CANADIAN UTILITIES LIMITED
An ATCO Company

INTERIM REPORT

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FILE NO. 82-34744

FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2004

SUPPL

TO THE SHARE OWNERS:

Canadian Utilities Limited reported earnings for the three months ended September 30, 2004 of $44.0 million ($0.70 per share). Earnings for the same three months in 2003 were $43.2 million ($0.68 per share).

Earnings increased primarily due to:

- higher margins in ATCO Midstream's natural gas liquids operations.

This increase was partially offset by:

- the negative impacts of the 2003/2004 general tariff decision and the generic cost of capital decision that reduced the common equity that ATCO Electric is allowed to earn a return on by $60.7 million over the two years, 2003 and 2004 ("ATCO Electric Decision").

Earnings for the nine months ended September 30, 2004 were $218.7 million ($3.45 per share) including the $55.1 million after tax gain on the transfer by ATCO Gas and ATCO Electric of their retail energy supply businesses to Direct Energy Marketing Limited and one of its affiliates on May 4, 2004 ("Retail Transfer Gain"). Earnings for the nine months ended September 30, 2004 excluding the Retail Transfer Gain were $163.6 million ($2.59 per share). Earnings for the same nine months in 2003 were $172.6 million ($2.72 per share).

Earnings excluding the Retail Transfer Gain decreased primarily due to:

- the negative impact of the ATCO Electric Decision; and
- a decrease in ATCO Power's earnings of $7.7 million due to lower prices on electricity sold to the Alberta Electric System Operator and the lower spark spread.

This decrease was partially offset by:

- improved earnings in ATCO Power's United Kingdom operations; and
- lower Alberta income tax rates.

Operational highlights of the third quarter:

- ATCO Electric completed construction of the $99 million, 350 kilometre, 240 kilovolt transmission line between Fort McMurray and Whitefish Lake in Alberta.
- The 580 megawatt Brighton Beach power plant in Windsor, Ontario, a partnership formed by ATCO Power, ATCO Resources and Ontario Power Generation, commenced commercial operation in July 2004.
- ATCO Power received a favourable arbitration decision in August 2004 with respect of the force majeure claim regarding the Battle River generating plant. This resulted in the recovery of $10.4 million of availability incentive payments.

	For the Three Months Ended September 30		For the Nine Months Ended September 30	
	2004	2003	**2004**	2003
	($ Millions except per share data) *(unaudited)*			
Revenues	**550.8**	622.6	**2,426.9**	2,792.3
Earnings attributable to Class A and Class B shares	**44.0**	43.2	**218.7**	172.6
Earnings per Class A and Class B share	**0.70**	0.68	**3.45**	2.72
Cash flow from operations	**128.4**	104.5	**373.9**	372.5

Revenues for the three months ended September 30, 2004 were $550.8 million compared to $622.6 million in 2003. This decrease was primarily due to:

- lower sales of electricity and natural gas purchased for customers on a "no margin" basis by ATCO Electric and ATCO Gas due to the transfer of the retail energy supply businesses on May 4, 2004.

Revenues for the nine months ended September 30, 2004 were $2,426.9 million compared to $2,792.3 million in 2003. This decrease was primarily due to:

- lower sales of electricity and natural gas purchased for customers on a "no-margin' basis by ATCO Electric and ATCO Gas due to the transfer of the retail energy supply businesses on May 4, 2004;
- lower prices of electricity and natural gas purchased for customers on a "no-margin" basis prior to May 4, 2004; and
- warmer temperatures in ATCO Gas which were 1.3% colder than normal, compared to 7.5% colder than normal for the same period in 2003.

Cash flow from operations for the three months ended September 30, 2004 was $128.4 million compared to $104.5 million in 2003. This increase was primarily due to:

- the receipt of $10.4 million of availability incentive payments in Alberta Power (2000) related to the Battle River arbitration decision; and
- availability incentive payments received for improved plant availability.

Cash flow from operations for the nine months ended September 30, 2004 was $373.9 million compared to $372.5 million in 2003.

Canadian Utilities Limited is part of the ATCO Group of Companies. ATCO Group is an Alberta based, worldwide organization of companies with more than 7,000 employees actively engaged in Power Generation, Utilities and Global Enterprises. More information about Canadian Utilities Limited can be found on its website www.canadian-utilities.com.

N.C. Southern
President & Chief Executive Officer

R.D. Southern
Chairman of the Board

CANADIAN UTILITIES LIMITED

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

The following discussion and analysis of financial condition and results of operations of Canadian Utilities Limited (the "Corporation") should be read in conjunction with the Corporation's unaudited comparative interim financial statements for the three and nine months ended September 30, 2004, and the audited comparative financial statements and management's discussion and analysis of financial condition and results of operations for the year ended December 31, 2003 ("2003 MD&A"). Information contained in the 2003 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 common share capital of the Corporation consists of Class A non-voting shares ("Class A shares") and Class B common shares ("Class B shares").

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 purchase obligations, planned capital expenditures, anticipated completion dates and construction costs of major projects, 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.

CORPORATE REORGANIZATION

In August 2004, the Corporation reorganized its structure into three business groups: **Utilities** (ATCO Gas, ATCO Electric and its subsidiaries, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical, ATCO Pipelines, CU Water, ATCO Utility Services); **Power Generation** (ATCO Power, Alberta Power (2000)); and **Global Enterprises** (ATCO Midstream, ATCO Frontec, ATCO I-Tek and its subsidiary ATCO I-Tek Business Services, ASHCOR Technologies, Genics, ATCO Travel). 2003 segmented figures have been restated to conform to the current basis of segmentation.

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 (refer to Note 9 to the comparative financial statements). Transactions between Business Groups are eliminated in all reporting of the Corporation's consolidated financial information.

Transfer of the Retail Energy Supply Businesses

On May 4, 2004, ATCO Gas and ATCO Electric closed the transfer of their retail energy supply businesses to Direct Energy Marketing Limited and one of its affiliates (collectively "DEML"), a subsidiary of Centrica plc ("Transfer of the Retail Energy Supply Businesses"). Proceeds of the transfer were $90 million, of which $45 million was paid at closing, with the remainder to be paid 12 months following closing. Net proceeds, after adjustments related to legal, transition and other deferred costs pertaining to the transfer of the retail energy supply businesses, resulted in a gain of $63.3 million before income taxes of $8.2 million. This transfer increased earnings for the nine months ended September 30, 2004, by $55.1 million.

The Corporation's revenues and natural gas supply and purchased power costs after May 4, 2004, will be reduced accordingly. Subsequent to May 4, 2004, ATCO Gas continued to purchase natural gas on behalf of DEML, pending the transfer of the relevant ATCO Gas natural gas purchase contracts to DEML. This transfer of contracts was completed by September 30, 2004. There will be no impact on earnings resulting from the transfer of these businesses as natural gas and electricity have historically been sold to customers on a "no-margin" basis. ATCO Gas and ATCO Electric continue to own and operate the natural gas and electricity distribution systems used to deliver energy.

Under the various transaction agreements, ATCO Gas and ATCO Electric have transferred to DEML certain retail functions, including the supply of natural gas and electricity to customers and billing and customer care functions (the "transferred functions").

On May 4, 2004, DEML commenced supplying natural gas and electricity at regulated rates to residential, farm and small business customers in the ATCO Gas and ATCO Electric service areas and billing customers for their natural gas and electricity service.

If DEML fails to perform all or part of the transferred functions, ATCO Gas and ATCO Electric will be required under existing legislation to perform such functions in the interim until DEML is able to perform such functions. 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 agreements will terminate and the functions will revert to ATCO Gas and/or ATCO Electric with no refund of the purchase price to DEML by ATCO Gas and/or ATCO Electric. In certain circumstances, if DEML is restrained or prohibited from carrying out the transferred functions, all functions will revert to ATCO Gas and ATCO Electric and a portion of the purchase price will be refunded to DEML, depending upon the timing of any such reversion.

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. The Centrica guarantee and letter of credit include limits for certain categories of claims, which limits cease to apply if the agreements are terminated. If the amount available to be drawn under the letter of credit at any time falls below $200 million, the agreements with DEML will terminate and the functions will revert to ATCO Gas and ATCO Electric with no refund of the purchase price to DEML by ATCO Gas and ATCO Electric.

The Corporation has provided a guarantee of ATCO Gas', ATCO Electric's and ATCO I-Tek Business Services' payment and indemnity obligations in respect of the ongoing relationships contemplated under the transaction agreements.

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

ATCO Gas and ATCO Electric have also agreed not to compete in the regulated and unregulated retail energy business in Alberta for a period of ten years.

In December 2003, the Alberta Energy and Utilities Board ("AEUB") issued a decision approving the transfer of the retail operations of ATCO Gas and ATCO Electric to DEML. The City of Calgary filed for leave to appeal the AEUB decision, including the allocation of proceeds to ATCO Gas and ATCO Electric. On June 30, 2004, the Alberta Court of Appeal dismissed the City of Calgary's application for leave to appeal.

SELECTED QUARTERLY INFORMATION

	For the Three Months Ended			
	Mar. 31	Jun. 30	Sep. 30	Dec. 31
	($ Millions except per share data) *(unaudited)*			
2004				
Revenues (1)	1,185.9	690.2	550.8	....
Earnings attributable to Class A and Class B shares (2) (4) (5)	74.5	100.2	44.0	....
Earnings per Class A and Class B share (2) (4) (5)	1.17	1.58	0.70	....
Diluted earnings per Class A and Class B share (2) (4) (5)	1.16	1.58	0.70	....
2003				
Revenues	1,372.2	797.5	622.6	950.3
Earnings attributable to Class A and Class B shares (3) (4) (5)	85.9	43.5	43.2	86.5
Earnings per Class A and Class B share (3) (4) (5)	1.35	0.69	0.68	1.37
Diluted earnings per Class A and Class B share (3) (4) (5)	1.34	0.69	0.68	1.36
2002				
Revenues	....	....	....	930.7
Earnings attributable to Class A and Class B shares (3) (4) (5)	....	....	....	73.7
Earnings per Class A and Class B share (3) (4) (5)	....	....	....	1.16
Diluted earnings per Class A and Class B share (3) (4) (5)	....	....	....	1.15

Notes:

(1) *Includes the reduction in revenues from the Transfer of the Retail Energy Supply Businesses for the three months ended June 30, 2004, and September 30, 2004.*

(2) *Includes the impact of the Transfer of the Retail Energy Supply Businesses for the three months ended June 30, 2004.*

(3) *2003 and 2002 earnings attributable to Class A shares and Class B shares have been restated for retroactive changes in the methods of accounting for asset retirement obligations and stock based compensation.*

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

(5) *Due to the seasonal nature of the Corporation's operations, changes in electricity prices in Alberta and the timing of rate decisions, earnings for any quarter are not necessarily indicative of operations on an annual basis.*

(6) *The above data has 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 caused variations in revenues for the three and nine months ended September 30, 2004, were:

- lower sales of electricity and natural gas purchased for customers on a "no-margin" basis by ATCO Electric and ATCO Gas due to the Transfer of the Retail Energy Supply Businesses (refer to the Transfer of the Retail Energy Supply Businesses section), and lower prices of electricity and natural gas purchased for customers on a "no-margin" basis prior to May 4, 2004 (refer to the Utilities section);
- fluctuations in electricity and natural gas prices (refer to the Power Generation section);
- fluctuations in temperatures (refer to the Utilities section); and
- timing of rate decisions (refer to the Utilities and Regulatory Matters sections).

The principal factors that caused variations in earnings for the three and nine months ended September 30, 2004, were:

- the Transfer of the Retail Energy Supply Businesses (refer to the Transfer of the Retail Energy Supply Businesses and the Utilities sections);
- fluctuations in electricity prices and related spark spreads in Alberta for ATCO Power (refer to the Power Generation section);

- fluctuations in temperatures (refer to the Utilities section); and
- timing of rate decisions (refer to the Utilities and Regulatory Matters sections).

Consolidated Operations

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

	For the Three Months Ended September 30		For the Nine Months Ended September 30	
	2004	2003	**2004**	2003
	($ Millions except per share data) *(unaudited)*			
Revenues (1)	**550.8**	622.6	**2,426.9**	2,792.3
Earnings attributable to Class A shares and Class B shares (2) (3) (4) (5)	**44.0**	43.2	**218.7**	172.6
Earnings per Class A share and Class B share (2) (3) (4) (5)	**0.70**	0.68	**3.45**	2.72
Diluted earnings per Class A share and Class B share (2) (3) (4) (5)	**0.70**	0.68	**3.44**	2.71

Notes:

(1) Includes the reduction in revenues from the Transfer of the Retail Energy Supply Businesses for the three and nine months ended September 30, 2004.

(2) Includes the impact of the Transfer of the Retail Energy Supply Businesses for the nine months ended September 30, 2004.

(3) 2003 earnings attributable to Class A shares and Class B shares have been restated for retroactive changes in the methods of accounting for asset retirement obligations and stock based compensation.

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

(5) Due to the seasonal nature of the Corporation's operations, changes in electricity prices in Alberta and the timing of rate decisions, earnings for any quarter are not necessarily indicative of operations on an annual basis.

(6) The above data has been prepared in accordance with Canadian generally accepted accounting principles and the reporting currency is the Canadian dollar.

Revenues for the three months ended September 30, 2004, decreased by $71.8 million to $550.8 million, primarily due to:

- lower sales of electricity and natural gas purchased for customers on a "no-margin" basis by ATCO Electric and ATCO Gas due to the Transfer of the Retail Energy Supply Businesses;
- expiry in September 2003 of ATCO Frontec's contract with the Department of National Defence to provide support services for six peace-keeping installations in Bosnia-Herzegovina (the "Balkans contract"); and
- lower cost of service revenues in Alberta Power (2000) from the H.R. Milner generating plant which was sold by the Alberta Balancing Pool on January 29, 2004.

This decrease was partially offset by:

- higher natural gas volumes purchased and resold for natural gas liquids extraction and higher prices received for natural gas liquids in ATCO Midstream;
- operations at the new 170 megawatt Scotford generating plant commissioned in December 2003 and at the new 580 megawatt Brighton Beach generating plant commissioned in July 2004;
- increased business activity and the commencement of work for new customers by ATCO I-Tek; and
- increased activity at ATCO Frontec's Voisey's Bay project.

Revenues for the nine months ended September 30, 2004, decreased by $365.4 million to $2,426.9 million, primarily due to:

- lower sales of electricity and natural gas purchased for customers on a "no-margin" basis by ATCO Electric and ATCO Gas due to the Transfer of the Retail Energy Supply Businesses, and lower prices of electricity and natural gas purchased for customers on a "no-margin" basis prior to May 4, 2004;
- warmer temperatures in ATCO Gas for the nine months ended September 30, 2004, which were 1.3% colder than normal, compared to 7.5% colder than normal for the corresponding period in 2003;
- expiry in September 2003 of ATCO Frontec's Balkans contract;
- lower cost of service revenues in Alberta Power (2000) from the H.R. Milner generating plant which was sold by the Alberta Balancing Pool on January 29, 2004;
- lower natural gas volumes purchased for ATCO Pipelines' customers as a result of customers moving from sales service (commodity and transportation revenues) to transportation service contracts (transportation revenue); and
- lower prices received for electricity sold to the Alberta Electric System Operator ("AESO") by ATCO Power.

This decrease was partially offset by:

- higher natural gas volumes purchased and resold for natural gas liquids extraction and higher prices received for natural gas liquids in ATCO Midstream;
- operations at the new 170 megawatt Scotford generating plant commissioned in December 2003 and at the new 580 megawatt Brighton Beach generating plant commissioned in July 2004;
- customer additions in ATCO Gas;
- increased activity at ATCO Frontec's Voisey's Bay project; and
- increased business activity and the commencement of work for new customers by ATCO I-Tek.

Earnings attributable to Class A shares and Class B shares for the three months ended September 30, 2004, increased by $0.8 million ($0.02 per share) to $44.0 million ($0.70 per share), primarily due to:

- higher margins in ATCO Midstream's natural gas liquids operations;
- improved earnings in ATCO Power's United Kingdom ("U.K.") operations;
- moderately positive impact of the ATCO Gas AEUB decision respecting the 2003/2004 general rate application that increased ATCO Gas' rate of return on common equity to 9.5% ("ATCO Gas Decision");
- increased business activity and the commencement of work for new customers by ATCO I-Tek; and
- lower Alberta income tax rates.

This increase was partially offset by:

- negative impact of recent AEUB decisions for ATCO Electric.

  For 2002, ATCO Electric's rate of return on common equity was 10.5% and the common equity ratio was 37% for transmission operations and 43% for distribution operations.

  The October 2, 2003, AEUB decision respecting the 2003/2004 general tariff application decreased ATCO Electric's rate of return on common equity to 9.4% and the common equity ratio to 32% for transmission operations and 35% for distribution operations. These reductions in the common equity ratios reduced the common equity that ATCO Electric was allowed to earn a return on by $83.0 million for 2003. The impact of this decision was recorded in the fourth quarter of 2003.

  The July 2, 2004, generic cost of capital decision (refer to Regulatory Matters section) revised the rate of return on common equity to 9.6% and the common equity ratio to 33% for transmission operations and 37% for distribution operations beginning in 2004. These increases in the common equity ratios increased the common equity that ATCO Electric is allowed to earn a return on by $22.3 million for 2004. The impact of this decision was recorded in the third quarter of 2004.

  In summary, the negative impacts of the 2003/2004 general tariff decision and the generic cost of capital decision reduced the common equity that ATCO Electric is allowed to earn a return on by $60.7 million over the two years, 2003 and 2004.

ATCO Electric's 2003/2004 general tariff decision as amended by the generic cost of capital decision is referred to in this MD&A as the "ATCO Electric Decision"; and

- expiry in September 2003 of ATCO Frontec's Balkans contract.

Earnings attributable to Class A shares and Class B shares for the nine months ended September 30, 2004, **including** the $55.1 million after tax gain on the Transfer of the Retail Energy Supply Businesses, increased by $46.1 million ($0.73 per share) to $218.7 million ($3.45 per share).

Earnings attributable to Class A shares and Class B shares for the nine months ended September 30, 2004, **excluding** the $55.1 million after tax gain on the Transfer of the Retail Energy Supply Businesses, decreased by $9.0 million ($0.13 per share) to $163.6 million ($2.59 per share), primarily due to:

- negative impact of the ATCO Electric Decision;
- decrease in ATCO Power's earnings of $7.7 million due to lower prices on electricity sold to the AESO and the related spark spread (as defined in the Power Generation section);
- expiry in September 2003 of ATCO Frontec's Balkans contract;
- warmer temperatures in ATCO Gas; and
- increased dividends on equity preferred shares, net of investment income, due to the issue in April 2003 of $150.0 million of 6.00% Cumulative Redeemable Second Preferred Shares Series X ("Series X Preferred Shares").

This decrease was partially offset by:

- improved earnings in ATCO Power's U.K. operations;
- lower Alberta income tax rates;
- moderately positive impact of the ATCO Gas Decision; and
- customer additions in ATCO Gas.

Operating expenses (consisting of natural gas supply, purchased power, operation and maintenance, selling and administrative and franchise fee costs) for the three months ended September 30, 2004, decreased by $74.8 million to $359.2 million, primarily due to:

- lower costs of electricity and natural gas purchased for customers on a "no-margin" basis by ATCO Electric and ATCO Gas due to the Transfer of the Retail Energy Supply Businesses;
- reduced operating and maintenance costs in ATCO Frontec due to the expiry of the Balkans contract;
- lower natural gas volumes purchased for ATCO Pipelines' customers as a result of customers moving from sales service (commodity and transportation costs) to transportation service contracts (transportation costs); and
- reduced operating and maintenance costs in Alberta Power (2000) from the H.R. Milner generating plant which was sold by the Alberta Balancing Pool on January 29, 2004.

This decrease was partially offset by:

- higher fuel costs in ATCO Power's Alberta generating plants due to higher prices and the commencement of operations at the new Scotford and Brighton Beach generating plants;
- higher natural gas volumes purchased for natural gas liquids extraction by ATCO Midstream; and
- additional operating and maintenance costs resulting from increased activity at ATCO Frontec's Voisey's Bay project.

Operating expenses for the nine months ended September 30, 2004, decreased by $365.2 million to $1,788.7 million, primarily due to:

- lower costs of electricity and natural gas purchased for customers on a "no-margin" basis by ATCO Electric and ATCO Gas due to the Transfer of the Retail Energy Supply Businesses, and lower costs of electricity and natural gas purchased for customers on a "no-margin" basis prior to May 4, 2004;
- reduced operating and maintenance costs in ATCO Frontec due to the expiry of the Balkans contract;
- lower natural gas volumes purchased for ATCO Pipelines' customers as a result of customers moving from sales service (commodity and transportation costs) to transportation service contracts (transportation costs); and

- reduced operating and maintenance costs in Alberta Power (2000) from the H.R. Milner generating plant which was sold by the Alberta Balancing Pool on January 29, 2004.

This decrease was partially offset by:

- additional operating and maintenance costs resulting from increased activity at ATCO Frontec's Voisey's Bay project; and
- higher fuel costs due to the commencement of operations at the new Scotford and Brighton Beach generating plants.

Depreciation and amortization expenses for the three months ended September 30, 2004, increased by $3.7 million to $66.1 million, primarily due to:

- capital additions in 2004 and 2003.

Depreciation and amortization expenses for the nine months ended September 30, 2004, increased by $13.9 million to $210.3 million, primarily due to:

- capital additions in 2004 and 2003.

Interest expense for the three months ended September 30, 2004, increased by $2.6 million to $50.3 million, primarily due to:

- interest on non-recourse financings for the new Oldman River, Scotford and Brighton Beach generating plants commissioned by ATCO Power in September 2003, December 2003 and July 2004, respectively.

Interest expense for the nine months ended September 30, 2004, increased by $7.6 million to $150.8 million, primarily due to:

- interest on non-recourse financings for the new Oldman River, Scotford and Brighton Beach generating plants commissioned by ATCO Power in September 2003, December 2003 and July 2004, respectively.

Interest and other income for the three months ended September 30, 2004, decreased by $1.3 million to $7.4 million, primarily due to:

- lower rates of interest earned on cash balances.

Interest and other income for the nine months ended September 30, 2004, decreased by $3.5 million to $20.4 million, primarily due to:

- lower rates of interest earned on cash balances.

This decrease was partially offset by:

- higher cash balances.

Income taxes for the three months ended September 30, 2004, decreased by $5.4 million to $29.6 million, primarily due to:

- lower Alberta income tax rates.

Income taxes for the nine months ended September 30, 2004, **including** the $8.2 million of income taxes resulting from the Transfer of the Retail Energy Supply Businesses, decreased by $10.7 million to $115.2 million.

Income taxes for the nine months ended September 30, 2004, **excluding** the $8.2 million of income taxes resulting from the Transfer of the Retail Energy Supply Businesses, decreased by $18.9 million to $107.0 million, primarily due to:

- lower earnings; and
- lower Alberta income tax rates.

Dividends on equity preferred shares for the nine months ended September 30, 2004, increased by $2.7 million to $26.9 million as a result of:

- issue of the Series X Preferred Shares.

Segmented revenues for the three and nine months ended September 30, 2004, were as follows:

	For the Three Months Ended September 30		For the Nine Months Ended September 30	
	2004	2003	**2004**	2003
	($ Millions) *(unaudited)*			
Utilities (1)	**194.2**	351.6	**1,491.9**	1,892.4
Power Generation	**156.1**	146.1	**469.3**	471.5
Global Enterprises	**230.6**	239.1	**784.4**	902.4
Corporate and Other	**1.9**	3.2	**7.7**	9.2
Intersegment eliminations	**(32.0)**	(117.4)	**(326.4)**	(483.2)
Total	**550.8**	622.6	**2,426.9**	2,792.3

Note:

(1) *Includes the reduction in revenues from the Transfer of the Retail Energy Supply Businesses for the three and nine months ended September 30, 2004.*

Segmented earnings attributable to Class A and Class B shares for the three and nine months ended September 30, 2004, were as follows:

	For the Three Months Ended September 30		For the Nine Months Ended September 30	
	2004	2003	**2004**	2003
	($ Millions) *(unaudited)*			
Utilities (1)	**10.3**	11.9	**130.2**	80.2
Power Generation (2)	**18.4**	17.6	**55.9**	57.1
Global Enterprises (2)	**18.6**	16.4	**41.3**	41.7
Corporate and Other (3)	**(3.6)**	(3.7)	**(11.2)**	(10.0)
Intersegment eliminations	**0.3**	1.0	**2.5**	3.6
Total	**44.0**	43.2	**218.7**	172.6

Notes:

(1) *The earnings for the nine months ended September 30, 2004, include earnings of $55.1 million from the Transfer of the Retail Energy Supply Businesses.*

(2) *2003 earnings have been restated for a retroactive change in the method of accounting for asset retirement obligations.*

(3) *2003 earnings have been restated for a retroactive change in the method of accounting for stock based compensation.*

Utilities

Revenues from the Utilities Business Group for the three months ended September 30, 2004, decreased by $157.4 million to $194.2 million, primarily due to:

- lower sales of electricity and natural gas purchased for customers on a "no-margin" basis by ATCO Electric and ATCO Gas due to the Transfer of the Retail Energy Supply Businesses.

This decrease was partially offset by:

- colder temperatures in ATCO Gas for the three months ended September 30, 2004, which were 15.8% colder than normal, compared to 16.0% warmer than normal for the corresponding period in 2003; and
- customer additions in ATCO Gas.

Revenues for the nine months ended September 30, 2004, decreased by $400.5 million to $1,491.9 million, primarily due to:

- lower sales of electricity and natural gas purchased for customers on a "no-margin" basis by ATCO Electric and ATCO Gas due to the Transfer of the Retail Energy Supply Businesses, and lower prices of electricity and natural gas purchased for customers on a "no-margin" basis prior to May 4, 2004;
- warmer temperatures in ATCO Gas for the nine months ended September 30, 2004, which were 1.3% colder than normal, compared to 7.5% colder than normal for the corresponding period in 2003; and
- lower natural gas volumes purchased for ATCO Pipelines' customers as a result of customers moving from sales service (commodity and transportation revenues) to transportation service contracts (transportation revenue).

This decrease was partially offset by:

- customer additions in ATCO Gas.

Earnings for the three months ended September 30, 2004, decreased by $1.6 million to $10.3 million, primarily due to:

- negative impact of the ATCO Electric Decision.

This decrease was partially offset by:

- moderately positive impact of the ATCO Gas Decision;
- colder temperatures in ATCO Gas; and
- increased earnings related to ATCO Gas' customer additions.

Earnings for the nine months ended September 30, 2004, **including** the $55.1 million after tax gain on the Transfer of the Retail Energy Supply Businesses, increased by $50.0 million to $130.2 million.

Earnings for the nine months ended September 30, 2004, **excluding** the $55.1 million after tax gain on the Transfer of the Retail Energy Supply Businesses, decreased by $5.1 million to $75.1 million, primarily due to:

- negative impact of the ATCO Electric Decision; and
- warmer temperatures in ATCO Gas.

This decrease was partially offset by:

- moderately positive impact of the ATCO Gas Decision; and
- increased earnings related to ATCO Gas' customer additions.

On August 30, 2004, ATCO Electric completed construction of a $99.0 million, 350 kilometre 240 kilovolt transmission line between Fort McMurray and Whitefish Lake. The project included three substations and the expansion of an existing substation. Construction was completed in 10 months. Typically, a project of this scale and complexity is constructed over two years.

Power Generation

Revenues from the Power Generation Business Group for the three months ended September 30, 2004, increased by $10.0 million to $156.1 million, primarily as a result of:

- operations at the new 170 megawatt Scotford generating plant commissioned in December 2003 and at the new 580 megawatt Brighton Beach generating plant commissioned in July 2004; and
- higher revenues from ATCO Power's U.K. generating plants.

This increase was partially offset by:

- lower cost of service revenues in Alberta Power (2000) for the H.R. Milner generating plant which was sold by the Alberta Balancing Pool on January 29, 2004; and
- lower prices received for electricity sold to the AESO by ATCO Power.

Revenues for the nine months ended September 30, 2004, decreased by $2.2 million to $469.3 million, primarily as a result of:

- lower cost of service revenues in Alberta Power (2000) for the H.R. Milner generating plant which was sold by the Alberta Balancing Pool on January 29, 2004; and

- lower prices received for electricity sold to the AESO by ATCO Power.

This decrease was partially offset by:

- operations at the new 170 megawatt Scotford generating plant commissioned in December 2003 and at the new 580 megawatt Brighton Beach generating plant commissioned in July 2004; and
- higher revenues from the U.K. generating plants.

Earnings for the three months ended September 30, 2004, increased by $0.8 million to $18.4 million, primarily due to:

- improved earnings in ATCO Power's U.K. operations; and
- operations at the new 170 megawatt Scotford generating plant commissioned in December 2003 and at the new 580 megawatt Brighton Beach generating plant commissioned in July 2004.

This increase was partially offset by:

- decrease in ATCO Power's earnings of $1.9 million due to lower prices on electricity sold to the AESO and the related spark spread.

  AESO electricity prices for the three months ended September 30, 2004, averaged $54.33 per megawatt hour, compared to average prices of $64.35 per megawatt hour for the corresponding period in 2003. Natural gas prices for the three months ended September 30, 2004, averaged $5.90 per gigajoule, compared to average prices of $5.52 per gigajoule for the corresponding period in 2003. The consequence of relatively stronger natural gas prices and weaker electricity prices was an average spark spread of $10.08 per megawatt hour for the three months ended September 30, 2004, compared to $22.05 per megawatt hour for the corresponding period in 2003.

  Spark spread is related to the difference between AESO electricity prices and the marginal cost of producing electricity from natural gas.

  Changes in spark spread affect the results of operation of approximately 320 megawatts of plant capacity owned in Alberta by ATCO Power out of a total owned capacity of approximately 1,320 megawatts.

Earnings for the nine months ended September 30, 2004, decreased by $1.2 million to $55.9 million, primarily due to:

- decrease in ATCO Power's earnings of $7.7 million due to lower prices on electricity sold to the AESO and the related spark spread.

  AESO electricity prices for the nine months ended September 30, 2004, averaged $54.43 per megawatt hour, compared to average prices of $65.75 per megawatt hour for the corresponding period in 2003. Natural gas prices for the nine months ended September 30, 2004, averaged $6.20 per gigajoule, compared to average prices of $6.58 per gigajoule for the corresponding period in 2003. The consequence of relatively weaker natural gas prices and electricity prices was an average spark spread of $7.93 per megawatt hour for the nine months ended September 30, 2004, compared to $16.36 per megawatt hour for the corresponding period in 2003.

- lower earnings from the transmission must run ("TMR") contracts that were not renewed in May 2004 at the Rainbow Lake IV and V generating plants. The TMR service is currently being conscripted by the AESO under AEUB regulated terms and conditions. The interpretation of the terms and conditions and the longer term procurement of TMR services by the AESO is under review by the AEUB; and
- lower cost of service revenues in Alberta Power (2000) from the H.R. Milner generating plant which was sold by the Alberta Balancing Pool on January 29, 2004.

This decrease was partially offset by:

- improved earnings in ATCO Power's U.K. operations; and
- operations at the new 170 megawatt Scotford generating plant commissioned in December 2003 and at the new 580 megawatt Brighton Beach generating plant commissioned in July 2004.

During the three months ended September 30, 2004, the deferred availability incentive account increased by $15.8 million to $38.0 million. The increase was primarily due to the receipt of $10.4 million from the Battle River arbitration decision (refer to Business Risks – Alberta Power (2000) section) and additional availability incentive payments received for improved plant availability. During the three months ended September 30, 2004, the amortization of deferred availability incentives, recorded in revenues, increased by $0.3 million to $2.0 million.

During the nine months ended September 30, 2004, the deferred availability incentive account decreased by $5.3 million to $38.0 million. The decrease was primarily due to planned outages at the Sheerness generating plant, partially offset by $10.4 million from the Battle River arbitration decision (refer to Business Risks-Alberta Power (2000) section). During the nine months ended September 30, 2004, the amortization of deferred availability incentives recorded in revenues was $5.6 million.

On November 19, 2002, an administration order was issued by a United Kingdom court for TXU Europe, which had a long term offtake agreement for 27.5% of the power produced by the Barking power plant, a 1,000 megawatt plant in London, England, in which the Corporation, through Barking Power Limited, has a 25.5% equity interest. Barking Power Limited has filed a claim with the Administrator and is working with the Administrator and Creditors' Committees on liquidation of TXU Europe and settlement of claims. The Barking power plant will continue to supply 725 megawatts of power under long term contracts. The 275 megawatts of power previously supplied to TXU Europe is being sold into the U.K. electricity market on a merchant basis under a one year marketing agreement.

A partnership formed by ATCO Power, ATCO Resources and Ontario Power Generation owns and operates the Brighton Beach power plant, a 580 megawatt natural gas-fired combined cycle generating plant in Windsor, Ontario. Commercial operation of the plant commenced in July 2004.

ATCO Power and SaskPower International Inc. announced in September 2004 that they will not proceed with their joint venture to build 150 megawatts of wind generation in Saskatchewan.

Global Enterprises

Revenues from the Global Enterprises Business Group for the three months ended September 30, 2004, decreased by $8.5 million to $230.6 million, primarily due to:

- lower volumes of natural gas purchased in ATCO Midstream for ATCO Gas as a result of the Transfer of the Retail Energy Supply Businesses; and
- expiry in September 2003 of ATCO Frontec's Balkans contract.

This decrease was partially offset by:

- higher natural gas volumes purchased and resold for natural gas liquids extraction and higher prices received for natural gas liquids in ATCO Midstream;
- increased activity at ATCO Frontec's Voisey's Bay project; and
- increased business activity and the commencement of work for new customers by ATCO I-Tek.

Revenues for the nine months ended September 30, 2004, decreased by $118.0 million to $784.4 million, primarily due to:

- lower volumes of natural gas purchased in ATCO Midstream for ATCO Gas as a result of the Transfer of the Retail Energy Supply Businesses; and
- expiry in September 2003 of ATCO Frontec's Balkans contract.

This decrease was partially offset by:

- higher natural gas volumes purchased and resold for natural gas liquids extraction and higher prices received for natural gas liquids in ATCO Midstream;
- increased activity at ATCO Frontec's Voisey's Bay project; and
- increased business activity and the commencement of work for new customers by ATCO I-Tek.

Earnings for the three months ended September 30, 2004, increased by $2.2 million to $18.6 million, primarily due to:

- higher margins in ATCO Midstream's natural gas liquids operations; and

- increased business activity and the commencement of work for new customers by ATCO I-Tek.

This increase was partially offset by:
- the expiry of ATCO Frontec's Balkans contract.

Earnings for the nine months ended September 30, 2004, decreased by $0.4 million to $41.3 million, primarily due to:
- the expiry of ATCO Frontec's Balkans contract.

This decrease was partially offset by:
- higher margins in ATCO Midstream's natural gas liquids operations;
- increased activity at ATCO Frontec's Voisey's Bay project; and
- increased business activity and the commencement of work for new customers by ATCO I-Tek.

Corporate and Other

Earnings for the three months ended September 30, 2004, increased by $0.1 million to $(3.6) million, essentially unchanged.

Earnings for the nine months ended September 30, 2004, decreased by $1.2 million to $(11.2) million, primarily due to:
- increased dividends on equity preferred shares, net of investment income, due to the issue in April 2003 of the Series X Preferred Shares.

This decrease was partially offset by:
- 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, 2003.

ATCOR Resources Ltd. Tax Reassessment

In 2001, the Corporation received and paid an income tax reassessment of $12.9 million relating to the 1996 disposal of ATCOR Resources Ltd. The Corporation did not agree with this reassessment and contested the matter with tax authorities. Accordingly, the payment was recorded as a reduction of future income tax liabilities.

During 2003, the Corporation was successful in appealing the reassessment to the Tax Court of Canada. The Federal Government appealed the Tax Court's decision to the Federal Court of Appeal, which issued a decision on June 18, 2004, in favor of the Corporation. The Federal Government did not appeal the Federal Court of Appeal's decision with the Supreme Court of Canada. Accordingly, the Corporation has reversed the future income tax reduction of $12.9 million and reduced income taxes payable pending receipt of the refund.

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.

In December 2003, the AEUB issued a decision approving the implementation of the "One Bill Model" no later than April 1, 2004. The One Bill Model is designed to ensure that customers who choose to purchase their natural gas requirements from a retailer will receive only one bill for natural gas service. Previously, customers would receive a bill from the retailer for the purchase of the commodity and a separate bill from ATCO Gas for the delivery service. ATCO Gas has now completed implementation of this process.

In July 2004, the AEUB issued its generic cost of capital decision. The decision established a standardized approach for each utility company regulated by the AEUB for determining the rate of return on common equity based upon a return of 9.60% on common equity. This rate of return will be adjusted annually by 75% of the change in long term Canada bond yield as forecast in the November Consensus Forecast, adjusted for the average difference between the

10 year and 30 year Canada bond yields for the month of October as reported in the National Post. This adjustment mechanism is the same as the National Energy Board uses in determining its formula based rate of return. The AEUB will undertake a review of this mechanism for the year 2009 or if the rate of return resulting from the formula is less than 7.6% or greater than 11.6%. The AEUB also noted that any party, at any time, could petition for a review of the adjustment formula if that party can demonstrate a material change in facts or circumstances.

The decision also established the appropriate capital structure for each utility regulated by the AEUB. The AEUB determined that any proposed changes to the approved capital structure which result from a material change in the investment risk of a utility will be addressed at utility specific rate applications.

ATCO Electric

For 2002, ATCO Electric's rate of return on common equity was 10.5% and the common equity ratio was 37% for transmission operations and 43% for distribution operations. 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. These reductions in the common equity ratios reduced the common equity that ATCO Electric is allowed to earn a return on by $83.0 million for 2003. ATCO Electric, as directed by the AEUB, refiled the 2003 and 2004 revenue requirements, incorporating the findings in the decision. In a decision dated February 17, 2004, the AEUB issued its final determination of the revenue requirements for the 2003 and 2004 test years, accepting the refiling with no material changes. Certain matters relating to transactions with affiliates will be addressed in separate proceedings. In a decision dated July 2, 2004, the AEUB issued its generic cost of capital decision which approved, among other things, a return on common equity of 9.60% for 2004 and a common equity ratio of 33% for ATCO Electric's transmission operations and 37% for its distribution operations beginning in 2004. These increases in the common equity ratios increased the common equity that ATCO Electric is allowed to earn a return on by $22.3 million for 2004.

In March 2004, ATCO Electric filed an application to settle several deferral account balances and to revise the 2004 interim distribution tariff to incorporate the AEUB decision regarding the revenue requirements for the 2003 and 2004 test years. In the application, ATCO Electric requested that an interim net refund rider be implemented for the period May 1, 2004, to December 31, 2004, to refund a total of approximately $43 million to customers. On April 22, 2004, the AEUB approved this application as filed. This refund has no impact on earnings. ATCO Electric submitted a Phase II application to finalize the interim distribution tariff on May 21, 2004. The hearing is scheduled to commence on November 9, 2004.

ATCO Gas

In December 2002, the AEUB issued a decision approving rates for ATCO Gas on an interim basis effective January 1, 2003. In a decision dated October 1, 2003, the AEUB approved for ATCO Gas, among other things, a rate of return on common equity of 9.50% for 2003 and 2004 and a common equity ratio of 37% for 2003 and 2004. ATCO Gas, as directed by the AEUB, refiled the 2003 and 2004 general rate application, incorporating the findings in the decision. In a decision dated June 15, 2004, the AEUB issued its final determination of the revenue requirements for the 2003 and 2004 test years, accepting the refiling with no material changes. Certain matters relating to transactions with affiliates will be addressed in separate proceedings. In a decision dated July 2, 2004, the AEUB issued its generic cost of capital decision which approved, among other things, ATCO Gas' common equity ratio of 38% beginning in 2005. As ATCO Gas' return on common equity for 2004 was already established, the standardized approach approved by the AEUB for determining the return on common equity (as described above) will be applied beginning in 2005.

In October 2001, the AEUB approved the sale by ATCO Gas of certain properties located in the City of Calgary, known as the Calgary Stores Block, for $6.6 million (excluding costs of disposition) and subsequently issued a decision allocating $4.1 million of the proceeds to customers, and $1.8 million to ATCO Gas. Leave to appeal this decision was granted on July 12, 2002. On January 27, 2004, the Alberta Court of Appeal issued a decision which overturned the AEUB decision and directed the AEUB to allocate $5.4 million of the proceeds to ATCO Gas. Subsequent to the receipt of this decision, the AEUB and the City of Calgary filed for leave to appeal the Alberta Court of Appeal decision to the Supreme Court of Canada. On October 7, 2004, the Supreme Court of Canada announced that the leave to appeal brought by the City of Calgary was granted with costs to the City of Calgary in any event of the cause. The application of ATCO Gas for leave to cross-appeal the Alberta Court of Appeal decision was also granted. In addition, the Supreme Court of Canada announced that the AEUB may participate as an intervenor and present arguments limited to the issue of its jurisdiction. Should the AEUB wish to pursue its application for leave to appeal, it will advise the Registrar accordingly within 10 days and an oral hearing will be ordered to address the question of the AEUB's standing to bring an application for leave to appeal. In the event the AEUB does not so advise, its leave application will be dismissed with no order as to costs. Accordingly, ATCO Gas has not yet recorded the impact of the Alberta Court of Appeal decision.

In March 2004, the AEUB issued a decision respecting the operation of ATCO Gas' Carbon storage facility for the 2004/2005 storage year. The decision, among other things, directed ATCO Gas to reserve 16.7 petajoules of storage capacity for utility customers and allowed ATCO Midstream to continue to utilize the remaining uncontracted capacity at a rate of $0.45 per gigajoule, up from $0.41 per gigajoule. On March 31, 2004, ATCO Gas filed for leave to appeal this decision to the Alberta Court of Appeal. A hearing to address the leave to appeal was held on September 14, 2004 with a decision from the Alberta Court of Appeal to follow. In July 2004, the AEUB initiated a written process, commencing August 16, 2004, to consider its role in regulating the operations of the Carbon storage facility.

ATCO Gas has filed an application with the AEUB to address, among other things, corrections required to historical transportation imbalances that have impacted ATCO Gas' deferred gas account. The application requests a recovery of approximately $11.3 million from ATCO Gas' south customers, and a refund of approximately $2.0 million to ATCO Gas' north customers. A decision from the AEUB is expected in 2004 or in the first quarter of 2005.

ATCO Pipelines

In a decision dated December 2, 2003, the AEUB approved for ATCO Pipelines, among other things, a rate of return on common equity of 9.50% and a common equity ratio of 43.5% for 2003. ATCO Pipelines, as directed by the AEUB, refiled the 2003 and 2004 general rate application, incorporating the findings in the decision. In a decision dated March 9, 2004, the AEUB approved interim rates to be effective from March 1, 2004 to October 31, 2004. In a decision dated April 30, 2004, the AEUB accepted the refiling of the revenue requirements for the 2003 and 2004 test years with no material changes. In a decision dated July 13, 2004, the AEUB awarded additional revenue with respect to the revenue forecasts of certain industrial customers. Certain matters relating to transactions with affiliates will be addressed in separate proceedings. In a decision dated July 2, 2004, the AEUB issued its generic cost of capital decision which approved, among other things, ATCO Pipelines' return on common equity of 9.60% for 2004 and a common equity ratio of 43% beginning in 2004.

In October 2003, ATCO Pipelines filed a 2004 Phase II general rate application for new rates. In a decision dated September 24, 2004, the AEUB substantially accepted ATCO Pipelines' rate design proposals. However, the AEUB deferred competitive issues between ATCO Pipelines and NOVA Gas Transmission Ltd. to a competitive proceeding to be held in 2005. In the decision, the AEUB confirmed that it intends to canvass interested parties, likely in the fall of 2004, to assist in developing the scope of the competitive proceeding.

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 and non-recourse 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.

Cash flow from operations for the three months ended September 30, 2004, increased by $23.9 million to $128.4 million, primarily due to:

- increased availability incentives in Alberta Power (2000), primarily due to recovery of $10.4 million of availability incentive payments (refer to Business Risks – Alberta Power (2000) section) and availability incentive payments received for improved plant availability.

Cash flow from operations for the nine months ended September 30, 2004, increased by $1.4 million to $373.9 million, primarily due to:

- increased cash flow from operations before non-cash adjustments.

This increase was partially offset by:

- payments made by Alberta Power (2000) with respect to availability incentive payments due to planned plant outages, partially offset by the recovery of $10.4 million of availability incentive payments (refer to Business Risks – Alberta Power (2000) section).

Investing for the three months ended September 30, 2004, increased by $6.8 million to $122.6 million, primarily due to:

- changes in non-cash working capital.

This increase was partially offset by:

- lower capital expenditures.

Capital expenditures for the three months ended September 30, 2004, decreased by $11.5 million to $122.8 million, primarily due to:

- lower investment in non-regulated and regulated power generation projects.

This decrease was partially offset by:

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

Investing for the nine months ended September 30, 2004, increased by $35.1 million to $344.1 million, primarily due to:

- higher capital expenditures.

This increase was partially offset by:

- changes in non-cash working capital; and
- proceeds from the Transfer of the Retail Energy Supply Businesses.

Capital expenditures for the nine months ended September 30, 2004, increased by $67.4 million to $386.4 million, primarily due to:

- increased investment in regulated electric transmission projects.

This increase was partially offset by:

- lower investment in non-regulated power generation projects.

During the three months ended September 30, 2004, the Corporation **issued**:

- $96.0 million of notes payable.

During the three months ended September 30, 2004, the Corporation **redeemed**:

- $27.0 million of long term debt; and
- $17.3 million of non-recourse long term debt.

These changes resulted in a **net debt increase** of $51.7 million.

During the nine months ended September 30, 2004, the Corporation **issued**:

- $96.0 million of notes payable;
- $180.0 million of 5.432% Debentures due January 23, 2019;
- $59.8 million of other long term debt; and
- $10.0 million of non-recourse long term debt.

During the nine months ended September 30, 2004, the Corporation **redeemed**:

- $100.0 million of 8.73% Debentures 1994 Series due June 1, 2004;
- $31.8 million of other long term debt; and
- $40.4 million of non-recourse long term debt.

These changes resulted in a **net debt increase** of $173.6 million.

Contractual obligations for the next five years have been updated from disclosure provided in the 2003 MD&A. As at September 30, 2004, contractual obligations have been reduced by approximately $1 billion from the amounts disclosed at December 31, 2003. This decrease is primarily due to reduced ATCO Gas natural gas purchase contracts deriving from the Transfer of the Retail Energy Supply Businesses (refer to Transfer of the Retail Energy Supply Businesses and Business Risks – Transfer of Retail Energy Supply Businesses sections). There will be no impact on future earnings resulting from this reduction in contractual obligations as natural gas has historically been sold to customers on a "no-margin" basis.

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

	Payments Due by Period				
Contractual Obligations	**Total**	**Less than 1 Year**	**1-3 Years**	**4-5 Years**	**After 5 Years**
			($ Millions) *(unaudited)*		
Long term debt	1,912.9	136.4	221.5	150.0	1,405.0
Non-recourse long term debt	818.4	47.7	123.0	153.7	494.0
Operating leases	69.6	12.8	23.2	20.2	13.4
Purchase obligations:					
ATCO Gas natural gas purchase contracts (1)	19.6	14.6	1.2	1.2	2.6
Alberta Power (2000) coal purchase contracts (2)	872.5	43.1	89.7	95.1	644.6
Alberta Power (2000) capital expenditures (3)	9.1	9.1	-	-	-
ATCO Power natural gas fuel supply contracts (4)	368.7	48.9	105.2	104.8	109.8
ATCO Power operating and maintenance agreements (5)	254.5	18.3	34.4	34.1	167.7
ATCO Power capital expenditures (6)	5.8	5.8	-	-	-
Other	23.3	22.8	0.5	-	-
Total	4,354.4	359.5	598.7	559.1	2,837.1

Notes:

(1) ATCO Gas has ongoing obligations to purchase fixed quantities of natural gas from various gas producers at market prices that are in effect at the time the quantities are purchased. These obligations relate mostly to storage purchases and operational contracts pertaining to the Carbon storage facility, which was not included in the Transfer of the Retail Energy Supply Businesses to DEML and continues to be subject to AEUB regulation. Some of these obligations are for the life of the gas reserves. The estimated value of these purchase obligations is based on the market price of natural gas in effect on September 30, 2004, and assumes a remaining life of 10 years for the gas reserves commencing January 1, 2004. The cost of natural gas purchased under these obligations is recoverable from ATCO Gas' customers.

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

(3) Alberta Power (2000) has entered into contracts with suppliers to improve operating efficiency at certain of its generating plants.

(4) ATCO Power has various contracts to purchase natural gas for its natural gas-fired generating plants. ATCO Power has long term offtake agreements with the purchasers of the electricity to recover 82% of these costs. The balance of 18%, related to ATCO Power's Barking generating plant, is currently being recovered through merchant sales in the U.K. electricity market.

(5) ATCO Power has various contracts with suppliers to provide operating and maintenance services at certain of its generating plants.

(6) ATCO Power has entered into various contracts to purchase goods and services with respect to its capital expenditure programs.

At September 30, 2004, the Corporation had the following **credit lines** that enable it to obtain funding for general corporate purposes.

	Total	**Used**	**Available**
		($ Millions) *(unaudited)*	
Long term committed	326.0	50.1	275.9
Short term committed	613.7	6.9	606.8
Uncommitted	69.1	5.4	63.7
Total	1,008.8	62.4	946.4

In the third quarter of 2004, following a review of ongoing cash requirements, the Corporation reduced its long term committed lines by $25.0 million, its short term committed lines by $9.6 million and its uncommitted lines by $108.4 million. These reductions were due primarily to reduced credit needs in CU Inc. following the Transfer of the Retail Energy Supply Businesses earlier in the year.

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 taxes of $236.3 million at September 30, 2004, 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, 2003, 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, 2004. Over the life of the bid, 73,600 shares were purchased, of which 17,000 shares were purchased in 2004. On May 20, 2004, the Corporation commenced a normal course issuer bid, pursuant to which the Corporation anticipates that it will purchase up to 3% of the outstanding Class A shares. The bid will expire on May 19, 2005. From May 20, 2004, to October 27, 2004, 99,400 shares have been purchased.

For the first three quarters of 2004, the **quarterly dividend** payment on the Corporation's Class A shares and Class B shares increased by $0.02 to $0.53 per share. The Corporation has increased its annual common share dividend each year since its inception as a holding company in 1972. The payment of any dividend is at the discretion of the Board of Directors and depends on the financial condition of the Corporation and other factors.

OUTSTANDING SHARE DATA

At October 27, 2004, the Corporation had outstanding 41,182,743 Class A shares and 22,179,192 Class B shares.

BUSINESS RISKS

Transfer of the Retail Energy Supply Businesses

Although ATCO Gas and ATCO Electric have transferred to DEML certain retail functions, including the supply of natural gas and electricity to customers and billing and customer care functions, ATCO Gas and ATCO Electric remain legally obligated to perform these functions if DEML fails to perform. If DEML fails to perform all or part of the transferred functions, ATCO Gas and ATCO Electric will be required under existing legislation to perform such functions in the interim until DEML is able to perform such functions. 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 purchase price to DEML by ATCO Gas and/or ATCO Electric. In certain circumstances, if DEML is restrained or prohibited from carrying out the transferred functions, all functions will revert to ATCO Gas and ATCO Electric and a portion of the purchase price will be refunded to DEML, depending upon the timing of any such reversion. In the event of a reversion of such functions, ATCO Gas and ATCO Electric could incur costs related to commodity procurement, transportation and delivery charges and various regulatory costs.

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 in respect of the ongoing relationships contemplated under the transaction agreements.

As a result of the agreements with DEML, ATCO Gas and ATCO Electric are no longer involved in arranging for the supply and sale of natural gas and electricity to customers, but will continue to own the assets and provide transportation and distribution services under AEUB approved rates that provide for a recovery of costs of service and fair return.

In December 2003, the AEUB issued a decision approving the transfer of the retail operations of ATCO Gas and ATCO Electric to DEML. The City of Calgary filed for leave to appeal the AEUB decision, including the allocation of proceeds to ATCO Gas and ATCO Electric. On June 30, 2004, the Alberta Court of Appeal dismissed the City of Calgary's application for leave to appeal.

Late Payment Penalties on Utility Bills

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

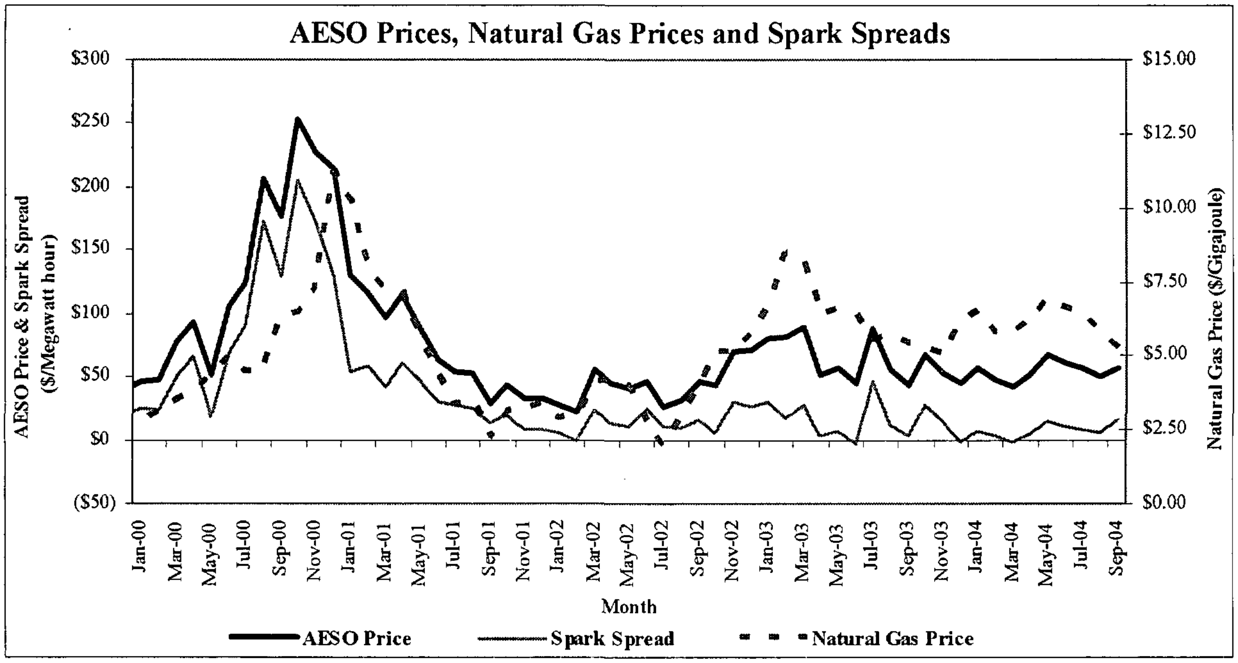
Alberta Power (2000)

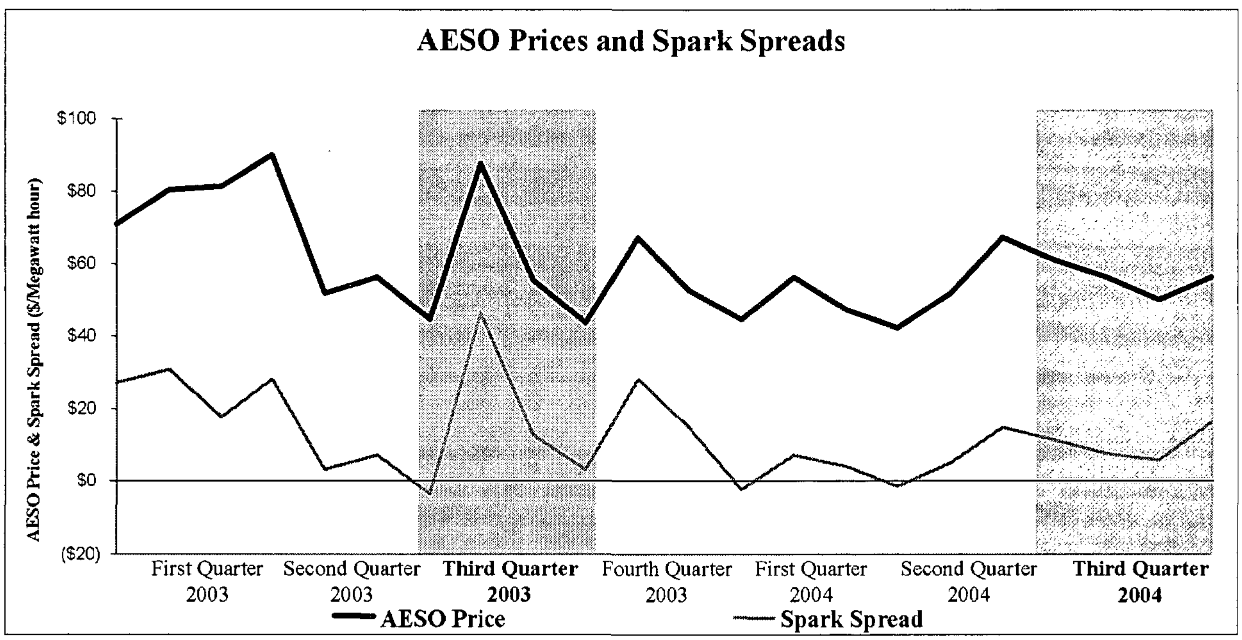
As a result of unprecedented drought conditions, the water level in the cooling pond used by the Battle River generating plant in its production of electricity had fallen to an all-time low in early 2003, and the Corporation made a force majeure claim in respect of short term curtailed plant production which was experienced during the first quarter of 2003. On August 11, 2004, an arbitration tribunal appointed under the Battle River Power Purchase Arrangement ("Battle River PPA") determined that Alberta Power (2000) is entitled to recovery of $10.4 million of availability incentive payments, plus interest, from EPCOR Utilities Inc. ("EPCOR"), the counterparty to the Battle River PPA. The decision of the arbitration tribunal is final and binding. This decision will not impact Alberta Power (2000)'s 2004 earnings. The $10.4 million of availability incentive payments plus interest, less costs associated with the arbitration proceedings, has been recorded in Alberta Power (2000)'s deferred availability incentive balance sheet account.

To date in 2004, the Battle River generating plant's water levels are below those of 2003 which has required the Corporation to limit generation to avoid exceeding the environmental license temperature limitations. The Corporation has made force majeure claims for the period June 24, 2004, to July 4, 2004, and the period July 13, 2004 to July 26, 2004. The outcome of the 2004 force majeure claims is not known at this time.

ATCO Power

AESO electricity prices, natural gas prices and related spark spreads can be very volatile, as shown in the following graphs, which illustrate a range of prices experienced during the periods January 2000 to September 2004, and from January 2003 to September 2004.





Changes in AESO 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.

Insurance Coverage

On October 14, 2004, the Attorney General of the State of New York filed suit against Marsh & McLennan. Certain insurance companies were also named in the suit, including American International Group and Ace Ltd. These insurers provide a portion of the Corporation's insurance coverage. The Corporation is unable at this time to determine what impact, if any, the suit may have on the ability of the insurers mentioned to pay any corporate insurance claims which may arise.

CRITICAL ACCOUNTING ESTIMATES

Employee Future Benefits

The expected long term rate of return on plan assets is determined at the beginning of the year on the basis of the long bond yield rate at the beginning of the year 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%, which, when added to the long bond yield rate of 6.25% at the beginning of 2004, resulted in an expected long term rate of return of 7.25% for 2004. 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.

The liability discount rate reflects market interest rates on high quality corporate bonds that match the timing and amount of expected benefit payments. The liability discount rate used to calculate the cost of benefit obligations for the three and nine months ended September 30, 2004, was 6.25%, the same rate that was used at the end of 2003.

The expected long term rate of return has declined over the past three years, from 8.1% in 2001 to 7.25% in the nine months ended September 30, 2004. The result has been a decrease in the expected return on plan assets. The difference between the expected return and the actual return on plan assets results in an experience gain or loss on plan assets. The liability discount rate has also declined over the same period, from 6.9% at the end of 2001 to 6.25% at September 30, 2004. The effect of this change has been to increase the accrued benefit obligations, resulting in experience losses in 2002 and 2003. 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 cumulative experience losses in 2003 for both pension benefit plans and other post employment benefit plans and continued this amortization during the three and nine months ended September 30, 2004.

The assumed annual health care cost trend rate increases used in measuring the accumulated post employment benefit obligations in the three and nine months ended September 30, 2004, are as follows: for drug costs, 9.9% starting in 2004 grading down over 9 years to 4.5%, and for other medical and dental costs, 4.0% for 2004 and thereafter. Combined with higher claims experience, the effect of these changes has been to increase 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, 2004, the Corporation retroactively adopted the Canadian Institute of Chartered Accountants ("CICA") recommendations on accounting for asset retirement obligations as described below. The prior year's financial statements have been restated for the change in the method of accounting for asset retirement obligations.

The CICA recommendations on accounting for asset retirement obligations require the Corporation to identify legal obligations associated with the retirement of tangible long lived assets. To the extent that they can be quantified, these obligations are measured and recognized at fair value, which is determined using present value techniques. An asset retirement obligation is recorded as a liability, with a corresponding increase to property, plant and equipment. The liability is accreted over the estimated time period until settlement of the obligation, with the accretion expense included in depreciation and amortization. The asset is depreciated over its estimated useful life. Prior to January 1, 2004, site restoration and removal costs that are now accounted for as asset retirement obligations were accrued over the estimated remaining useful lives of the assets.

Asset retirement obligations for regulated natural gas and electric transmission and distribution assets were not recognized as the Corporation expects to use the assets in service for an indefinite period. As such, no final removal date can be determined and, consequently, a reasonable estimate of the related retirement obligations cannot be made at this time. Asset retirement obligations have been recorded for the regulated generating plants of Alberta Power (2000) and other generating plants and natural gas liquids extraction and processing plants.

The effect of adopting these recommendations is presented as increases (decreases) below:

	For the Three Months Ended September 30		For the Nine Months Ended September 30	
	2004	2003	**2004**	2003
	($ Millions) *(unaudited)*			
Statement of earnings				
Site restoration and removal costs, included in operation and maintenance	**-**	(0.1)	**-**	(0.2)
Depreciation and amortization	**(0.2)**	(0.2)	**(0.6)**	(1.2)
Accretion expense, included in depreciation and amortization	**0.4**	0.5	**1.4**	1.4
Income taxes	**-**	-	**(0.1)**	(0.1)
Earnings attributable to Class A and Class B shares	**(0.2)**	(0.2)	**(0.7)**	0.1

	January 1 2003
	($ Millions) *(unaudited)*
Balance sheet	
Retirement assets and site restoration and removal costs, included in property, plant and equipment	24.2
Asset retirement obligations, included in deferred credits	30.1
Accrual for future removal and site restoration costs, included in deferred credits	(3.3)
Future income tax liabilities	0.5
Retained earnings at beginning of period	(3.1)

Changes in asset retirement obligations are summarized below:

	For the Three Months Ended September 30		For the Nine Months Ended September 30	
	2004	2003	**2004**	2003
	($ Millions) *(unaudited)*			
Obligations at beginning of period	**33.3**	31.0	**32.3**	30.1
Obligations incurred	**0.5**	-	**0.5**	-
Accretion expense	**0.4**	0.5	**1.4**	1.4
Obligations at end of period	**34.2**	31.5	**34.2**	31.5

The Corporation estimates the undiscounted amount of cash flow required to settle the asset retirement obligations is approximately $93 million, which will be incurred between 2005 and 2052. A weighted average discount rate of 5.9% was used to calculate the fair value of the asset retirement obligations.

Effective January 1, 2004, the Corporation prospectively adopted the CICA recommendations on accounting for asset impairment. These recommendations require an impairment of property, plant and equipment, intangible assets with finite lives, deferred operating costs and long term prepaid expenses to be recognized in earnings when the asset's carrying value exceeds the total cash flows expected from its use and eventual disposition. The impairment loss is then calculated as the difference between the asset's carrying value and its fair value, which is determined using present value techniques. This change in accounting had no effect on earnings or earnings per share for the three and nine months ended September 30, 2004.

Effective January 1, 2004, the Corporation retroactively adopted the CICA recommendations on accounting for stock based compensation. These recommendations require the expensing of stock options granted on and after January 1, 2002. The Corporation determines the fair value of the options on the date of grant using an option pricing model and recognizes the fair value over the vesting period of the options granted as compensation expense and contributed surplus. Contributed surplus is reduced as the options are exercised and the amount initially recorded in contributed surplus is credited to Class A and Class B share capital. No compensation expense is recorded for stock options granted prior to January 1, 2002, as permitted by the recommendations. This retroactive change in accounting had no effect on earnings for the three months ended September 30, 2004, and reduced earnings for the nine months ended September 30, 2004, by $0.1 million with no effect on earnings per share in either period, had no effect on earnings for the three months ended September 30, 2003, and reduced earnings for the nine months ended September 30, 2003, by $0.1 million with no effect on earnings per share in either period and resulted in a charge of $0.1 million to retained earnings at January 1, 2003. The prior year's financial statements have been restated for the change in the method of accounting for stock options.

Effective January 1, 2004, the Corporation prospectively adopted the CICA recommendations that define the primary sources of GAAP. While the recommendations encourage the application of the primary sources of GAAP to all operations, the recommendations do not require that assets and liabilities arising from rate regulation be recognized and measured in accordance with the primary sources of GAAP. The Corporation has chosen to retain its existing accounting policies for its regulated operations, which are permitted by GAAP.

October 27, 2004

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

	Note	Three Months Ended September 30 2004	Three Months Ended September 30 2003 (Restated, Notes 1, 6)	Nine Months Ended September 30 2004	Nine Months Ended September 30 2003 (Restated, Notes 1, 6)
		(Unaudited)		*(Unaudited)*	
Revenues		$ **550.8**	$ 622.6	**$2,426.9**	$2,792.3
Costs and expenses					
Natural gas supply	1	**73.5**	135.5	**860.6**	1,151.2
Purchased power		**8.8**	45.3	**80.4**	163.0
Operation and maintenance		**220.5**	200.6	**637.1**	642.1
Selling and administrative		**37.5**	37.0	**114.7**	105.5
Depreciation and amortization		**66.1**	62.4	**210.3**	196.4
Interest		**36.8**	37.5	**114.7**	113.5
Interest on non-recourse long term debt		**13.5**	10.2	**36.1**	29.7
Franchise fees		**18.9**	15.6	**95.9**	92.1
		475.6	544.1	**2,149.8**	2,493.5
		75.2	78.5	**277.1**	298.8
Gain on transfer of retail energy supply businesses	3	**-**	-	**63.3**	-
Interest and other income		**7.4**	8.7	**20.4**	23.9
Earnings before income taxes		**82.6**	87.2	**360.8**	322.7
Income taxes		**29.6**	35.0	**115.2**	125.9
		53.0	52.2	**245.6**	196.8
Dividends on equity preferred shares		**9.0**	9.0	**26.9**	24.2
Earnings attributable to Class A and Class B shares	3	**44.0**	43.2	**218.7**	172.6
Retained earnings at beginning of period as restated	4	**1,540.0**	1,372.2	**1,435.4**	1,311.7
		1,584.0	1,415.4	**1,654.1**	1,484.3
Dividends on Class A and Class B shares		**33.6**	32.3	**100.8**	97.0
Direct charges	5	**2.1**	1.0	**5.0**	5.2
Retained earnings at end of period		**$1,548.3**	$1,382.1	**$1,548.3**	$1,382.1
Earnings per Class A and Class B share	7	$ **0.70**	$ 0.68	$ **3.45**	$ 2.72
Diluted earnings per Class A and Class B share	7	$ **0.70**	$ 0.68	$ **3.44**	$ 2.71
Dividends paid per Class A and Class B share		$ **0.53**	$ 0.51	$ **1.59**	$ 1.53

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

	Note	September 30 2004	September 30 2003	December 31 2003
			(Restated, Notes 1, 6)	(Restated, Notes 1, 6)
		(Unaudited)	*(Unaudited)*	*(Audited)*
ASSETS				
Current assets				
Cash and short term investments		**$ 559.5**	$ 517.2	$ 328.1
Accounts receivable		**336.9**	346.0	540.6
Inventories		**162.2**	167.7	171.3
Income taxes recoverable		**-**	-	10.2
Deferred natural gas costs		**-**	-	27.2
Deferred electricity costs		**-**	2.9	-
Prepaid expenses		**33.3**	37.2	25.6
		1,091.9	1,071.0	1,103.0
Property, plant and equipment		**4,974.1**	4,738.5	4,835.4
Security deposits for debt		**22.9**	22.4	23.1
Other assets		**120.8**	129.3	135.0
		$6,209.7	$5,961.2	$6,096.5
LIABILITIES AND SHARE OWNERS' EQUITY				
Current liabilities				
Accounts payable and accrued liabilities		**$ 284.7**	$ 326.2	$ 478.8
Income taxes payable		**4.1**	5.2	-
Future income taxes		**12.8**	3.4	11.5
Deferred natural gas cost recoveries		**0.2**	1.2	-
Deferred electricity cost recoveries		**25.2**	-	1.0
Notes payable		**96.0**	42.0	-
Long term debt due within one year		**6.9**	-	-
Non-recourse long term debt due within one year		**47.7**	41.0	46.3
		477.6	419.0	537.6
Future income taxes	12	**223.5**	229.4	227.4
Deferred credits		**135.9**	118.4	135.1
Long term debt		**1,906.0**	1,859.0	1,805.3
Non-recourse long term debt		**770.7**	808.3	806.1
Equity preferred shares		**636.5**	636.5	636.5
Class A and Class B share owners' equity				
Class A and Class B shares	7	**512.5**	509.5	510.5
Contributed surplus	1	**0.4**	0.2	0.3
Retained earnings		**1,548.3**	1,382.1	1,435.4
Foreign currency translation adjustment		**(1.7)**	(1.2)	2.3
		2,059.5	1,890.6	1,948.5
		$6,209.7	$5,961.2	$6,096.5

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

	Note	Three Months Ended September 30		Nine Months Ended September 30	
		2004	2003 (Restated, Notes 1, 6)	**2004**	2003 (Restated, Notes 1, 6)
		(Unaudited)		*(Unaudited)*	
Operating activities					
Earnings attributable to Class A and Class B shares		**$ 44.0**	$ 43.2	**$ 218.7**	$ 172.6
Adjustments for:					
Depreciation and amortization		**66.1**	62.4	**210.3**	196.4
Future income taxes		**(0.6)**	2.0	**(2.5)**	5.9
Gain on transfer of retail energy supply businesses - net of income taxes	3	**-**	-	**(55.1)**	-
Deferred availability incentives		**15.8**	(2.8)	**(5.3)**	(0.2)
Other		**3.1**	(0.3)	**7.8**	(2.2)
Cash flow from operations		**128.4**	104.5	**373.9**	372.5
Changes in non-cash working capital		**(46.3)**	37.1	**133.3**	30.0
		82.1	141.6	**507.2**	402.5
Investing activities					
Purchase of property, plant and equipment		**(122.8)**	(134.3)	**(386.4)**	(319.0)
Proceeds on transfer of retail energy supply businesses - net of income taxes	3	**-**	-	**22.5**	-
Proceeds (costs) on disposal of property, plant and equipment		**(3.5)**	2.4	**(1.9)**	12.5
Contributions by utility customers for extensions to plant		**11.2**	10.6	**40.6**	34.3
Non-current deferred electricity costs		**2.0**	3.9	**(9.9)**	8.8
Changes in non-cash working capital		**(9.3)**	1.6	**(4.9)**	(45.3)
Other		**(0.2)**	-	**(4.1)**	(0.3)
		(122.6)	(115.8)	**(344.1)**	(309.0)
Financing activities					
Change in notes payable		**96.0**	42.0	**96.0**	42.0
Deferred electricity cost obligation		**-**	(15.9)	**-**	(51.0)
Issue of long term debt		**-**	8.0	**239.8**	13.5
Issue of non-recourse long term debt		**-**	-	**10.0**	40.7
Repayment of long term debt		**(27.0)**	(63.5)	**(131.8)**	(72.3)
Repayment of non-recourse long term debt		**(17.3)**	(15.3)	**(40.4)**	(32.5)
Issue of equity preferred shares		**-**	-	**-**	150.0
Purchase of Class A shares, net of stock option exercises		**(0.8)**	(1.0)	**(3.2)**	(2.5)
Dividends paid to Class A and Class B share owners		**(33.6)**	(32.3)	**(100.8)**	(97.0)
Changes in non-cash working capital		**(1.0)**	(0.5)	**0.1**	6.2
Other		**0.6**	2.5	**(1.0)**	(1.8)
		16.9	(76.0)	**68.7**	(4.7)
Foreign currency translation		**(2.3)**	0.9	**(0.4)**	(5.5)
Cash position (1)					
Increase (decrease)		**(25.9)**	(49.3)	**231.4**	83.3
Beginning of period		**585.4**	566.5	**328.1**	433.9
End of period		**$ 559.5**	$ 517.2	**$ 559.5**	$ 517.2

(1) Cash position consists of cash and short term investments, and includes $51.8 million (2003 - $60.4 million) which is only available for use in joint ventures.

1. Financial statement presentation

The accompanying consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and should be read in conjunction with the consolidated financial statements and related notes included in the Corporation's Financial Information contained in its 2003 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, 2003, except as described below.

Effective January 1, 2004, the Corporation retroactively adopted the Canadian Institute of Chartered Accountants ("CICA") recommendations on accounting for asset retirement obligations as described in Note 6. The prior year's financial statements have been restated for the change in the method of accounting for asset retirement obligations.

Effective January 1, 2004, the Corporation prospectively adopted the CICA recommendations on accounting for asset impairment. These recommendations require an impairment of property, plant and equipment, intangible assets with finite lives, deferred operating costs and long term prepaid expenses to be recognized in earnings when the asset's carrying value exceeds the total cash flows expected from its use and eventual disposition. The impairment loss is then calculated as the difference between the asset's carrying value and its fair value, which is determined using present value techniques. This change in accounting had no effect on earnings or earnings per share for the three and nine months ended September 30, 2004.

Effective January 1, 2004, the Corporation retroactively adopted the CICA recommendations on accounting for stock based compensation. These recommendations require the expensing of stock options granted on and after January 1, 2002. The Corporation determines the fair value of the options on the date of grant using an option pricing model and recognizes the fair value over the vesting period of the options granted as compensation expense and contributed surplus. Contributed surplus is reduced as the options are exercised and the amount initially recorded in contributed surplus is credited to Class A and Class B share capital. No compensation expense is recorded for stock options granted prior to January 1, 2002 as permitted by the recommendations. This retroactive change in accounting had no effect on earnings for the three months ended September 30, 2004 and reduced earnings for the nine months ended September 30, 2004 by $0.1 million with no effect on earnings per share in either period, had no effect on earnings for the three months ended September 30, 2003 and reduced earnings for the nine months ended September 30, 2003 by $0.1 million with no effect on earnings per share in either period, and resulted in a charge of $0.1 million to retained earnings at January 1, 2003. The prior year's financial statements have been restated for the change in the method of accounting for stock options.

Effective January 1, 2004, the Corporation prospectively adopted the CICA recommendations that define the primary sources of GAAP. While the recommendations encourage the application of the primary sources of GAAP to all operations, the recommendations do not require that assets and liabilities arising from rate regulation be recognized and measured in accordance with the primary sources of GAAP. The Corporation has chosen to retain its existing accounting policies for its regulated operations, which are permitted by GAAP, as described in Note 2.

Natural gas supply expense includes purchases of natural gas for regulated operations and other subsidiaries. Accounting policies applicable to the regulated operations are disclosed in Note 2 and the impact of the transfer of retail energy supply businesses is disclosed in Note 3. Natural gas supply expense for other subsidiaries consists of natural gas volumes purchased and resold for natural gas liquids extraction and marketing.

Due to the seasonal nature of the Corporation's operations, changes in electricity prices in Alberta and the timing of rate decisions, the consolidated statements of earnings and retained earnings for the three and nine months ended September 30, 2004 and September 30, 2003 are not necessarily indicative of operations on an annual basis.

Certain 2003 figures have been reclassified to conform to the current presentation.

2. Regulation

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., CU Water and the generating plants of Alberta Power (2000), all of which are wholly owned subsidiaries of Canadian Utilities Limited's wholly owned subsidiary, CU Inc., are collectively referred to in these consolidated financial statements as the "regulated operations".

The generating plants of Alberta Power (2000) were regulated by the Alberta Energy and Utilities Board ("AEUB") until December 31, 2000 but are now governed by legislatively mandated Power Purchase Arrangements ("PPA") that were approved by the AEUB. These plants are included in regulated operations primarily because the PPA's are designed to allow the owners of generating plants constructed before January 1, 1996 to recover their forecast fixed and variable costs and to earn a return at the rate specified in the PPA's. The plants will become deregulated upon the expiry of the PPA's. Each PPA is to remain in effect until the earlier of the last day of the life of the related generating plant and December 31, 2020.

Differences between the Corporation's accounting policies for its regulated operations and the primary sources of GAAP occur when the AEUB renders its decisions on the Corporation's rate applications and generally involve the timing of revenue and expense recognition to ensure that the Corporation has achieved proper matching of revenues and expenses. Where regulatory practice dictates, the Corporation defers certain costs or revenues as assets or liabilities in the balance sheet and records them as expenses or revenues in the earnings statement as it collects or refunds amounts through future customer rates. Any differences between the amounts deferred and amounts approved by the AEUB for collection or refund in future customer rates are recognized in earnings in the period that the AEUB renders a decision. The Corporation anticipates that there would be no material differences between the amounts approved by the AEUB for collection or refund and the amounts included in assets or liabilities on the balance sheet.

The significant accounting policies that differ from those required by the primary sources of GAAP are described as follows:

a) *Depreciation* – Depreciation rates for regulated assets are approved by the AEUB or, in the case of Alberta Power (2000)'s generating plants, are determined by the PPA's.

b) *Future removal and site restoration costs* – Depreciation rates for regulated assets, excluding Alberta Power (2000)'s generating plants, include a provision for future removal costs and site restoration costs. On retirement of these depreciable regulated assets, the accumulated depreciation is charged with the cost of the retired unit, net disposal costs and site restoration costs.

c) *Allowance for funds used during construction* – Certain regulated operations include in property, plant and equipment an allowance for funds used during construction at rates approved by the AEUB for debt and equity capital.

d) *Employee future benefits* – Costs of employee future benefits in the regulated operations, excluding Alberta Power (2000), are recognized in earnings when paid rather than accrued. The differences between the amounts accrued and paid are deferred.

Significant accounting policies that are consistent with those required by the primary sources of GAAP for items that are subject to regulatory approval include:

a) *Purchased power* – Purchased power expense for the regulated operations in the Yukon Territory and the Northwest Territories is based on the actual cost of electricity purchased. The amount included in customer rates in the Yukon Territory is based on actual costs and in the Northwest Territories is based on forecast cost. Revenues are adjusted for variances from forecast cost, and the variances are deferred until such time as approval from the regulator is obtained for refund to or collection from customers.

2. Regulation (continued)

b) *Income taxes* – The regulated operations follow the method of accounting for income taxes that is consistent with the method of determining the income tax component of their rates. When future income taxes are not provided in the income tax component of current rates, such future income taxes are not recognized to the extent that it is expected that they will be recovered from customers through inclusion in future rates.

c) Certain costs as required or permitted by the AEUB are deferred for recovery through future rates.

Significant accounting policies that pertained to the retail energy supply businesses that were transferred as of May 4, 2004 (see Note 3) and were consistent with those required by the primary sources of GAAP for items that were subject to regulatory approval included:

a) *Natural gas supply* – Natural gas supply expense was based on the forecast cost of natural gas included in customer rates. Variances from forecast costs were deferred until such time as approval from the AEUB was obtained for refund to or collection from customers and revenues and natural gas supply expense was adjusted accordingly.

b) *Purchased power* – Purchased power expense in ATCO Electric was based on the actual cost of electricity purchased, whereas the amount included in customer rates was based on forecast cost. Revenues were adjusted for variances from forecast cost, and the variances were deferred until such time as approval from the AEUB was obtained for refund to or collection from customers.

3. Transfer of retail energy supply businesses

On May 4, 2004, ATCO Gas and ATCO Electric closed the transfer of their retail energy supply businesses to Direct Energy Marketing Limited and one of its affiliates (collectively "DEML"), a subsidiary of Centrica plc. Proceeds of the transfer were $90 million, of which $45 million was paid at closing, with the remainder to be paid 12 months following closing. Net proceeds, after adjustments related to legal, transition and other deferred costs pertaining to the transfer of the retail energy supply businesses, resulted in a gain of $63.3 million before income taxes of $8.2 million. This transfer increased earnings for the nine months ended September 30, 2004 by $55.1 million. The Corporation's revenues and natural gas supply and purchased power costs after May 4, 2004 will be reduced accordingly. Subsequent to May 4, 2004, ATCO Gas continued to purchase natural gas on behalf of DEML pending the transfer of the relevant ATCO Gas natural gas purchase contracts to DEML. This transfer of contracts was completed by September 30, 2004. There will be no impact on earnings resulting from the transfer of these businesses as natural gas and electricity have historically been sold to customers on a "no-margin" basis. ATCO Gas and ATCO Electric continue to own and operate the natural gas and electricity distribution systems used to deliver energy.

Under the various transaction agreements, ATCO Gas and ATCO Electric have transferred to DEML certain retail functions, including the supply of natural gas and electricity to customers and billing and customer care functions ("the transferred functions").

On May 4, 2004, DEML commenced supplying natural gas and electricity at regulated rates to residential, farm and small business customers in the ATCO Gas and ATCO Electric service areas and billing customers for their natural gas and electricity service.

If DEML fails to perform all or part of the transferred functions, ATCO Gas and ATCO Electric will be required under existing legislation to perform such functions in the interim until DEML is able to perform such functions. 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 agreements will terminate and the functions will revert to ATCO Gas and/or ATCO Electric with no refund of the purchase price to DEML by ATCO Gas and/or ATCO Electric. In certain circumstances, if DEML is restrained or prohibited from carrying out the transferred functions, all functions will revert to ATCO Gas and ATCO Electric and a portion of the purchase price will be refunded to DEML, depending upon the timing of any such reversion.

3. Transfer of retail energy supply businesses (continued)

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. The Centrica guarantee and letter of credit include limits for certain categories of claims, which limits cease to apply if the agreements are terminated. If the amount available to be drawn under the letter of credit at any time falls below $200 million, the agreements with DEML will terminate and the functions will revert to ATCO Gas and ATCO Electric with no refund of the purchase price to DEML by ATCO Gas and ATCO Electric.

Canadian Utilities Limited has provided a guarantee of ATCO Gas', ATCO Electric's and ATCO I-Tek Business Services' payment and indemnity obligations in respect of the ongoing relationships contemplated under the transaction agreements.

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

ATCO Gas and ATCO Electric have also agreed not to compete in the regulated and unregulated retail energy business in Alberta for a period of ten years.

In December 2003, the AEUB issued a decision approving the transfer of the retail operations of ATCO Gas and ATCO Electric to DEML. The City of Calgary filed for leave to appeal the AEUB decision, including the allocation of proceeds to ATCO Gas and ATCO Electric. On June 30, 2004, the Alberta Court of Appeal dismissed the City of Calgary's application for leave to appeal.

4. Retained earnings at beginning of period as restated

	Three Months Ended September 30		Nine Months Ended September 30	
	2004	2003	**2004**	2003
Retained earnings at beginning of period as previously reported	**$1,540.0**	$1,375.2	**$1,438.8**	$1,314.9
Adjustment to retained earnings for prior years' effect of change in method of accounting for asset retirement obligations (after income taxes)	**-**	(2.9)	**(3.1)**	(3.1)
Adjustment to retained earnings for prior years' effect of change in method of accounting for stock options	**-**	(0.1)	**(0.3)**	(0.1)
Retained earnings at beginning of period as restated	**$1,540.0**	$1,372.2	**$1,435.4**	$1,311.7

5. Direct charges to retained earnings

	Three Months Ended September 30		Nine Months Ended September 30	
	2004	2003	**2004**	2003
Issue costs of equity preferred shares (after income taxes)	**$ -**	$ -	**$ -**	$2.7
Purchase of Class A shares	**2.1**	1.0	**5.0**	2.5
	$2.1	$1.0	**$5.0**	$5.2

6. Asset retirement obligations

The CICA recommendations on accounting for asset retirement obligations require the Corporation to identify legal obligations associated with the retirement of tangible long lived assets. To the extent that they can be quantified, these obligations are measured and recognized at fair value, which is determined using present value techniques. An asset retirement obligation is recorded as a liability, with a corresponding increase to property, plant and equipment. The liability is accreted over the estimated time period until settlement of the obligation, with the accretion expense included in depreciation and amortization. The asset is depreciated over its estimated useful life. Prior to January 1, 2004, site restoration and removal costs that are now accounted for as asset retirement obligations were accrued over the estimated remaining useful lives of the assets.

Asset retirement obligations for regulated natural gas and electric transmission and distribution assets were not recognized as the Corporation expects to use the assets in service for an indefinite period. As such, no final removal date can be determined and, consequently, a reasonable estimate of the related retirement obligations cannot be made at this time. Asset retirement obligations have been recorded for the regulated generating plants of Alberta Power (2000) and other generating plants and natural gas liquids extraction and processing plants.

The effect of adopting these recommendations is presented as increases (decreases) below:

	Three Months Ended September 30		Nine Months Ended September 30	
	2004	2003	**2004**	2003
Statement of earnings				
Site restoration and removal costs, included in operation and maintenance	**$ -**	$(0.1)	**$ -**	$(0.2)
Depreciation and amortization	**(0.2)**	(0.2)	**(0.6)**	(1.2)
Accretion expense, included in depreciation and amortization	**0.4**	0.5	**1.4**	1.4
Income taxes	**-**	-	**(0.1)**	(0.1)
Earnings attributable to Class A and Class B shares	**$(0.2)**	$(0.2)	**$(0.7)**	$ 0.1

	January 1 2003
Balance sheet	
Retirement assets and site restoration and removal costs, included in property, plant and equipment	$24.2
Asset retirement obligations, included in deferred credits	30.1
Accrual for future removal and site restoration costs, included in deferred credits	(3.3)
Future income tax liabilities	0.5
Retained earnings at beginning of period	(3.1)

Changes in asset retirement obligations are summarized below:

	Three Months Ended September 30		Nine Months Ended September 30	
	2004	2003	**2004**	2003
Obligations at beginning of period	**$33.3**	$31.0	**$32.3**	$30.1
Obligations incurred	**0.5**	-	**0.5**	-
Accretion expense	**0.4**	0.5	**1.4**	1.4
Obligations at end of period	**$34.2**	$31.5	**$34.2**	$31.5

The Corporation estimates the undiscounted amount of cash flow required to settle the asset retirement obligations is approximately $93 million, which will be incurred between 2005 and 2052. A weighted average discount rate of 5.9% was used to calculate the fair value of the asset retirement obligations.

7. Class A and Class B shares

There were 41,173,043 (2003 – 40,136,744) Class A non-voting shares and 22,190,192 (2003 – 23,228,891) Class B common shares outstanding on September 30, 2004. In addition, there were 837,000 options to purchase Class A non-voting shares outstanding at September 30, 2004 under the Corporation's stock option plan. From October 1, 2004, to October 27, 2004, no stock options were granted, 600 stock options were exercised and 1,900 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:

	Three Months Ended September 30		Nine Months Ended September 30	
	2004	2003	**2004**	2003
Weighted average shares outstanding	**63,348,767**	63,377,086	**63,385,759**	63,395,141
Effect of dilutive stock options	**241,494**	318,479	**267,372**	275,928
Weighted average diluted shares outstanding	**63,590,261**	63,695,565	**63,653,131**	63,671,069

8. Employee future benefits

In the three months ended September 30, 2004, net expense of $0.9 million (2003 – $0.6 million) was recognized for pension benefit plans and net expense of $0.8 million (2003 - $0.9 million) was recognized for other post employment benefit plans.

In the nine months ended September 30, 2004, net expense of $1.4 million (2003 – $0.4 million income) was recognized for pension benefit plans and net expense of $2.9 million (2003 – $2.6 million) was recognized for other post employment benefit plans.

9. Segmented information

In August 2004, the Corporation reorganized its structure into three business groups: **Utilities** (ATCO Gas, ATCO Electric and its subsidiaries, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical, ATCO Pipelines, CU Water, ATCO Utility Services); **Power Generation** (ATCO Power, Alberta Power (2000)); and **Global Enterprises** (ATCO Midstream, ATCO Frontec, ATCO I-Tek and its subsidiary, ATCO I-Tek Business Services, ASHCOR Technologies, Genics, ATCO Travel). 2003 segmented figures have been restated to conform to the current basis of segmentation.

Segmented results – Three months ended September 30

2004 2003	Utilities	Power Generation	Global Enterprises	Corporate and Other	Intersegment Eliminations	Consolidated
Revenues – external	**$190.1**	**$156.1**	**$204.4**	**$ 0.2**	**$ -**	**$550.8**
	$345.5	$146.1	$130.7	$ 0.3	$ -	$622.6
Revenues – intersegment	**4.1**	**-**	**26.2**	**1.7**	**(32.0)**	**-**
	6.1	-	108.4	2.9	(117.4)	-
Revenues	**$194.2**	**$156.1**	**$230.6**	**$ 1.9**	**$ (32.0)**	**$550.8**
	$351.6	$146.1	$239.1	$ 3.2	$(117.4)	$622.6
Earnings attributable to Class A and Class B shares	**$ 10.3**	**$ 18.4**	**$ 18.6**	**$(3.6)**	**$ 0.3**	**$ 44.0**
	$ 11.9	$ 17.6	$ 16.4	$(3.7)	$ 1.0	$ 43.2

9. Segmented information (continued)

Segmented results – Nine months ended September 30

2004 2003	Utilities	Power Generation	Global Enterprises	Corporate and Other	Intersegment Eliminations	Consolidated
Revenues – external	**$1,477.8** $1,875.6	**$ 469.3** $ 471.5	**$479.0** $444.6	**$ 0.8** $ 0.6	**$ -** $ -	**$2,426.9** $2,792.3
Revenues – intersegment	**14.1** 16.8	**-** -	**305.4** 457.8	**6.9** 8.6	**(326.4)** (483.2)	**-** -
Revenues	**$1,491.9** $1,892.4	**$ 469.3** $ 471.5	**$784.4** $902.4	**$ 7.7** $ 9.2	**$(326.4)** $(483.2)	**$2,426.9** $2,792.3
Earnings attributable to to Class A and Class B shares	**$ 130.2** $ 80.2	**$ 55.9** $ 57.1	**$ 41.3** $ 41.7	**$ (11.2)** $ (10.0)	**$ 2.5** $ 3.6	**$ 218.7** $ 172.6
Total assets	**$3,265.4** $3,097.1	**$2,191.9** $2,187.7	**$298.3** $299.9	**$434.7** $418.6	**$ 19.4** $ (42.1)	**$6,209.7** $5,961.2

10. Regulatory matters

For 2002, ATCO Electric's rate of return on common equity was 10.5% and the common equity ratio was 37% for transmission operations and 43% for distribution operations. 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. These reductions in the common equity ratios reduced the common equity that ATCO Electric is allowed to earn a return on by $83.0 million for 2003. ATCO Electric, as directed by the AEUB, refiled the 2003 and 2004 revenue requirements, incorporating the findings in the decision. In a decision dated February 17, 2004, the AEUB issued its final determination of the revenue requirements for the 2003 and 2004 test years, accepting the refiling with no material changes. Certain matters relating to transactions with affiliates will be addressed in separate proceedings. In a decision dated July 2, 2004, the AEUB issued its generic cost of capital decision which approved, among other things, a return on common equity of 9.60% for 2004 and a common equity ratio of 33% for ATCO Electric's transmission operations and 37% for its distribution operations beginning in 2004. These increases in the common equity ratios increased the common equity that ATCO Electric is allowed to earn a return on by $22.3 million for 2004. In summary, the negative impacts of the 2003/2004 general tariff decision and the generic cost of capital decision reduced the common equity that ATCO Electric is allowed to earn a return on by $60.7 million over the two years, 2003 and 2004.

In December 2002, the AEUB issued a decision approving rates for ATCO Gas on an interim basis effective January 1, 2003. In a decision dated October 1, 2003, the AEUB approved for ATCO Gas, among other things, a rate of return on common equity of 9.50% for 2003 and 2004 and a common equity ratio of 37% for 2003 and 2004. ATCO Gas, as directed by the AEUB, refiled the 2003 and 2004 general rate application, incorporating the findings in the decision. In a decision dated June 15, 2004, the AEUB issued its final determination of the revenue requirements for the 2003 and 2004 test years, accepting the refiling with no material changes. Certain matters relating to transactions with affiliates will be addressed in separate proceedings. In a decision dated July 2, 2004, the AEUB issued its generic cost of capital decision which approved, among other things, ATCO Gas' common equity ratio of 38% beginning in 2005. As ATCO Gas' return on common equity for 2004 was already established, the standardized approach approved by the AEUB for determining the return on common equity (as described below) will be applied beginning in 2005.

10. Regulatory matters (continued)

In a decision dated December 2, 2003, the AEUB approved for ATCO Pipelines, among other things, a rate of return on common equity of 9.50% and a common equity ratio of 43.5% for 2003. ATCO Pipelines, as directed by the AEUB, refiled the 2003 and 2004 general rate application, incorporating the findings in the decision. In a decision dated March 9, 2004, the AEUB approved interim rates to be effective from March 1, 2004 to October 31, 2004. In a decision dated April 30, 2004, the AEUB accepted the refiling of the revenue requirements for the 2003 and 2004 test years with no material changes. In a decision dated July 13, 2004, the AEUB awarded additional revenue with respect to the revenue forecasts of certain industrial customers. Certain matters relating to transactions with affiliates will be addressed in separate proceedings. In a decision dated July 2, 2004, the AEUB issued its generic cost of capital decision which approved, among other things, ATCO Pipelines' return on common equity of 9.60% for 2004 and a common equity ratio of 43% beginning in 2004.

The generic cost of capital decision established a standardized approach for each utility company regulated by the AEUB for determining the rate of return on common equity based upon a return of 9.60% on common equity. This rate of return will be adjusted annually by 75% of the change in long term Canada bond yield as forecast in the November Consensus Forecast, adjusted for the average difference between the 10 year and 30 year Canada bond yields for the month of October as reported in the National Post. This adjustment mechanism is the same as the National Energy Board uses in determining its formula based rate of return. The AEUB will undertake a review of this mechanism for the year 2009 or if the rate of return resulting from the formula is less than 7.6% or greater than 11.6%. The AEUB also noted that any party, at any time, could petition for a review of the adjustment formula if that party can demonstrate a material change in facts or circumstances.

The decision also established the appropriate capital structure for each utility regulated by the AEUB. The AEUB determined that any proposed changes to the approved capital structure which result from a material change in the investment risk of a utility will be addressed at utility specific rate applications.

11. Contingency

As a result of recent 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.

12. ATCOR Resources Ltd. tax reassessment

In 2001, Canadian Utilities received and paid an income tax reassessment of $12.9 million relating to the 1996 disposal of ATCOR Resources Ltd. The Corporation did not agree with this reassessment and contested the matter with tax authorities. Accordingly, the payment was recorded as a reduction of future income tax liabilities.

During 2003, the Corporation was successful in appealing the reassessment to the Tax Court of Canada. The Federal Government appealed the Tax Court's decision to the Federal Court of Appeal, which issued a decision on June 18, 2004 in favor of the Corporation. The Federal Government did not appeal the Federal Court of Appeal's decision with the Supreme Court of Canada. Accordingly, the Corporation has reversed the future income tax reduction of $12.9 million and reduced income taxes payable pending receipt of the refund.

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