATCO Power as its joint venture partner to potentially develop up to 150 megawatts of wind generation in Saskatchewan.

On September 30, 2003, ATCO Power opened the 32 megawatt Oldman River hydroelectric generating facility at the Oldman River dam near Pincher Creek, Alberta. All of the electricity produced in the plant will be sold to the AESO. ATCO Power owns an 80% interest in the project and ATCO Resources owns a 20% interest. The Piikani Nation of Brockett, Alberta has an option which expires May 31, 2005, to purchase a 25% interest in the project.

Logistics and Energy Services

Revenues from the Logistics and Energy Services Business Group for the three and nine months ended September 30, 2003, increased by $29.4 million to $247.7 million, and by $278.5 million to $947.9 million, respectively. These increases were primarily due to higher prices for natural gas purchased for ATCO Midstream's customers and higher natural gas liquids prices.

Earnings for the three months ended September 30, 2003, increased by $0.1 million to $17.7 million. This increase was primarily due to higher earnings from natural gas liquids operations (ATCO Midstream) and higher project earnings in ATCO Frontec, partially offset by lower earnings in ATCO Pipelines. Earnings for the nine months ended September 30, 2003, increased by $1.5 million to $46.5 million. This increase was primarily due to higher earnings from natural gas liquids operations (ATCO Midstream), partially offset by lower earnings from ATCO Pipelines and from ATCO Frontec projects and lower earnings from ATCO Midstream's storage operations.

Technologies and Other Businesses

Revenues from Technologies and Other Businesses for the three and nine months ended September 30, 2003, increased by $6.3 million to $32.6 million, and by $16.7 million to $92.6 million, respectively. These increases were primarily due to increased business activity and commencement of work for new customers.

Earnings for the three and nine months ended September 30, 2003, increased by $1.3 million to $5.2 million, and by $5.7 million to $14.0 million, respectively. These increases were primarily due to increased business activity and commencement of work for new customers.

Corporate

Earnings for the three and nine months ended September 30, 2003, decreased by $4.5 million to $(3.8) million, and by $9.1 million to $(10.0) million, respectively. These decreases were primarily due to higher preferred share dividends and interest expense related to the issue of preferred shares, $150.0 million in December 2002 and $150.0 million in April 2003, and $100.0 million of debentures issued in November 2002, net of investment income.

In 2001, the Corporation received and paid an income tax reassessment of $12.9 million relating to the 1996 disposal of ATCOR Resources Ltd. Management did not agree with this assessment and contested the matter with tax authorities. Accordingly, the payment was recorded as a reduction of future income tax liabilities. During the third quarter of 2003, the Corporation was successful in appealing the reassessment to the Tax Court of Canada. However, the Federal Government has commenced an appeal of the Tax Court's decision with the Federal Court of Appeal. Consequently, the future income tax reduction of $12.9 million has not been adjusted.

REGULATORY MATTERS

Regulated operations are conducted by ATCO Electric, the ATCO Gas and ATCO Pipelines divisions of ATCO Gas and Pipelines Ltd., CU Water and the generating plants of Alberta Power (2000), all of which are wholly owned subsidiaries of the Corporation's wholly owned subsidiary, CU Inc.

The regulatory matters disclosed in Management's Discussion and Analysis of Financial Condition and Results of Operations for the year ended December 31, 2002, remain substantially unchanged, except for the following recent developments.

In December 2002, Direct Energy Marketing Limited ("Direct Energy") agreed to purchase the retail energy businesses of ATCO Gas and ATCO Electric. The transaction is subject to the satisfaction of certain conditions, including the receipt of required regulatory approvals and the Alberta Legislature passing amendments to Alberta's Natural Gas and Electricity Legislation that improve the environment for retail competition in the Province and closing occurring by November 15, 2003, subject to such extensions as may be agreed by the parties. Amendments to the Electric Utilities Act and Gas Utilities Act received Royal Assent in March 2003 and were proclaimed in force in June 2003. In April 2003, ATCO Gas and ATCO Electric filed applications with the AEUB for approval to sell their retail operations to Direct Energy. Hearings were completed in September 2003, and a decision is expected by mid November 2003.

In April 2003, the AEUB determined that it would proceed with a generic cost of capital hearing to focus on the possibility of establishing a standardized approach to determine the rate of return on equity and capital structure for all utilities under the jurisdiction of the AEUB. Based on the proposed proceeding schedule, the hearing will commence in November 2003. A decision from the AEUB is not expected until 2004.

In May 2003, the AEUB issued a decision respecting affiliate transactions between ATCO Electric, ATCO Gas and ATCO Pipelines (the "ATCO utilities") and their affiliates. The decision and the resulting Code of Conduct set the framework for ongoing affiliate transactions. The ATCO utilities must be able to demonstrate that an affiliate can provide a service or product at a lower cost than the ATCO utility can, and the pricing from the affiliate must be at fair market value.

In August 2002, ATCO Electric filed a general tariff application with the AEUB for the 2003, 2004 and 2005 test years. In a decision dated December 11, 2002, the AEUB approved interim rates effective January 1, 2003. Hearings for ATCO Electric's general tariff application for the 2003, 2004 and 2005 test years commenced on April 15, 2003 and were completed in May 2003. During the hearings, ATCO Electric withdrew the 2005 test year from its application in light of uncertainty around whether the equity component and return for 2005 would be determined based on the merits of its application or through the generic cost of capital proceeding. In a decision dated October 2, 2003, the AEUB approved, among other things, a rate of return on common equity of 9.40% and a common equity ratio of 32% for ATCO Electric's transmission operations, and 35% for its distribution operations for 2003. The 2004 rate of return on common equity and the common equity ratios for the transmission and distribution operations will be determined as part of the generic cost of capital hearing. The AEUB also directed ATCO Electric to refile the 2003 and 2004 general tariff applications, incorporating the findings in the decision, on or before December 1, 2003. The AEUB will provide its determination on the revenue requirements for the 2003 and 2004 test years following the refiling.

In June 2003, the AEUB issued a decision approving the interim balances as applied for by ATCO Electric of $4.8 million for the 2002 regulated rate option deferral accounts and $16.6 million for the 2003 regulated rate option energy deferral account accumulated for the first 3 months of 2003. The AEUB directed that ATCO Electric collect these interim balances from customers over the period July 1, 2003 to December 31, 2003.

In September 2003, ATCO Electric received approval from the AEUB to build a $95.0 million, 350 kilometre 240 kilovolt transmission line between Fort Saskatchewan and Fort McMurray. The line includes three substations and is expected to be completed by August 31, 2004.

In August 2002, ATCO Gas filed a general rate application with the AEUB for the 2003 and 2004 test years. In December 2002, the AEUB issued a decision approving rates on an interim basis effective January 1, 2003. In a decision dated October 1, 2003, the AEUB approved, among other things, a rate of return on common equity of 9.50% for 2003 and 2004 and a common equity ratio of 37%. The AEUB also directed ATCO Gas to refile the general rate application, incorporating the findings in the decision, on or before December 1, 2003. The AEUB will provide its determination on the revenue requirements for the 2003 and 2004 test years following the refiling.

In February 2003, the AEUB issued a decision approving the methodology of distributing the proceeds from the sale of the Beaverhill Lake and Fort Saskatchewan natural gas producing properties, and in March 2003, $23 million of the related sales proceeds was refunded to ATCO Gas' North division customers. The sale has no impact on earnings. Also in March 2003, $2.5 million resulting from the AEUB approval of the final distribution service rates for ATCO Gas' North division for 2002, established in a negotiated settlement, was refunded to ATCO Gas' North division customers.

In January 2003, the AEUB issued a decision approving ATCO Pipelines' negotiated settlement of the 2001/2002 exchange deferred account deficit, which arose from the exchange mechanism utilized to deliver net producer transportation quantities sourced on the ATCO system onto the system owned by NOVA Gas Transmission Ltd. The decision approved mechanisms to collect ATCO Pipelines' South division deficit of approximately $9.2 million over a two year period and ATCO Pipelines' North division deficit of $2.3 million in 2003. The decision also provided for the recovery of carrying costs.

In February 2003, ATCO Pipelines filed a general rate application for the 2003 and 2004 test years. Hearings were completed July 8, 2003. A decision from the AEUB is expected later this year.

LIQUIDITY AND CAPITAL RESOURCES

Cash flow from operations provides a substantial portion of the Corporation's cash requirements. Additional cash requirements are met externally through bank borrowings and the issuance of long term debt, preferred shares and common equity. Commercial paper borrowings and short term bank loans are used to provide flexibility in the timing and amounts of long term financing.

Cash flow from operations for the three and nine months ended September 30, 2003, increased by $3.5 million to $105.3 million, and by $30.9 million to $367.0 million, respectively. These increases were primarily the result of increased earnings, excluding the impact of the sale of the Viking property in 2002. In addition, in the first quarter of 2002, ATCO Gas refunded to customers a total of $405.6 million related to the sale of the Viking property, of which $20.6 million had reduced cash flow from operations.

Investing for the three months ended September 30, 2003, decreased by $27.4 million to $115.8 million. This decrease was primarily due to lower capital expenditures and higher contributions by utility customers for extensions to plant, partially offset by lower recovery of non-current deferred electricity costs and changes in non-cash working capital in respect of investing activities. Investing for the nine months ended September 30, 2003, excluding the $106.9 million sale of the Viking property, decreased by $70.9 million to $309.0 million. This decrease was primarily due to lower capital expenditures, increased proceeds on disposal of other property, plant and equipment and increased contributions by utility customers for extensions to plant, partially offset by lower recovery of non-current deferred electricity costs and changes in non-cash working capital in respect of investing activities. Investing for the nine months ended September 30, 2002, including the impact of the sale of the Viking property, was $273.0 million. Capital expenditures for the three and nine months ended September 30, 2003, decreased by $12.6 million to $134.3 million, and by $95.7 million to $319.0 million, respectively. These decreases were primarily due to lower investment in power generation projects and in electric and natural gas transmission projects, partially offset by increased investment in regulated natural gas distribution projects.

During the three months ended September 30, 2003, the Corporation issued $42.0 million of notes payable and $8.0 million of long term debt and redeemed $60.0 million of 7.25% debentures, $3.5 million of other long term debt and $15.3 million of non-recourse long term debt, resulting in a net debt reduction of $28.8 million. During the nine months ended September 30, 2003, the Corporation issued $42.0 million of notes payable, $13.5 million of long term debt and $40.7 million of non-recourse long term debt and redeemed $60.0 million of 7.25% debentures, $12.3 million of other long term debt and $32.5 million of non-recourse long term debt, resulting in a net debt reduction of $8.6 million.

During the three months ended September 30, 2003, the deferred electricity cost obligation was reduced by $15.9 million, which represents the amount of the deferred electricity cost obligation collected and remitted during the period July 1, 2003, to September 30, 2003. During the nine months ended September 30, 2003, the deferred electricity cost obligation was reduced by $51.0 million, which represents the amount of the deferred electricity cost obligation collected and remitted during the period January 1, 2003, to September 30, 2003. The deferred electricity cost obligation has now been fully repaid.

On April 17, 2003, the Corporation issued 6,000,000 Series X Preferred Shares, having a dividend rate of 6.00%, at a price of $25.00 per share, for aggregate gross proceeds of $150,000,000. The net proceeds of the issue were added to the general funds of the Corporation to be used for general corporate purposes including capital expenditures.

At September 30, 2003, the Corporation had the following credit lines that enable it to obtain funding for general corporate purposes.

	Total	**Used**	**Available**
		($ Millions)	
Long term committed	350.0	64.9	285.1
Short term committed	622.9	79.7	543.2
Uncommitted	185.1	1.6	183.5
Total	1,158.0	146.2	1,011.8

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

Current and long term future income tax liabilities of $232.4 million at September 30, 2003, 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, 2002, the Corporation commenced a Normal Course Issuer Bid for the purchase of up to 3% of the outstanding Class A shares. The offer expired on May 19, 2003. Over the life of the offer, 17,300 shares were purchased. On May 20, 2003, the Corporation commenced a Normal Course Issuer Bid for the purchase of up to 3% of the outstanding Class A shares. The offer will expire on May 19, 2004. From May 20, 2003, to October 21, 2003, 40,000 shares have been purchased.

BUSINESS RISKS

The business risks disclosed in Management's Discussion and Analysis of Financial Condition and Results of Operations for the year ended December 31, 2002, remain substantially unchanged, except for the following recent developments.

The water levels in the cooling pond used by Alberta Power (2000)'s Battle River generating plant have returned to normal levels. Consequently, the plant is now producing electricity according to its Power Purchase Arrangement contractual requirements. Prior to the return to normal water levels, the Corporation made a force majeure claim in respect of short term curtailed plant production which was experienced during the first quarter of 2003.

October 21, 2003

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

	Note	Three Months Ended September 30 2003	Three Months Ended September 30 2002	Nine Months Ended September 30 2003	Nine Months Ended September 30 2002
Revenues		**$ 622.6**	$ 542.7	**$2,792.3**	$2,045.2
Costs and expenses					
Natural gas supply		**135.5**	115.5	**1,151.2**	633.6
Purchased power		**45.3**	30.9	**163.0**	124.8
Operation and maintenance		**200.7**	177.6	**642.3**	540.8
Selling and administrative		**37.0**	29.6	**105.4**	97.8
Depreciation and amortization		**62.1**	58.6	**196.2**	176.5
Interest		**37.5**	39.6	**113.5**	116.4
Interest on non-recourse long term debt		**10.2**	7.0	**29.7**	22.4
Franchise fees		**15.6**	11.9	**92.1**	69.6
		543.9	470.7	**2,493.4**	1,781.9
		78.7	72.0	**298.9**	263.3
Gain on sale of Viking-Kinsella property	2	**-**	-	**-**	108.5
Interest and other income		**8.7**	6.6	**23.9**	18.3
Earnings before income taxes		**87.4**	78.6	**322.8**	390.1
Income taxes		**35.0**	29.9	**126.0**	145.6
Net earnings		**52.4**	48.7	**196.8**	244.5
Dividends on equity preferred shares		**9.0**	4.3	**24.2**	13.0
Earnings attributable to Class A and Class B shares	2	**43.4**	44.4	**172.6**	231.5
Retained earnings at beginning of period		**1,375.2**	1,261.9	**1,314.9**	1,136.9
		1,418.6	1,306.3	**1,487.5**	1,368.4
Dividends on Class A and Class B shares		**32.3**	31.1	**97.0**	93.2
Direct charges	3	**1.0**	-	**5.2**	-
Retained earnings at end of period		**$1,385.3**	$1,275.2	**$1,385.3**	$1,275.2
Earnings per Class A and Class B share	2,4	**$ 0.68**	$ 0.70	**$ 2.72**	$ 3.65
Diluted earnings per Class A and Class B share	2,4	**$ 0.68**	$ 0.70	**$ 2.71**	$ 3.64
Dividends paid per Class A and Class B share		**$ 0.51**	$ 0.49	**$ 1.53**	$ 1.47

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

	Note	September 30 2003	September 30 2002	December 31 2002
ASSETS		*(Unaudited)*		*(Audited)*
Current assets				
Cash and short term investments		**$ 517.2**	$ 293.6	$ 438.9
Accounts receivable		**346.0**	288.8	459.4
Inventories		**167.7**	119.9	121.7
Income taxes recoverable		**-**	0.2	20.2
Deferred natural gas costs		**-**	11.0	31.2
Deferred electricity costs		**2.9**	42.4	20.7
Prepaid expenses		**37.2**	31.2	25.4
		1,071.0	787.1	1,117.5
Property, plant and equipment		**4,713.1**	4,575.9	4,657.0
Security deposits for debt		**22.4**	25.8	26.1
Other assets		**129.3**	134.5	133.8
		$5,935.8	$5,523.3	$5,934.4
LIABILITIES AND SHARE OWNERS' EQUITY				
Current liabilities				
Bank indebtedness		**$ -**	$ 13.5	$ 5.0
Accounts payable and accrued liabilities		**326.2**	336.3	451.3
Income taxes payable		**5.2**	-	-
Future income taxes		**3.4**	7.0	16.8
Deferred natural gas cost recoveries		**1.2**	-	-
Notes payable		**42.0**	7.2	-
Deferred electricity cost obligation		**-**	65.9	51.0
Non-recourse long term debt due within one year		**41.0**	32.4	46.1
		419.0	462.3	570.2
Future income taxes		**229.0**	209.2	230.8
Deferred credits		**90.4**	82.0	78.8
Long term debt		**1,859.0**	1,816.3	1,916.9
Non-recourse long term debt		**808.3**	828.3	821.1
Equity preferred shares	6	**636.5**	336.5	486.5
Class A and Class B share owners' equity				
Class A and Class B shares	4	**509.5**	509.5	509.6
Retained earnings		**1,385.3**	1,275.2	1,314.9
Foreign currency translation adjustment		**(1.2)**	4.0	5.6
		1,893.6	1,788.7	1,830.1
		$5,935.8	$5,523.3	$5,934.4

CANADIAN UTILITES LIMITED
CONSOLIDATED STATEMENT OF CASH FLOWS
(Unaudited, Millions of Canadian Dollars)

	Note	Three Months Ended September 30		Nine Months Ended September 30	
		2003	2002	**2003**	2002
Operating activities					
Earnings attributable to Class A and Class B shares		**$ 43.4**	$ 44.4	**$ 172.6**	$ 231.5
Non-cash items included in earnings:					
Depreciation and amortization		**62.1**	58.6	**196.2**	176.5
Future income taxes		**2.0**	0.8	**5.9**	(1.6)
Gain on sale of Viking-Kinsella property - net of current income taxes	2	**-**	-	**-**	(66.7)
Other - net		**(2.2)**	(2.0)	**(7.7)**	(3.6)
Cash flow from operations		**105.3**	101.8	**367.0**	336.1
Changes in non-cash working capital		**37.1**	(0.9)	**30.0**	(101.4)
		142.4	100.9	**397.0**	234.7
Investing activities					
Purchase of property, plant and equipment		**(134.3)**	(146.9)	**(319.0)**	(414.7)
Sale of Viking-Kinsella property - net of current income taxes	2	**-**	-	**-**	106.9
Proceeds (costs) on disposal of other property, plant and equipment		**2.4**	(0.3)	**12.5**	0.7
Contributions by utility customers for extensions to plant		**10.6**	5.3	**34.3**	19.9
Non-current deferred electricity costs		**3.9**	12.0	**8.8**	29.1
Changes in non-cash working capital		**1.6**	(6.6)	**(45.3)**	(3.5)
Other		**-**	(6.7)	**(0.3)**	(11.4)
		(115.8)	(143.2)	**(309.0)**	(273.0)
Financing activities					
Change in notes payable		**42.0**	2.2	**42.0**	2.6
Deferred electricity cost obligation		**(15.9)**	65.9	**(51.0)**	65.9
Issue of long term debt		**8.0**	-	**13.5**	-
Issue of non-recourse long term debt		**-**	127.9	**40.7**	168.2
Repayment of long term debt		**(63.5)**	(12.5)	**(72.3)**	(41.1)
Repayment of non-recourse long term debt		**(15.3)**	(16.0)	**(32.5)**	(39.2)
Issue of equity preferred shares	6	**-**	-	**150.0**	-
Issue (purchase) of Class A shares		**(1.0)**	-	**(2.5)**	2.8
Dividends paid to Class A and Class B share owners		**(32.3)**	(31.1)	**(97.0)**	(93.2)
Changes in non-cash working capital		**(0.5)**	8.7	**6.2**	8.1
Other		**1.7**	(1.8)	**3.7**	(2.8)
		(76.8)	143.3	**0.8**	71.3
Foreign currency translation		**0.9**	3.7	**(5.5)**	4.2
Cash position [(1)]					
Increase (decrease)		**(49.3)**	104.7	**83.3**	37.2
Beginning of period		**566.5**	175.4	**433.9**	242.9
End of period		**$ 517.2**	$ 280.1	**$ 517.2**	$ 280.1

[(1)] Cash position is defined as cash and short term investments less current bank indebtedness, and includes $60.4 million (2002 - $104.7 million) which is only available for use in joint ventures.

CANADIAN UTILITIES LIMITED
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
SEPTEMBER 30, 2003

(Unaudited, Tabular Amounts in Millions of Canadian Dollars)

1. Financial statement presentation

The accompanying unaudited 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 2002 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, 2002.

Due to the seasonal nature of the Corporations' operations and the timing of rate decisions, the consolidated statements of earnings and retained earnings for the three and nine months ended September 30, 2003 and September 30, 2002 are not necessarily indicative of operations on an annual basis.

Certain 2002 figures have been reclassified to conform to the current presentation.

2. Gain on sale of Viking-Kinsella property

In 2002, the Corporation sold its Viking-Kinsella natural gas producing property, having a net book value of approximately $40 million, for $550 million. In accordance with an Alberta Energy and Utilities Board ("AEUB") decision, $385.0 million plus related adjustments for future abandonment and future income taxes of $20.6 million, for a total of $405.6 million, was distributed to customers by way of lump sum payments.

The Corporation's share of the net proceeds was $148.7 million, after adjustments, resulting in a gain of $108.5 million before income taxes of $41.8 million. This sale increased earnings for the nine months ended September 30, 2002 by $66.7 million, earnings per share by $1.05 and diluted earnings per share by $1.04.

3. Direct charges to retained earnings

	Three Months Ended September 30		Nine Months Ended September 30	
	2003	2002	**2003**	2002
Issue costs of equity preferred shares (after income taxes)	**$ -**	$ -	**$2.7**	$ -
Purchase of Class A shares	**1.0**	-	**2.5**	-
	$1.0	$ -	**$5.2**	$ -

4. Class A and Class B shares

There were 40,136,744 (2002 – 40,095,794) Class A non-voting shares and 23,228,891 (2002 – 23,314,791) Class B common shares outstanding on September 30, 2003. In addition, there were 980,250 options to purchase Class A non-voting shares outstanding at September 30, 2003 under the Corporation's stock option plan. From October 1, 2003, to October 21, 2003, 1,200 Class A non-voting

4. Class A and Class B shares (continued)

shares have been purchased under the Corporation's Normal Course Issuer Bid, no stock options were granted and there were no changes to shares under option.

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

	Three Months Ended September 30		Nine Months Ended September 30	
	2003	2002	**2003**	2002
Weighted-average shares outstanding	**63,377,086**	63,410,552	**63,395,141**	63,382,353
Effect of dilutive stock options	**318,479**	310,749	**275,928**	316,575
Weighted-average diluted shares outstanding	**63,695,565**	63,721,301	**63,671,069**	63,698,928

5. Stock based compensation

While the recommendations of the Canadian Institute of Chartered Accountants on accounting for stock-based compensation and other stock-based payments encourage the adoption of the fair value based method of accounting for stock options, other methods of accounting are permitted. The Corporation has chosen to retain its existing accounting policy, which is permitted by the recommendations, whereby no compensation expense is recognized upon the granting or exercise of stock options.

Had the Corporation adopted the fair value based method of accounting for stock options, earnings for the three and nine months ended September 30, 2003 would have been reduced by $0.1 million, but there would have been no effect on earnings per share. For the three and nine months ended September 30, 2002, there would have been no effect on reported earnings and earnings per share.

6. Equity preferred shares

On April 17, 2003, the Corporation issued $150.0 million of Cumulative Redeemable Second Preferred Shares Series X for cash. The dividend rate has been fixed at 6.0%.

7. Segmented information

Nine months ended **September 30, 2003** September 30, 2002	Utilities	Power Generation	Logistics & Energy Services	Technologies And Other Businesses	Corporate	Intersegment Eliminations	Consolidated
Revenues – external	**$1,777.3**	**$ 471.5**	**$526.0**	**$17.5**	**$ -**	**$ -**	**$2,792.3**
	$1,177.8	$ 418.8	$441.0	$ 7.6	$ -	$ -	$2,045.2
Revenues – intersegment	**53.1**	**-**	**421.9**	**75.1**	**8.6**	**(558.7)**	**-**
	62.3	-	228.4	68.3	8.3	(367.3)	-
Revenues	**$1,830.4**	**$ 471.5**	**$947.9**	**$92.6**	**$ 8.6**	**$(558.7)**	**$2,792.3**
	$1,240.1	$ 418.8	$669.4	$75.9	$ 8.3	$(367.3)	$2,045.2
Earnings attributable to Class A and Class B shares	**$ 61.5**	**$ 57.0**	**$ 46.5**	**$14.0**	**$(10.0)**	**$ 3.6**	**$ 172.6**
	$ 120.9	$ 51.9	$ 45.0	$ 8.3	$ (0.9)	$ 6.3	$ 231.5
Total assets	**$2,395.1**	**$2,163.8**	**$800.6**	**$53.2**	**$557.2**	**$ (34.1)**	**$5,935.8**
	$2,422.9	$2,110.5	$837.7	$45.1	$113.7	$ (6.6)	$5,523.3

7. **Segmented information** (continued)

Three months ended **September 30, 2003** September 30, 2002	Utilities	Power Generation	Logistics & Energy Services	Technologies And Other Businesses	Corporate	Intersegment Eliminations	Consolidated
Revenues – external	**$317.7**	**$146.1**	**$151.7**	**$ 7.1**	**$ -**	**$ -**	**$622.6**
	$230.6	$141.0	$168.0	$ 3.1	$ -	$ -	$542.7
Revenues – intersegment	**13.7**	**-**	**96.0**	**25.5**	**2.9**	**(138.1)**	**-**
	20.5	-	50.3	23.2	2.8	(96.8)	-
Revenues	**$331.4**	**$146.1**	**$247.7**	**$32.6**	**$ 2.9**	**$(138.1)**	**$622.6**
	$251.1	$141.0	$218.3	$26.3	$ 2.8	$ (96.8)	$542.7
Earnings attributable to Class A and Class B shares	**$ 5.5**	**$ 17.8**	**$ 17.7**	**$ 5.2**	**$(3.8)**	**$ 1.0**	**$ 43.4**
	$ 1.1	$ 18.9	$ 17.6	$ 3.9	$ 0.7	$ 2.2	$ 44.4

8. **Regulatory matters**

The AEUB issued decisions regarding ATCO Gas' and ATCO Electric's general rate applications on October 1, 2003 and October 2, 2003, respectively. These decisions approved, among other things, for ATCO Electric, a rate of return on common equity of 9.4% and a common equity ratio of 32% for transmission operations and 35% for distribution operations for 2003; and, for ATCO Gas, a rate of return on common equity of 9.5% and a common equity ratio of 37% for 2003 and 2004.

ATCO Electric's 2004 rate of return on common equity and the common equity ratios for the transmission and distribution operations will be determined as part of a generic cost of capital hearing which will commence in November 2003.

The AEUB also directed ATCO Electric and ATCO Gas to refile the 2003 and 2004 general rate applications, incorporating the findings in the decisions, on or before December 1, 2003. The AEUB will provide its determination on the revenue requirements for the 2003 and 2004 test years following the refilings.

These decisions will be recorded in the Corporation's fourth quarter results. Had these decisions been recorded in the accompanying consolidated financial statements, the effect on earnings for the nine months ended September 30, 2003 would have been negligible as the AEUB had issued decisions in December 2002 for ATCO Electric and ATCO Gas approving rates on an interim basis effective January 1, 2003.