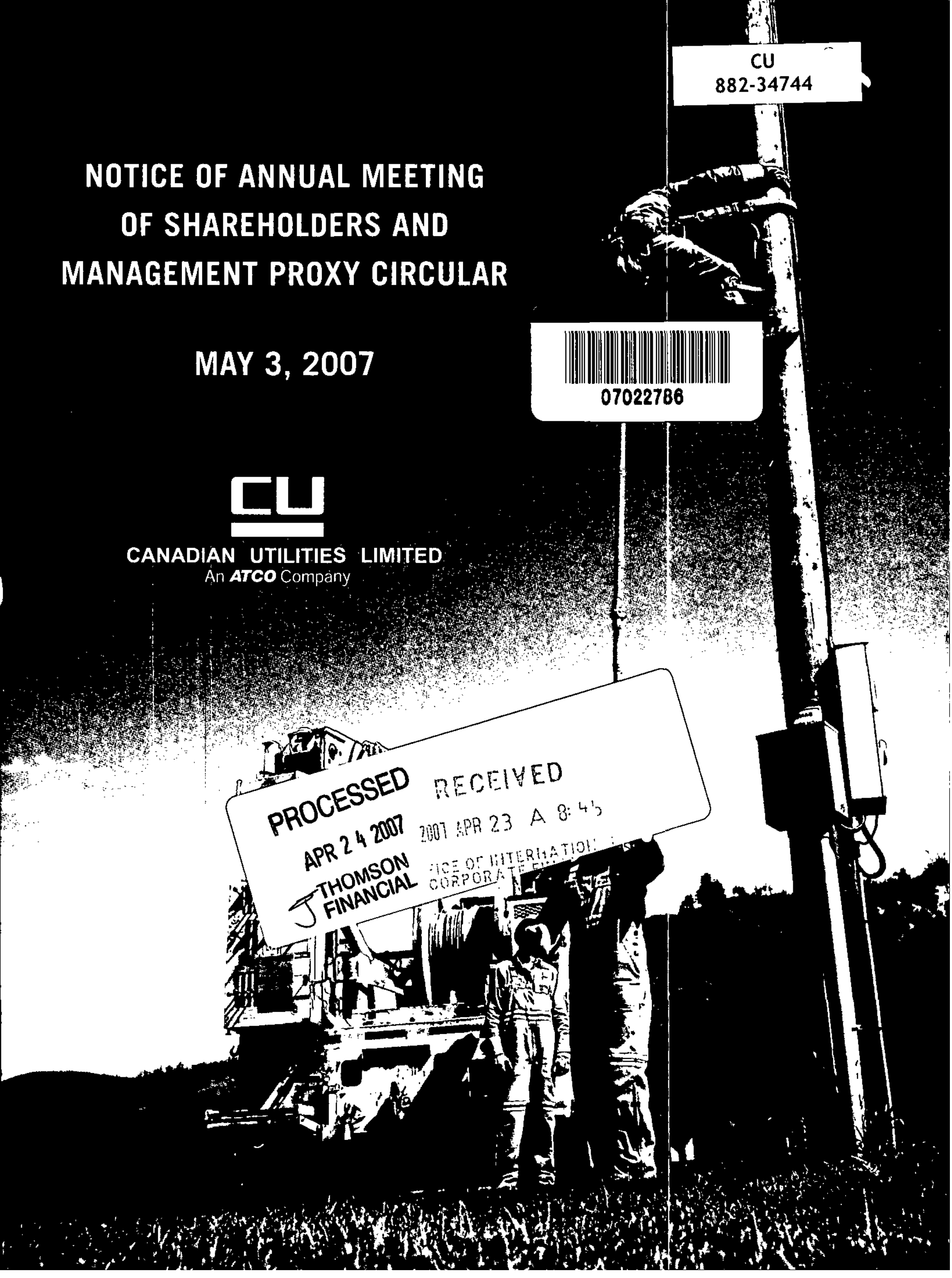
NOTICE OF ANNUAL MEETING OF SHAREHOLDERS AND MANAGEMENT PROXY CIRCULAR

MAY 3, 2007

CANADIAN UTILITIES LIMITED
An ATCO Company



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CANADIAN UTILITIES LIMITED

An *ATCO* Company

Dear Share Owner:

We are pleased to invite you to attend the annual meeting of share owners of Canadian Utilities Limited to be held in the Empire Ballroom, The Fairmont Hotel Macdonald, 10065 - 100th Street, Edmonton, Alberta, at 10:00 a.m. on Thursday, May 3, 2007.

Your meeting materials are enclosed. If you are an owner of Class B common shares and are unable to attend the meeting, please complete and sign the proxy and return it in the envelope provided for that purpose. May we also encourage all owners of Class A non-voting shares to attend the meeting.

We hope you will join us after the meeting for some light refreshments.

Sincerely,

R.D. Southern
Chairman of the Board

N.C. Southern
President & Chief Executive Officer

Calgary, Alberta
March 1, 2007

CANADIAN UTILITIES LIMITED

NOTICE OF ANNUAL MEETING OF SHAREHOLDERS

The annual meeting of shareholders of Canadian Utilities Limited (the "Corporation") will be held in the Empire Ballroom, The Fairmont Hotel Macdonald, 10065 - 100th Street, Edmonton, Alberta, at 10:00 a.m. on Thursday, May 3, 2007, for the following purposes:

(a) to receive the consolidated financial statements for the year ended December 31, 2006, accompanied by the report of the auditor;

(b) to elect the directors;

(c) to appoint the auditor;

(d) to approve, subject to receiving all required approvals from the Toronto Stock Exchange, amendments to the stock option plan of the Corporation; and

(e) to transact such other business as may properly come before the meeting or any adjournment thereof.

All holders of Class A non-voting shares or Class B common shares are entitled to attend the meeting, but only the holders of Class B common shares are entitled to vote at the meeting or to appoint proxyholders.

Holders of Class B common shares who are unable to attend the meeting in person are requested to complete and sign the accompanying form of proxy and return it in the prepaid envelope provided to CIBC Mellon Trust Company to be received by Canadian Utilities Limited, c/o CIBC Mellon Trust Company, not later than 5:00 p.m. Eastern Daylight Time on Tuesday, May 1, 2007.

Alternatively, registered shareholders may submit a form of proxy by fax, telephone or via the internet. Instructions are set out on the reverse of the form of proxy and are contained in the Management Proxy Circular.

By order of the Board of Directors.

P. Spruin

P. Spruin
Corporate Secretary

Calgary, Alberta
March 1, 2007

CANADIAN UTILITIES LIMITED
An **ATCO** Company

MANAGEMENT PROXY CIRCULAR

SECTION 1 VOTING INFORMATION

Solicitation of Proxies

This management proxy circular is furnished in connection with the solicitation by the management of CANADIAN UTILITIES LIMITED (the "Corporation") of proxies to be used at the annual meeting of shareholders of the Corporation and at any adjournment thereof, for the purposes set forth in the accompanying notice. The cost of solicitation by management will be borne by the Corporation.

Appointment of Proxyholders and Revocation of Proxies

The persons named in the accompanying form of proxy are directors of the Corporation. **A shareholder entitled to vote at the meeting has the right to appoint a person or company to represent the shareholder at the meeting other than the persons designated in the accompanying form of proxy.** This right may be exercised either by striking out the names of the persons designated in the accompanying form of proxy and inserting in the space provided the name of the person appointed or by completing and executing another proper form of proxy. A shareholder desiring to be represented at the meeting by a proxyholder must deposit a proxy with the Corporation at the address set forth in the accompanying notice not later than 5:00 p.m. Eastern Daylight Time on Tuesday, May 1, 2007.

A shareholder may revoke a proxy by depositing an instrument in writing executed by the shareholder or by the shareholder's attorney authorized in writing with the Corporation, c/o CIBC Mellon Trust Company, Attention: Proxy Department, P.O. Box 721, Agincourt, Ontario, M1S 0A1, at any time up to and including the last business day preceding the day of the meeting, or any adjournment thereof, at which the proxy is to be used, or with the chairman of the meeting on the day of the meeting or any adjournment thereof.

Exercise of Discretion by Proxyholders

All shares represented by a proxy will be voted or withheld from voting in accordance with the instructions of the shareholder on any ballot that may be called for, and if the shareholder specifies a choice with respect to any matter to be acted upon, the shares will be voted accordingly. **In the absence of such instructions, all of such shares will be voted in favour of the election of the directors, the appointment of the auditor, and the approval of the amendments to the stock option plan.** The accompanying form of proxy confers discretionary authority upon the persons named therein with respect to amendments to matters identified in the notice of the meeting and other matters that may properly come before the meeting. The management of the Corporation is not aware of any such amendments or other matters. If any such amendments or matters should properly come before the meeting, the persons named in the accompanying form of proxy will vote on such matters in accordance with their best judgment.

Class B Common Shares and Principal Holders

The Class B common shares of the Corporation are the only shares entitled to be voted at the meeting. As at March 1, 2007, there were 43,926,484 Class B common shares outstanding. Each Class B common share entitles the holder thereof to one vote at the meeting.

The record date for the meeting is March 14, 2007. Holders of Class B common shares whose names are entered in the applicable register at the close of business on that date will be entitled to receive notice of and to attend and vote at the meeting.

To the knowledge of the directors and officers of the Corporation, the only person who beneficially owns, directly or indirectly, or controls or directs shares of the Corporation carrying 10% or more of the votes attached to any class of voting securities of the Corporation is ATCO Ltd. ATCO Ltd. directly or indirectly owns 32,665,452 Class B common shares, being approximately 74.36% of the outstanding Class B common shares. R.D. Southern controls ATCO Ltd.

Class A Non-Voting Shares

The holders of the Class A non-voting shares of the Corporation are entitled to receive notice of the meeting and to attend and participate in discussions at the meeting, but are not entitled to vote at the meeting.

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

Voting by Non-Registered Shareholders

Shareholders who do not hold their shares in their own name ("non-registered shareholders") may have their shares voted at the meeting by providing voting instructions to their nominee, which is usually a trust company, broker or other financial institution. Nominees will typically seek voting instructions by sending with this circular a voting instruction form instead of a form of proxy. A voting instruction form can be used only to provide voting instructions to a non-registered shareholder's nominee. Every nominee has its own signing and return instructions, which non-registered shareholders must follow to ensure that their shares are voted at the meeting.

Alternatively, non-registered shareholders may attend the meeting and vote their shares as proxyholder by entering their own name in the space provided on the voting instruction form supplied by their nominee and following the signing and return instructions. Non-registered shareholders who follow this procedure will be recognized at the meeting as proxyholders and will be permitted to vote their shares in that capacity.

For additional information please refer to Schedule C: Questions and Answers on Voting and Proxies at the back of this circular.

SECTION 2 BUSINESS OF THE MEETING

FINANCIAL STATEMENTS

The consolidated financial statements of the Corporation for the year ended December 31, 2006, along with the auditor's report, will be placed before the meeting. Copies of the financial statements may be obtained from the Corporate Secretary upon request and will be available at the meeting. The statements are also available on the Corporation's website at www.canadian-utilities.com and on SEDAR at www.sedar.com.

ELECTION OF DIRECTORS

The management of the Corporation, on behalf of the Corporate Governance - Nomination, Compensation and Succession Committee, proposes to nominate, and the persons named in the accompanying form of proxy intend to vote for the election as directors of the Corporation, the persons whose names are set forth below. The management of the Corporation does not contemplate that any of the nominees will be unable to serve as a director. Each director elected will hold office until the close of the next annual meeting of shareholders of the Corporation.

All of the nominees, with the exception of Dr. R. Urwin, are currently directors and have been for the periods indicated. If elected, Dr. Urwin will be an independent director of the Corporation.

Directors' Attendance

All directors are expected to attend meetings of the Board and the committees on which they serve. However, there may, from time to time, be extenuating circumstances for directors not attending meetings, especially for directors in positions of leadership in other corporations, particularly when they are in the process of assuming new positions or involved in major undertakings. It is also understood that directors may have, on occasion, family bereavement or health issues. The Corporation is supportive and understanding of such circumstances. When a director's attendance is deemed to be unsatisfactory, interviews are conducted by each of the Chairman and the Lead Director during which a clear understanding of the Corporation's expectations for attendance are formally communicated to assure significant improvement and optimal attendance in subsequent reporting periods.

Robert T. Booth
Age: 54
Calgary, AB Canada
Director Since: 1998
Not Independent[1]
Meets share ownership guidelines[2]

Mr. Booth is a partner in the law firm Bennett Jones LLP, based in Calgary, Alberta, and brings an extensive background in energy and natural resource law to the Canadian Utilities Limited Board. A member of the Law Society of Alberta and the Canadian Bar Association, Mr. Booth obtained a Bachelor of Engineering degree from the Royal Military College of Canada, Kingston, Ontario and an LLB from Dalhousie University, Halifax, Nova Scotia.

Board/Committee Membership:	**Attendance:**		**Other Public Board/Committee Memberships:**		
			Company	Term	Committees
Board of Directors	9 of 10	90%	N/A	N/A	N/A
Strategy Conference[6]	1 of 1	100%			
Round Tables	4 of 4	100%			
Risk Review	2 of 2	100%			

Securities Held:[4][5]

Canadian Utilities Limited		**ATCO Ltd.**	
Class A non-voting	3,800	Class I Non-Voting	0
Class B common	0	Class II Voting	0

William L. Britton, Q.C.

Age: 72
Calgary, AB Canada
Director Since: 1980
Not Independent[1]
Meets share ownership guidelines[2]

Mr. Britton is Vice Chairman of the Board for Canadian Utilities Limited and ATCO Ltd. He is also Chairman Emeritus and the past chairman and national managing partner of Bennett Jones LLP and a member of the Law Society of Alberta and the Canadian Bar Association. Mr. Britton is a director of Sentgraf Enterprises Ltd., Barking Power Limited, AKITA Drilling Ltd., Forest Oil Corporation, Denver Broncos Football Club, Hanzell Vineyards Ltd., Geary-Market Investment Company Ltd., and virtually all of the ATCO Group subsidiary companies.

Board/Committee Membership:	Attendance:	
Board of Directors	10 of 10	100%
Strategy Conference[6]	1 of 1	100%
Round Tables	4 of 4	100%
GOCOM [3] (Chair)	4 of 4	100%

Other Public Board/Committee Memberships:

Company	Term	Committees
ATCO Ltd.	Since 1975	GOCOM[3] (Chair) Crisis Management (Chair)
AKITA Drilling Ltd.	Since 1992	GOCOM[3]
CU Inc.	Since 1999	-
Forest Oil Corporation	Since 1996	Nominating & Corporate Governance

Securities Held:[4] [5]

Canadian Utilities Limited		ATCO Ltd.	
Class A non-voting	15,999	Class I Non-Voting	30,726
Class B common	0	Class II Voting	7,870

Loraine M. Charlton

Age: 50
Calgary, AB Canada
Director Since: 2006
Independent[1]
See note (2) below on share ownership guidelines.

Ms. Charlton has most recently been Vice President, Chief Operating Officer of Investors' Petroleum Consultants Ltd., an oil and gas consulting and management company. She has been with Investors' Petroleum Consultants Ltd. since 1984, and will continue with the company as a consultant.

Board/Committee Membership:	Attendance: [7]	
Board of Directors	6 of 6	100%
Strategy Conference[6]	1 of 1	100%
Round Tables	3 of 3	100%
Audit	3 of 3	100%
Special Committee	1 of 1	100%

Other Public Board/Committee Memberships:

Company	Term	Committees
AKITA Drilling Ltd.	Since 2006	Audit

Securities Held:[4] [5]

Canadian Utilities Limited		ATCO Ltd.	
Class A non-voting	415	Class I Non-Voting	100
Class B common	100	Class II Voting	0

Brian P. Drummond

Age: 75
Montreal, QC Canada
Director Since: 1997
Independent[1]
Meets share ownership guidelines[2]

Mr. Drummond is a founding director of ATCO Ltd. Most recently he was Vice Chairman, Richardson Greenshields of Canada Limited. He was also previously President and Chairman of the Executive Committee of Greenshields Incorporated. Mr. Drummond is a director and member of the Executive Committee of the McGill University Health Centre Foundation and is a director of the Montreal General Hospital Foundation. He is a past Chairman of the Investment Dealers Association of Canada and the Montreal Exchange. Mr. Drummond is a member of the Investment Committee of the Canadian Medical Protective Association.

Board/Committee Membership:	**Attendance:**	
Board of Directors	9 of 10	90%
Strategy Conference[6]	1 of 1	100%
Round Tables	3 of 4	75%
GOCOM [3]	2 of 4	50%
Pension Fund	4 of 4	100%

Other Public Board/Committee Memberships:

Company	Term	Committees
ATCO Ltd.	Since 1968	Audit (Chair) GOCOM[3] Risk Review

Securities Held:[4] [5]

Canadian Utilities Limited		**ATCO Ltd.**	
Class A non-voting	6,500	Class I Non-Voting	17,198
Class B common	0	Class II Voting	7,800

Basil K. French

Age: 73
Calgary, AB Canada
Director Since: 1981
Independent[1]
Meets share ownership guidelines[2]

Mr. French is the President of Karusel Management Ltd., a Calgary based company specializing in management consulting and property management. Prior to the establishment of Karusel Management, Mr. French was with the firms of Buchanan, Barry, Miller and French Chartered Accountants and Price Waterhouse & Co.

Board/Committee Membership:	**Attendance:**	
Board of Directors	10 of 10	100%
Strategy Conference[6]	1 of 1	100%
Round Tables	4 of 4	100%
Audit	5 of 5	100%
Risk Review	2 of 2	100%

Other Public Board/Committee Memberships:

Company	Term	Committees
ATCO Ltd.	Since 1982	Audit GOCOM[3] Risk Review Crisis Management
CU Inc.	Since 1999	Audit (Chair)

Securities Held:[4] [5]

Canadian Utilities Limited		**ATCO Ltd.**	
Class A non-voting	4,900	Class I Non-Voting	17,298
Class B common	700	Class II Voting	5,800
Series W Second Preferred	500		
Series X Second Preferred	2,000		

Linda A. Heathcott

Age: 43
Calgary, AB Canada
Director Since: 2000
Not Independent(1)
Meets share ownership guidelines(2)

Mrs. Heathcott is President and Chief Executive Officer of Spruce Meadows. A former professional equestrian rider, Mrs. Heathcott was a member of the Canadian Equestrian Team for nine years and competed in the 1996 Olympic Summer Games in Atlanta, Georgia. In 2006 Mrs. Heathcott was appointed the Chairman of the Board of AKITA Drilling Ltd. Mrs. Heathcott also serves on the Board of Sentgraf Enterprises Ltd.

Board/Committee Membership:	Attendance:*	
Board of Directors	6 of 10	60%
Strategy Conference(6)	0 of 1	0%
Round Tables	2 of 4	50%
Pension Fund	1 of 4	25%

Other Public Board/Committee Memberships:

Company	Term	Committees
AKITA Drilling Ltd. (Chair)	Since 1992	Pension

Securities Held:(4) (5)

Canadian Utilities Limited		ATCO Ltd.	
Class A non-voting	4,500	Class I Non-Voting	8,900
Class B common	2,000	Class II Voting	4,200
Series Q Second Preferred	2,600	5.75% Series 3 Preferred	2,000
Series R Second Preferred	3,900		

* In 2005, Mrs. Heathcott's attendance was 100%.

Helmut M. Neldner

Age: 68
Westerose, AB Canada
Director Since: 1991
Independent(1)
Meets share ownership guidelines(2)

Mr. Neldner has extensive experience in the telecommunications industry and is the former President & Chief Executive Officer of AGT and Telus Corporation. He started his career with AGT in 1964 and later served as Vice President, Finance and Vice President, Corporate Planning and Engineering before retiring as President & Chief Executive Officer of TELUS Corporation in 1994.

Board/Committee Membership:	Attendance:	
Board of Directors	10 of 10	100%
Strategy Conference(6)	1 of 1	100%
Round Tables	4 of 4	100%
Audit	5 of 5	100%
GOCOM(3) (8)	1 of 1	100%
Pension Fund (Chair)	4 of 4	100%
Risk Review (Chair)	2 of 2	100%

Other Public Board/Committee Memberships:

Company	Term	Committees
ATCO Ltd.	Since 1997	Audit GOCOM (Deputy Chair)(3) Risk Review (Chair)
CU Inc.	Since 2000	Audit

Securities Held:(4) (5)

Canadian Utilities Limited		ATCO Ltd.	
Class A non-voting	4,500	Class I Non-Voting	16,498
Class B common	0	Class II Voting	0

Michael R.P. Rayfield

Age: 64
Toronto, ON
Canada
Director Since: 2004
Independent(1)
See note (2) below on share ownership guidelines.

Mr. Rayfield joined the Bank of Montreal in 1982, in New York, as Senior Vice-President, with responsibility for the Bank's corporate banking business in the United States, Latin America, Australia and Japan. In 1986 he was appointed Executive Vice-President, and is currently Vice Chairman, Investment and Corporate Banking. Prior to joining the Bank, he held senior executive positions with Barclays Bank in London, Chicago and New York. Mr. Rayfield is a graduate of the Institute of Bankers, UK; the Senior Managers Program at Harvard University; Advanced Executive Program, J.L. Kellogg Graduate School of Management; Northwestern University and has studied at Cambridge University. Mr. Rayfield is on the Board of the Canadian Institute of International Affairs and the Board of Governors, Charter for Business, Duke of Edinburgh's Award Programme.

Board/Committee Membership:	**Attendance:**	
Board of Directors	8 of 10*	80%
Strategy Conference(6)	1 of 1	100%
Round Tables	3 of 4	75%
Pension Fund	4 of 4	100%
Special Committee	1 of 1	100%

Other Public Board/Committee Memberships:

Company	Term	Committees
N/A	N/A	N/A

Securities Held:(4) (5)

Canadian Utilities Limited		ATCO Ltd.	
Class A non-voting	1,126	Class I Non-Voting	0
Class B common	0	Class II Voting	0

*Due to a conflict of interest, Mr. Rayfield did not attend two Board meetings.

James W. Simpson

Age: 62
Danville, CA, USA
Director Since: 2004
Independent(1)
Meets share ownership guidelines(2)

Mr. Simpson is Lead Director for the Board of Canadian Utilities Limited. Mr. Simpson, former President of Chevron Canada Resources, retired after a career with Chevron Texaco that spanned 30 years. Some of his key management assignments included General Manager Research Services at the laboratory in Los Angeles; General Manager of the Executive Staff in San Ramon, California; Managing Director of New Ventures in the international upstream company and Vice President of Middle East and North Africa in the Business Development group. He is former Chairman of the Canadian Association of Petroleum Producers and has been active in the United Way and the World Petroleum Congress.

Board/Committee Membership:	**Attendance:**	
Board of Directors	10 of 10	100%
Strategy Conference(6)	1 of 1	100%
Round Tables	4 of 4	100%
Audit	5 of 5	100%
GOCOM(3)	4 of 4	100%
Risk Review	2 of 2	100%
Special Committee	1 of 1	100%

Other Public Board/Committee Memberships:

Company	Term	Committees
Petro-Canada	Since 2004	Audit, Finance and Risk Management Resources and Compensation

Securities Held:(4) (5)

Canadian Utilities Limited		ATCO Ltd.	
Class A non-voting	4,288	Class I Non-Voting	0
Class B common	0	Class II Voting	0

Nancy C. Southern

Age: 50
Calgary, AB Canada
Director Since: 1990
Not Independent[1]
Meets share ownership guidelines[2]

Nancy Southern was appointed President & Chief Executive Officer of ATCO Ltd. and Canadian Utilities Limited on January 1, 2003. Previously, she was Co-Chairman & Chief Executive Officer from 2000 until 2003, Deputy Chief Executive Officer from 1998 until 2000, and Deputy Chairman from 1996 until 1998. Ms. Southern has full responsibility for executing strategic direction and the on-going operations of the Corporation, reporting to the Board of Directors. She is currently a director of ATCO Ltd. and serves on the Boards of all the ATCO Group subsidiary companies. She is also a director of the Bank of Montreal, Shell Canada Limited, AKITA Drilling Ltd., and Sentgraf Enterprises Ltd. Ms. Southern is a member of The Business Council, a U.S. based association of Chief Executive Officers representing a broad range of global businesses.

Board/Committee Membership:	Attendance:	
Board of Directors	10 of 10	100%
Strategy Conference[6]	1 of 1	100%
Round Tables	4 of 4	100%

Other Public Board/Committee Memberships:

Company	Term	Committees
ATCO Ltd.	Since 1989	-
AKITA Drilling Ltd.	Since 1992	-
Bank of Montreal	Since 1996	Risk Review
CU Inc.	Since 1999	-
Shell Canada Ltd.	Since 2001	Health, Safety, Environment & Social Responsibility (Chair) Nominating and Governance

Securities Held:[4][5]

Canadian Utilities Limited		ATCO Ltd.	
Class A non-voting	1,850	Class I Non-Voting	65,495
Class B common	2,500	Class II Voting	21,300

Ronald D. Southern, C.B.E., C.C., LL.D.

Age: 76
Calgary, AB Canada
Director Since: 1977
Not Independent[1]
Meets share ownership guidelines[2]

Ron Southern is Chairman of the Board of Canadian Utilities Limited and ATCO Ltd. Together with his late father, S.D. Southern, Mr. Southern founded ATCO Group in 1947 and served as ATCO's President for 48 years. He is credited with transforming the company to what it is today — a corporation with assets of $7.4 billion and employing more than 7,000 people. Mr. Southern also serves as Chairman of Sentgraf Enterprises Ltd. and Deputy Chairman of AKITA Drilling Ltd. Some of Mr. Southern's many distinctions include: Companion of the Order of Canada, 2007, Commander of the Order of the British Empire, 1995, Officer of the Order of the Orange-Nassau, 2006.

Board/Committee Membership:	Attendance:	
Board of Directors	10 of 10	100%
Strategy Conference[6]	1 of 1	100%
Round Tables	4 of 4	100%

Other Public Board/Committee Memberships:[10]

Company	Term	Committees
ATCO Ltd. (Chair)	Since 1963	-
AKITA Drilling Ltd. (Deputy Chair)	Since 1992	-
CU Inc. (Chair)	Since 1999	-

Securities Held:[4][5][9]

Canadian Utilities Limited		ATCO Ltd.	
Class A non-voting	256,104	Class I Non-Voting	12,098,326
Class B common	144,804	Class II Voting	5,725,760
Series Q Second Preferred	20,000		
Series W Second Preferred	320,000		
Series X Second Preferred	120,000		

Dr. Roger Urwin

Age: 61
London, England
New Nominee[1]

Dr. Urwin recently retired as Group Chief Executive of National Grid Group plc, an international gas and electric utility. He played a key role in establishing the company's international strategy and its successful expansion into the U.S. Dr. Urwin was Managing Director and Chief Executive of London Electricity from 1990 to 1995. He is also a non-executive director of Utilico Investment Trust plc and Alfred McAlpine and a Fellow of the Royal Academy of Engineering.

Board/Committee Membership:	**Attendance:**		**Other Public Board/Committee Memberships:**		
			Company	Term	Committees
N/A	N/A	N/A	Alfred McAlpine Utilico Investment Trust plc	Since 2006 Since 2005	 Audit Management Engagement Remuneration

Securities Held:[4] [5]

Canadian Utilities Limited		**ATCO Ltd.**	
Class A non-voting Class B common	0 0	Class I Non-Voting Class II Voting	0 0

Charles W. Wilson

Age: 67
Evergreen, CO, USA
Director Since: 2000
Independent[1]
Meets share ownership guidelines[2]

Mr. Wilson is a former President, Chief Executive Officer and director of Shell Canada Limited and a former President and director of Shell Investments Limited (Canada). Mr. Wilson graduated from the University of New Mexico with his Master of Science in Engineering and held several senior executive positions in refining and marketing, chemical, oil & gas production and corporate planning during his career at Shell.

Board/Committee Membership:	**Attendance:**		**Other Public Board/Committee Memberships:**		
			Company	Term	Committees
Board of Directors Strategy Conference[6] Round Tables Audit Risk Review	9 of 10 1 of 1 4 of 4 5 of 5 2 of 2	90% 100% 100% 100% 100%	ATCO Ltd. AKITA Drilling Ltd. Big Rock Brewery Income Trust Talisman Energy Inc.	Since 2002 Since 2002 Since 1999 Since 2002	Audit GOCOM[3] Risk Review GOCOM[3] Corporate Governance Audit Executive Reserves

Securities Held:[4] [5]

Canadian Utilities Limited		**ATCO Ltd.**	
Class A non-voting Class B common	10,500 0	Class I Non-Voting Class II Voting	8,497 0

(1) "Independent" refers to the determination of whether a director is independent as that term is defined in Multilateral Instrument 52-110 *Audit Committees*. See Schedule A, Corporate Governance Disclosure, Section 1. If elected, Dr. Urwin will be independent.
(2) Within five years of being appointed to the Board of the Corporation, directors should directly or indirectly own shares of the Corporation having an aggregate fair market value of at least $150,000. This ownership is to be maintained for the duration the director remains on the Board. L.M. Charlton and M.R.P. Rayfield have less than five years tenure on the Board.
(3) Corporate Governance – Nomination, Compensation and Succession Committee.
(4) The number of shares beneficially owned or over which control or direction is exercised by the director, as of March 1, 2007.
(5) The information as to shares beneficially owned or controlled has been furnished by the nominees.
(6) The directors annually attend a comprehensive four to five day strategy conference.
(7) L.M. Charlton was appointed to the Board on May 4, 2006.
(8) H.M. Neldner was appointed to GOCOM effective August 2006.
(9) An associate of R.D. Southern, other than Sentgraf Enterprises Ltd., owns 3,296 Class I Non-Voting and 1,648 Class II Voting Shares of ATCO Ltd. Shares held by this associate are not included in the shareholdings of R.D. Southern.
(10) Canadian Airlines Corporation filed for protection under the Companies' Creditors Arrangement Act within one year after R.D. Southern resigned as a director.

Compensation of Directors

The following table sets forth the annual retainers and attendance fees paid to members of the Board during 2006:

Directors' Remuneration	($)
Annual Retainers	
Director	95,000
Chairman of the Board	250,000 [1]
Vice Chairman of the Board	50,000
Lead Director	30,000
Audit Committee Chairman [2]	15,000
Audit Committee Members	5,000
Corporate Governance - Nomination, Compensation and Succession Committee Chairman	5,000
Risk Review Committee Chairman	5,000
Pension Committee Chairman	5,000
Meeting Fees	
Board Meeting, Strategy, Round Table, and Briefing Session	2,000
Meeting for routine administrative matters where nature of discussion is brief	800
Committee Meeting	800

(1) The Chairman of the Board's consolidated annual retainer for the ATCO Group was $250,000, of which $27,500, or 11%, was paid by ATCO Ltd. and $222,500, or 89%, was paid by Canadian Utilities Limited.

(2) Effective July 1, 2006, the Audit Committee Chairman's annual retainer was increased from $10,000 to $15,000.

Fees Paid to Individual Directors

The following table summarizes the cash compensation that was paid to each non-employee director of the Corporation for the fiscal year ended December 31, 2006:

Name	Board Retainer ($)	Committee Chair Retainer ($)	Committee Member Retainer ($)	Board Attendance Fees[4] ($)	Committee Attendance Fees[4] ($)	Other Fees[4] [5] ($)	Total Fees Paid ($)
R.T. Booth	95,000	-	-	12,400	800	23,600	131,800
W.L. Britton	145,000 [1]	5,000	-	11,666	2,200	15,533	179,399
L.M. Charlton	63,333	-	3,333	9,600	2,400	22,400	101,066
B.P. Drummond	95,000	-	-	11,000	5,600	8,000	119,600
B.K. French	95,000	12,500	-	11,866	1,868	20,398	141,632
L.A. Heathcott	95,000	-	-	8,400	800	12,400	116,600
H.M. Neldner	95,000	10,000	5,000	11,866	9,068	24,798	155,732
M.R.P. Rayfield	95,000	-	-	10,400	4,000	16,800	126,200
J.W. Simpson	125,000 [2]	-	5,000	13,200	8,800	29,200	181,200
R.D. Southern	222,500 [3]	-	-	-	-	-	222,500
C.W. Wilson	95,000	-	5,000	11,133	2,400	15,933	129,466
Total	1,220,833	27,500	18,333	111,531	37,936	189,062	1,605,195

(1) Includes retainer for Vice Chairman of the Board.

(2) Includes retainer for Lead Director.

(3) Represents the Corporation's 89% share of the consolidated annual retainer for the Chairman of the Board of the Corporation and ATCO Ltd.

(4) Directors are paid $2,000 for each regularly scheduled meeting of the Board. For other Board and committee meetings, the directors are paid a maximum fee of up to $2,000 per day. For the directors that are on the board and committees of both ATCO Ltd. and Canadian Utilities Limited the fees are shared proportionately when meetings are held on the same day.

(5) Includes fees for attendance at the annual strategy conference, round tables, briefing sessions, business group board meetings, designated audit director meetings and ad hoc committee meetings, as applicable.

Effective January 1, 2006, a minimum of $20,000 of a director's annual retainer must be paid in Class A non-voting shares of the Corporation. Directors have the option of receiving up to 50% of their annual retainer in Class A non-voting shares.

In addition to regular Board and committee meetings, the directors participate in an annual strategy conference and round table and briefing sessions. During 2006 four round tables and one briefing session were held.

From time to time, the Board forms ad hoc committees to undertake special initiatives. The chairman and members of any such ad hoc committees receive such fees as may be determined when any such ad hoc committees are appointed. A special committee was established to ensure a fair market valuation was used in relation to a non-arm's length transaction. J.W. Simpson, M.R.P. Rayfield and L.M. Charlton were members of the committee and were each paid a retainer of $800.

Directors are reimbursed for travel and other expenses incurred for attendance at Board and Committee meetings. Directors who are full-time salaried employees of the Corporation receive no remuneration for serving as a director.

Directors are eligible to receive grants of options and share appreciation rights under the Corporation's long-term incentive plans. A grant of 2,000 options was made to L.M. Charlton upon her appointment as a director of the Corporation in May 2006.

Directors who are not employees of the Corporation exercised options and share appreciation rights during the year. The following table summarizes the number of securities acquired on exercise and the aggregate dollar value realized. All of the exercised options and share appreciation rights were granted in 1997 and were due to expire on January 1, 2007.

	Canadian Utilities Limited	
Name	**Securities Acquired on Exercise (1) (#)**	**Aggregate Value Realized ($)**
W.L. Britton	28,000 (2)	784,280
L.A. Heathcott	120,000 (3)	3,273,050
H.M. Neldner	8,000 (4)	200,922
R.D. Southern	194,400 (5)	5,281,056

(1) Figures have been adjusted to reflect the two-for-one stock split by way of stock dividend paid on September 15, 2005.
(2) Represents the exercise of 14,000 options to acquire Class A non-voting shares of the Corporation and the exercise of 14,000 share appreciation rights of the Corporation.
(3) Represents the exercise of 60,000 options to acquire Class A non-voting shares of the Corporation and the exercise of 60,000 share appreciation rights of the Corporation.
(4) Represents the exercise of 4,000 options to acquire Class A non-voting shares of the Corporation and the exercise of 4,000 share appreciation rights of the Corporation.
(5) Represents the exercise of 127,200 options to acquire Class A non-voting shares of the Corporation and the exercise of 67,200 share appreciation rights of the Corporation.

Board Committees

The Board of the Corporation has four committees: Audit Committee, Corporate Governance - Nomination, Compensation and Succession Committee, Risk Review Committee and Pension Fund Committee. The Board annually appoints committee members and reviews and approves the committee mandates. The Corporation does not have an executive committee. In addition, from time to time, ad hoc committees of the Board are appointed to consider matters such as related party transactions and other issues of importance to the Board and the Corporation.

Director	Board Committees			
	Audit	GOCOM	Risk Review	Pension Fund
R.T. Booth			X	
W.L. Britton		X		
L.M. Charlton	X			
B.P. Drummond		X		X
B.K. French	X		X	
L.A. Heathcott				X
H.M. Neldner	X	X	X	X
M.R.P. Rayfield				X
J.W. Simpson	X	X	X	
C.W. Wilson	X		X	

Audit Committee

Chairman: B.K. French

The Audit Committee is comprised of five members. Each member is independent and financially literate within the meaning of these terms as defined in Multilateral Instrument 52-110 *Audit Committees*. The Committee held five meetings in 2006 and the Chairman of the Committee reports regularly to the Board of Directors. The Committee recommends to the Board of Directors the external auditor fees and the reappointment of the external auditor. In addition the Committee reviews, and recommends to the Board of Directors, the annual financial statements, including management's discussion and analysis, the annual information form and the annual earnings press release. The Committee also is responsible for ensuring procedures have been established for the receipt, retention and treatment of complaints received regarding accounting, internal accounting controls, auditing matters, fraud or theft and the confidential, anonymous submission by employees of concerns regarding questionable accounting or auditing matters, fraud or theft.

The Committee is directly responsible for:

- Overseeing the work of the external auditor
- Pre-approving all non-audit services
- Reviewing and approving the interim financial statements, management's discussion and analysis and earnings press releases
- Ensuring adequate procedures are in place for the review and disclosure of financial information
- Ensuring the Corporation has implemented appropriate systems of internal control over financial reporting and that these systems are operating effectively
- Ensuring the internal audit function has been effectively carried out and the internal auditors have adequate resources
- Reviewing and approving the Corporation's hiring policies regarding partners, employees and former partners and employees of the external auditor
- Reviewing annually the adequacy of the Committee mandate.

The Audit Committee mandate is disclosed in the Corporation's annual information form and is also available on the Corporation's website at www.canadian-utilities.com.

Corporate Governance - Nomination, Compensation and Succession Committee

Chairman: W.L. Britton

The Corporate Governance – Nomination, Compensation and Succession Committee ("GOCOM") has four members and one member of the Committee is not independent. The Committee held four meetings in

2006 with two of the meetings several days in length. The Committee Chairman provides regular reports to the Board of Directors. The responsibilities of GOCOM are outlined on page 15 and the full mandate of this Committee is available on the Corporation's website at www.canadian-utilities.com.

Risk Review Committee

Chairman: H.M. Neldner

The Risk Review Committee is comprised of five members. The Committee held two meetings in 2006 and the Chairman of the Committee reports regularly to the Board of Directors. The Committee reviews risks that are identified as being significant to the Corporation as well as significant risks of its subsidiaries and is responsible for ensuring identified risks are appropriately addressed. The Committee also is responsible for ensuring there are adequate processes, policies, procedures and means to manage and mitigate identified risks. The Risk Review Committee mandate is available on the Corporation's website at www.canadian-utilities.com.

Pension Fund Committee

Chairman: H.M. Neldner

The Pension Fund Committee is comprised of four members. The Committee held four meetings in 2006 and the Chairman of the Committee reports regularly to the Board of Directors. The Committee oversees the retirement plans for employees of the Corporation in accordance with the Pension Governance Policy. The primary responsibilities of this Committee are to oversee the governance structure of the pension plan and approve policy decisions for benefit design and liability management, funding and investment of the plan and to select and monitor the investment managers for the plan. The Pension Fund Committee mandate is available on the Corporation's website at www.canadian-utilities.com.

Directors' and Officers' Liability Insurance

The Corporation, ATCO Ltd. and their affiliates have purchased insurance with an annual aggregate limit of $175,000,000 for such corporations and their directors and officers. The premium paid by the Corporation in the financial year ended December 31, 2006, was $561,000. No part of the premium was paid by a director or officer. The Corporation is responsible for the first $1,000,000 of any loss and there is no deductible in respect of claims against any director or officer.

APPOINTMENT OF AUDITOR

The persons named in the accompanying form of proxy intend to vote for the appointment of PricewaterhouseCoopers LLP as the auditor of the Corporation to hold office until the next annual meeting of shareholders of the Corporation. Appointment of the auditor requires the approval of a majority of the votes cast by the holders of the Class B common shares.

Auditor's Fees

The aggregate fees incurred by the Corporation and its subsidiaries for professional services provided by PricewaterhouseCoopers LLP in 2006 and 2005 were as follows ($ millions):

	2006	**2005**
Audit	$1.4	$1.3
Audit Related	0.1	0.1
Tax	0.3	0.3
	$1.8	$1.7

Representatives of PricewaterhouseCoopers LLP are planning to attend the meeting and will be available to respond to appropriate questions.

AMENDMENTS TO STOCK OPTION PLAN

The Corporation has a stock option plan (the "Plan") under which options are granted to reward sustainable profitable growth. For more information regarding the Plan, refer to "Long-Term Incentive Plans – Stock Options and Share Appreciation Rights" on page 18. Management believes that it would be in the best interests of the Corporation to amend the Plan as described in the following paragraphs. The Board has approved these amendments, subject to the approval of the shareholders and the Toronto Stock Exchange (the "TSX").

New General Amendment Provisions

In certain circumstances, the TSX now allows issuers to amend compensation arrangements such as stock option plans without the need for shareholder approval for amendments if the text of the plan includes a detailed amendment procedure that was specifically disclosed to shareholders at the time the plan was approved.

TSX-listed issuers have until June 30, 2007, to amend their compensation plans to include detailed amendment procedures. The TSX has strongly recommended that issuers introduce new amending provisions to their compensation plans at their next meeting of shareholders in order to obtain the requisite approval for the new amendment procedure.

Management proposes to change the Plan amendment provisions to provide the Board with the broadest scope of amendment powers permitted by the TSX, including the power to make fundamental amendments to the Plan without shareholder approval, except in cases where the TSX requires shareholder approval in any event. Management believes that this will position the Corporation to respond promptly in the future to changing industry and market compensation practices by enabling it to make TSX-permitted amendments to the Plan. The proposed amendment reads as follows:

"The Board may, at any time, suspend or terminate the Plan. The Board may also at any time, without shareholder approval, add to or repeal any of the terms of the Plan or any Options and, without limiting the generality of the foregoing, may make the following changes, deletions, revisions or amendments ("amendments"):

(a) any amendment to the vesting provisions of the Plan or any Option;

(b) any amendment to the termination provisions of the Plan or any Option, provided that such amendment does not entail an extension beyond the expiry date of the Option as provided for in Sections 9 and 14;

(c) any amendment to the persons eligible to receive Options or otherwise relating to the eligibility of anyone to receive Options other than an amendment which would have the potential of broadening or increasing insider participation;

(d) any amendment with respect to the method or manner of exercise of any Option;

(e) any amendment of a "housekeeping" nature; and

(f) any other amendment that under the rules of the TSX (or such other stock exchange on which the Shares may be listed) does not require shareholder approval;

provided that no such addition, repeal, or amendment shall in any manner materially adversely affect the rights of any Participant under any Options theretofore granted under the Plan without such Participant's consent.

This Section 21 is intended to provide the Board with the broadest scope of amendment powers permitted by the rules of the TSX (or such other stock exchange on which the Shares may be listed), as such rules may be amended from time to time."

Blackout Periods

The extension of an option is considered by the TSX to be an amendment to a plan that requires shareholder approval, however, the term of an option that expires during or shortly after a blackout period can be extended for up to five to ten business days after the expiry of the blackout period if the plan contains a provision permitting such extension. A proposed amendment to permit such extensions reads as follows:

"Notwithstanding Section 9, if the Option Period of an Option expires during or within ten (10) business days after a blackout period imposed by the Corporation under the ATCO Group Insider Trading Policy ("Blackout Period"), then the Option Period of such Option shall be extended to the date which is ten (10) business days after the last day of the Blackout Period, after which time such Option shall expire and terminate."

Miscellaneous

The foregoing amendments to the Plan will not become effective unless they are approved by the shareholders of the Corporation. Shareholders will be asked to pass a resolution approving the amendments. The resolution requires approval by a simple majority of the votes cast with respect thereto at the Meeting.

SECTION 3 EXECUTIVE COMPENSATION

Composition of the Corporate Governance - Nomination, Compensation and Succession Committee

The members of the Corporate Governance - Nomination, Compensation and Succession Committee of the Board of Directors ("GOCOM") are W.L. Britton (Chairman), H.M. Neldner (Deputy Chairman), B.P. Drummond and J.W. Simpson.

The Committee reviews and determines the Corporation's overall compensation program for all officers of the Corporation and its subsidiaries including salary, bonuses, and long term incentives. GOCOM reviews the mandates of the Board and its committees on an annual basis, is responsible for the disclosure of corporate governance practices as described in Schedule A of this circular and disclosure respecting compensation and the basis on which performance is measured. The Committee also assesses the effectiveness of the Board, reviews the size and composition of the Board, and considers persons as nominees for directors.

Executive Compensation Principles and Program Objectives

ATCO's group-wide compensation philosophy is to provide "competitive pay for competitive performance". This philosophy is designed to closely align the interests of executives and shareholders, and to support the continued success of the Corporation. GOCOM approves the compensation principles and objectives that ensure the achievement of this approach.

Compensation Principles

The Corporation's compensation principles are as follows:

1. Establish total compensation target levels (the sum of base salary, short-term incentives and long-term incentives) at the median of the relevant comparator markets. Compensation can be increased to deliver pay above the median when corporate and individual performance exceeds expectations in terms of year-over-year growth and relative performance as measured against the relevant comparator markets.

2. Utilize relevant peer industries and companies that are comprised from general industry, the utility industry and that may be national or Alberta based. Companies are either of a similar size and scope of operations or the data is adjusted to reflect the appropriate size and scope through linear regression analysis. Comparator company data is obtained from the Towers Perrin National Compensation Database, the Towers Perrin Energy Survey, the Mercer Benchmark Database, and the Mercer Petroleum Survey.

3. Provide a significant portion of total direct compensation based on corporate and individual performance which is to be paid in the event that prescribed targets are met or exceeded.

4. Establish the value of pensions, benefits and perquisites at the market median of the relevant comparator markets.

Compensation Objectives

The objectives of the Corporation's compensation plan are as follows:

1. Attract, retain, and align to the Corporation's business objectives, talented executives in a highly competitive business environment.

2. Evaluate each executive officer position, from Vice President to Chief Executive Officer, on the following factors and provide a base salary based on:

   - the individual's demonstrated ability to perform the role
   - skill and competency requirements
   - level of responsibility, and
   - market value of the role.

3. Compensate executives in a way that creates sustained shareholder value by:

   - ensuring all executives have an "at risk" component of total compensation that reflects their ability to influence business outcomes and financial performance
   - linking short-term incentives to prudent corporate performance and paying in the event that prescribed targets and objectives are met or exceeded
   - aligning the performance of the executive to the strategic plan of the Corporation, and
   - linking long-term incentives to sustainable profitable growth.

Independent Advice

GOCOM may engage independent compensation consultants to undertake market competitive compensation analysis of executive positions, to provide information on current market practices, and to provide advice in the development of new or revision of existing elements of the executive compensation programs.

GOCOM Decision-Making Criteria

GOCOM reviews each individual executive's total compensation annually, taking into consideration several factors. GOCOM reviews market data that shows how the executive is paid in relationship to the market median (50th percentile) for base salary, short-term incentives and long-term incentives (Total Direct Compensation or "TDC"). This analysis provides an understanding of each element of compensation and the amount of adjustment required to reach the market median. Market competitiveness is also combined with other factors in considering pay adjustments; these factors include:

- the executive's demonstrated performance through delivery of results,
- the executive's demonstrated alignment to the values and direction of the Corporation, and
- the executive's ability to develop and mentor other high-potential employees.

GOCOM considers these factors in totality, together with any other considerations that are determined to be relevant, in making its compensation decisions.

Executive Compensation Program Elements

Executive compensation consists of three main elements: base salary, short-term incentives (bonus), and long-term incentives (stock options and share appreciation rights). The percentage of total direct compensation for each element is aligned with the executive's responsibilities and ability to influence business results. The target incentive amount for short-term and long-term incentives varies with an executive's performance and level of responsibility and is considered in conjunction with regular reviews of competitive practice.

The three main elements of executive compensation are described below:

1. *Base Salary*

The relative levels of base salary for the executive officers are based on the accountabilities and responsibilities of each executive's position and market practices. Base salaries are reviewed annually and compared against similar positions in the comparator group of companies. In addition, the Committee may make adjustments in an individual's salary during the year based on changes in the executive's responsibilities.

2. *Short-Term Incentive Plan - Bonus*

The short-term incentive plan rewards executives based on a percentage of the officer's salary, for the achievement of predetermined strategic, operational and financial performance targets as well as individual performance objectives.

2.1 *Performance Measures*

Financial, Operational and Individual performance measures are set each year. Operational measures are based on operational metrics at the business unit level, which reinforce the importance of operating efficiency, safety goals and other metrics that are relevant to the business unit. Financial targets are set by GOCOM each year, with a range of performance measures from threshold to target for each company. The final measure is the individual performance of the executive in contributing to the achievement of the Corporation's goals.

2.2 *Short-Term Incentive Payouts*

Based on the achievement of 2006 performance targets, bonuses were awarded to our named executive officers as shown in the Summary Compensation Table on page 19.

3. *Long-Term Incentive Plans – Stock Options and Share Appreciation Rights*

The long-term incentive plans are designed to reward sustainable profitable growth. GOCOM awards stock options and share appreciation rights on an ad-hoc basis in conjunction with an analysis of each executive's total compensation package and individual performance.

The Corporation is authorized to grant options to purchase 6,400,000 Class A non-voting shares (7.86% of the number of outstanding Class A non-voting shares). At December 31, 2006, options to purchase 3,823,000 Class A non-voting shares (4.69% of the number of outstanding Class A non-voting shares) had been granted, of which 1,442,400 had been exercised, 1,122,800 had been settled by paying the in-the-money amount without issuing any shares and 49,800 had been cancelled.

Long-Term Incentive Plan Specific Terms

GOCOM may designate directors, officers and key employees of the Corporation and its subsidiaries to be granted options to purchase Class A non-voting shares at an exercise price equal to the weighted average of the trading price of the shares on the TSX for the five trading days immediately preceding the date of grant. The vesting provisions and exercise period are determined at the time of grant. Options are not assignable and cannot be converted into share appreciation rights. Options terminate on the earlier of their expiration or 90 days after a participant ceases to be a director, officer or employee for any reason other than death, disability or retirement, in which case they terminate after two years.

Share Appreciation Rights Plan

In addition to the stock option plan, the Corporation has a share appreciation rights plan. GOCOM may designate directors, officers and key employees of the Corporation and its subsidiaries to be granted share appreciation rights based on the Class A non-voting shares. The vesting provisions and exercise period, which cannot exceed ten years, are determined at the time of grant. The holder is entitled on exercise to receive a cash payment from the Corporation equal to any increase in the market price of the Class A non-voting shares over the base value of the share appreciation rights exercised. The base value is equal to the weighted average of the trading price of the Class A non-voting shares on the TSX for the five trading days immediately preceding the date of grant. Rights are not assignable and terminate on the earlier of their expiration or 90 days after a participant ceases to be a director, officer or employee for any reason other than death, disability or retirement, in which case they terminate after two years.

Summary Compensation Table

The summary compensation table (page 19) sets out information concerning the compensation during the last three fiscal years of the Chief Executive Officer and the Chief Financial Officer of the Corporation and the three other executive officers of the Corporation and its subsidiaries employed at December 31, 2006, who had the highest individual aggregate salary and bonuses during 2006 (the "Named Executive Officers"). This information reflects all compensation received by the Named Executive Officers from the Corporation and its subsidiaries for their services as executive officers in all capacities.

Consolidated Total Compensation of Named Executive Officers

N.C. Southern, K.M. Watson, M.M. Shaw, S.W. Kiefer and S.R. Werth also served in 2006 in similar senior executive positions with ATCO Ltd., the parent of the Corporation. The salary and bonus amounts for these officers of ATCO Ltd. and Canadian Utilities Limited are determined annually on a consolidated basis.

These officers do not receive separate salaries or bonuses for serving both corporations. The amounts reported in this circular reflect the total compensation provided to these officers for their contribution to Canadian Utilities Limited and its subsidiaries.

Formula for Apportionment of Salaries of Named Executive Officers

Canadian Utilities Limited's share of the consolidated amount of total compensation is based on a number of considerations, including:

- the portion of the consolidated assets of ATCO Ltd. that the assets of Canadian Utilities Limited represent
- the estimated portion of each executive officer's time anticipated to be spent performing services as an executive officer of Canadian Utilities Limited and its subsidiaries, and
- decisions of the Alberta Energy and Utilities Board.

For 2006, Canadian Utilities Limited paid 89% (89% in 2005 and 2004) of the consolidated salary and bonus amounts paid to the Named Executive Officers by Canadian Utilities Limited and ATCO Ltd. The amounts paid by Canadian Utilities Limited are set out in the following table.

Summary Compensation Table – Canadian Utilities Limited

Name and Principal Occupation [1]	Year Ended Dec 31	Salary [2] ($)	Bonus [2] ($)	Other Annual Compensation [3] ($)	Securities Under Options/SARs Granted [4] [5] (#)	All Other Compensation ($)
N.C. Southern President & Chief Executive Officer	2006 2005 2004	890,000 [2] 890,000 [2] 756,500 [2]	890,000 [2] 890,000 [2] Nil [2]	Nil Nil Nil	50,000/Nil 200,000/200,000 Nil/30,000	8,900 [6] Nil Nil
K.M. Watson Senior Vice President & Chief Financial Officer	2006 2005 2004	293,700 [2] 267,000 [2] 218,791 [2]	307,050 [2] 329,300 [2] Nil [2]	Nil Nil Nil	5,000/5,000 Nil/Nil Nil/5,000	1,068 [6] Nil Nil
M.M. Shaw Managing Director, Global Enterprises	2006 2005 2004	391,600 [2] 373,800 [2] 356,000 [2]	391,600 [2] 498,400 [2] Nil [2]	Nil Nil Nil	5,000/5,000 Nil/Nil Nil/10,000	22,738 [7] 18,000 [8] 16,500 [8]
S.W. Kiefer Managing Director, Utilities & Chief Information Officer	2006 2005 2004	391,600 [2] 347,100 [2] 311,500 [2]	391,600 [2] 391,600 [2] 89,000 [2]	Nil Nil Nil	10,000/5,000 Nil/Nil Nil/10,000	3,471 [6] Nil Nil
S.R. Werth Senior Vice President & Chief Administration Officer	2006 2005 2004	289,250 [2] 275,900 [2] 258,100 [2]	302,600 [2] 320,400 [2] Nil [2]	Nil Nil Nil	5,000/5,000 Nil/Nil Nil/5,000	534 [6] Nil Nil

(1) All Named Executive Officers hold the same offices for both ATCO Ltd. and Canadian Utilities Limited.
(2) The amounts shown under salary and bonus were paid by Canadian Utilities Limited and reflect 89% of the Named Executive Officers' total salary and bonus in 2006. The balance of the salary and bonus (11%) was paid by ATCO Ltd., the parent corporation.
(3) The value of perquisites and other personal benefits received by each Named Executive Officer was less than the lesser of $50,000 and 10% of the total of his or her annual salary and bonus, and therefore is reported as nil in accordance with National Instrument 51-102.
(4) Figures have been adjusted to reflect the two-for-one stock split by way of stock dividend paid on September 15, 2005.
(5) Represents the aggregate number of options and SARs granted by the Corporation.
(6) Represents the employer contribution to the Employee Share Purchase Plan.
(7) Represents the amount contributed by the Corporation to M.M. Shaw's defined contribution pension ($19,000) and the amount of the employer contribution to the Employee Share Purchase Plan ($3,738).
(8) Represents the amount contributed by the Corporation to M.M. Shaw's defined contribution pension.

Amendments to the Stock Option Plan

Since January 1, 2006, the Board of Directors of the Corporation has approved the following amendments to the stock option plan deemed to be of a housekeeping nature only and not requiring shareholder approval:

(a) clarification of participant's status and rights;
(b) expansion of the definition of "change of control" to include a provision that conversion into a trust would not constitute a change of control;
(c) removal of the ten-year limit on the duration of options;
(d) removal of the five-percent limit on grants to any one participant; and
(e) addition of a provision that limits the number of securities issued to insiders within any one-year period and the number of securities issuable to insiders at any time under the stock option plan and any other security based compensation arrangements to ten percent of the Corporation's issued and outstanding securities.

Equity Compensation Plan Information

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options	Weighted Average Exercise Price of Outstanding Options	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Outstanding Options)
Equity compensation plans approved by shareholders	1,208,000	$25.12	2,626,800

Option/SAR Grants During 2006

The following table sets out the individual grants of options to purchase or acquire securities of the Corporation or any of its subsidiaries and share appreciation rights ("SARs") made during 2006 to the Named Executive Officers.

Name	Securities Under Options/SARs Granted [1] (#)	% of Total Options/SARs Granted to Employees in 2006 (%)	Exercise Price ($/Security)	Market Value of Securities Underlying Options/SARs on the Date of Grant ($/Security)	Expiration Date
N.C. Southern	50,000/Nil	41/0	43.56	43.56	January 2, 2016
K.M. Watson	5,000/5,000	4/13	43.56	43.56	January 2, 2016
M.M. Shaw	5,000/5,000	4/13	43.56	43.56	January 2, 2016
S.W. Kiefer	10,000/5,000	8/13	43.56	43.56	January 2, 2016
S.R. Werth	5,000/5,000	4/13	43.56	43.56	January 2, 2016

(1) Stock options and share appreciation rights based on Class A non-voting shares of the Corporation which vest as to 20% annually on each of the first five anniversaries of the date of grant.

Aggregated Option/SAR Exercises During 2006 and Year-End Option/SAR Values

The following table sets out information regarding the exercise of options and SARs during 2006 by each of the Named Executive Officers and the financial year-end value of unexercised options and SARs on an aggregate basis.

Name	Securities Acquired on Exercise (#)	Aggregate Value Realized ($)	Unexercised Options/SARs at December 31, 2006 [1]		Value of Unexercised In-the-Money Options/SARs at December 31, 2006 [1]	
			Exercisable (#)	Unexercisable (#)	Exercisable (#)	Unexercisable (#)
N.C. Southern	70,000 [4]	836,790	164,000 [2] Nil [3]	218,000 [2] 190,000 [3]	3,856,360 [2] Nil [3]	3,180,700 [2] 3,395,560 [3]
K.M. Watson	9,300 [5]	210,054	12,600 [2] 4,400 [3]	6,600 [2] 9,600 [3]	322,938 [2] 89,720 [3]	55,770 [2] 111,780 [3]
M.M. Shaw	12,000 [6]	343,020	27,500 [2] 22,000 [3]	13,000 [2] 23,000 [3]	693,405 [2] 467,530 [3]	195,450 [2] 394,770 [3]
S.W. Kiefer	16,000 [7]	325,360	30,000 [2] 4,000 [3]	14,000 [2] 19,000 [3]	739,300 [2] 74,680 [3]	129,000 [2] 307,470 [3]
S.R. Werth	Nil	Nil	22,400 [2] 14,400 [3]	6,600 [2] 9,600 [3]	552,830 [2] 335,970 [3]	55,770 [2] 111,780 [3]

(1) Figures have been adjusted to reflect the two-for-one stock split by way of stock dividend paid on September 15, 2005.
(2) Options to acquire Class A non-voting shares of the Corporation.
(3) Share appreciation rights based on Class A non-voting shares of the Corporation.
(4) Represents the exercise of 70,000 share appreciation rights of the Corporation.
(5) Represents the exercise of 3,300 options to acquire Class A non-voting shares of the Corporation and the exercise of 6,000 share appreciation rights of the Corporation.
(6) Represents the exercise of 6,000 options to acquire Class A non-voting shares of the Corporation and the exercise of 6,000 share appreciation rights of the Corporation.
(7) Represents the exercise of 16,000 share appreciation rights of the Corporation.

Pension and Retirement Arrangements

Canadian Utilities Pension Plan

The Named Executive Officers participate in The Retirement Plan for Employees of Canadian Utilities Limited and Participating Companies (the "CU Plan"). The CU Plan is comprised of two components: defined benefit (DB) and defined contribution (DC). The DC component was introduced on January 1, 1997; existing DB members were provided the option to remain in the DB component or to move to the DC component. N.C. Southern, K.M. Watson, S.W. Kiefer and S.R. Werth participate in the DB component; M.M. Shaw participates in the DC component. Participation in both the DB and DC components is non-contributory for the Named Executive Officers.

Canadian Utilities Limited has undertaken to provide K.M. Watson, M.M. Shaw, S.W. Kiefer and S.R. Werth with pensions under a supplemental arrangement to compensate for limitations on DB pension benefits or on DC pension contributions imposed by the Income Tax Act. This supplemental pension allows the company to provide retirement income that is relative to their final earnings level and ensures market competitiveness. The supplemental arrangements are not funded. Benefits accrued under the supplemental arrangement use the same formula as the underlying DB registered pension plan. Service for the supplemental arrangement is capped at 35 years. The supplemental arrangement, when included with the pension payable under the CU Plan, the estimated Canada Pension Plan ("CPP") integration amount, and any amounts payable under pension plans or supplemental arrangements of the affiliates of Canadian Utilities Limited, provides a pension based on 2% of the average of the highest five consecutive years of salary, excluding bonuses, multiplied by the number of years of credited service, up to a maximum of 35 years. Under this Plan, an executive may be entitled to receive a pension of up to 70% of the average of the highest five years of salary.

Pension Plan Table

The following table sets forth the annual pension payable to K.M. Watson, M.M. Shaw, S.W. Kiefer and S.R. Werth at normal retirement age 65, inclusive of all registered pension plans and supplemental arrangements and the estimated CPP integration amount based on 2% of the average of the highest five consecutive years of salary, excluding bonuses, multiplied by the number of years of credited service up to a maximum of 35 years. The benefit is payable for the participant's lifetime and provides their spouse with a survivor benefit of at least 60% of the monthly payment. Pension benefits may be indexed on an ad hoc basis.

Remuneration	**Years of Service**				
$	**15**	**20**	**25**	**30**	**35**
200,000	60,000	80,000	100,000	120,000	140,000
250,000	75,000	100,000	125,000	150,000	175,000
300,000	90,000	120,000	150,000	180,000	210,000
400,000	120,000	160,000	200,000	240,000	280,000
500,000	150,000	200,000	250,000	300,000	350,000
600,000	180,000	240,000	300,000	360,000	420,000
700,000	210,000	280,000	350,000	420,000	490,000
800,000	240,000	320,000	400,000	480,000	560,000

For purposes of the supplemental arrangement, the calculation of annual pension payable assumes that the amount payable under the CU Plan is the same regardless of whether a participant elects the DB or DC provisions of the CU Plan. For participants of the DC provisions, the actual pension payable at retirement will vary depending on the value of their investment account at retirement.

Years of Credited Service Under the CU Plan as at December 31, 2006

Named Executive Officer	**Credited Service**
N.C. Southern	11.00
K.M. Watson	28.75
M.M. Shaw	20.00
S.W. Kiefer	23.00
S.R. Werth	25.67

Compensation of the Chief Executive Officer

GOCOM reviews and determines annually the total direct compensation of the Chief Executive Officer on the basis of achievement of the strategic, operational and financial performance of the Corporation.

1. *Base salary*

Base salary is provided to compensate the Chief Executive Officer for performing the requirements and achieving the goals of the Corporation. Base salary is determined by reviewing competitive market data for the role, and the performance assessment by GOCOM. Base salary is reviewed annually and approved by GOCOM.

2. *Short-Term Incentive*

The short-term incentive plan rewards the Chief Executive Officer, based on a percentage of salary, for the achievement of predetermined strategic, operational and financial performance related to ATCO Group and for individual performance.

GOCOM may also award discretionary bonuses to reward Executive Officers for their contribution to especially notable accomplishments.

3. *Long-Term Incentives*

The long-term incentive rewards to the Chief Executive Officer are based on her ability to achieve sustainable profitable growth for shareholders of the Corporation. Information on the base salary and short and long-term incentive award decisions for Ms. Southern and the other Named Executive Officers made by GOCOM can be found in the Summary Compensation Table.

Employment Agreement for N.C. Southern, President & Chief Executive Officer

Term of Agreement

The Corporation has an employment agreement with N.C. Southern extending to February 1, 2008, and continuing from year to year thereafter. The amount of salary and the value of benefits paid in 2006 under this agreement have been included in the Summary Compensation Table on page 19.

Termination of Agreement

Employment of the executive officer may be terminated by the Corporation on notice equal to the greater of two years and the remaining term of the agreement or payment in lieu of notice, and may be terminated by the executive officer on 90 days notice.

Retiring Allowance

Pursuant to her employment agreement with the Corporation, N.C. Southern is eligible upon retirement to receive a pension of 70% of the average of the highest five years of income, including salary and bonuses, during the last ten years of employment prior to retirement.

The pension payable to N.C. Southern under her employment agreement is inclusive of the pension payable under the CU Plan. The benefit is payable for Ms. Southern's lifetime and provides her spouse with a survivor benefit of at least 60% of the monthly payment. Pension benefits may be indexed on an ad hoc basis.

Disability and Life Insurance

N.C. Southern's employment agreement provides for the payment of certain benefits upon the death or total disability of the executive officer prior to retirement or termination. The amount of such benefits is based on the executive officer's salary and is determined in accordance with formulas that take into account amounts payable to the executive officer under the group life insurance policies and disability income programs of the Corporation.

Submitted by the Corporate Governance - Nomination, Compensation and Succession Committee of the Board of Directors.

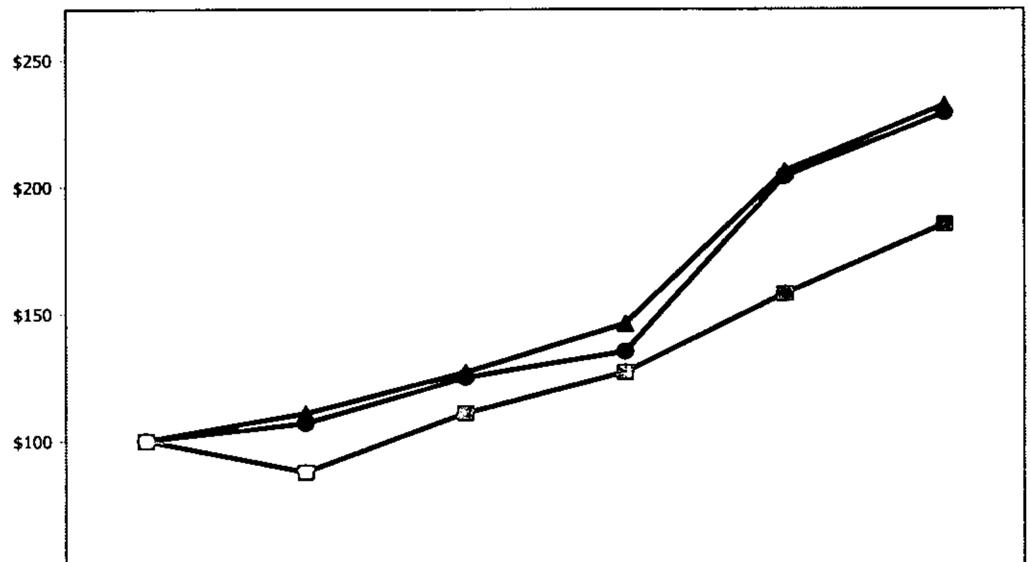
W.L. Britton, Chairman
H.M. Neldner, Deputy Chairman
B.P. Drummond
J.W. Simpson

SECTION 4 OTHER INFORMATION

PERFORMANCE GRAPH

The graph below compares the five-year cumulative return on the Class A non-voting shares and Class B common shares of the Corporation (assuming reinvestment of dividends) with the cumulative total return of the S&P/TSX Composite Index.

Five Year Total Return on $100 Investment



	2001	2002	2003	2004	2005	2006
Class A non-voting	100	107	125	135	204	229
Class B common	100	111	127	146	206	232
S&P/TSX Composite	100	88	111	127	158	185

(1) Figures have been adjusted to reflect the two-for-one stock split by way of stock dividend paid on September 15, 2005.
(2) 2006 figures include a special dividend of 25 cents per share paid on September 1, 2006.

CORPORATE GOVERNANCE

The Board of the Corporation views effective corporate governance as an essential element for the ongoing well-being of the Corporation and its shareholders. The Corporation strives to ensure that its corporate governance practices provide for effective stewardship of the Corporation and evaluates its practices on an ongoing basis. The corporate governance disclosure for the Corporation is attached to this management proxy circular as Schedule A. Additional information regarding the Corporation's Board of Directors and its committees is set forth below.

The Board generally meets seven times a year and additionally during the year as the need arises. The frequency and length of meetings and the nature of agenda items depend upon the circumstances. Meetings are generally lengthy, detailed and well attended, and are conducted in an atmosphere which encourages participation and independence. In addition to regularly scheduled Board and committee meetings, the directors annually attend a comprehensive four to five day strategy session. Round table discussion sessions and director briefings are also held throughout the year. Each director's meeting attendance is disclosed on pages 3 through 9. The Board mandate, attached to this proxy circular as Schedule B, outlines the roles and responsibilities of the Board.

The Corporation's operations are conducted through its principal operating subsidiaries, and each subsidiary is assigned to one of four business group boards: Power Generation, Utilities, Energy Services & Technologies and Industrials & Logistics. Directors of the Corporation may sit on a business group board, and there are nine other outside directors who are not directors of the Corporation. These individuals provide independent advice regarding the operations of the principal operating subsidiaries within their business groups and gain experience with respect to the roles and responsibilities of public company directors.

As a significant shareholder, R.D. Southern is closely identified with the Corporation by industry participants, the investment community and the Corporation's shareholders. The Corporation's business approach, strategies, practices and culture have developed and evolved under Mr. Southern's leadership.

ADDITIONAL INFORMATION

Additional information relating to the Corporation is available on SEDAR at www.sedar.com. Information regarding the business of the Corporation is provided in the Corporation's annual information form dated February 21, 2007. Financial information is provided in the Corporation's comparative consolidated financial statements and the management's discussion and analysis of financial condition and results of operations for the year ended December 31, 2006. Copies of these documents and the Corporation's interim financial statements and additional copies of this management proxy circular may be obtained upon request from the Corporate Secretary of the Corporation at 1400 ATCO Centre, 909 - 11th Avenue S.W., Calgary, Alberta, T2R 1N6.

Corporate information, including our privacy commitment, is also available on the Corporation's website: www.canadian-utilities.com.

Directors' Approval

The Board of the Corporation has approved the contents and the sending of this management proxy circular.

General

November 30, 2007, is the final date by which an eligible shareholder must submit to the Corporation a proposal that is to be included in the management proxy circular for any matter at the next annual meeting of shareholders.

DATED at Calgary, Alberta, this 1st day of March, 2007.

P. Spruin
Corporate Secretary

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SCHEDULE A CORPORATE GOVERNANCE DISCLOSURE UNDER NATIONAL INSTRUMENT 58-101

Disclosure Requirement	CU Corporate Governance Practices
1. **Board of Directors**	
(a) Disclose the identity of directors who are independent.	The following directors are independent as that term is defined in section 1.4 of Multilateral Instrument 52-110 *Audit Committees:* L.M. Charlton B.P. Drummond B.K. French H.M. Neldner M.R.P. Rayfield J.W. Simpson C.W. Wilson
(b) Disclose the identity of directors who are not independent, and describe the basis for that determination.	N.C. Southern, R.D. Southern, W.L. Britton, L.A. Heathcott and R.T. Booth are not independent because they are considered to have a material relationship with the issuer. N.C. Southern is the President & Chief Executive Officer of the Corporation (the "CEO"). R.D. Southern is the Chairman of the Board. W.L. Britton is the Vice Chairman of the Board. L.A. Heathcott is an immediate family member of the Chairman. R.T. Booth is a partner in a firm that is the Corporation's legal counsel.
(c) Disclose whether or not a majority of directors is independent. If a majority of directors is not independent, describe what the board of directors does to facilitate its exercise of independent judgment in carrying out its responsibilities.	A majority of the directors of the Corporation is independent.
(d) If a director is presently a director of any other issuer that is a reporting issuer (or the equivalent) in a jurisdiction or a foreign jurisdiction, identify both the director and the other issuer.	The following directors are also directors of the issuers set out beneath their respective names below:

Disclosure Requirement	CU Corporate Governance Practices

W.L. Britton

- AKITA Drilling Ltd. (TSX), member of the Corporate Governance - Nomination, Compensation and Succession Committee
- ATCO Ltd. (TSX), Chairman of the Crisis Management and the Corporate Governance - Nomination, Compensation and Succession Committees
- CU Inc.
- Forest Oil Corp. (NYSE), member of the Nominating & Corporate Governance Committee

L.M. Charlton

- AKITA Drilling Ltd. (TSX), member of the Audit Committee

B.P. Drummond

- ATCO Ltd. (TSX), Chairman of the Audit Committee and member of the Risk Review and Corporate Governance - Nomination, Compensation and Succession Committees

B.K. French

- ATCO Ltd. (TSX), member of the Audit, Crisis Management, Risk Review and Corporate Governance - Nomination, Compensation and Succession Committees
- CU Inc., Chairman of the Audit Committee

L.A. Heathcott

- AKITA Drilling Ltd. (TSX), Chairman of the Board and a member of the Pension Committee

H.M. Neldner

- ATCO Ltd. (TSX), Chairman of the Risk Review Committee, Deputy Chairman of the Corporate Governance - Nomination, Compensation and Succession Committee and member of the Audit Committee
- CU Inc., member of the Audit Committee

J.W. Simpson

- Petro-Canada (TSX, NYSE), member of the Audit, Finance and Risk and Management Resources and Compensation Committees

Disclosure Requirement	CU Corporate Governance Practices
	N.C. Southern ▪ AKITA Drilling Ltd. (TSX) ▪ ATCO Ltd. (TSX) ▪ CU Inc. ▪ Bank of Montreal (TSX, NYSE), member of the Risk Review Committee ▪ Shell Canada Ltd. (TSX), Chairman of the Health, Safety, Environment & Social Responsibility Committee and a member of the Nominating and Governance Committee **R.D. Southern** ▪ AKITA Drilling Ltd. (TSX), Deputy Chairman of the Board ▪ ATCO Ltd. (TSX), Chairman of the Board ▪ CU Inc., Chairman of the Board **C.W. Wilson** ▪ AKITA Drilling Ltd. (TSX), member of the Corporate Governance - Nomination, Compensation and Succession Committee ▪ ATCO Ltd. (TSX), member of the Audit, Risk Review and Corporate Governance - Nomination, Compensation and Succession Committees ▪ Big Rock Brewery Income Trust (TSX), member of the Corporate Governance Committee ▪ Talisman Energy Inc. (TSX, NYSE), member of the Audit, Executive and Reserves Committees
(e) Disclose whether or not the independent directors hold regularly scheduled meetings at which non-independent directors and members of management are not in attendance. If the independent directors hold such meetings, disclose the number of meetings held since the beginning of the issuer's most recently completed financial year. If the independent directors do not hold such meetings, describe what the board does to facilitate open and candid discussion among its independent directors.	In-camera meetings with independent directors are scheduled at each of the main board meetings. In 2006, independent directors had four in-camera meetings. Directors are entitled to request through the Lead Director additional meetings at any time.
(f) Disclose whether or not the chair of the board is an independent director. If the board has a chair or lead director who is an independent director, disclose the identity of the	R.D. Southern, the Chairman of the Board, is not an independent director. The Corporation's Lead Director, J.W. Simpson, is independent.

Disclosure Requirement	CU Corporate Governance Practices
independent chair or lead director, and describe his or her role and responsibilities. If the board has neither a chair that is independent nor a lead director that is independent, describe what the board does to provide leadership for its independent directors.	The primary function of the Lead Director is to provide independent leadership to ensure the Board of Directors (the "Board") functions independently of management of the Corporation. The position description for the Lead Director is available on the Corporation's website at www.canadian-utilities.com.
(g) Disclose the attendance record of each director for all board meetings held since the beginning of the issuer's most recently completed financial year.	The attendance record of each director at Board, committee and other relevant meetings is disclosed on pages 3 through 9.
2. **Board Mandate**	
Disclose the text of the board's written mandate. If the board does not have a written mandate, describe how the board delineates its role and responsibilities.	The mandate of the Board is attached as Schedule B and is also available on the Corporation's website at www.canadian-utilities.com. The Corporation's Corporate Governance - Nomination, Compensation and Succession Committee ("GOCOM") is responsible for reviewing the mandates of the Board and its committees on an annual basis and recommending to the Board such amendments to those mandates as GOCOM believes are necessary or desirable.
3. **Position Descriptions**	
(a) Disclose whether or not the board has developed written position descriptions for the chair and the chair of each board committee. If the board has not developed written position descriptions for the chair and/or the chair of each board committee, briefly describe how the board delineates the role and responsibilities of each such position.	The Board has approved written position descriptions for the Chairman of the Board and the chair of each Board committee. The position descriptions are reviewed annually by GOCOM. Copies of these descriptions are available on the Corporation's website at www.canadian-utilities.com.
(b) Disclose whether or not the board and CEO have developed a written position description for the CEO. If the board and CEO have not developed such a position description, briefly describe how the board delineates the role and responsibilities of the CEO.	The Board has approved a written position description for the CEO. The position description is reviewed annually by GOCOM and is available on the Corporation's website at www.canadian-utilities.com.
4. **Orientation and Continuing Education**	
(a) Briefly describe what measures the board takes to orient new directors regarding: (i) the role of the board, its committees and its directors, and	New directors attend a briefing with the Chairman of the Board and the Vice Chairman of the Board in addition to attending comprehensive meetings at which they receive briefings on all aspects of the nature and operation of the Corporation's business

Disclosure Requirement	CU Corporate Governance Practices
(ii) the nature and operation of the issuer's business.	by senior management of the Corporation and its subsidiaries. New directors are also provided with a manual which contains information about each of the Business Groups, organization structure, by-laws, Board and committee mandates and corporate policies, including the Corporation's Code of Ethics and Disclosure Policy.
(b) Briefly describe what measures, if any, the board takes to provide continuing education for its directors. If the board does not provide continuing education, describe how the board ensures that its directors maintain the skill and knowledge necessary to meet their obligations as directors.	Directors, together with senior management, attend an annual four to five day strategy conference which has been held consecutively since 1981. At these sessions, the Board receives detailed briefings on the business activities of the Corporation and its subsidiaries as well as other pertinent information required for directors to fulfill their obligations. Visits to various operating sites are also arranged for directors. In addition, directors attend and participate in seminars and other continuing education programs. L.M. Charlton completed the Institute of Corporate Directors' "Financial Literacy for Directors and Executives" course in April, 2006, and is currently enrolled in the Directors' Education Program at the Institute of Corporate Directors. Outside experts are brought in as required to provide directors with ongoing education on general and/or specific subject matters. The Corporation's business group boards provide continuing education for current directors and serve as a "training ground" for potential future directors of the Corporation.
5. **Ethical Business Conduct**	
(a) Disclose whether or not the board has adopted a written code for the directors, officers and employees. If the board has adopted a written code:	The Board has adopted a written Code of Ethics (the "Code"), which is subject to periodic review and revision to ensure it is in line with best practices.
(i) disclose how a person or company may obtain a copy of the code;	A copy of the Code may be obtained upon request from the Corporate Secretary of the Corporation at 1400 ATCO Centre, 909 – 11th Avenue S.W., Calgary, Alberta, T2R 1N6. The Code is also available on the Corporation's website atwww.canadian-utilities.com and on the SEDAR website at www.sedar.com.
(ii) describe how the board monitors compliance with its code, or if the board	A copy of the Code has been provided to each director, officer and employee of the Corporation

Disclosure Requirement	CU Corporate Governance Practices
does not monitor compliance, explain whether and how the board satisfies itself regarding compliance with its code; and	and each such person is required to acknowledge annually that he or she has read the Code and disclosed any transactions or matters of potential conflict. Similarly, copies of the Code will be provided to each new director, officer and employee of the Corporation, and each such person shall acknowledge that he or she has read the Code before commencing activities as a director, officer or employee, as the case may be.
(iii) provide a cross-reference to any material change report filed since the beginning of the issuer's most recently completed financial year that pertains to any conduct of a director or executive officer that constitutes a departure from the code.	No material change reports have been filed by the Corporation since January 1, 2006 relating to a director's or executive officer's departure from the Code. Further, no waivers of the Code have ever been granted to any director, officer or other employee of the Corporation.
(b) Describe any steps the board takes to ensure directors exercise independent judgment in considering transactions and agreements in respect of which a director or executive officer has a material interest.	Directors who have, or may be reasonably perceived to have, a personal interest in a transaction or agreement being contemplated by the Corporation are required to declare such interest at any directors' meeting where the matter is being considered are requested to leave the meeting during discussion on such matter and abstain from voting.
(c) Describe any other steps the board takes to encourage and promote a culture of ethical business conduct.	The Board encourages and promotes a culture of ethical business conduct by expecting each director, all officers and management to act in a manner that exemplifies ethical business conduct. This expectation sets the tone for all employees of the Corporation. The Corporation strives to ensure that prospective employees are of good character.
6. **Nomination of Directors**	
(a) Describe the process by which the board identifies new candidates for board nomination.	GOCOM is responsible for, among other things, identifying and recommending potential candidates for nomination to the Board. The identification of potential Board members is undertaken with a view to ensuring overall diversity of experience, backgrounds, skills and geographic representation of Board members. GOCOM receives advice from the Board respecting individuals best suited to serve as directors, and maintains its own standing list of appropriate candidates for directorships.
(b) Disclose whether or not the board has a nominating committee composed entirely of independent directors. If the board does not have a nominating committee composed	One of the four members of GOCOM is not independent. GOCOM conducts its business on the basis of majority approval which encourages an objective nomination process. Should a conflict be

Disclosure Requirement	CU Corporate Governance Practices
entirely of independent directors, describe what steps the board takes to encourage an objective nomination process.	identified, the non-independent member would excuse himself from the meeting and abstain from voting.
(c) If the board has a nominating committee, describe the responsibilities, powers and operation of the nominating committee.	GOCOM is responsible for reviewing the size and composition of the Board from time to time and considering persons as nominees for directors for the approval of the Board and election by the shareholders. The responsibilities of GOCOM can be found in its mandate which is available on the Corporation's website at www.canadian-utilities.com.
7. **Compensation**	
(a) Describe the process by which the board determines the compensation for the issuer's directors and officers.	GOCOM is responsible for assessing the compensation of directors and officers and making recommendations to the Board. GOCOM reviews director compensation from time to time to determine whether such compensation is appropriate for the responsibilities, time commitment and risks assumed by the directors. GOCOM reviews officer compensation annually against information from other corporations and published data, and from time to time retains independent compensation consultants to undertake market comparisons and provide advice on developing appropriate compensation programs. Please refer to pages 15 to 23 of the management proxy circular for details of the executive compensation structure and policies.
(b) Disclose whether or not the board has a compensation committee composed entirely of independent directors. If the board does not have a compensation committee composed entirely of independent directors, describe what steps the board takes to ensure an objective process for determining such compensation.	One of the four members of GOCOM is not independent. GOCOM conducts its business on the basis of majority approval which encourages an objective process for determining compensation. Should a conflict be identified, the non-independent member would excuse himself from the meeting and abstain from voting.
(c) If the board has a compensation committee, describe the responsibilities, powers and operation of the compensation committee.	GOCOM annually reviews and determines executive compensation packages for the senior officers of the Corporation and its wholly owned subsidiaries, including salary, short-term incentives, stock options or awards, share appreciation rights and other incentives. The performance and development profile for each high-potential employee and officer is reviewed by GOCOM in conjunction with the Corporation's succession

Disclosure Requirement	CU Corporate Governance Practices
	planning process. GOCOM also reviews and recommends directors' compensation from time to time, as appropriate. In addition, GOCOM prepares and reviews public or regulatory disclosure respecting compensation and the basis on which performance is measured. GOCOM has the authority to retain and compensate any outside advisor as it determines necessary to permit it to carry out its duties.
(d) If a compensation consultant or advisor has, at any time since the beginning of the issuer's most recently completed financial year, been retained to assist in determining compensation for any of the issuer's directors and officers, disclose the identity of the consultant or advisor and briefly summarize the mandate for which they have been retained. If the consultant or advisor has been retained to perform any other work for the issuer, state that fact and briefly describe the nature of the work.	Towers Perrin, independent consultants, were engaged to undertake market comparisons, gather information on competitive compensation practices and to provide advice on developing appropriate compensation programs for the Corporation's executive officers. In addition, Towers Perrin performs other consulting services in the areas of benefits and administration.
8. **Other Board Committees**	
If the board has standing committees other than the audit, compensation and nominating committees, identify the committees and describe their function.	The Board's other standing committees are the Risk Review Committee and the Pension Fund Committee. The responsibilities of these committees, together with GOCOM and the Audit Committee, can be found in their mandates which are available on the Corporation's website at www.canadian-utilities.com.
9. **Assessments**	
Disclose whether or not the board, its committees and individual directors are regularly assessed with respect to effectiveness and contribution. If assessments are regularly conducted, describe the process used for the assessments. If assessments are not regularly conducted, describe how the board satisfies itself that the board, its committees, and its individual directors are performing effectively.	The Board, its committees and its individual directors are assessed at least annually with respect to effectiveness and contribution. This function is facilitated by GOCOM, which provides its conclusions to the Chairman of the Board.

Copies of position descriptions and mandates noted herein as being available on the Corporation's website may also be obtained on request from the Corporate Secretary.

SCHEDULE B BOARD OF DIRECTORS MANDATE

The Board of Directors (the "Board") of Canadian Utilities Limited (the "Corporation") is responsible for the stewardship of the Corporation and for overseeing the conduct of the business of the Corporation and the activities of management, who are responsible for the day-to-day conduct of the business.

Composition and Operation

The Board operates by reserving certain powers to itself and delegating certain of its authorities to management. The Board retains responsibility for managing its own affairs, including selecting its chair, nominating candidates for election to the Board, constituting committees of the Board, and determining director compensation. Subject to the articles and by-laws of the Corporation and the Canada Business Corporations Act, the Board may constitute, seek the advice of, and delegate powers, duties and responsibilities to, committees of the Board.

Responsibilities

The Board's primary responsibilities are to preserve and enhance long-term shareholder value and to ensure that the Corporation meets its obligations on an on-going basis and operates in a reliable and prudent manner. In performing its duties, the Board should also consider the legitimate interests other interested parties, such as employees, customers and communities, may have in the Corporation. In broad terms, the stewardship of the Corporation involves the Board in strategic planning, risk management and mitigation, senior management determination, communication planning, and internal control integrity. More specifically, the Board is responsible for

(a) to the extent feasible, satisfying itself as to the integrity of the Chief Executive Officer ("CEO") and other executive officers and that the CEO and other executive officers create a culture of integrity throughout the organization;

(b) adopting a strategic planning process and approving, on an annual basis, a strategic plan for the Corporation which takes into account, among other things, the opportunities and risks of the business;

(c) identifying the principal risks of the Corporation's business and ensuring the implementation of appropriate systems to manage these risks;

(d) succession planning (including appointing, training and monitoring senior management);

(e) adopting a communication policy for the Corporation that includes measures for receiving feedback from interested parties;

(f) the Corporation's internal control and management information systems;

(g) developing the Corporation's approach to corporate governance, including developing a set of corporate governance principles and guidelines that are specifically applicable to the Corporation; and

(h) on an individual basis, attending Board meetings, reviewing meeting materials in advance of meetings, and complying with the other expectations and responsibilities of directors of the Corporation established by the Board.

Specific Duties

The Board's specific duties, obligations and responsibilities fall into the following categories:

1. *Legal Requirements*

(a) The Board has oversight responsibility for the Corporation's satisfaction of its legal obligations and for properly preparing, approving and maintaining the Corporation's documents and records.

(b) The Board has the statutory obligation to

(i) supervise the management of the business and affairs of the Corporation,

(ii) act honestly and in good faith with a view to the best interests of the Corporation,

(iii) exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances, and

(iv) act in accordance with its obligations contained in the Canada Business Corporations Act and the regulations thereunder, the Corporation's articles and by-laws, and other relevant legislation and regulations.

(c) The Board has the statutory obligation to consider certain matters as a board of directors. The Board may not delegate to management or to a committee of the Board the authority to

(i) submit to the shareholders any question or matter requiring the approval of the shareholders,

(ii) fill a vacancy among the directors or in the office of auditor,

(iii) issue securities except in the manner and on the terms authorized by the Board,

(iv) declare dividends,

(v) purchase, redeem or otherwise acquire shares issued by the Corporation, except in the manner and on the terms authorized by the Board,

(vi) pay a commission to any person in consideration of the person's purchasing or agreeing to purchase shares of the Corporation from the Corporation or from any other person, or procuring or agreeing to procure purchasers for shares of the Corporation,

(vii) approve any management proxy circular relating to a solicitation of proxies by or on behalf of management of the Corporation,

(viii) approve any take-over bid circular or directors' circular,

(ix) approve any annual financial statements of the Corporation, or

(x) adopt, amend or repeal by-laws.

2. *Independence*

The Board is responsible for implementing appropriate structures and procedures to permit the Board to function independently of management.

3. *Strategic Planning*

The Board is responsible for ensuring that there are long-term goals and a strategic planning process in place for the Corporation and participating with management directly or through its committees in approving the strategic plan by which the Corporation proposes to achieve its goals.

4. *Risk Management*

The Board is responsible for understanding the principal risks of the business in which the Corporation is engaged, achieving a proper balance between risks incurred and the potential return to shareholders, and confirming that there are systems in place that effectively monitor and manage those risks with a view to the long-term viability of the Corporation.

5. *Appointment, Training and Monitoring of Senior Management*

The Board is responsible for

(a) appointing the CEO of the Corporation, monitoring and assessing the CEO's performance, determining the CEO's compensation, and providing advice and counsel to the CEO in the execution of the CEO's duties,

(b) approving the appointment and remuneration of all officers of the Corporation, and

(c) confirming that adequate provision has been made for the training and development of management and for the orderly succession of management.

6. *Reporting and Communication*

The Board is responsible for

(a) verifying that the Corporation has in place policies and programs to enable the Corporation to communicate effectively with its shareholders, other interested parties and the public generally,

(b) verifying that the financial performance of the Corporation is adequately reported to shareholders, other security holders and regulators on a timely and regular basis,

(c) verifying that the Corporation's financial results are reported fairly and in accordance with generally accepted accounting principles,

(d) verifying the timely reporting of any other developments that have a significant and material effect on the value of the Corporation, and

(e) reporting annually to shareholders on the Board's stewardship of the affairs of the Corporation for the preceding year.

7. *Monitoring and Acting*

The Board is responsible for

(a) verifying that the Corporation operates at all times within applicable laws and regulations to the highest ethical and moral standards,

(b) approving and monitoring compliance with the significant policies and procedures by which the Corporation is operated,

(c) verifying that the Corporation sets high environmental standards in its operations and is in compliance with environmental laws and legislation,

(d) verifying that the Corporation has in place appropriate programs and policies for the health and safety of its employees in the workplace,

(e) monitoring the Corporation's progress toward its goals and objectives and revising and altering its direction through management in response to changing circumstances,

(f) taking action when the Corporation's performance falls short of its goals and objectives or when other special circumstances warrant,

(g) verifying that the Corporation has implemented adequate disclosure controls and procedures and internal control and information systems,

(h) ensuring that the Board receives from senior management on a timely basis the information and input required to enable the Board to effectively perform its duties,

(i) adopting a written code of business conduct and ethics and monitoring compliance with the code, and

(j) conducting and acting upon annual assessments and evaluations of the Board, committees of the Board and individual directors.

8. *Other*

The Board may perform any other activities consistent with this mandate, the Corporation's articles and by-laws, and any other governing laws, as the Board deems necessary or appropriate.

SCHEDULE C QUESTIONS AND ANSWERS ON VOTING AND PROXIES

The information contained in the following questions and answers is similar to that provided in Section 1 of the management proxy circular. This format is designed as additional guidance to help a shareholder in determining how to vote. A flow chart is also included that outlines the differences if you are voting as a registered or non-registered shareholder. Any further questions may be directed to our transfer agent, CIBC Mellon Trust Company, by mail at:

CIBC Mellon Trust Company
P.O. Box 721
Agincourt, ON
M1S 0A1

or by telephone:

Within Canada and the U.S.:
1 (800) 387-0825

In the Toronto area, or from any other country:
(416) 643-5500

A Glossary is included as Schedule D for your convenience. You may wish to review the Glossary prior to reading the following questions and their answers.

Q. Am I entitled to vote?

A. You are entitled to vote if you were a holder of Class B common shares of Canadian Utilities Limited as of the close of business on March 14, 2007. Each Class B common share entitles its holder to one vote.

Q. How many shareholders are required to constitute a quorum at the meeting?

A. The Corporation's by-laws provide that for the transaction of business at the meeting a quorum will be two persons present and holding or representing by proxy twenty-five percent of the shares entitled to vote at the meeting.

Q. What am I voting on?

A. You are voting on the following business matters that are to be addressed at the annual meeting:

- the election of the directors;
- the appointment of the auditor;
- the approval of amendments to the stock option plan;
- such other business as may properly come before the meeting or any adjournment thereof.

Q. What if amendments are made to these matters or if other matters are brought before the meeting?

A. If you attend the annual meeting in person and are eligible to vote, you may vote on such matters as you choose.

If you have properly completed and returned a form of proxy, the person named in the form of proxy will have discretionary authority with respect to voting on amendments or variations to matters identified in the notice of the annual meeting, and on other matters which may properly come before the annual meeting.

Q. Who is soliciting my proxy?

A. The management of Canadian Utilities Limited is soliciting your proxy.

Q. How do I vote?

A. If you are a **registered shareholder**, you may vote in one of the following ways:

- in person at the annual meeting;
- by properly completing and signing the enclosed form of proxy appointing the named persons or some other person you choose to represent you as proxyholder and vote your shares at the annual meeting, and returning it in the enclosed prepaid envelope;
- by faxing both sides of your properly completed form of proxy to CIBC Mellon Trust Company on 1-866-781-3111 (from within Canada and the U.S.) or (416) 368-2502 (from outside North America);
- by telephone using the following toll free number – 1-866-271-1207 – and following the voice prompts. You will need to enter the 13 digit Control Number located in the left-hand corner

on the reverse of the form of proxy mailed to you in order to enter your voting instructions;

- via the internet by accessing www.eproxyvoting.com/canadianutilities and following the prompts. You will need to enter your 13 digit Control Number located in the left-hand corner on the reverse of the form of proxy mailed to you in order to enter your voting instructions.

If you are a **non-registered shareholder** and your shares are held in the name of a nominee (usually a bank, broker, or trust company) you will have received a request for voting instructions from your nominee. If you wish to vote in person at the annual meeting, insert your own name in the space provided on the voting instruction form and return it by following the instructions provided. Please register with the Corporation's transfer agent, CIBC Mellon, upon arrival at the annual meeting. If you do not intend to attend the annual meeting in person, follow the instructions on your voting instruction form to vote by telephone, internet or fax, or complete, sign and mail the voting instruction form in the postage prepaid envelope provided.

Q. Who votes my shares and how will they be voted if I return a form of proxy?

A. By properly completing and returning a form of proxy, you are authorizing R. D. Southern, Chairman of the Board, or failing him, N.C. Southern, President & Chief Executive Officer, to attend the annual meeting and to vote your shares. You can use the enclosed proxy form, or any other proper form of proxy, to appoint your proxyholder.

The shares represented by your proxy must be voted as you instruct in the form of proxy. If you properly complete and return your form of proxy but do not specify how you wish the votes cast, your shares will be voted as your proxyholder sees fit.

If neither you nor your proxyholder gives specific instructions, your shares will be voted as follows:

- **FOR the election as directors of those nominees set out in the management proxy circular;**
- **FOR the appointment of PricewaterhouseCoopers LLP, as the auditor of the Corporation; and**
- **FOR the approval of the amendments to the stock option plan.**

Q. Can I appoint someone other than the individuals named in the enclosed form of proxy to vote my shares?

A. Yes, you have the right to appoint another person of your choice, who need not be a shareholder, as your proxyholder to attend and act on your behalf at the annual meeting. If you wish to appoint a person other than those named in the enclosed form of proxy, then draw a line through the printed names appearing on the form of proxy and insert the name of your chosen proxyholder in the space provided. This can also be accomplished via the internet.

It is important for you to ensure that any other person you appoint as your proxyholder will attend the annual meeting and is aware that his or her appointment has been made to vote your shares. Proxyholders should, on arrival at the annual meeting, present themselves to a representative of CIBC Mellon.

Q. Who may sign the form of proxy?

A. For a shareholder who is an individual, the form of proxy may be signed either by the individual or by his or her authorized attorney. In the case of a shareholder which is a body corporate or an association, the form of proxy must be signed by a duly authorized officer or by an authorized attorney. Persons signing as executors, administrators or trustees should so indicate and must provide a true copy of the document establishing their authority. An authorized person(s) of a partnership should sign in the partnership name.

Q. What if my shares are registered in more than one name or in the name of a company?

A. If the shares are registered in more than one name, all those persons in whose name the shares are registered must sign the form of proxy. If the shares are registered in the name of a company or any name other than your own, you should provide documentation that proves you are authorized to sign the form of proxy on behalf of that company or name. If you have any questions as to what supporting documentation is required, contact CIBC Mellon prior to submitting your proxy.

Q. Where do I send my form of proxy?

A. Please return your properly completed form of proxy to our transfer agent in the postage paid envelope provided or mail it to CIBC Mellon Trust Company, P.O. Box 721, Agincourt, Ontario, M1S 0A1. Alternatively, you may fax both sides of your completed proxy to (416) 368-2502 or 1-866-781-3111 (toll free within Canada and the U.S.).

Q. What is the deadline for submitting my form of proxy?

A. To be effective your form of proxy must be received by CIBC Mellon before 5:00 p.m. Eastern Daylight Time on May 1, 2007.

Q. Can I change my mind once I have submitted my proxy to the Corporation?

A. Yes, if you complete another form of proxy prior to the submission deadline, the later-dated form of proxy will replace the one submitted earlier.

If you are a **registered shareholder**, you can revoke your proxy by stating clearly, in writing, that you want to revoke your proxy. This statement should be delivered:

- To the Corporation's Secretary by mail at 1400 ATCO Centre, 909 - 11th Avenue S.W., Calgary, Alberta, T2R 1N6, or by fax at (403) 292-7623 at any time up to and including the last business day preceding the day of the annual meeting or any adjournment thereof;
- To the Chairman of the annual meeting prior to the commencement of the meeting on the day of the meeting or any adjournment thereof.

If you are a **non-registered shareholder**, you should contact your nominee for instructions to revoke your proxy.

Q. How many shares are entitled to vote?

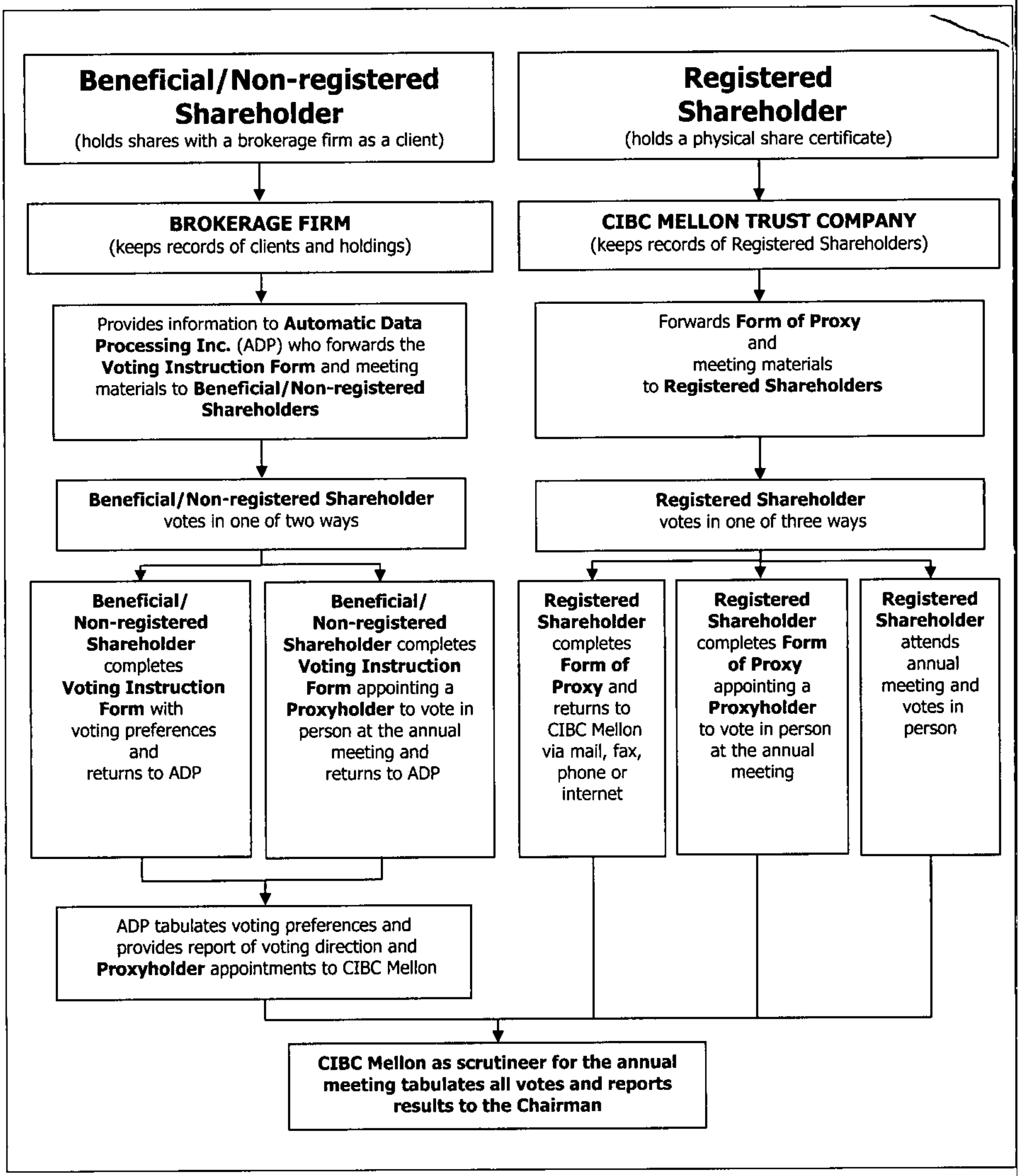
A. As of the date of the management proxy circular, there were 43,926,484 Class B common shares outstanding. Each registered shareholder has one vote for each common share of Canadian Utilities Limited held at the close of business on March 14, 2007.

Q. What if ownership of shares has been transferred after March 14, 2007?

A. Class B common shares can be voted at the meeting only by those persons who were registered shareholders at the close of business on March 14, 2007, and their duly appointed proxyholders.

A person who acquires Class B common shares after March 14, 2007, cannot vote those shares at the annual meeting.

SHAREHOLDER VOTING PROCESS



SCHEDULE D GLOSSARY

Acronyms

CPP
Canada Pension Plan

DB
Defined Benefit

DC
Defined Contribution

GOCOM
Corporate Governance - Nomination, Compensation and Succession Committee

NEO
Named Executive Officer

SAR
Share Appreciation Right

SEDAR
System for Electronic Document Analysis and Retrieval

TDC
Total Direct Compensation

TSX
Toronto Stock Exchange

At Risk

At risk is the amount of money that is invested in the shares of the Corporation that is exposed to the possibility of loss.

Ballot

A ballot is a formal record of a vote taken at the meeting.

Comparator Markets

Comparator markets are comprised of General Industry and Utility/Alberta companies of similar size and scope of operations.

Discretionary Authority

If you are not attending the meeting in person, the individual you appoint on your proxy to vote your shares will have the authority to vote at his or her discretion on matters that are not specifically set out in the notice of meeting as well as on any variations to the matters that are set out in the notice of meeting.

Exercise Price

The price fixed by the Board at the time that an option is granted. The price is the weighted average of the trading price of the Class A non-voting shares on the TSX for the five trading days immediately preceding the date of the grant.

Form of Proxy

If you are a voting shareholder of the Corporation, either a form of proxy (for registered shareholders) or a voting instruction form ("VIF") (for non-registered shareholders) will be included with your management proxy circular. A form of proxy or VIF allows you to appoint another person to vote your shares for you in the event that you are unable to attend the annual meeting. A form of proxy or VIF denotes the business that is to be acted upon at the annual meeting of shareholders.

Named Executive Officer

Named Executive Officer or "NEO" means the following individuals: the Chief Executive Officer ("CEO"), the Chief Financial Officer ("CFO") and each of the company's three other most highly compensated executive officers who were serving as executive officers at the end of the most recently completed financial year or any additional individuals for whom disclosure would have been provided except that they were not serving as an officer at the end of the most recently completed year.

Nominee

Your shares will be held by a nominee if you are a non-registered shareholder. A nominee may be your stockbroker, your bank, or a trust company.

Non-Registered Shareholder

You are a non-registered shareholder if your shares are not held in your own name, but in the name of a Nominee such as your bank, broker or trust company.

Option

Through the stock option plan, individuals are awarded options to purchase non-voting shares of the Corporation at a future date at a particular price.

Proxyholder

A proxyholder is the person you appoint to attend, speak at, vote and otherwise act at the annual meeting on your behalf. If you choose to specify how you want your shares voted on a particular matter, your proxyholder is obligated to vote your shares that way. If you do not choose to specify how you want your shares to be voted, your proxyholder has discretionary authority to vote your shares in any manner he or she wishes.

Record Date

The Corporation is required by the *Canada Business Corporations Act* to establish a record date that is no fewer than 21 days and no more than 60 days before the annual meeting date. The record date is established for the purpose of determining which shareholders are entitled to receive notice of the annual meeting of shareholders or the shareholders that are entitled to vote at the annual meeting of shareholders. March 14, 2007 is the record date that has been established for the 2007 annual meeting of shareholders.

Registered Office of the Corporation

The registered office of Canadian Utilities Limited is 20th Floor, 10035 – 105 Street, Edmonton, Alberta, T5J 2V6. The principal office of the Corporation is 1600, 909 – 11th Avenue S.W., Calgary, Alberta, T2R 1N6.

Registered Shareholder

You are a registered shareholder if your shares are held in your name. You will usually have a paper share certificate denoting your ownership of the shares.

Revocation of Proxy

If you submit your proxy and subsequently change your mind, you must replace your original proxy with a later-dated instruction (either in the form of a new proxy or a letter).

S&P/TSX Composite Index

The S&P/TSX Composite Index is currently a list of the 271 largest companies on the TSX as measured by market capitalization.

SEDAR

SEDAR stands for System for Electronic Document Analysis and Retrieval and www.sedar.com is the official site that provides access to most public securities documents and information filed by public companies with the Canadian Securities Administrators.

Share Appreciation Rights

Through the share appreciation rights plan, individuals are awarded share appreciation rights or "SARs" which allow the individual the right to receive a payment in cash equal to the appreciation in the company's shares over a specified period.

Stock Dividend/Split

A stock dividend by way of a stock split is an increase in the number of outstanding shares of a company, such that the proportionate equity of each shareholder remains the same.

Solicitation of Proxies

Proxy solicitation is the process of acquiring votes and support for the matters to be voted on.

Voting Instruction Form

If you are a non-registered shareholder, you will receive a voting instruction form or "VIF" rather than a form of proxy. The VIF will be included with your management proxy circular. A VIF allows you to appoint another person or company to vote your shares for you in the event that you are unable to attend the annual meeting. A VIF denotes the business that is to be acted upon at the annual meeting of shareholders.

CANADIAN UTILITIES LIMITED

1400, 909 – 11th Avenue SW
Calgary, Alberta T2R 1N6

Telephone: (403) 292-7500
Fax: (403) 292-7623

www.canadian-utilities.com

CANADIAN UTILITIES LIMITED
An ATCO Company

CANADIAN UTILITIES IS A DIVERSIFIED, CANADIAN BASED, INTERNATIONAL GROUP OF COMPANIES

CANADIAN UTILITIES

CANADIAN UTILITIES LIMITED ANNUAL REPORT 2006

2006: A YEAR OF NOTABLE SUCCESS
Letter from the Chairman

REACHING NEW HEIGHTS
Profiling the Diversity of Canadian Utilities

CANADIAN UTILITIES LIMITED
An ATCO Company

GENERAL INFORMATION:

INCORPORATION
Canadian Utilities Limited was incorporated under the laws of Canada on May 18, 1927 and was continued under the Canada Business Corporations Act by Articles of Continuance on August 15, 1979.

ANNUAL MEETING
The Annual Meeting of Share Owners will be held at 10:00 a.m., M.D.T. Thursday, May 3, 2007 at The Fairmont Hotel Macdonald, 10065-100 Street, Edmonton, Alberta.

AUDITORS
PricewaterhouseCoopers LLP
Calgary, Alberta

COUNSEL
Bennett Jones LLP
Calgary, Alberta

TRANSFER AGENT AND REGISTRAR
Class A Non-Voting and
Class B Common Shares and
Second Preferred
(Series Q, R, S, W and X) Shares
CIBC Mellon Trust Company
Calgary/Montreal/Toronto/Vancouver

TRUSTEE AND REGISTRAR
Debentures
CIBC Mellon Trust Company

STOCK EXCHANGE LISTINGS
Class A Non-Voting Symbol CU
Class B Common Symbol CU.X
Listing: The Toronto Stock Exchange

CUMULATIVE REDEEMABLE
SECOND PREFERRED SHARES
5.90% Series Q CU.PR.T
5.30% Series R CU.PR.V
6.60% Series S CU.PR.D
5.80% Series W CU.PR.A
6.00% Series X CU.PR.B
Listing: The Toronto Stock Exchange

ATCO GROUP ANNUAL REPORTS
Annual Reports to Share Owners and Management's Discussion and Analysis for Canadian Utilities Limited and its parent company, ATCO Ltd., are available upon request from:
ATCO Ltd. & Canadian Utilities Limited
1400, 909 – 11th Avenue SW
Calgary, Alberta T2R 1N6
Telephone: (403) 292-7500
Website: www.canadian-utilities.com

SHARE OWNER INQUIRIES
Dividend information and other inquiries concerning shares should be directed to:
CIBC Mellon Trust Company
Stock Transfer Department
600 The Dome Tower
333 – 7th Avenue SW
Calgary, Alberta T2P 2Z1
Telephone: 1-800-387-0825
Website: www.cibcmellon.com

Printed in Canada

President's Letter

BY NANCY C. SOUTHERN

Dear Share Owners,

We had a remarkable year in Canadian Utilities Limited improving our 2006 earnings per share by 23 per cent over 2005 and, at the same time, experiencing favourable growth throughout all facets of our enterprise. Much of this was due to the world's commodity driven economy which indeed provided our company with an economic environment that exceeded our expectations.

You will notice in our financial statements that our utility companies' earnings do not appear as robust as our other segments. This is a direct result of low interest rates which are the basis for the Alberta Energy and Utilities Board's determination of its utility rate of return.

In simplified terms, the Alberta Energy and Utilities Board uses a formula that is based on the November forecast of the yield on long term Goverment of Canada bonds. Each year, this formula automatically adjusts for changes in the forecast. When this formula was first introduced in 2004, the forecast yield on the long term bonds was 5.68 per cent; since then it has decreased steadily to 4.78 per cent in 2006 and 4.22 per cent in 2007. This reduction has translated into a corresponding decline in the utility rate of return: from 9.60 per cent in 2004 to 8.93 per cent in 2006 and 2007 will see a further reduction in the rate of return – to 8.51 per cent.

This formula is applied on an industry wide basis. Therefore, with the support of other utility companies, we have initiated discussions with the Alberta Energy and Utilities Board to explore the possibility of a less punitive formula.

The positive offset to the rate of return for our utilities is our unprecedented growth required to meet Alberta's infrastructure demands.

Our 2006 capital investment in ATCO Gas, ATCO Pipelines, and ATCO Electric was $500 million and our outlook over the next year is for a further $650 million of investment that will be required of all our regulated companies.

These capital expenditures will be primarily for new electrical transmission to support the growth in oilsands and heavy oil projects, as well as natural gas distribution hookups to new homes which will accommodate the population expansion in Alberta.

Provincial growth has also impacted our company's power generation business as excess supply of power has decreased thereby increasing the price per megawatt available to generators.

Coincidentally, in the United Kingdom, this same tightening of power supply is also occurring, producing higher margins for our 25 percent share of the 1,000 MW gas fired, combined cycle Barking power plant.

We think these conditions will continue throughout our international power generation markets, and we expect the development of new power projects to be on the horizon. This will allow us to capitalize on our well developed plans for clean generation opportunities. The caveat, however, will be the final outcome of environmental legislation and regulation in Canada, the United Kingdom, and Australia.

Led by ATCO Midstream, our Global Enterprises business group realized record performance in 2006. Frac spreads, gas throughput on our system and storage differentials all contributed to ATCO Midstream's performance.

While 2006 delivered strong earnings, our Directors and Officers remain aware that many of our principal operating subsidiaries are cyclical in nature and results may fluctuate considerably in the future.

The heated Alberta and world markets continue to put stress on human resources and materials availability. Potential staffing shortfalls are being addressed with the implementation of a comprehensive global recruitment strategy designed to complement our current workforce.

We have increased focus on our project controls and operational efficiencies to proactively manage equipment, supplies, and labour costs. We are also continuing to improve on our operating procedures and processes to validate the accuracy of our real time information flow and due diligence competencies.

Our overarching preferred strategy for Canadian Utilities Limited is to continue improving the strong balance sheet we have created. Our growing capacity will allow us to invest more in our existing activities and give us the flexibility to act on other opportunities such as a bolt on accretive acquisition during an economic downturn.

The diversity of our enterprise has proven to be a successful model. It has the merit of stable utility earnings while, at the same time, stimulating our workforce to remain close to our customers and continue to develop profitable new products and services in our non-regulated divisions.

Business is still about people. It is what we believe gives us our competitive advantage. We have a great company that is made so by 6,000 men and women who each and every day bring determined commitment and strong basic values of loyalty and integrity to their work.

I also want to recognize and extend my heartfelt appreciation to our Board of Directors for their wise counsel on our strategies and their dedication to excellence in our corporate governance. They remain ever mindful of their duties to protect and bring fair-minded judgment for both majority and minority share owners.

Finally, I hope you will join me in congratulating our Chairman on ATCO Group's 60th birthday. He, along with his father, S.D. Southern, and the talented and dedicated men and women who have followed them, have created an enterprise of excellence based on basic family values, which continues to deliver outstanding compounding value for the owners of our shares.

Thank you!

Sincerely,

N.C. South

N.C. Southern
PRESIDENT & CHIEF EXECUTIVE OFFICER

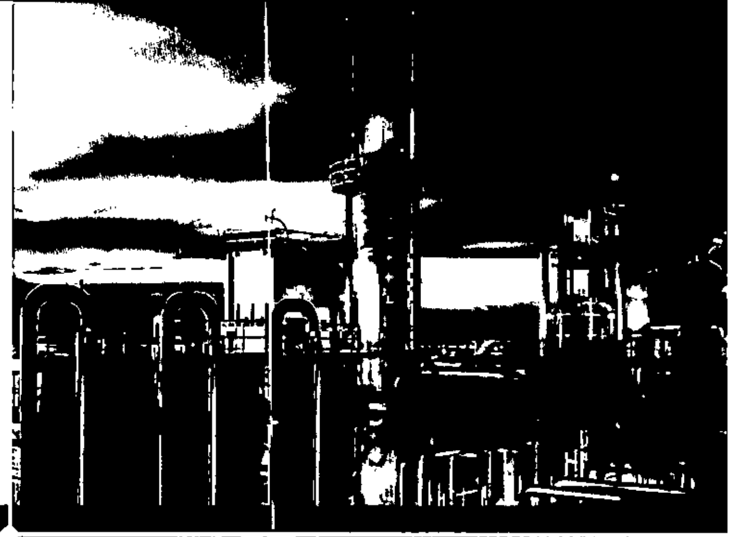
ATCO GAS is an Alberta wide natural gas distribution company serving nearly one million customers in almost 300 communities. With more than 90 years experience providing natural gas service to homes, farms and businesses, ATCO Gas is headquartered in Edmonton with 62 district offices where its employees live and work. In part due to Alberta's booming economy, capital expenditures in 2006 doubled from five years ago to $167.4 million as the company expanded a delivery system consisting of 35,935 kilometres of pipeline.

ATCO PIPELINES operates a natural gas pipeline system of 8,419 kilometres connecting producers with Alberta markets and providing interconnections with all major pipeline systems that export gas out of the province. ATCO Pipelines is a significant player in the gas transportation industry with on-system receipts exceeding 1.3 billion cubic feet (bcf) per day and peak delivery of 3.7 bcf per day. Customers can access the markets of their choice through ATCO Pipelines' innovative, flexible and cost-effective transportation solutions.

ATCO ELECTRIC serves more than 186,000 customers in northern and east-central Alberta and through its subsidiaries, Yukon Electrical and Northland Utilities, also serves consumers in Canada's far north. Headquartered in Edmonton with 37 service offices, ATCO Electric in 2006 employed 1,088 people, including engineers, accountants, line crews, servicemen, technologists and clerical staff. For 80 years, ATCO Electric has delivered power to homes, farms and businesses, in cities, towns, Native reserves and Metis settlements – in 245 communities in all.

ATCO POWER is a world-class developer, construction manager, owner and operator of technologically advanced and environmentally progressive independent power generation plants. Established in 1988, projects have been developed in the United Kingdom, Australia, British Columbia, Alberta, Saskatchewan and, most recently, in Ontario. ATCO Power now has assets of $2.24 billion representing 51 per cent ownership in approximately 4,800 MW of capacity at 19 facilities operated by the company. Following deregulation in Alberta, the regulated generating plants of ATCO Electric were transferred to an ATCO Power company.

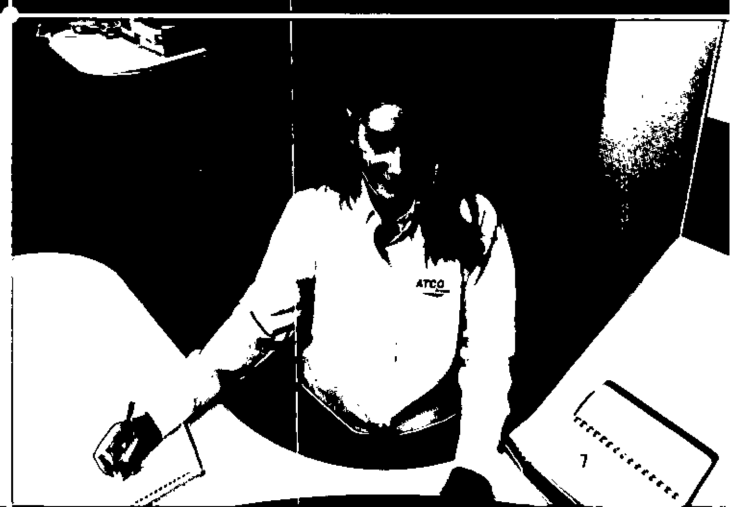
ATCO MIDSTREAM provides gas gathering, processing, storage, and natural gas liquids solutions to its customers within the Canadian natural gas industry. With almost 1,000 kilometres of field gathering lines, the company has a diverse asset base including 11 natural gas gathering and processing facilities and four natural gas extraction facilities, which together have a total processing capacity of more than 1.5 billion cubic feet of gas per day. The company also provides innovative natural gas storage services with more than 40 billion cubic feet of capacity available.



ATCO FRONTEC has proven expertise in the delivery of technical services, site support, facilities management and camp services to a wide range of customers and varied industries throughout Canada, into Alaska, across Europe and in the Middle East. Unique opportunities created from various joint venture and aboriginal alliances, as well as increasing support for deployed military operations, serve as foundations of the company business. Headquartered in Calgary, the company won its first contract with the United Nations in 2006 to provide catering and camp support services at four locations in Kosovo.

ATCO I-TEK delivers customer care, billing and information technology solutions to a diverse group of clients that operate around the world. Headquartered in Edmonton, ATCO I-Tek is a disciplined business-to-business service provider with proven processes, controls and a service-oriented team of more than 900 people. In 2006, ATCO I-Tek answered more than 1.7 million customer calls, produced 12 million statements, processed more than 10.5 million payments and collected close to $3.0 billion in revenue for its clients.

ATCO TRAVEL is one of the largest corporate travel management companies in Canada, with its head office in Calgary, and branch offices in Edmonton, Fort McMurray and Ottawa. With almost 130 employees and independent associates, ATCO Travel in 2006 was recognized as the winner of the Association of Canadian Travel Agents Atlas Award as 'Travel Agent of the Year' for Alberta and N.W.T. ATCO Travel has established a leading reputation by providing clients with superior quality and personalized service in both corporate travel management and vacation services.



Canadian Utilities Limited

Financial Statements

MD&A

Management's Discussion & Analysis

KAREN M. WATSON

Senior Vice President
& Chief Financial Officer

Financial Achievements 2006

- Earnings per share increased to $2.57 from $2.09 in 2005.
- Earnings increased by $58.3 million to $323.9 million from $265.6 million in 2005.
- Dividends paid per Class A and Class B share increased by $0.30 to $1.40 from $1.10 in 2005. This increase included a Special Dividend of $0.25 paid to Class A and Class B share owners on September 1, 2006. Dividends have increased each year since 1972 – 34 years!
- Return on common equity was 14.3 per cent compared to 12.2 per cent in 2005.
- Total assets increased by $176 million to $7.0 billion compared to $6.8 billion in 2005.
- Long term debt increased by $181 million to $2.4 billion.
- Non-recourse long term debt decreased by $47 million to $627 million.
- Share owners' equity increased by $101 million to $2.3 billion compared to $2.2 billion in 2005.
- Funds generated by operations is virtually unchanged at $658 million.
- Capital expenditures were $568 million in 2006 compared to $527 million in 2005. Over the previous five years, capital expenditures averaged $539 million per year.
- CU issued $320 million of debentures and $36 million of other debt in 2006. CU redeemed $175 million of debentures in 2006.
- CU redeemed $65 million of non-recourse long term debt in 2006.
- CU purchased $73 million of Class A non-voting shares in 2006.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL REPORTING

Management is responsible for the preparation of the consolidated financial statements, management's discussion and analysis of financial condition and results of operations and other financial information relating to the Corporation contained in this annual report. The consolidated financial statements have been prepared in conformity with Canadian generally accepted accounting principles using methods appropriate for the industries in which the Corporation operates and necessarily include some amounts that are based on informed judgments and best estimates of management. The financial information contained elsewhere in the annual report is consistent with that in the consolidated financial statements.

Management has established internal accounting control systems to meet its responsibility for reliable and accurate reporting. These control systems are subject to periodic review by the Corporation's internal auditors.

PricewaterhouseCoopers, our independent auditors, are engaged to express a professional opinion on the consolidated financial statements.

The Board of Directors, through its Audit Committee comprised entirely of outside Directors, oversees management's responsibilities for financial reporting. The Audit Committee meets regularly with management, the internal auditors and the independent auditors to discuss auditing and reporting on financial matters, to assure that management is carrying out its responsibilities and to review and approve the consolidated financial statements. The auditors have full and free access to the Audit Committee and management.

K.M. Watson
Senior Vice President & Chief Financial Officer

P.G. Wright
Vice President, Finance and Controller

February 21, 2007

AUDITORS' REPORT

TO THE SHARE OWNERS OF CANADIAN UTILITIES LIMITED

We have audited the consolidated balance sheets of Canadian Utilities Limited as at December 31, 2006 and 2005 and the consolidated statements of earnings and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement preparation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2006 and 2005 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta

February 21, 2007

CANADIAN UTILITIES LIMITED

CONSOLIDATED STATEMENT OF EARNINGS AND RETAINED EARNINGS

(Millions of Canadian Dollars except per share data)

		Three Months Ended December 31		Year Ended December 31	
	Note	**2006**	2005	**2006**	2005
		(Unaudited)			
Revenues		**$ 671.1**	$ 680.3	**$ 2,430.4**	$ 2,515.8
Costs and expenses					
Natural gas supply		**10.2**	18.3	**36.4**	162.2
Purchased power		**12.5**	12.2	**46.1**	45.4
Operation and maintenance		**243.5**	261.7	**950.3**	1,003.6
Selling and administrative		**74.9**	57.3	**207.5**	190.4
Depreciation and amortization		**95.6**	84.5	**348.5**	311.5
Interest	7, 12	**54.6**	51.4	**222.9**	210.0
Franchise fees		**42.4**	49.5	**150.4**	152.3
		533.7	534.9	**1,962.1**	2,075.4
		137.4	145.4	**468.3**	440.4
Interest and other income	6	**18.9**	10.6	**58.5**	36.6
Earnings before income taxes		**156.3**	156.0	**526.8**	477.0
Income taxes	7	**47.4**	58.0	**167.1**	175.6
		108.9	98.0	**359.7**	301.4
Dividends on equity preferred shares		**8.9**	8.9	**35.8**	35.8
Earnings attributable to Class A and Class B shares		**100.0**	89.1	**323.9**	265.6
Retained earnings at beginning of period		**1,741.1**	1,670.4	**1,721.9**	1,603.4
		1,841.1	1,759.5	**2,045.8**	1,869.0
Dividends on Class A and Class B shares		**36.3**	34.9	**176.7**	139.6
Purchase of Class A shares and other direct charges to retained earnings	8	**0.4**	2.7	**64.7**	7.5
Retained earnings at end of period		**$ 1,804.4**	$ 1,721.9	**$ 1,804.4**	$ 1,721.9
Earnings per Class A and Class B share	15	**$ 0.80**	$ 0.70	**$ 2.57**	$ 2.09
Diluted earnings per Class A and Class B share	15	**$ 0.80**	$ 0.69	**$ 2.56**	$ 2.08
Dividends paid per Class A and Class B share	15	**$ 0.29**	$ 0.275	**$ 1.40**	$ 1.10

CANADIAN UTILITIES LIMITED
CONSOLIDATED BALANCE SHEET

(Millions of Canadian Dollars)

		December 31	
	Note	**2006**	2005
ASSETS			
Current assets			
Cash and short term investments	18	**$ 798.8**	$ 824.6
Accounts receivable		**362.3**	353.4
Inventories		**96.5**	88.0
Regulatory assets	2	**13.3**	19.1
Prepaid expenses		**23.6**	19.9
		1,294.5	1,305.0
Property, plant and equipment	9	**5,426.1**	5,208.7
Regulatory assets	2	**43.2**	35.0
Other assets	10	**229.7**	269.1
		$ 6,993.5	$ 6,817.8
LIABILITIES AND SHARE OWNERS' EQUITY			
Current liabilities			
Bank indebtedness		**$ -**	$ 0.2
Accounts payable and accrued liabilities		**338.8**	342.6
Income taxes payable		**22.7**	26.7
Future income taxes	7	**0.3**	4.1
Regulatory liabilities	2	**0.5**	6.4
Non-recourse long term debt due within one year	12	**59.3**	57.0
		421.6	437.0
Future income taxes	7	**194.7**	200.3
Regulatory liabilities	2	**148.8**	161.9
Deferred credits	13	**229.0**	253.8
Long term debt	12	**2,411.5**	2,231.0
Non-recourse long term debt	12	**626.7**	673.8
Equity preferred shares	14	**636.5**	636.5
Class A and Class B share owners' equity			
Class A and Class B shares	15	**516.0**	519.1
Contributed surplus	16	**1.2**	0.7
Retained earnings		**1,804.4**	1,721.9
Foreign currency translation adjustment		**3.1**	(18.2)
		2,324.7	2,223.5
		$ 6,993.5	$ 6,817.8

N.C. Southern
N.C. SOUTHERN
DIRECTOR

B.K. French
B.K. FRENCH
DIRECTOR

CANADIAN UTILITIES LIMITED

CONSOLIDATED STATEMENT OF CASH FLOWS

(Millions of Canadian Dollars)

		Three Months Ended December 31		Year Ended December 31	
		(Unaudited)			
	Note	**2006**	2005	**2006**	2005
Operating activities					
Earnings attributable to Class A and Class B shares		**$100.0**	$ 89.1	**$323.9**	$265.6
Adjustments for:					
Depreciation and amortization		**95.6**	84.5	**348.5**	311.5
Future income taxes		**11.3**	0.6	**(1.6)**	7.7
Deferred availability incentives		**(41.0)**	14.5	**(20.2)**	13.7
TXU Europe settlement – net of income taxes	5	**(3.3)**	(3.7)	**(1.6)**	45.8
Other		**5.8**	2.8	**8.5**	15.0
Funds generated by operations		**168.4**	187.8	**657.5**	659.3
Changes in non-cash working capital	17	**(48.5)**	(1.2)	**(39.6)**	90.2
Cash flow from operations		**119.9**	186.6	**617.9**	749.5
Investing activities					
Purchase of property, plant and equipment		**(184.0)**	(181.2)	**(567.7)**	(526.7)
Proceeds on transfer of retail energy supply businesses - net of income taxes	3	**-**	-	**-**	43.4
Costs on disposal of property, plant and equipment		**(4.3)**	(4.4)	**(10.4)**	(5.9)
Contributions by utility customers for extensions to plant		**20.1**	6.7	**81.3**	44.1
Non-current deferred electricity costs		**(8.7)**	(5.7)	**4.5**	(15.7)
Changes in non-cash working capital	17	**15.4**	24.4	**(18.3)**	(3.4)
Income tax reassessment	7	**-**	-	**(12.8)**	-
Other		**0.9**	(0.1)	**(4.1)**	(6.2)
		(160.6)	(160.3)	**(527.5)**	(470.4)
Financing activities					
Issue of long term debt		**320.0**	185.0	**355.5**	222.0
Repayment of long term debt		**(175.0)**	(35.4)	**(175.0)**	(167.1)
Repayment of non-recourse long term debt		**(12.6)**	(9.1)	**(64.6)**	(54.3)
Net issue (purchase) of Class A shares		**1.9**	(2.7)	**(67.5)**	(2.7)
Dividends paid to Class A and Class B share owners		**(36.3)**	(34.9)	**(176.7)**	(139.6)
Changes in non-cash working capital	17	**(0.1)**	0.3	**(0.1)**	3.1
Other		**(2.6)**	(2.1)	**(3.9)**	(3.2)
		95.3	101.1	**(132.3)**	(141.8)
Foreign currency translation		**11.6**	0.2	**16.3**	(11.2)
Cash position [1]					
Increase (decrease)		**66.2**	127.6	**(25.6)**	126.1
Beginning of period		**732.6**	696.8	**824.4**	698.3
End of period		**$798.8**	$824.4	**$798.8**	$824.4

[1] *Cash position consists of cash and short term investments less current bank indebtedness.*

CANADIAN UTILITIES LIMITED
NOTES TO CON...IDATED FINANCIAL STATEMENTS
(tabular amoun... Canadian dollars)

...SIGNIFICANT ACCOUNTING POLICIES

...nt Presentation

...ing consolidated financial statements have been prepared in accordance with Canadian generally ...ounting principles ("GAAP") and include the accounts of Canadian Utilities Limited and its ... including a proportionate share of joint venture investments (the "Corporation"). Principal ... are Utilities (ATCO Electric, ATCO Gas, ATCO Pipelines), Power Generation (ATCO Power, Alberta Power ...000)) and Global Enterprises (ATCO Midstream, ATCO Frontec, ATCO I-Tek). Significant joint venture investments consist principally of power generation plants; a substantial portion of Power Generation's operations are conducted through joint ventures.

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

Rate 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. 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". Accounting for rate regulated operations is described in Note 2.

Use of Estimates

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

Revenue Recognition

For regulated operations, revenues are recognized in a manner that is consistent with the underlying rate design as mandated by the regulator.

Revenues from ATCO Gas' regulated distribution of natural gas include variable charges, which are recognized on the basis of meter readings upon delivery of natural gas to customers and include an estimate of usage not yet billed, and fixed charges, based on the provision of the distribution service during the period. Revenues from the sale of natural gas by ATCO Gas from storage, which ended on March 31, 2005, were recognized upon delivery.

Revenues from ATCO Electric's regulated distribution of electricity include variable charges, which are recognized on the basis of meter readings upon delivery of electricity to customers and include an estimate of usage not yet billed, and fixed charges, based on the provision of the distribution service during the period. Revenues for the use of ATCO Electric's regulated transmission facilities are based on an annual tariff and are recognized evenly throughout the year.

Revenues from ATCO Pipelines' regulated transportation of natural gas are recognized on the basis of contractual arrangements. For certain services, revenues are recognized on the basis of meter readings upon delivery of natural gas to customers and include an estimate of usage not yet billed.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Revenues from regulated sales and distribution of natural gas and electricity by ou
excluding Alberta Power (2000), are recognized upon delivery, primarily on the basis o
include an estimate of usage not yet billed.

Revenues from generating plants are recognized upon delivery of output or upon availability o
prescribed by contractual arrangements. Incentives and penalties associated with Power Purchase Arra
("PPA") are recognized as described under the accounting policy for deferred availability incentives.

Revenues from ATCO Midstream's natural gas storage and processing capacity are recognized on the basis o contractual arrangements, and revenues from the sale of natural gas liquids are recognized upon delivery.

Revenues from the supply of contracted services are recorded by the percentage of completion method; full provision is made for any anticipated loss. Other revenues are recognized when products are delivered or services are provided.

Natural Gas Supply

Natural gas supply expense for regulated operations, which consists of natural gas volumes purchased for sales to customers (see Note 3 regarding natural gas supply of regulated operations following the transfer of retail energy supply businesses by ATCO Gas and ATCO Electric in 2004), is based on actual costs incurred.

Natural gas supply expense for other subsidiaries, which consists of natural gas volumes purchased for natural gas liquids extraction and sales to third parties, is based on actual costs incurred.

Purchased Power

Purchased power expense 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.

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.

Other subsidiaries follow the liability method of accounting for income taxes. Under this method, future tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. Future tax liabilities and assets are measured using enacted and substantively enacted tax rates. The effect on future tax liabilities and assets of a change in tax rates is recognized in income in the period that the change occurs.

Inventories

Inventories are valued at the lower of average cost or net realizable value.

Property, Plant and Equipment

Property, plant and equipment are recorded at cost less accumulated depreciation and unamortized contributions by utility customers for extensions to plant.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Regulated operations include in property, plant and equipment an allowance for funds used during construction at rates approved by the Alberta Energy and Utilities Board ("AEUB") for debt and equity capital. Property, plant and equipment in the other subsidiaries include capitalized interest incurred during construction.

Certain regulated additions are made with the assistance of non-refundable cash contributions from customers when the estimated revenue is less than the cost of providing service or where special equipment is needed to supply the customers' specific requirements. These contributions are amortized on the same basis as, and offset the depreciation charge of, the assets to which they relate.

Depreciation is provided on assets on a straight-line basis over their estimated useful lives. Depreciation rates for regulated assets, excluding Alberta Power (2000)'s generating plants, are approved by the AEUB and include a provision for future removal costs and site restoration costs (see the accounting policy for asset retirement obligations below). 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.

Property, plant and equipment and intangible assets with finite lives are tested for recoverability whenever events or changes in circumstances indicate a possible impairment. An impairment of property, plant and equipment and intangible assets with finite lives is 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.

Deferred Financing Charges

Issue costs of long term debt are amortized over the life of the debt, issue costs of preferred shares relating to regulated operations are amortized over the expected life of the issue and issue costs of preferred shares relating to other subsidiaries are charged to retained earnings. Unamortized premiums and issue costs of redeemed long term debt and preferred shares relating to regulated operations are amortized over the life of the issue funding the redemption.

Deferred Availability Incentives

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

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

Asset Retirement Obligations

Asset retirement obligations are 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 in deferred credits, 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.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Asset retirement obligations for regulated natural gas and electric transmission and distribution assets are 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.

Effective January 1, 2006, the Corporation retroactively adopted the Canadian Institute of Chartered Accountant's ("CICA") Emerging Issues Abstract regarding conditional asset retirement obligations. This abstract requires an entity to record a liability for an asset retirement obligation where the timing and/or method of settlement are conditional upon the occurrence of a future event that may or may not be within the control of the entity. Adoption of this abstract had no effect on the consolidated financial statements for the year ended December 31, 2006.

Long Term Debt Due Within One Year

When the Corporation intends to refinance long term debt due within one year on a long term basis and there is a written undertaking from an underwriter to act on the Corporation's behalf with respect thereto, or sufficient capacity exists under long term bank loan agreements to issue commercial paper or assume bank loans, then long term debt due within one year is classified as long term.

Hedging

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

The Corporation designates each derivative instrument as a hedge of specific assets or liabilities on the balance sheet or specific firm commitments or anticipated transactions. The Corporation also assesses, both at the hedge's inception and on an ongoing basis, whether the derivative instruments that are used in hedging transactions are effective in offsetting changes in fair values or cash flows of the hedged items.

Payments or receipts on derivative instruments that are designated and effective as hedges are recognized concurrently with, and in the same financial category as, the hedged item.

If a derivative instrument is terminated or ceases to be effective as a hedge prior to maturity, the gain or loss at that date is deferred and recognized in income concurrently with the hedged item. Subsequent changes in the value of the derivative instrument are reflected in income. If the designated hedged item is sold, extinguished or matures prior to the termination of the related derivative instrument, the gain or loss at that date on such derivative instrument is recognized in income.

Employee Future Benefits

The Corporation accrues for its obligations under defined benefit pension and other post employment benefit plans. Costs of these benefits are determined using the projected benefits method prorated on service and reflects management's best estimates of investment returns, wage and salary increases, age at retirement and expected health care costs.

Pension plan assets at the end of the year are reported at market value. 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. Expected return on plan assets for the year is calculated by applying the expected long term rate of return to the market related value of plan assets, which is the average of the market value of plan assets at the end of the preceding three years.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Accrued benefit obligations at the end of the year are determined using a discount rate that reflects market interest rates on high quality corporate bonds that match the timing and amount of expected benefit payments.

Experience gains and losses and the effect of changes in assumptions in excess of 10% of the greater of the accrued benefit obligations or the market value of plan assets, adjustments resulting from plan amendments and the net transitional liability or asset, which arose upon the adoption in 2000 of the current accounting standard, are amortized over the estimated average remaining service life of employees.

Pursuant to an AEUB decision effective January 1, 2000, the regulated operations, excluding Alberta Power (2000), are required to expense contributions for other post employment benefit and certain other defined benefit pension plans as paid. The differences between the amounts accrued and paid are deferred in non-current regulatory assets and liabilities.

Employer contributions to the defined contribution pension plans are expensed as paid.

Stock Based Compensation Plans

The Corporation expenses stock options granted on and after January 1, 2002; no compensation expense is recorded for stock options granted prior to January 1, 2002 as permitted by GAAP. 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 recognized when share appreciation rights are granted. Prior to vesting, compensation expense arising from an increase or decrease in the market price of the shares over the base value of the rights is accrued equally over the remaining months to the date of vesting. After that date, compensation expense arising from an increase or decrease in the market price of the shares is recognized monthly in earnings.

Effective January 1, 2006, the Corporation retroactively adopted the CICA Emerging Issues Abstract regarding stock based compensation for employees eligible to retire before the vesting date. This abstract requires an entity to recognize the compensation cost attributable to such an award over the period from grant date to the date the employee becomes eligible to retire. Since the Corporation does not have stock based compensation plans that contain such provisions, adoption of this abstract had no effect on the consolidated financial statements for the year ended December 31, 2006.

Foreign Currency Translation

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

Monetary assets and liabilities of integrated foreign operations are translated into Canadian dollars at the rate of exchange in effect at the balance sheet date, non-monetary assets and liabilities are translated at rates of exchange in effect when the assets were acquired or liabilities incurred, and revenues and expenses are translated at the average monthly rates of exchange during the year. Gains or losses on translation of integrated foreign operations are recognized in earnings.

Transactions undertaken by Canadian operations that are denominated in foreign currencies are translated into Canadian dollars at the rate of exchange in effect at the transaction date.

2. ACCOUNTING FOR RATE REGULATED OPERATIONS

Nature and economic effects of rate regulation

ATCO Electric, ATCO Gas and ATCO Pipelines (the "utilities") are regulated primarily by the AEUB, which administers acts and regulations covering such matters as rates, financing, accounting, construction, operation and service area.

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

The utilities are subject to a cost of service regulatory mechanism under which the AEUB establishes the revenues required (i) to recover the forecast operating costs, including depreciation and amortization and income taxes, of providing the regulated service, and (ii) to provide a fair and reasonable return on utility investment, or rate base. Whereas actual operating conditions may vary from forecast, actual returns achieved can differ from approved returns.

Rate base for each utility is the aggregate of the AEUB approved investment in property, plant and equipment, less accumulated depreciation, plus an allowance for working capital. Rate base also excludes no-cost capital, which consists of unamortized contributions by utility customers for extensions to plant. The utilities earn a return on rate base intended to meet the cost of the debt and preferred share components of rate base and to provide share owners with a fair return on the common equity component of rate base.

The AEUB approves rates of return for the debt and preferred share components of rate base based on the actual or forecast weighted average cost of each utility's debt and preferred shares. On July 2, 2004, the AEUB established a standardized approach for determining the rate of return on common equity for each utility regulated by the AEUB. This rate of return will be adjusted annually by 75% of the change in long term Government of Canada bond yield as forecast in the November Consensus Forecast, adjusted for the average difference between the 10 year and 30 year Government of Canada bond yields for the month of October as reported in the National Post. In January 2006, the AEUB clarified that the generic return on equity determined on an annual basis in accordance with the generic cost of capital decision should apply to each year of the test period in the utilities' applications. If no rate applications are filed for a particular year, then there will be no adjustment to the common equity rate of return for that year.

The AEUB also established the capital structure for each utility and 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.

Under the cost of service methodology, the utilities seek approval for their revenue requirement either through submission of general rate applications to the AEUB or a negotiated settlement process with interested parties. In the latter case, the AEUB monitors the negotiated settlement process and approves any agreement that is reached. The AEUB may approve interim rates or approve recovery of costs on a placeholder basis, subject to final determination.

Financial statement effects of rate regulation

Certain items in these consolidated financial statements are accounted for differently than they would be in the absence of rate regulation. CICA recommendations do not require that assets and liabilities arising from rate regulation be recognized and measured in accordance with the primary sources of GAAP.

2. ACCOUNTING FOR RATE REGULATED OPERATIONS (CONTINUED)

Where regulatory decisions dictate, the utilities defer certain costs or revenues as assets or liabilities on the balance sheet and record them as expenses or revenues in the earnings statement as they collect or refund amounts through future customer rates. Any adjustments to these deferred amounts are recognized in earnings in the period that the AEUB renders a subsequent decision.

Circumstances in which rate regulation affects the accounting for a transaction or event are described below. For these regulatory items, the expected recovery or settlement period, or likelihood of recovery or settlement, is affected by risks and uncertainties relating to the ultimate authority of the regulator in determining the item's treatment for rate setting purposes, and, unless specifically indicated, is indeterminate.

The regulatory assets and liabilities comprise the following:

	2006	2005
Regulatory assets – current:		
Deferred hearing costs	**$ -**	$ 8.8
Deferred electricity costs	**1.7**	-
Other regulatory assets	**11.6**	10.3
	$ 13.3	$ 19.1
Regulatory assets – non-current:		
Regulatory other post employment benefits asset (Note 20)	**$ 27.6**	$ 22.0
Deferred electricity costs	**7.1**	5.4
Deferred hearing costs	**1.4**	1.6
Reserves for injuries and damages	**2.0**	5.4
Other regulatory assets	**5.1**	0.6
	$ 43.2	$ 35.0
Regulatory liabilities – current:		
Deferred electricity cost recoveries	**$ -**	$ 4.0
Reserves for injuries and damages	**-**	0.8
Other regulatory liabilities	**0.5**	1.6
	$ 0.5	$ 6.4
Regulatory liabilities – non-current:		
Regulatory pension liability (Note 20)	**$118.7**	$139.4
Deferred royalty credits	**19.7**	18.1
Deferred electricity cost recoveries	**6.2**	-
Deferred hearing costs	**0.4**	2.6
Reserves for injuries and damages	**2.8**	0.8
Other regulatory liabilities	**1.0**	1.0
	$148.8	$161.9

Employee future benefits

The Corporation accrues for its obligations under defined benefit pension and other post employment benefit plans. The regulatory asset (liability) reflects an AEUB decision, effective January 1, 2000, to record costs of employee future benefits in the utilities when paid rather than accrued. The variances between the amounts paid and accrued for each of the defined benefit pension plans and the other post employment benefit plans will vary depending on the performance of plan assets and the actuarial valuations of plan obligations. These variances will be deferred until the plans are paid, settled or terminated.

GAAP requires that the variances between the amounts accrued and paid be recognized as an expense or reduction in expense in the period in which they are accrued. Consequently, defined benefit pension plan cost in 2006 would have been $19.5 million higher (2005 – $1.6 million lower), and other post employment benefit plan cost in 2006 would have been $3.5 million higher (2005 – $3.3 million higher), in the absence of rate regulation.

2. ACCOUNTING FOR RATE REGULATED OPERATIONS (CONTINUED)

Upon the adoption of the current accounting standard in 2000, the utilities had recorded deferred pension assets of $23.0 million. The utilities have been earning an AEUB approved rate of return on these assets through customer rates as the assets form part of the utilities' AEUB approved rate base. In the absence of rate regulation, the utilities would not be able to earn a return on these assets. Consequently, revenues in 2006 would have been $1.7 million lower (2005 – $2.1 million lower). On October 11, 2006, the AEUB issued a decision that approved recovery of these assets for a nine-year period commencing January 1, 2005 and permitted the utilities to continue to earn an AEUB approved rate of return on the unrecovered portion of these assets over the recovery period. In 2006, the utilities amortized $5.1 million (2005 – nil) of the deferred pension asset.

Deferred electricity costs (recoveries)

Variances between ATCO Electric's actual and forecast transmission access payments may arise due to changes in tariffs charged by the Alberta Power Pool. The amount included in customer rates is based on forecast cost. Revenues are adjusted for changes in tariffs, and the variances are deferred until approval from the AEUB is obtained for refund to or collection from customers, which is expected to occur in the following year. GAAP requires that revenues be based on the rates approved by the AEUB and not adjusted for variances between forecast and actual costs.

In Alberta, major transmission capital projects are planned by the Alberta Power Pool and directly assigned to one of the transmission facility owners in the province. Revenue requirement includes a return on forecast rate base. Whereas actual capital costs may vary from forecast capital costs, variances may arise between the return on forecast rate base and the return on actual rate base. Revenues are adjusted for these variances, and the variances are deferred until approval from the AEUB is obtained for refund to or collection from the Alberta Power Pool, which is expected to occur in the following year. GAAP requires that revenues be based on the rates approved by the AEUB and not adjusted for variances between the returns on forecast and actual rate base.

Consequently, revenues in 2006 would have been $1.2 million lower (2005 – $23.4 million lower) in the absence of rate regulation.

Deferred hearing costs

The utilities incur hearing costs on an ongoing basis associated with various AEUB regulatory proceedings. These costs are comprised primarily of legal and consulting expenses incurred by the utilities in addition to costs incurred by intervenor groups that have been reimbursed by the utilities as directed by the AEUB. Hearing costs are deferred to the balance sheet and are expensed using AEUB approved annual amounts that are collected through customer rates. Variances between the approved annual amounts and actual costs incurred are deferred until the next general rate application or until a specific application is made to the AEUB requesting recovery from or refund to customers. GAAP requires that hearing costs be expensed in the period in which they are incurred. Consequently, expenses in 2006 would have been $6.8 million lower (2005 – $4.0 million higher) in the absence of rate regulation.

Reserves for injuries and damages

The AEUB has approved the use of reserves for injuries and damages by the utilities as a means of self-insurance. The reserves for injuries and damages are established based on annual amounts approved by the AEUB to be expensed by each utility and collected through customer rates. Variances between the approved annual amounts and actual costs incurred are deferred until the following general rate application or until a specific application is made to the AEUB requesting recovery from or refund to customers. GAAP requires that claims be expensed in the period in which they are incurred. Consequently, expenses in 2006 would have been $3.6 million lower (2005 – $1.1 million lower) in the absence of rate regulation.

2. ACCOUNTING FOR RATE REGULATED OPERATIONS (CONTINUED)

For Alberta Power (2000), reserves for injuries and damages are recoverable under the terms of the PPA's on a straight line basis through 2008. GAAP requires that claims be expensed in the period in which they are incurred. Consequently, expenses in 2006 would have been $1.0 million lower (2005 – $1.0 million lower) in the absence of rate regulation.

Deferred royalty credits

Under the terms of PPA's, the compensation for certain royalties incurred by Alberta Power (2000) for coal supply are averaged over the term of each PPA. As such, royalty costs incurred are deferred and expensed on the same average cost basis as reflected in the underlying PPA revenues. GAAP requires that royalty costs be expensed in the period in which they are incurred. Consequently, expenses in 2006 would have been $1.6 million lower (2005 – $4.0 million lower) in the absence of rate regulation.

Other regulatory assets and liabilities

Other regulatory assets and liabilities include the following:

a) ATCO Gas has received AEUB approval to defer:
   i) Bad debt and collection agency fees incurred after June 1, 2004 related to billings prior to that date and associated late payment charges net of bad debt recoveries of $(0.1) million (2005 – $1.4 million);
   ii) Charges from the Government of Alberta for funding of the office of the Utilities Consumer Advocate and the Consumer Protection and Consumer Choice Campaign, net of AEUB approved recoveries from customers, of $(0.6) million (2005 – $1.0 million); and,
   iii) Removal and abandonment costs related to previously disposed of production properties, net of AEUB approved recoveries from customers, of nil (2005 – $5.0 million).

   Variances between the approved annual amounts and actual costs are deferred until the following general rate application or until a specific application is made to the AEUB requesting recovery from or refund to customers. GAAP requires that these net costs be expensed in the period in which they are incurred. Consequently, expenses in 2006 would have been $8.1 million lower (2005 – $2.1 million higher) in the absence of rate regulation. Liabilities of $0.7 million are included in non-current regulatory liabilities (2005 – $6.9 million in current regulatory assets and $0.5 million in non-current regulatory assets).

b) In October 2005, ATCO Gas filed an application with the AEUB to approve the sale of its Red Deer Operating Centre. In December 2005, the AEUB approved the sale and deferred its decision on the distribution of net proceeds of $1.0 million until the Supreme Court of Canada rendered a judgment in the appeal regarding the Calgary Stores Block disposition and allocation of proceeds thereon. The Supreme Court of Canada rendered its decision on the Calgary Stores Block matter on February 9, 2006 and the AEUB complied with that decision on August 11, 2006. Subsequently, ATCO Gas submitted a filing to the AEUB to approve the allocation of the net proceeds from the sale of the Red Deer Operating Centre. On December 13, 2006, the AEUB issued a decision approving the distribution of the proceeds to ATCO Gas. GAAP requires that gains and losses related to asset dispositions be recognized in the period the disposition was made. Consequently, revenues in 2006 would have been $1.0 million lower (2005 – $1.0 million higher) in the absence of rate regulation.

c) ATCO Pipelines has received AEUB approval to defer the variances between actual and AEUB approved forecast revenues and costs associated with the movement (receipt or delivery) of natural gas between ATCO Pipelines' system and other connected pipeline systems. ATCO Pipelines expects that the recovery of these deferral accounts will occur in the next general rate application. GAAP requires that actual revenues and costs be recognized in the period in which they are earned or incurred. Consequently, revenues in 2006 would have been $0.9 million higher (2005 – $0.1 million lower) and expenses would have been $0.6 million lower (2005 – $1.6 million lower) in the absence of rate regulation. Assets of $2.7 million and $0.2 million (2005 – $2.2 million and nil) are included in current regulatory assets and non-current regulatory assets, respectively, and liabilities of $0.5 million and $0.3 million (2005 – $1.6 million and nil) are included in current regulatory liabilities and non-current regulatory liabilities, respectively.

2. ACCOUNTING FOR RATE REGULATED OPERATIONS (CONTINUED)

d) ATCO Pipelines has received AEUB approval to establish a deferral account for the Salt Cavern Storage facility to collect (i) the revenue requirements for return on rate base and associated income taxes related to the necessary working capital for the natural gas in storage, and (ii) the gains or losses associated with the sale of natural gas in the market upon withdrawal from storage. ATCO Pipelines is required to submit an application to the AEUB, either separately or in conjunction with a general rate application for that particular year, requesting recovery from or refund to customers of the deferral amount should the deferral account exceed $2.0 million at the end of the annual injection/withdrawal cycle on March 31 of a particular year. GAAP requires that actual revenues and costs be recognized in the period in which they are earned or incurred. Consequently, revenues in 2006 would have been $2.6 million lower (2005 – $1.2 million lower) in the absence of rate regulation. Assets of $3.7 million are included in non-current regulatory assets (2005 – $1.2 million in current regulatory assets) in the balance sheet.

e) In 2006, ATCO Pipelines received AEUB approval to establish deferral accounts to collect the costs and revenues arising from load balancing transactions. Load balancing requires the purchase or sale of natural gas to maintain appropriate operating pressures on ATCO Pipelines' North and South transmission pipeline systems. Should the deferral account for either North or South exceed $2.0 million, ATCO Pipelines may submit an application to the AEUB requesting recovery from or refund to customers of that particular deferral amount. GAAP requires that actual revenues and costs be recognized in the period in which they are earned or incurred. Consequently, expenses in 2006 would have been $8.9 million higher in the absence of rate regulation. Assets of $8.9 million are included in current regulatory assets in the balance sheet.

Other items affected by rate regulation

The AEUB permits an allowance for funds used ("AFU"), based on each utility's weighted average cost of capital, to be included in rate base. AFU is also included in the cost of property, plant and equipment for financial reporting purposes, and is depreciated as part of the total cost of the related asset, based on the expectation that depreciation expense, including the AFU component, will be approved for inclusion in future customer rates. Since AFU includes preferred share and common equity components, it exceeds the amount allowed to be capitalized in similar circumstances in the absence of rate regulation.

The utilities and the generating plants of Alberta Power (2000) follow the method of accounting for income taxes that is consistent with the method of determining the income tax component of its rates. When future income taxes are not included in the income tax component of current rates, such future income taxes are not recognized to the extent that they will be recovered from customers through inclusion in future rates. GAAP requires the recognition of all future income tax liabilities and future tax assets in the absence of rate regulation (see Note 7).

3. TRANSFER OF RETAIL ENERGY SUPPLY BUSINESSES

On May 4, 2004, ATCO Gas and ATCO Electric transferred their retail energy supply businesses to Direct Energy Marketing Limited and one of its affiliates (collectively "DEML"), a subsidiary of Centrica plc. Proceeds of the transfer were $90 million, of which $45 million was paid at closing, and the remainder was paid on May 4, 2005. ATCO Gas and ATCO Electric continue to own and operate the natural gas and electricity distribution systems used to deliver energy.

ATCO Pipelines, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical did not participate in this transfer and continue to purchase natural gas and electricity for sale to customers. In addition, the AEUB issued a decision that directed ATCO Gas to continue to reserve for the benefit of utility customers 16.7 petajoules of storage capacity at its Carbon storage facility for the 2004/2005 storage year, which ended on March 31, 2005, and issued a decision that terminated ATCO Pipelines' obligation to purchase natural gas for sale to customers effective October 31, 2005.

3. TRANSFER OF RETAIL ENERGY SUPPLY BUSINESSES (CONTINUED)

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

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

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

4. REGULATORY MATTERS

On March 17, 2006, ATCO Electric received a decision on its general tariff application for 2005 and 2006 which was filed with the AEUB in May 2005. The decision establishes the amount of revenue ATCO Electric can recover through its rates for electric distribution and transmission service provided to its customers for 2005 and 2006. In July and September 2005, the AEUB had approved interim refundable rates for distribution and transmission operations, respectively; revenues associated with these interim refundable rates were recorded in 2005. The impact of the decision for 2005 reduced earnings by $1.3 million and was recorded in the first quarter of 2006. The impact of the decision for the full year 2006, as compared to the decision for the full year 2005, further reduced earnings by $1.6 million. The decision also confirmed the return on common equity as determined by the AEUB's standardized rate of return methodology. The rate of return on common equity was 9.5% in 2005 and is 8.93% in 2006.

On January 27, 2006, ATCO Gas received a decision on its general rate application which was filed with the AEUB in May 2005 for the 2005, 2006 and 2007 test years. The decision establishes the amount of revenue ATCO Gas can recover through distribution rates for natural gas distribution service to its customers over the period of 2005 to 2007. The decision also approved the return on common equity as determined by the AEUB's standardized rate of return methodology. The rate of return on common equity was 9.5% in 2005, is 8.93% in 2006, and will be 8.51% for 2007. The final impact of the decision will not be known until a subsequent regulatory process is finalized. A decision from the AEUB with respect to a second regulatory process that was pending at the end of 2005 was received on October 11, 2006; the effect of this decision on the earnings of the Corporation was not material.

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

5. TXU EUROPE SETTLEMENT

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

5. TXU EUROPE SETTLEMENT (CONTINUED)

Barking Power received a total of four distributions in settlement of its claim: a first distribution of £112.3 million (approximately $257 million) on March 30, 2005, of which the Corporation's share was $65.4 million; a second distribution of £32.2 million (approximately $69.6 million) on August 2, 2005, of which the Corporation's share was $17.7 million; a third distribution of £31.8 million (approximately $65.2 million) on January 19, 2006, of which the Corporation's share was $16.6 million; and a final distribution of £3.0 million (approximately $6.2 million) on July 20, 2006, of which the Corporation's share was $1.6 million. Income taxes of approximately $28.1 million relating to the distributions have been paid. Income taxes of approximately $0.4 million relating to the final distribution will be paid in 2007 as part of the Corporation's normal tax installments.

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

6. INTEREST AND OTHER INCOME

	2006	2005
Interest	**$39.3**	$29.0
Allowance for funds used by regulated operations	**9.3**	7.0
Gains on dispositions of property, plant and equipment	**8.3**	1.7
Other income (expense)	**1.6**	(1.1)
	$58.5	$36.6

7. INCOME TAXES

The income tax provision differs from that computed using the statutory tax rates for the following reasons:

	2006		2005	
Earnings before income taxes	**$526.8**	%	$477.0	%
Income taxes, at statutory rates	**$208.0**	**39.5**	$193.8	40.6
Federal general tax reduction [1]	**(23.2)**	**(4.4)**	(18.1)	(3.8)
Manufacturing and processing tax credit	**(7.7)**	**(1.5)**	(7.5)	(1.6)
Resource allowance	**(1.6)**	**(0.3)**	(2.8)	(0.6)
Crown royalties and other non-deductible Crown payments	**0.7**	**0.1**	1.1	0.2
Foreign tax rate variance	**(7.6)**	**(1.4)**	(6.2)	(1.3)
Non-deductible interest on foreign financing	**1.3**	**0.3**	1.4	0.3
Large Corporations Tax	**-**	**-**	7.8	1.7
Change in future income taxes resulting from reduction in tax rates	**(12.2)**	**(2.3)**	-	-
Change in method of accounting for future income taxes in certain regulated operations	**(4.0)**	**(0.8)**	-	-
Unrecorded future income taxes relating to regulated operations	**2.5**	**0.5**	1.0	0.2
H.R. Milner income tax reassessment	**7.4**	**1.4**	-	-
Other	**3.5**	**0.6**	5.1	1.1
	167.1	**31.7**	175.6	36.8
Current income taxes	**183.0**		185.8	
Future income taxes (recoveries)	**$ (15.9)**		$ (10.2)	

(1) *The federal general tax reduction of 7% is applicable to earnings that have not otherwise benefited from the manufacturing and processing tax credit and/or the resource allowance. An additional federal tax reduction of 5% (2005 – 3%) is applicable to earnings that have benefited from the resource allowance.*

7. INCOME TAXES (CONTINUED)

The future income tax liabilities (assets) comprise the following:

	2006	2005
Property, plant and equipment	**$212.2**	$222.7
Deferred assets and liabilities	**(17.1)**	(18.3)
Tax loss carryforwards	**(0.1)**	(0.3)
Other	**-**	0.3
	195.0	204.4
Less: Amounts included in current future income taxes	**0.3**	4.1
	$194.7	$200.3

At December 31, 2006, unrecorded future income tax liabilities of the regulated operations amounted to $141.3 million and unrecorded future income tax assets of other operations amounted to $0.5 million. The liabilities include $14.6 million in respect of Alberta Power (2000)'s generating plants, which will be recovered through future payments received in respect of the PPA's.

In 2006, the Canada Revenue Agency ("CRA") issued a reassessment for Alberta Power (2000)'s 2001 taxation year. The CRA's reassessment treats the proceeds received from the sale of the H.R. Milner generating plant to the Alberta Balancing Pool as income rather than as a sale of an asset. The Corporation has made submissions to the CRA opposing the CRA's position. The impact of the reassessment is a $12.4 million increase in interest and income tax expense, a $12.4 million decrease in earnings and a $28.8 million payment associated with the tax and interest assessed. It is expected that $16.4 million of this cash payment will be recovered by reducing income taxes payable through higher capital cost allowance claims. Due to the uncertainty as to whether the reassessment will ultimately be resolved in the Corporation's favour, the Corporation reduced earnings by $12.4 million in 2006.

There are tax loss carryforwards of $0.4 million for Canadian subsidiary corporations and $7.6 million for a foreign subsidiary corporation for which no tax benefit has been recorded. The losses for Canadian subsidiary corporations begin to expire in 2010 and the losses for the foreign subsidiary corporation do not expire.

Income taxes paid amounted to $187.0 million (2005 – $178.6 million).

8. PURCHASE OF CLASS A SHARES AND OTHER DIRECT CHARGES TO RETAINED EARNINGS

	2006	2005
Purchase of Class A shares	**$64.4**	$7.5
Purchase of ATCO Európa Szerkezetgyártó és Kereskedelmi Kft. (Note 19)	**0.3**	-
	$64.7	$7.5

9. PROPERTY, PLANT AND EQUIPMENT

		2006		2005	
	Composite Depreciation Rates	**Cost**	**Accumulated Depreciation**	Cost	Accumulated Depreciation
Utilities	3.7%	**$6,490.4**	**$2,411.1**	$6,022.0	$2,240.8
Power Generation	3.2%	**2,853.7**	**1,026.1**	2,753.9	921.4
Global Enterprises	9.2%	**269.5**	**140.8**	270.3	127.1
Other	4.7%	**26.7**	**6.7**	27.7	6.1
		$9,640.3	**3,584.7**	$9,073.9	3,295.4
Property, plant and equipment less accumulated depreciation			**6,055.6**		5,778.5
Unamortized contributions by utility customers for extensions to plant			**629.5**		569.8
			$5,426.1		$5,208.7

9. PROPERTY, PLANT AND EQUIPMENT (CONTINUED)

Accumulated depreciation includes amounts provided for future removal and site restoration costs, net of salvage value, of $374.6 million (2005 – $323.6 million).

Composite depreciation rates reflect total depreciation in the year as a percentage of mid-year cost, excluding construction work-in-progress of $114.2 million (2005 – $91.1 million) and non-depreciable assets of $52.3 million (2005 – $41.3 million).

10. OTHER ASSETS

	2006	2005
Accrued pension asset (Note 20)	**$157.1**	$192.2
Security deposits for debt	**22.8**	20.0
Deferred financing charges [1]	**25.0**	25.4
Other [2]	**24.8**	31.5
	$229.7	$269.1

[1] *Amortization of deferred financing charges, which was recorded in interest expense, amounted to $2.8 million (2005 – $2.8 million).*

[1] *Amortization of certain other assets, which was recorded in depreciation and amortization, amounted to $14.9 million (2005 – $5.9 million).*

11. CREDIT LINES

At December 31, 2006, the Corporation has the following credit lines that enable it to obtain financing for general business purposes:

	2006			2005		
	Total	**Used**	**Available**	Total	Used	Available
Long term committed	**$326.0**	**$47.4**	**$278.6**	$326.0	$11.9	$314.1
Short term committed	**600.0**	**14.0**	**586.0**	600.0	-	600.0
Uncommitted	**69.1**	**7.1**	**62.0**	69.1	8.3	60.8
	$995.1	**$68.5**	**$926.6**	$995.1	$20.2	$974.9

Of the $68.5 million used at December 31, 2006, $47.0 million is included in long term debt and $21.5 million represents outstanding letters of credit.

12. LONG TERM DEBT AND NON-RECOURSE LONG TERM DEBT

Long term debt

	2006	2005
CU Inc. debentures – unsecured		
2001 4.84% due November 2006	$ -	$ 175.0
2002 4.801% due November 2007	50.0	50.0
2000 6.97% due June 2008	100.0	100.0
1989 Series 10.20% due November 2009	125.0	125.0
1990 Series 11.40% due August 2010	125.0	125.0
2000 7.05% due June 2011	100.0	100.0
2004 5.096% due November 2014	100.0	100.0
2002 6.145% due November 2017	150.0	150.0
2004 5.432% due January 2019	180.0	180.0
1999 Series 6.8% due August 2019	300.0	300.0
1990 Second Series 11.77% due November 2020	100.0	100.0
2006 4.801% due November 2021	160.0	-
1991 Series 9.92% due April 2022	125.0	125.0
1992 Series 9.40% due May 2023	100.0	100.0
2004 5.896% due November 2034	200.0	200.0
2005 5.183% due November 2035	185.0	185.0
2006 5.032% due November 2036	160.0	-
Canadian Utilities Limited debentures – unsecured		
2002 6.14% due November 2012	100.0	100.0
	2,360.0	2,215.0
ATCO Midstream Ltd. credit facility, at BA rates, due June 2011, unsecured [1]	25.0	-
ATCO Power Canada Ltd. credit facility, at BA rates, due August 2011, secured by a pledge of cash [1]	22.0	11.5
Other long term obligation, at 5.0%, due June 2007, unsecured	4.5	4.5
	$ 2,411.5	$ 2,231.0

Non-recourse long term debt

	2006	2005
Barking Power Limited project financing, payable in British pounds:		
At fixed rates averaging 7.95%, due to 2010	$ 52.1	$ 54.7
At LIBOR, due to 2010 [1]	85.5	89.6
Osborne Cogeneration Pty Ltd. project financing, payable in Australian dollars:		
At Bank Bill rates, due to 2013 [1]	1.7	1.8
At 7.3325%, due to 2013 [1]	31.8	34.4
ATCO Power Alberta Limited Partnership ("APALP") project financing:		
At 7.54% to 2008, at LIBOR thereafter, due to 2016 [1]	2.6	3.8
At 7.317% to 2008, at LIBOR thereafter, due to 2016 [1]	3.6	5.4
At 7.50% to 2011, at LIBOR thereafter, due to 2016 [1]	83.8	87.5
Joffre project financing:		
At 7.286%, due to 2012 [1]	15.6	26.7
At 8.59%, due to 2020	32.0	32.0
Scotford project financing:		
At 5.212%, due to 2008, at BA rates thereafter, due to 2014 [1]	42.8	46.2
At 5.212%, due to 2008, at LIBOR thereafter, due to 2014 [1]	10.7	11.6
At 7.93%, due to 2022	26.1	26.9

12. LONG TERM DEBT AND NON-RECOURSE LONG TERM DEBT (CONTINUED)

Non-recourse long term debt (continued)

	2006	2005
Muskeg River project financing:		
At 5.287%, due 2007, at BA rates thereafter, due to 2014 (1)	**40.8**	44.4
At BA rates, due to 2014 (1)	**0.1**	0.3
At 7.56%, due to 2022	**29.4**	31.2
Brighton Beach project financing:		
At 5.8367%, due 2009, at BA or Canadian Eurodollar rates thereafter, due to 2019 (1)	**8.9**	9.4
At BA or Canadian Eurodollar rates, due to 2019 (1)	**2.7**	2.5
At 6.575%, due to 2019 (1)	**36.1**	37.8
At 6.924%, due to 2024	**107.8**	110.5
Cory project financing:		
At BA rates, due to 2011 (1)	**0.3**	0.3
At 6.346%, due to 2011 (1)	**2.7**	3.3
At 7.586%, due to 2025	**36.5**	37.4
At 7.601%, due to 2026	**32.4**	33.1
	686.0	730.8
Less: Amounts due within one year	**59.3**	57.0
	$626.7	$673.8

BA – Bankers' Acceptance
LIBOR – London Interbank Offered Rate

(1) The above interest rates have additional margin fees at a weighted average rate of 1.1% (2005 – 1.1%) (Note 21). The margin fees are subject to escalation.

The Corporation has fixed interest rates, either directly or through interest rate swap agreements, on 96% (2005 — 96%) of total long term debt and non-recourse long term debt.

The non-recourse long term debt is secured by charges on the projects' assets and by an assignment of the projects' bank accounts, outstanding contracts and agreements. The book value of the pledged assets and bank accounts at December 31, 2006 was $1,415.2 million (2005 – $1,342.4 million).

Guarantees

Canadian Utilities Limited has provided a number of guarantees related to ATCO Power's obligations under non-recourse loans associated with certain of its projects. These guarantees cover the following items:

a) **Construction liens** – Represents liens currently registered against project assets. Effective September 30, 2005, ATCO Power entered into an indemnity agreement with Brighton Beach Power Ltd. obligating it to cover any cash shortfalls associated with clearing the construction liens registered against the project. This agreement allowed the project to achieve financial completion under the terms of the project financing agreement. The maximum amount of the indemnity is $8.3 million. Canadian Utilities Limited issued a guarantee to Brighton Beach Power Ltd. guaranteeing the payments under the indemnity agreement. The indemnity and the guarantee are reduced as the liens are settled.

12. LONG TERM DEBT AND NON-RECOURSE LONG TERM DEBT (CONTINUED)

b) **Project cash flows** – Represents annual payments related to maintaining base case margins for electricity prices on the merchant power component of the project, being 24 megawatts ("MW") for the Scotford project and 48 MW for the Muskeg River project. These guarantees became effective upon the commercial operation of the plants and exist until 2022, when the project debt is to be fully repaid. The amounts payable under these guarantees will vary each year depending on the pool price received for the merchant power generated. Any payments made to maintain the project base case margins will either be available for distribution to the owners or be applied to mandatory prepayment of the project debt in accordance with the terms of the project financing agreement depending upon the specific operating results of the plant. At December 31, 2006, no amounts were outstanding under the guarantee.

c) **Reserve amounts** – Represents amounts to be set aside for major maintenance and debt service reserves as stipulated in the project's financing agreement. These reserves are intended to be funded with project cash flows. To the extent that project cash flows are insufficient to meet reserve requirements, Canadian Utilities Limited may choose to provide guarantees in lieu of ATCO Power providing security. At December 31, 2006, the amount of the obligations under these guarantees is:

Project	Major Maintenance	Debt Service
APALP project financing	Nil [1]	$6.9
Brighton Beach project financing	Nil [2]	Nil
Cory project financing	Nil [1]	$3.9
Joffre project financing	Nil [3]	$4.7
Muskeg River project financing	Nil [1]	$5.0
Scotford project financing	Nil [1]	$5.6

[1] *No major maintenance reserve required for this financing.*
[2] *Reserve requirements of $0.3 million met with project cash flows.*
[3] *Reserve requirements of $1.0 million met with project cash flows.*

d) **Prepaid operating and maintenance fee** – Should ATCO Power cease to be operator of the APALP generating plants as a result of a termination of the operating agreement, Canadian Utilities Limited has guaranteed the payment of the unamortized portion of the prepaid operating and maintenance fee to APALP, the proceeds of which are to be used to repay project debt in accordance with the project financing agreements. This guarantee, which declines by $1.2 million per year, remains in effect until 2016, when the project debt is to be fully repaid. At December 31, 2006, the maximum value of the guarantee is $30.0 million.

e) **Purchase project assets** – Represents an obligation to purchase the Scotford and Muskeg River projects at a price sufficient to repay any outstanding project debt upon the occurrence of any one of the following very limited events:

(i) where all of the following events have occurred:
- the insolvency of ATCO Power;
- the failure of the project debt lenders to complete a sale of the project pursuant to their security within a fixed period of time; and
- the project purchaser of electricity and steam elects to terminate its purchase contracts due to the insolvency of ATCO Power;

(ii) where the project purchaser of electricity and steam does not remove ATCO Power as operator of the project after an event of default under the project financing agreements in circumstances where such default is either:
- a deliberate or willful breach of a project financing agreement; or
- where ATCO Power has failed to co-operate with the lenders in a sale of the project; and

(iii) where the project purchaser of electricity and steam terminates its purchase contracts for the project as a result of a default by ATCO Power's project minority joint venturers. ATCO Power has the right to cure any such default by acquiring the minority interest which is in default.

These guarantees remain in effect until the project debt is fully repaid. At December 31, 2006, no such events have occurred.

12. LONG TERM DEBT AND NON-RECOURSE LONG TERM DEBT (CONTINUED)

Canadian Utilities Limited has also guaranteed ATCO Power's duties to operate the Barking Power, Scotford and Muskeg River generating plants in accordance with acceptable industry operating standards under the relevant project contracts.

ATCO Power (80%) and ATCO Resources (20%), a wholly owned subsidiary of Canadian Utilities Limited's parent corporation, ATCO Ltd., have a joint venture in the above projects subject to guarantees, excluding Barking Power.

The foregoing guaranteed amounts represent ATCO Power's 80% interest. Canadian Utilities Limited has also guaranteed similar obligations in respect of ATCO Resources' 20% interest. ATCO Ltd. has indemnified and agreed to reimburse Canadian Utilities Limited for any amounts it may be required to pay under these guarantees in respect of ATCO Resources' 20% interest.

To date, Canadian Utilities Limited has not been required to pay any of its guaranteed obligations.

Minimum debt repayments

The minimum annual debt repayments for each of the next five years are as follows:

	Long Term Debt	Non-Recourse Long Term Debt	Total
2007	$ 54.5	$ 59.3	$113.8
2008	100.0	77.9	177.9
2009	125.0	72.4	197.4
2010	125.0	79.4	204.4
2011	147.0	44.8	191.8
	$551.5	$333.8	$885.3

Of the $113.8 million due in 2007, $54.5 million is to be refinanced and is, therefore, excluded from long term debt due within one year in the balance sheet.

Interest expense

Interest expense is as follows:

	2006	2005
Long term debt	**$161.0**	$154.5
Non-recourse long term debt	**49.0**	51.4
Notes payable	**0.3**	-
Bank indebtedness	**1.5**	1.3
Amortization of deferred financing charges	**2.8**	2.8
Interest on H.R. Milner tax reassessment (Note 7)	**8.3**	-
	$222.9	$210.0

Interest paid amounted to $220.8 million (2005 – $207.2 million).

12. LONG TERM DEBT AND NON-RECOURSE LONG TERM DEBT (CONTINUED)

Fair values

Fair values for the above debt, determined using quoted market prices for the same or similar issues, are shown below. Where the market prices are not available, fair values are estimated using discounted cash flow analysis based on the Corporation's current borrowing rate for similar borrowing arrangements.

	2006	2005
Long term debt		
Fixed rate	**$2,741.4**	$2,656.2
Floating rate	**47.0**	11.5
	$2,788.4	$2,667.7
Non-recourse long term debt		
Fixed rate	**$ 635.3**	$ 683.9
Floating rate	**90.2**	94.5
	$ 725.5	$ 778.4

13. DEFERRED CREDITS

	2006	2005
Accrued other post employment benefits liability (Note 20)	**$ 45.1**	$ 35.4
Deferred revenues (Note 5)	**46.8**	59.6
Deferred availability incentives	**39.6**	59.7
Asset retirement obligations	**69.4**	62.2
Accrued equipment repairs and maintenance	**7.5**	8.8
Other	**20.6**	28.1
	$229.0	$253.8

Deferred availability incentives

Amortization of deferred availability incentives, which was recorded in revenues, amounted to $10.6 million (2005 – $8.9 million).

The amount to be amortized is dependent upon estimates of future generating unit availability and future electricity prices over the term of the PPA's. Each quarter, the Corporation uses these estimates to forecast the incentives to be received from, less penalties to be paid to, the PPA counterparties. These forecasts are added to the accumulated unamortized deferred availability incentives outstanding at the end of the quarter; the resulting total is divided by the remaining term of the PPA to arrive at the amortization for the quarter.

Asset retirement obligations

Changes in asset retirement obligations are summarized below:

	2006	2005
Obligations at beginning of year	**$62.2**	$34.7
Obligations incurred	**3.7**	25.4
Accretion expense	**3.5**	2.1
Obligations at end of year	**$69.4**	$62.2

The Corporation estimates the undiscounted amount of cash flow required to settle the asset retirement obligations is approximately $131 million, which will be incurred between 2007 and 2052. The discount rates used to calculate the fair value of the asset retirement obligations have a weighted average rate of 5.7%.

14. EQUITY PREFERRED SHARES

Authorized and issued

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

Issued:

	Stated Value	Redemption Dates	2006 Shares	2006 Amount	2005 Shares	2005 Amount
	(dollars)					
Cumulative Redeemable Second Preferred Shares						
5.9% Series Q	$25.00	Open	**2,277,675**	**$ 56.9**	2,277,675	$ 56.9
5.3% Series R	$25.00	Open	**2,146,730**	**53.7**	2,146,730	53.7
6.6% Series S	$25.00	Open	**635,700**	**15.9**	635,700	15.9
5.8% Series W	$25.00	See below	**6,000,000**	**150.0**	6,000,000	150.0
6.0% Series X	$25.00	See below	**6,000,000**	**150.0**	6,000,000	150.0
Perpetual Cumulative Second Preferred Shares						
4.35% Series O	$25.00	December 2, 2011	**1,600,000**	**40.0**	1,600,000	40.0
4.35% Series T	$25.00	December 2, 2011	**1,600,000**	**40.0**	1,600,000	40.0
4.35% Series U	$25.00	December 2, 2011	**800,000**	**20.0**	800,000	20.0
5.25% Series V	$25.00	October 3, 2007	**4,400,000**	**110.0**	4,400,000	110.0
				$636.5		$636.5

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

Fair values

Fair values for preferred shares determined using quoted market prices for the same or similar issues are $666.8 million (2005 – $669.1 million).

Redemption privileges

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

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

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

15. CLASS A AND CLASS B SHARES

Authorized and issued

	Class A Non-Voting		Class B Common		Total	
	Shares	Amount	Shares	Amount	Shares	Amount
Authorized:	Unlimited		Unlimited			
Issued and outstanding:						
December 31, 2004	82,740,586	$374.8	44,042,484	$139.5	126,783,070	$514.3
Purchased	(228,600)	(1.0)	-	-	(228,600)	(1.0)
Stock options exercised	338,000	5.8	-	-	338,000	5.8
Converted: Class B to Class A	26,200	0.1	(26,200)	(0.1)	-	-
December 31, 2005	**82,876,186**	**379.7**	**44,016,284**	**139.4**	**126,892,470**	**519.1**
Purchased	**(1,832,200)**	**(8.4)**	**-**	**-**	**(1,832,200)**	**(8.4)**
Stock options exercised	**327,900**	**5.3**	**-**	**-**	**327,900**	**5.3**
Converted: Class B to Class A	**84,800**	**0.3**	**(84,800)**	**(0.3)**	**-**	**-**
December 31, 2006	**81,456,686**	**$376.9**	**43,931,484**	**$139.1**	**125,388,170**	**$516.0**

From January 1, 2007 to February 16, 2007, 600 Class A non-voting shares were issued with respect to the exercises of stock options and 5,000 Class B common shares were converted to Class A non-voting shares.

Earnings per share

Earnings per Class A non-voting and Class B common share is calculated by dividing the earnings attributable to Class A and Class B shares by the weighted average shares outstanding. Diluted earnings per share is calculated using the treasury stock method, which reflects the potential exercise of stock options on the weighted average Class A non-voting and Class B common shares outstanding. The average number of shares used to calculate earnings per share are as follows:

	Three Months Ended December 31		Year Ended December 31	
	2006	2005	**2006**	2005
	(Unaudited)			
Weighted average shares outstanding	**125,321,693**	126,928,689	**126,218,722**	126,901,614
Effect of dilutive stock options	**512,786**	685,048	**468,457**	551,357
Weighted average diluted shares outstanding	**125,834,479**	127,613,737	**126,687,179**	127,452,971

Share owner rights

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

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

15. CLASS A AND CLASS B SHARES (CONTINUED)

Normal course issuer bid

On May 20, 2005, Canadian Utilities Limited commenced a normal course issuer bid for the purchase of up to 3% of the outstanding Class A non-voting shares. The bid expired on May 19, 2006. Over the life of the bid, 348,100 shares were purchased, of which 195,600 were purchased in 2005 and 152,500 were purchased in 2006. On May 23, 2006, Canadian Utilities Limited commenced a new normal course issuer bid for the purchase of up to 5% of the outstanding Class A shares. The bid will expire on May 22, 2007. From May 23, 2006, to February 16, 2007, 1,679,700 shares have been purchased, all of which were purchased in 2006.

Special dividend

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

16. STOCK BASED COMPENSATION PLANS

Stock option plan

Of the 6,400,000 Class A non-voting shares reserved for issuance in respect of options under Canadian Utilities Limited's stock option plan, 2,626,800 Class A non-voting shares are available for issuance at December 31, 2006. Options may be granted to directors, officers and key employees of Canadian Utilities Limited and its subsidiaries at an exercise price equal to the weighted average of the trading price of the shares on the Toronto Stock Exchange for the five trading days immediately preceding the date of grant. The vesting provisions and exercise period (which cannot exceed 10 years) are determined at the time of grant.

Changes in shares under option are summarized below:

	2006		2005	
	Class A Shares	**Weighted Average Exercise Price**	Class A Shares	Weighted Average Exercise Price
Options at beginning of year	**1,415,500**	**$21.59**	1,555,600	$19.45
Granted	**121,000**	**43.45**	204,000	30.50
Exercised	**(327,900)**	**16.62**	(338,000)	17.07
Cancelled	**(600)**	**24.52**	(6,100)	24.93
Options at end of year	**1,208,000**	**$25.12**	1,415,500	$21.59

Information about stock options outstanding at December 31, 2006 is summarized below:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Class A Shares	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Class A Shares	Weighted Average Exercise Price
$17.23 - $18.87	342,600	2.9	$17.84	342,600	$17.84
$20.65 - $28.65	540,400	3.3	23.60	494,400	23.39
$30.25 - $43.56	325,000	8.4	35.33	40,800	30.50
$17.23 - $43.56	1,208,000	4.6	$25.12	877,800	$21.56

In 2006, Canadian Utilities Limited granted 121,000 options to purchase Class A non-voting shares at a weighted average exercise price of $43.45 per share. The options have a term of ten years and vest over the first five years.

On January 2, 2007, Canadian Utilities Limited granted 161,500 options to purchase Class A non-voting shares at an exercise price of $47.84 per share. The options have a term of ten years and vest over the first five years.

16. STOCK BASED COMPENSATION PLANS (CONTINUED)

Changes in contributed surplus are summarized below:

	2006	2005
Contributed surplus at beginning of year	**$0.7**	$0.4
Stock option expense	**0.5**	0.3
Contributed surplus at end of year	**$1.2**	$0.7

The Corporation uses the Black-Scholes option pricing model, which estimated the weighted average fair value of the options granted during 2006 at $6.24 per option (2005 – $3.21 per option) using the following weighted average assumptions:

	2006	2005
Risk free interest rate	**4.0%**	4.0%
Expected holding period prior to exercise	**6.2 years**	6.3 years
Share price volatility	**11.9%**	11.7%
Estimated annual Class A share dividend	**2.5%**	3.5%

Share appreciation rights

Directors, officers and key employees of the Corporation may be granted share appreciation rights that are based on Class A non-voting shares of Canadian Utilities Limited or Class I Non-Voting shares of ATCO Ltd. The vesting provisions and exercise period (which cannot exceed 10 years) are determined at the time of grant. The base value of the share appreciation rights is equal to the weighted average of the trading price of the Class A non-voting shares and the Class I Non-Voting shares, respectively, on the Toronto Stock Exchange for the five trading days immediately preceding the date of grant. The holder is entitled on exercise to receive a cash payment equal to any increase in the market price of the Class A non-voting shares and Class I Non-Voting shares, respectively, over the base value of the share appreciation rights exercised.

Share appreciation rights expense amounted to $2.4 million (2005 – $9.0 million).

17. CHANGES IN NON-CASH WORKING CAPITAL

	2006	2005
Operating activities, changes related to:		
Accounts receivable	**$ (25.6)**	$ (6.7)
Inventories	**0.5**	85.3
Regulatory assets	**(10.6)**	(1.4)
Prepaid expenses	**(3.0)**	(1.7)
Accounts payable and accrued liabilities	**1.7**	29.3
Income taxes	**6.4**	(12.0)
Future income taxes	**(3.8)**	5.3
Regulatory liabilities	**(5.2)**	(7.9)
	$ (39.6)	$90.2
Investing activities, changes related to:		
Inventories	**$ (8.1)**	$ (1.5)
Prepaid expenses	**(0.3)**	0.1
Accounts payable and accrued liabilities	**(6.2)**	9.0
Income taxes	**(3.7)**	(11.0)
	$ (18.3)	$ (3.4)
Financing activities, changes related to:		
Accounts receivable	**$ (0.1)**	$ 3.1

18. JOINT VENTURES

The Corporation's interest in joint ventures is summarized below:

	2006	2005
Statement of earnings		
Revenues	**$ 533.0**	$ 528.6
Operating expenses	**328.1**	355.1
Depreciation and amortization	**40.4**	43.1
Interest	**41.2**	41.5
	123.3	88.9
Interest and other income	**8.9**	7.7
Earnings from joint ventures before income taxes	**$ 132.2**	$ 96.6
Balance sheet		
Current assets	**$ 266.9**	$ 247.4
Current liabilities	**(174.0)**	(159.6)
Property, plant and equipment	**933.2**	922.3
Deferred items – net	**(93.1)**	(101.3)
Non-recourse long term debt	**(465.2)**	(504.2)
Investment in joint ventures	**$ 467.8**	$ 404.6
Statement of cash flows		
Operating activities	**$ 180.8**	$ 175.4
Investing activities	**(19.1)**	(16.0)
Financing activities	**(131.0)**	(79.1)
Foreign currency translation	**14.1**	(9.5)
Increase in cash position	**$ 44.8**	$ 70.8

Current assets include cash of $160.9 million (2005 — $118.6 million) which is only available for use within the joint ventures (see Note 5).

19. RELATED PARTY TRANSACTIONS

In transactions with ATCO Ltd. and its wholly owned subsidiary corporations, the Corporation sold fuel in the amount of $2.2 million (2005 — $2.5 million), provided computer operations and systems development services totaling $2.4 million (2005 – $5.0 million), recovered administrative expenses totaling $2.4 million (2005 — $2.4 million) and incurred administrative expenses and corporate signature rights totaling $8.6 million (2005 — $7.1 million). Also, in transactions with an entity related through common control, the Corporation provided security services and recovered administrative expenses totaling $0.2 million (2005 – $0.2 million) and incurred advertising and promotion expenses totaling $1.7 million (2005 — $1.4 million).

At December 31, 2006, accounts receivable due from related parties amounted to $4.9 million (2005 – $1.8 million) and accounts payable due to related parties amounted to $3.2 million (2005 – $0.5 million).

These transactions are in the normal course of business and under normal commercial terms.

On October 1, 2006, the Corporation purchased the common shares of ATCO Európa Szerkezetgyártó és Kereskedelmi Kft. from an affiliate corporation for $0.5 million cash, partially offset by the forgiveness of $0.4 million of debt owed by the Corporation to the affiliate corporation. This purchase was recorded at carrying value, resulting in a charge to retained earnings of $0.3 million.

20. EMPLOYEE FUTURE BENEFITS

The Corporation maintains defined benefit and defined contribution pension plans for most of its employees and provides other post employment benefits, principally health, dental and life insurance, for retirees and their dependants. The defined benefit pension plans provide for pensions based on employees' length of service and final average earnings. As of 1997, new employees automatically participate in the defined contribution pension plan and employees participating in the defined benefit pension plans may transfer to the defined contribution pension plan at any time. Upon transfer, further accumulation of benefits under the defined benefit pension plans ceases.

Information about the Corporation's benefit plans, in aggregate, is as follows:

	2006		2005	
	Pension Benefit Plans	**Other Post Employment Benefit Plans**	Pension Benefit Plans	Other Post Employment Benefit Plans
Benefit plan assets, obligations and funded status				
Market value of plan assets:				
Beginning of year	**$1,561.1**	**$ -**	$1,402.1	$ -
Actual return on plan assets	**187.3**	**-**	197.0	-
Employee contributions	**3.7**	**-**	4.0	-
Benefit payments	**(39.8)**	**-**	(36.4)	-
Payments to defined contribution plans [1]	**(8.2)**	**-**	(5.6)	-
End of year	**$1,704.1**	**$ -**	$1,561.1	$ -
Accrued benefit obligations:				
Beginning of year	**$1,485.0**	**$ 80.3**	$1,232.7	$ 67.0
Current service cost	**38.0**	**3.0**	32.2	2.5
Interest cost	**80.8**	**4.2**	73.9	4.2
Employee contributions	**3.7**	**-**	4.0	-
Benefit payments from plan assets [2]	**(39.8)**	**-**	(36.4)	-
Benefit payments by employer	**(4.3)**	**(1.8)**	(4.7)	(1.9)
Experience losses (gains) [3]	**78.6**	**(2.2)**	183.3	8.5
End of year	**$1,642.0**	**$ 83.5**	$1,485.0	$ 80.3
Funded status:				
Excess (deficiency) of assets over obligations	**$ 62.1**	**$ (83.5)**	$ 76.1	$(80.3)
Amounts not yet recognized in financial statements:				
Unrecognized net cumulative experience losses on plan assets and accrued benefit obligations	**316.0**	**17.7**	369.5	21.9
Unrecognized net transitional liability (asset)	**(221.0)**	**20.7**	(253.4)	23.0
Accrued asset (liability) (Notes 10, 13)	**$ 157.1**	**$ (45.1)**	$ 192.2	$(35.4)
Regulatory asset (liability) [4] (Note 2)	**$ (118.7)**	**$ 27.6**	$ (139.4)	$ 22.0

(1) *Employer contributions for certain of the Corporation's defined contribution pension plans are paid from the assets of the defined benefit pension plans.*

(1) *Pension plan benefit payments are indexed to increases in the Canadian Consumer Price Index to a maximum increase of 3% per annum.*

(2) *Changes in assumptions regarding the average compensation rate increase for the year and age at retirement resulted in experience losses in 2006 of approximately $66 million for the pension benefit plans. A change in the liability discount rate assumption resulted in experience losses in 2005 of approximately $178 million for the pension benefit plans.*

(3) *The regulatory asset (liability) reflects an AEUB decision to record costs of employee future benefits in the regulated operations, excluding Alberta Power (2000), when paid rather than accrued.*

20. EMPLOYEE FUTURE BENEFITS (CONTINUED)

	2006		2005	
	Pension Benefit Plans	**Other Post Employment Benefit Plans**	Pension Benefit Plans	Other Post Employment Benefit Plans
Benefit plan cost				
Components of benefit plan cost:				
Current service cost	**$ 38.0**	**$ 3.0**	$ 32.2	$ 2.5
Interest cost	**80.8**	**4.2**	73.9	4.2
Actual return on plan assets	**(187.3)**	**-**	(197.0)	-
Experience losses (gains) on accrued benefit obligations	**78.6**	**(2.2)**	183.3	8.5
	10.1	**5.0**	92.4	15.2
Adjustments to recognize long term nature of employee future benefits:				
Unrecognized portion of actual return on plan assets	**107.6**	**-**	108.5	-
Unrecognized portion of experience gains (losses) on accrued benefit obligations	**(78.6)**	**2.2**	(183.3)	(8.5)
Amortization of net cumulative experience losses on plan assets and accrued benefit obligations	**24.5**	**2.0**	15.5	0.6
Amortization of net transitional liability (asset)	**(32.4)**	**2.3**	(32.8)	2.3
	21.1	**6.5**	(92.1)	(5.6)
Defined benefit plans cost	**31.2**	**11.5**	0.3	9.6
Defined contribution plans cost	**9.7**	**-**	7.0	-
Total cost	**40.9**	**11.5**	7.3	9.6
Less: Capitalized	**1.9**	**2.7**	1.4	2.3
Less: Unrecognized defined benefit plans cost (income) (1) (2)	**19.5**	**3.5**	(1.6)	3.3
Net cost recognized (2)	**$ 19.5**	**$ 5.3**	$ 7.5	$ 4.0

(1) The unrecognized defined benefit plans cost (income) reflects an AEUB decision to record costs of employee future benefits in the regulated operations, excluding Alberta Power (2000), when paid rather than accrued.

(2) Net cost recognized for pension benefit plans in the three months ended December 31, 2006 includes the amortization of $5.1 million of the deferred pension assets recorded by the Corporation upon the adoption of the current accounting standard in 2000. On October 11, 2006, the AEUB approved recovery of these assets for a nine-year period commencing January 1, 2005 (Note 2).

In the unaudited three months ended December 31, 2006, net cost of $7.8 million (2005 – $1.7 million) was recognized for pension benefit plans and net cost of $1.6 million (2005 – $0.6 million) was recognized for other post employment benefit plans.

Weighted average assumptions

	2006		2005	
	Pension Benefit Plans	**Other Post Employment Benefit Plans**	Pension Benefit Plans	Other Post Employment Benefit Plans
Assumptions regarding benefit plan cost:				
Expected long term rate of return on plan assets for the year	**6.1%**	**-**	6.9%	-
Liability discount rate for the year	**5.1%**	**5.1%**	5.9%	5.9%
Average compensation increase for the year	**3.5%**	**-**	3.25%	-
Assumptions regarding accrued benefit obligations:				
Liability discount rate at December 31	**5.1%**	**5.1%**	5.1%	5.1%
Long term inflation rate	**2.5%**	**(1)**	2.5%	(1)

(1) The assumed annual health care cost trend rate increases used in measuring the accumulated post employment benefit obligation are as follows: for drug costs, 8.5% for 2006 grading down over 7 years to 4.5% (2005 – 9.3% for 2005 grading down over 8 years to 4.5%), and, for other medical and dental costs, 4.0% for 2006 and thereafter (2005 – 4.0% for 2005 and thereafter).

20. EMPLOYEE FUTURE BENEFITS (CONTINUED)

The sensitivities of key assumptions used in measuring accrued benefit obligations and benefit plan cost for 2006 are outlined in the following table. The sensitivities of each key assumption have been calculated independently of changes in other key assumptions. Actual experience may result in changes in a number of assumptions simultaneously.

	2006 Pension Benefit Plans		2006 Other Post Employment Benefit Plans	
	Accrued Benefit Obligation	Benefit Plan Cost	Accrued Benefit Obligation	Benefit Plan Cost
Expected long term rate of return on plan assets				
1% increase [1]	-	$ (3.4)	-	-
1% decrease [1]	-	$ 3.4	-	-
Liability discount rate				
1% increase [1]	$(79.5)	$ (6.4)	$ (3.7)	$ (0.4)
1% decrease [1]	$101.7	$ 7.5	$ 4.7	$ 0.5
Future compensation rate				
1% increase [1]	$ 22.9	$ 2.9	-	-
1% decrease [1]	$(20.8)	$ (2.6)	-	-
Long term inflation rate				
1% increase [1] [2] [3]	$ 34.5	$ 3.9	$ 4.2	$ 0.7
1% decrease [1] [3]	$(60.4)	$ (6.9)	$ (3.4)	$ (0.5)

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

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

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

Pension benefit plan assets

	2006		2005	
	Amount	**%**	Amount	%
Plan asset mix:				
Equity securities [1]	**$1,028.7**	**60.4**	$ 922.9	59.1
Fixed income securities [2]	**605.6**	**35.5**	567.7	36.4
Real estate [3]	**32.7**	**1.9**	31.1	2.0
Cash and other assets [4]	**37.1**	**2.2**	39.4	2.5
	$1,704.1	**100.0**	$1,561.1	100.0

(1) *Equity securities consist of investments in domestic and foreign preferred and common shares. At December 31, 2006, the market values of investments in United States' securities and international equities, denominated in a number of different currencies, are $236.7 million and $238.2 million, respectively (2005 – $144.0 million and $174.0 million, respectively).*

(2) *Fixed income securities consist of investments in federal and provincial government and corporate bonds and debentures.*

(3) *Real estate consists of investments in closed-end real estate funds.*

(4) *Cash and other assets consist of cash, short term notes and money market funds.*

At December 31, 2006, plan assets include long term debt of CU Inc. having a market value of $8.7 million (2005 – $6.0 million), Class A non-voting and Class B common shares of Canadian Utilities Limited having a market value of $19.1 million (2005 – $17.6 million) and Class I Non-Voting shares of ATCO Ltd. having a market value of $18.2 million (2005 – $14.8 million).

20. EMPLOYEE FUTURE BENEFITS (CONTINUED)

Funding

Employees are required to contribute a percentage of their salary to the defined benefit pension plans. The Corporation is required to provide the balance of the funding, based on triennial actuarial valuations, necessary to ensure that benefits will be fully provided for at retirement. Based on the most recent actuarial valuation for funding purposes as of December 31, 2004, the Corporation is continuing a contribution holiday that began on April 1, 1996. The next actuarial valuation for funding purposes is required as of December 31, 2007.

Included in the accrued benefit obligations are certain supplementary defined benefit pension plans that are paid by the Corporation out of general revenues. These supplementary plans had accrued benefit obligations of $84.2 million at December 31, 2006 (2005 – $77.4 million).

21. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

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

Interest rate risk

Long term debt and non-recourse long term debt have variable interest rates that have been hedged through the following interest rate swap agreements:

Swap Fixed Interest Rate [1]	Variable Debt Interest Rate	Completion Date	Principal/Face Value 2006	2005
5.287%	90 day BA	December 2007	**$ 40.8**	$ 44.4
5.212%	90 day BA	September 2008	**54.2**	59.2
7.54%	90 day BA	November 2008	**2.6**	3.8
7.317%	90 day BA	December 2008	**3.6**	5.4
5.8367%	90 day BA	June 2009	**8.9**	9.4
6.346%	90 day BA	June 2011	**2.7**	3.3
7.50%	6 month LIBOR	December 2011	**83.8**	87.5
7.286%	90 day BA	September 2012	**24.0**	28.2
7.3325%	Bank Bill Rate in Australia	December 2013	**31.8**	34.4
6.575%	90 day BA	March 2019	**36.1**	37.8
			$288.5	$313.4

BA – Bankers' Acceptance
LIBOR – London Interbank Offered Rate

(1) The above swap fixed interest rates include any long term debt margin fees; the margin fees are subject to escalation (Note 12).

Foreign exchange rate risk

The Corporation has exposure to changes in the carrying values of its foreign operations, including assets and liabilities, as a result of changes in exchange rates.

The Corporation has entered into foreign exchange forward contracts in order to fix the exchange rate on certain planned equipment expenditures denominated in U.S. dollars and Euros. At December 31, 2006, the contracts consist of purchases of $0.2 million U.S. (2005 – $2.6 million U.S.) and sales of 3.0 million Euros (2005 – 2.0 million Euros).

21. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (CONTINUED)

Energy commodity price risk

In March 2004, the AEUB issued a decision respecting the operation of ATCO Gas' Carbon storage facility for the 2004/2005 storage year, which ended on March 31, 2005. The decision directed ATCO Gas to continue to reserve 16.7 petajoules of storage capacity for the benefit of utility customers. As a result of an AEUB approved storage plan, ATCO Gas entered into certain energy contracts for the forward purchase and sale of natural gas for storage purposes. All associated costs and benefits of these contracts were passed to customers through regulated rates and, accordingly, ATCO Gas did not bear any risk for price fluctuations provided that the contracts were in accordance with the storage plan. Since April 1, 2005, ATCO Gas has leased the entire storage capacity of the Carbon facility to ATCO Midstream.

Fair values

The fair values of derivatives have been estimated using year-end market rates. These fair values approximate the amount that the Corporation would either pay or receive to settle the contract at December 31.

	2006			2005		
	Notional Principal	**Fair Value (Payable) Receivable**	**Maturity**	Notional Principal	Fair Value (Payable) Receivable	Maturity
Interest rate swaps	**$288.5**	**$ (7.3)**	**2007-2019**	$313.4	$(10.5)	2007-2019
Foreign exchange forward contracts	**$ 4.6**	**$ 0.3**	**2007**	$ 5.9	$ (0.1)	2006

Credit risk

Derivative credit risk arises from the possibility that a counterparty to a contract fails to perform according to the terms and conditions of that contract. Derivative credit risk is minimized by dealing with large, credit-worthy counterparties in accordance with established credit approval policies. Accounts receivable credit risk is reduced by a large and diversified customer base, requirement of letters of credit, and, for regulated operations other than Alberta Power (2000), the ability to recover an estimate for doubtful accounts through approved customer rates.

22. COMMITMENTS AND CONTINGENCIES

Commitments

The Corporation has contractual obligations in the normal course of business; future minimum payments are as follows:

	2007	2008	2009	2010	2011	Total of All Subsequent Years
Operating leases [1]	$ 18.5	$ 15.8	$ 8.8	$ 7.7	$ 6.0	$ 4.8
Purchase obligations:						
Coal purchase contracts [2]	47.7	48.9	50.3	51.8	53.4	355.6
Natural gas purchase contracts [3]	52.9	52.9	52.9	52.9	22.1	18.9
Operating and maintenance agreements [4]	21.2	24.1	21.2	20.6	17.8	93.3
	$140.3	$141.7	$133.2	$133.0	$ 99.3	$472.6

(1) *Operating leases are comprised primarily of long term leases for office premises and equipment.*

(2) *Alberta Power (2000) has fixed price long term contracts to purchase coal for its coal-fired generating plants.*

(3) *Natural gas purchase contracts consist primarily of ATCO Power contracts to purchase natural gas for certain of its natural gas-fired generating plants.*

(4) *ATCO Power has long term service agreements with suppliers to provide operating and maintenance services at certain of its generating plants.*

22. COMMITMENTS AND CONTINGENCIES (CONTINUED)

Contingencies

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

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

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

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

23. SEGMENTED INFORMATION

Description of segments

The Corporation operates in the following business segments:

The **Utilities** Business Group includes the regulated distribution of natural gas by ATCO Gas, the regulated distribution and transmission of electric energy by ATCO Electric and its subsidiaries, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical, the regulated transportation of natural gas by ATCO Pipelines, the regulated transmission and distribution of water by CU Water, and the provision of non-regulated complementary projects by ATCO Utility Services.

The **Power Generation** Business Group includes the non-regulated supply of electricity and cogeneration steam by ATCO Power, the regulated supply of electricity by Alberta Power (2000), and the sale of fly ash and other combustion byproducts produced in coal fired electrical generating plants by ASHCOR Technologies.

The **Global Enterprises** Business Group includes the non-regulated gathering, processing, storage, purchase and sale of natural gas by ATCO Midstream, the provision of project management and technical services for customers in the industrial, defence and transportation sectors by ATCO Frontec, the development, operation and support of information systems and technologies by ATCO I-Tek, the provision of billing services, payment processing, credit, collection and call centre services by ATCO I-Tek's subsidiary, ATCO I-Tek Business Services, and the sale of travel services to both business and consumer sectors by ATCO Travel. The Corporation sold its 50% interest in Genics, a manufacturer of wood preservation products, effective August 1, 2006.

The Corporate and Other segment includes commercial real estate owned by the Corporation in Alberta.

23. SEGMENTED INFORMATION (CONTINUED)

Segmented results – Three months ended December 31

2006 2005	Utilities	Power Generation [2]	Global Enterprises [2]	Corporate & Other	Intersegment Eliminations	Consolidated
(Unaudited)						
Revenues – external	**$308.4**	**$226.7**	**$135.6**	**$ 0.4**	**$ -**	**$671.1**
	$ 299.1	$ 211.0	$ 169.9	$ 0.3	$ -	$ 680.3
Revenues – intersegment [1]	**6.3**	**-**	**38.3**	**2.9**	**(47.5)**	**-**
	6.4	-	30.0	2.9	(39.3)	-
Revenues	**$314.7**	**$226.7**	**$173.9**	**$ 3.3**	**$(47.5)**	**$671.1**
	$ 305.5	$ 211.0	$ 199.9	$ 3.2	$ (39.3)	$ 680.3
Earnings attributable to Class A and Class B shares	**$ 43.7**	**$ 36.9**	**$ 27.3**	**$ (6.5)**	**$ (1.4)**	**$100.0**
	$ 32.5	$ 36.7	$ 27.6	$ (7.5)	$ (0.2)	$ 89.1

Segmented results – Year ended December 31

2006 2005	Utilities	Power Generation [2]	Global Enterprises [2]	Corporate & Other	Intersegment Eliminations	Consolidated
Revenues – external	**$1,086.2**	**$ 799.5**	**$543.3**	**$ 1.4**	**$ -**	**$2,430.4**
	$ 1,173.5	$ 770.7	$ 570.4	$ 1.2	$ -	$ 2,515.8
Revenues – intersegment [1]	**24.6**	**-**	**123.9**	**11.3**	**(159.8)**	**-**
	22.4	-	108.6	11.2	(142.2)	-
Revenues	**1,110.8**	**799.5**	**667.2**	**12.7**	**(159.8)**	**2,430.4**
	1,195.9	770.7	679.0	12.4	(142.2)	2,515.8
Operating expenses	**601.4**	**431.3**	**490.5**	**18.7**	**(151.2)**	**1,390.7**
	716.9	420.4	533.1	24.4	(140.9)	1,553.9
Depreciation & amortization	**220.2**	**95.4**	**31.5**	**1.4**	**-**	**348.5**
	189.3	95.8	24.8	1.6	-	311.5
Interest expense	**132.5**	**92.2**	**2.2**	**162.4**	**(166.4)**	**222.9**
	124.9	84.8	2.4	154.6	(156.7)	210.0
Interest and other income	**(20.3)**	**(11.9)**	**(4.1)**	**(188.6)**	**166.4**	**(58.5)**
	(11.8)	(9.3)	(2.0)	(170.2)	156.7	(36.6)
Earnings before income taxes	**177.0**	**192.5**	**147.1**	**18.8**	**(8.6)**	**526.8**
	176.6	179.0	120.7	2.0	(1.3)	477.0
Income taxes	**45.4**	**69.7**	**46.1**	**8.7**	**(2.8)**	**167.1**
	60.2	70.2	41.9	3.7	(0.4)	175.6
	131.6	**122.8**	**101.0**	**10.1**	**(5.8)**	**359.7**
	116.4	108.8	78.8	(1.7)	(0.9)	301.4
Dividends on equity preferred shares	**10.4**	**3.6**	**-**	**21.8**	**-**	**35.8**
	10.4	3.6	-	21.8	-	35.8
Earnings attributable to Class A and Class B shares	**$ 121.2**	**$ 119.2**	**$101.0**	**$ (11.7)**	**$ (5.8)**	**$ 323.9**
	$ 106.0	$ 105.2	$ 78.8	$ (23.5)	$ (0.9)	$ 265.6
Total Assets	**$3,799.0**	**$2,240.0**	**$278.1**	**$576.2**	**$100.2**	**$6,993.5**
	$ 3,526.8	$ 2,219.6	$ 303.7	$ 614.9	$ 152.8	$ 6,817.8
Purchase of property, plant and equipment	**$ 505.0**	**$ 48.1**	**$ 14.2**	**$ 0.4**	**$ -**	**$ 567.7**
	$ 472.9	$ 41.2	$ 11.9	$ 0.7	$ -	$ 526.7

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

(2) *In 2006, ASHCOR Technologies was transferred from the Global Enterprises Business Group to the Power Generation Business Group. 2005 segmented figures have been reclassified to conform to the current basis of segmentation.*

23. SEGMENTED INFORMATION (CONTINUED)

Geographic segments

	Domestic		Foreign		Consolidated	
	2006	2005	**2006**	2005	**2006**	2005
Revenues	**$2,130.6**	$2,253.6	**$299.8**	$262.2	**$2,430.4**	$2,515.8
Property, plant and equipment	**$5,099.5**	$4,905.9	**$326.6**	$302.8	**$5,426.1**	$5,208.7

CANADIAN UTILITIES LIMITED

Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD&A")

For The Year Ended December 31, 2006

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 consolidated interim financial statements for the three months ended December 31, 2006, and the audited consolidated financial statements for the year ended December 31, 2006. Additional information relating to the Corporation, including the Corporation's Annual Information Form, is available on SEDAR at www.sedar.com.

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

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

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FORWARD-LOOKING INFORMATION

Certain statements contained in this MD&A constitute forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "anticipate", "plan", "estimate", "expect", "may", "will", "intend", "should", and similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Corporation believes that the expectations reflected in the forward-looking statements are reasonable, but no assurance can be given that these expectations will prove to be correct and such forward-looking statements should not be unduly relied upon.

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

NON-GAAP FINANCIAL MEASURES

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

CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

As of December 31, 2006, the Corporation's management evaluated the effectiveness of the design and operation of its disclosure controls and procedures ("Disclosure Controls") as defined under rules adopted by the Canadian Securities Administrators. This evaluation was performed under the supervision of, and with the participation of, the Chief Executive Officer ("CEO") and the Chief Financial Officer ("CFO").

Disclosure Controls are procedures designed to ensure that information required to be disclosed in documents filed with securities regulatory authorities is recorded, processed, summarized and reported on a timely basis, and is accumulated and communicated to the Corporation's management, including the CEO and the CFO, as appropriate, to allow timely decisions regarding required disclosure.

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

Based on the evaluation of Disclosure Controls, the CEO and the CFO have concluded that, subject to the inherent limitations noted above, the Corporation's Disclosure Controls are effective in providing reasonable assurance that material information relating to the Corporation and its consolidated subsidiaries is made known to the Corporation's management.

Internal Control Over Financial Reporting

As of December 31, 2006, management of the Corporation is responsible for evaluating the design of internal control over financial reporting ("Internal Control Over Financial Reporting"), as defined under rules adopted by the Canadian Securities Administrators. This evaluation was performed under the supervision of, and with the participation of, the CEO and the CFO. The Corporation's internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

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

There were no changes in the Corporation's internal controls over financial reporting that have occurred during the three months ended December 31, 2006, that have materially affected, or are reasonably likely to materially affect, the Corporation's internal control over financial reporting.

BUSINESS OF THE CORPORATION

The Corporation's financial statements are consolidated from three Business Groups: Utilities, Power Generation and Global Enterprises. For the purposes of financial disclosure, corporate transactions are accounted for as Corporate and Other (refer to Note 23 to the consolidated financial statements for the year ended December 31, 2006). Transactions between Business Groups are eliminated in all reporting of the Corporation's consolidated financial information.

In 2006, ASHCOR Technologies was transferred from the Global Enterprises Business Group to the Power Generation Business Group. 2005 segmented figures have been reclassified to conform to the current basis of segmentation. On August 1, 2006, the Corporation sold its 50% equity interest in Genics Inc., which was part of the Global Enterprises Business Group.

STRATEGIC ALTERNATIVES FOR MIDSTREAM ASSETS

On November 24, 2006, the Corporation announced that its Board of Directors had completed its review of the strategic alternatives available for its gas gathering and processing and natural gas liquids midstream business and reached a decision to retain the business under the Corporation's current structure. The strategic review, commenced in May 2006, was conducted by the Board of Directors in conjunction with the Corporation's management and legal and financial advisors. The review involved the evaluation of a number of alternatives, including reorganization into a business trust or newly-created company or a sale to a third party.

TXU EUROPE SETTLEMENT

On November 19, 2002, an administration order was issued by an English Court against TXU Europe Energy Trading Limited ("TXU Europe") for breach of its contract to purchase 27.5% of the power produced by the 1,000 megawatt Barking generating plant, in which the Corporation owns a 25.5% equity interest. In 2005, the Corporation received $83.1 million as its share of the partial settlement of the claim for damages related to TXU Europe's breach of this contract. An additional payment of $16.6 million was received on January 19, 2006 and a final installment of approximately $1.6 million was received on July 20, 2006. The settlement is expected to generate earnings after income taxes of approximately $69 million, based on foreign currency exchange rates in effect on March 30, 2005, which will be recognized over the remaining term of the TXU Europe contract from October 1, 2004, to September 30, 2010, at approximately $11 million per year. These earnings will be dependent upon the foreign currency exchange rates in effect at the time the earnings are recognized. For a description of the settlement, refer to Note 5 to the consolidated financial statements for the year ended December 31, 2006.

H.R. MILNER INCOME TAX REASSESSMENT

In 2006, the Canada Revenue Agency ("CRA") issued a reassessment for Alberta Power (2000)'s 2001 taxation year. The CRA's reassessment treats the proceeds received from the sale of the H.R. Milner generating plant to the Alberta Balancing Pool as income rather than as a sale of an asset. The Corporation has made submissions to the CRA opposing the CRA's position. The impact of the reassessment is a $12.4 million increase in interest and income tax expense, a $12.4 million decrease in earnings and a $28.8 million payment associated with the tax and interest assessed. It is expected that $16.4 million of this cash payment will be recovered by reducing income taxes payable through higher capital cost allowance claims. Due to the uncertainty as to whether the reassessment will ultimately be resolved in the Corporation's favour, the Corporation reduced earnings by $12.4 million in 2006.

RECENT CHANGES IN INCOME TAXES AND RATES

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

SELECTED ANNUAL AND QUARTERLY INFORMATION

($ Millions except per share data)	For the Three Months Ended (unaudited) Mar. 31	Jun. 30	Sep. 30	Dec. 31	Year Ended Dec. 31
2006 (1) (2)					
Revenues (3) (4)	642.0	563.4	553.9	671.1	2,430.4
Earnings attributable to Class A and Class B shares (4)	86.9	70.2	66.8	100.0	323.9
Earnings per Class A and Class B share	0.68	0.56	0.53	0.80	2.57
Diluted earnings per Class A and Class B share	0.68	0.55	0.53	0.80	2.56
2005 (1) (2)					
Revenues (3) (4)	745.2	552.9	537.4	680.3	2,515.8
Earnings attributable to Class A and Class B shares (4)	80.0	50.0	46.5	89.1	265.6
Earnings per Class A and Class B share	0.63	0.39	0.37	0.70	2.09
Diluted earnings per Class A and Class B share	0.63	0.39	0.37	0.69	2.08
2004 (1) (2)					
Revenues (3) (4)					3,011.4
Earnings attributable to Class A and Class B shares (5)					309.0
Earnings per Class A and Class B share (5)					2.44
Diluted earnings per Class A and Class B share (5)					2.43

Notes:

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

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

(3) *Reduced recoveries of natural gas costs in revenues in 2006 and 2005 as ATCO Gas ceased selling natural gas from its natural gas storage facilities on March 31, 2005, in accordance with Alberta Energy and Utilities Board directives.*

(4) *Prior to the Transfer of the Retail Energy Supply Businesses on May 4, 2004, the cost of natural gas and electricity purchased for ATCO Gas' and ATCO Electric's customers was included in revenues. As ATCO Gas and ATCO Electric no longer purchase natural gas and electricity for their customers, revenues since May 4, 2004, have decreased accordingly.*

(5) *Includes earnings of $55.1 million, earnings per share of $0.44 and diluted earnings per share of $0.43 on the Transfer of the Retail Energy Supply Businesses for the year ended December 31, 2004.*

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

SELECTED ANNUAL AND QUARTERLY INFORMATION

	Year Ended December 31		
	2006	2005	2004
	($ Millions except per share data)		
Cash dividends declared per share:			
Series Second Preferred Shares:			
Series O [(2)]	1.26	1.26	1.26
Series Q	1.48	1.48	1.48
Series R	1.33	1.33	1.33
Series S	1.65	1.65	1.65
Series T [(2)]	1.26	1.26	1.26
Series U [(2)]	1.26	1.26	1.26
Series V	1.31	1.31	1.31
Series W	1.45	1.45	1.45
Series X	1.50	1.50	1.50
Class A and Class B shares	1.40	1.10	1.06
Total assets	6,993.5	6,817.8	6,617.5
Long term debt	2,411.5	2,231.0	2,171.0
Non-recourse long term debt	626.7	673.8	760.9
Equity preferred shares	636.5	636.5	636.5
Class A and Class B share owners' equity	2,324.7	2,223.5	2,117.7

Notes:

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

[(2)] *The dividend was reset to $1.09 (4.35%) for the period between December 2, 2006, and December 2, 2011.*

RESULTS OF OPERATIONS

The principal factors that caused variations in **revenues** over the eight most recently completed quarters were:

- reduced recoveries of natural gas costs in revenues in 2006 as ATCO Gas ceased selling natural gas from its natural gas storage facilities on March 31, 2005, in accordance with Alberta Energy and Utilities Board ("AEUB") directives;
- fluctuations in temperatures (refer to the Utilities section);
- timing of rate decisions (refer to the Utilities and Regulatory Matters sections);
- availability of generating plants in ATCO Power and Alberta Power (2000) (refer to the Power Generation section);
- fluctuations in electricity and natural gas prices (refer to the Power Generation section); and
- changes in market conditions in natural gas liquids and storage operations (refer to the Global Enterprises section).

The principal factors that caused variations in **earnings** over the eight most recently completed quarters were:

- fluctuations in temperatures (refer to the Utilities section);
- timing of rate decisions (refer to the Utilities and Regulatory Matters sections);
- fluctuations in electricity prices and related spark spreads in Alberta and the United Kingdom ("U.K.") (refer to the Power Generation section);
- the TXU Europe Settlement (refer to TXU Europe Settlement section);
- H.R. Milner income tax reassessment (refer to H.R. Milner Income Tax Reassessment section);
- availability of generating plants in ATCO Power and Alberta Power (2000) (refer to the Power Generation section);
- changes in market conditions in natural gas liquids and storage operations (refer to the Global Enterprises section);
- recent changes in income taxes and rates (refer to Recent Changes in Income Taxes and Rates section); and

- changes in share appreciation rights expense due to changes in Canadian Utilities Limited Class A non-voting share and ATCO Ltd. Class I Non-Voting Share prices (refer to Corporate and Other section).

Consolidated Operations

Revenues for the three months ended December 31, 2006, **decreased** by $9.2 million to $671.1 million, primarily due to:

- lower recovery of natural gas costs in revenues due to customers supplying shrinkage gas in ethane extraction operations in ATCO Midstream;
- lower volumes of natural gas purchased and resold for natural gas liquids extraction in ATCO Midstream; and
- lower franchise fees collected by ATCO Gas on behalf of cities and municipalities.

This decrease was partially offset by:

- higher availability (due to a planned outage in 2005), improved merchant performance, and higher natural gas fuel purchases recovered on a "no-margin" basis in ATCO Power's U.K. operations; and
- colder temperatures in ATCO Gas.

Revenues for the year ended December 31, 2006, **decreased** by $85.4 million to $2,430.4 million, primarily due to:

- reduced recoveries of natural gas costs in revenues in 2006 as ATCO Gas ceased selling natural gas from its natural gas storage facilities on March 31, 2005, in accordance with Alberta Energy and Utilities Board ("AEUB") directives;
- lower recovery of natural gas costs in revenues due to customers supplying shrinkage gas in ethane extraction operations in ATCO Midstream;
- lower volumes of natural gas purchased and resold for natural gas liquids extraction in ATCO Midstream;
- lower business activity in ATCO Frontec; and
- impact of lower U.K. and Australia exchange rates on conversion of revenues to Canadian dollars in ATCO Power.

This decrease was partially offset by:

- improved merchant performance, higher natural gas fuel purchases recovered on a "no-margin" basis, and higher availability (due to a planned outage in 2005) in ATCO Power's U.K. operations;
- higher storage revenues due to higher capacity leased, and the timing and demand of storage capacity sold, by ATCO Midstream; and
- higher customer rates for ATCO Electric (refer to Regulatory Matters – ATCO Electric section). The impact of the ATCO Electric GTA Decision on 2006 was positive as ATCO Electric had lower customer rates during 2005.

Earnings attributable to Class A and Class B shares for the three months ended December 31, 2006, **increased** by $10.9 million ($0.10 per share) to $100.0 million ($0.80 per share), primarily due to:

- higher earnings in ATCO Power's Alberta generating plants due to higher spark spreads realized on sales of electricity in the Alberta market; and
- colder temperatures in ATCO Gas.

This increase was partially offset by:

- higher maintenance expenses due to a planned outage in 2006 at Alberta Power (2000)'s Battle River generating plant; and
- a settlement with a supplier was recorded in the fourth quarter of 2005 for damages due to equipment defects in ATCO Power's U.K. operations.

Earnings attributable to Class A and Class B shares for the year ended December 31, 2006, **increased** by $58.3 million ($0.48 per share) to $323.9 million ($2.57 per share), primarily due to:

- higher earnings in ATCO Power's Alberta generating plants due to higher spark spreads realized on sales of electricity in the Alberta market;
- higher margins received for natural gas liquids, higher storage earnings due to higher capacity leased, and the timing and demand of storage capacity sold by ATCO Midstream; and
- $11.8 million adjustment in the second quarter of 2006 to reflect recent tax changes (refer to Recent Changes in Income Taxes and Rates section).

This increase was partially offset by:
- H.R. Milner Income Tax Reassessment (refer to H.R. Milner Income Tax Reassessment section); and
- a 2005 AEUB decision adjusting the 2001 and 2002 revenue requirements for changes in future income taxes recorded in ATCO Electric (refer to Regulatory Matters – ATCO Electric section).

Return on common equity was 14.3% in 2006.

Operating expenses (consisting of natural gas supply, purchased power, operation and maintenance, selling and administrative and franchise fee costs) for the three months ended December 31, 2006, **decreased** by $15.5 million to $383.5 million, primarily due to:
- lower costs for natural gas liquids extraction in ATCO Midstream.

This decrease was partially offset by:
- higher maintenance expenses due to a planned outage in 2006 at Alberta Power (2000)'s Battle River generating plant.

Operating expenses for the year ended December 31, 2006, **decreased** by $163.2 million to $1,390.7 million, primarily due to:
- reduced natural gas supply costs in 2006 as ATCO Gas ceased selling natural gas from its natural gas storage facilities on March 31, 2005, in accordance with AEUB directives; and
- lower volumes of natural gas purchased for natural gas liquids extraction in ATCO Midstream.

Depreciation and amortization expenses for the three months ended December 31, 2006, **increased** by $11.1 million to $95.6 million, primarily due to:
- capital additions in 2006 and 2005.

Depreciation and amortization expenses for the year ended December 31, 2006, **increased** by $37.0 million to $348.5 million, primarily due to:
- capital additions in 2006 and 2005.

Interest expense for the three months ended December 31, 2006, **increased** by $3.2 million to $54.6 million, primarily due to:
- interest on new financings issued in 2006 and 2005 to fund capital expenditures in Utilities operations.

This increase was partially offset by:
- repayment of non-recourse financings in 2006 and 2005.

Interest expense for the year ended December 31, 2006, **increased** by $12.9 million to $222.9 million, primarily due to:
- H.R. Milner Income Tax Reassessment (refer to H.R. Milner Income Tax Reassessment section); and
- interest on new financings issued in 2006 and 2005 to fund capital expenditures in Utilities operations.

This increase was partially offset by:
- repayment of non-recourse financings in 2006 and 2005.

Interest and other income for the three months ended December 31, 2006, **increased** by $8.3 million to $18.9 million, primarily due to:
- higher short term interest rates on cash balances.

Interest and other income for the year ended December 31, 2006, **increased** by $21.9 million to $58.5 million, primarily due to:
- Calgary Stores Block Decision (refer to Regulatory Matters – ATCO Gas section); and
- higher short term interest rates on larger cash balances.

Income taxes for the three months ended December 31, 2006, **decreased** by $10.6 million to $47.4 million, primarily due to:
- lower tax rates.

Income taxes for the year ended December 31, 2006, **decreased** by $8.5 million to $167.1 million, primarily due to:
- adjustment to reflect recent tax changes (refer to Recent Changes in Income Taxes and Rates section).

This decrease was partially offset by:

- higher earnings; and
- H.R. Milner Income Tax Reassessment (refer to H.R. Milner Income Tax Reassessment section).

Segmented Information

Segmented revenues for the three months and the year ended December 31, 2006, were as follows:

	For the Three Months Ended December 31		For the Year Ended December 31	
($ Millions)	**2006**	2005	**2006**	2005
	(unaudited)			
Utilities [1]	**314.7**	305.5	**1,110.8**	1,195.9
Power Generation [2]	**226.7**	211.0	**799.5**	770.7
Global Enterprises [2]	**173.9**	199.9	**667.2**	679.0
Corporate and Other	**3.3**	3.2	**12.7**	12.4
Intersegment eliminations	**(47.5)**	(39.3)	**(159.8)**	(142.2)
Total	**671.1**	680.3	**2,430.4**	2,515.8

Notes:

(1) Reduced recoveries of natural gas costs in revenues in 2006 as ATCO Gas ceased selling natural gas from its natural gas storage facilities on March 31, 2005, in accordance with AEUB directives.

(2) In 2006, ASHCOR Technologies was transferred from the Global Enterprises Business Group to the Power Generation Business Group. 2005 segmented figures have been reclassified to conform to the current basis of segmentation.

Segmented earnings attributable to Class A and Class B shares for the three months and the year ended December 31, 2006, were as follows:

	For the Three Months Ended December 31		For the Year Ended December 31	
($ Millions)	**2006**	2005	**2006**	2005
	(unaudited)			
Utilities	**43.7**	32.5	**121.2**	106.0
Power Generation [1]	**36.9**	36.7	**119.2**	105.2
Global Enterprises [1]	**27.3**	27.6	**101.0**	78.8
Corporate and Other	**(6.5)**	(7.5)	**(11.7)**	(23.5)
Intersegment eliminations	**(1.4)**	(0.2)	**(5.8)**	(0.9)
Total	**100.0**	89.1	**323.9**	265.6

Note:

(1) In 2006, ASHCOR Technologies was transferred from the Global Enterprises Business Group to the Power Generation Business Group. 2005 segmented figures have been reclassified to conform to the current basis of segmentation.

Utilities

Revenues from the Utilities Business Group for the three months ended December 31, 2006, **increased** by $9.2 million to $314.7 million, primarily due to:

- colder temperatures in ATCO Gas;
- higher customer rates for ATCO Electric (refer to Regulatory Matters – ATCO Electric section). The impact of the ATCO Electric GTA Decision on the fourth quarter of 2006 was positive as ATCO Electric had lower customer rates during the fourth quarter of 2005; and
- customer growth in ATCO Gas.

This increase was partially offset by:

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

Temperatures in ATCO Gas for the three months ended December 31, 2006, were 5.2% colder than normal, compared to 14.1% warmer than normal for the corresponding period in 2005.

Revenues for the year ended December 31, 2006, **decreased** by $85.1 million to $1,110.8 million, primarily due to:

- reduced recoveries of natural gas costs in revenues in 2006 as ATCO Gas ceased selling natural gas from its natural gas storage facilities on March 31, 2005, in accordance with AEUB directives; and
- lower income taxes recovered from ATCO Electric's customers on a flow through basis, reflecting lower income tax rates in 2006.

This decrease was partially offset by:

- higher customer rates for ATCO Electric (refer to Regulatory Matters – ATCO Electric section). The impact of the ATCO Electric GTA Decision on 2006 was positive as ATCO Electric had lower customer rates during 2005; and
- customer growth in ATCO Gas.

Temperatures in ATCO Gas in 2006 were 5.5% warmer than normal, compared to 7.8% warmer than normal in 2005.

Earnings for the three months ended December 31, 2006, **increased** by $11.2 million to $43.7 million, primarily due to:

- colder temperatures in ATCO Gas.

This increase was partially offset by:

- lower sales per customer in ATCO Gas.

Earnings for the year ended December 31, 2006, **increased** by $15.2 million to $121.2 million , primarily due to:

- customer growth in ATCO Gas;
- Calgary Stores Block Decision and Red Deer Operating Centre Decision (refer to Regulatory Matters – ATCO Gas section); and
- colder temperatures in ATCO Gas.

This increase was partially offset by:

- a 2005 AEUB decision adjusting the 2001 and 2002 revenue requirements for changes in future income taxes recorded in ATCO Electric (refer to Regulatory Matters - ATCO Electric section); and
- lower sales per customer in ATCO Gas.

Operating expenses for the year ended December 31, 2006, **decreased** by $115.5 million to $601.4 million, primarily due to:

- reduced natural gas supply costs in 2006 as ATCO Gas ceased selling natural gas from its natural gas storage facilities on March 31, 2005, in accordance with AEUB directives.

Power Generation

Revenues from the Power Generation Business Group for the three months ended December 31, 2006, **increased** by $15.7 million to $226.7 million, primarily due to:

- higher availability (due to a planned outage in 2005), improved merchant performance, and higher natural gas fuel purchases recovered on a "no-margin" basis in ATCO Power's U.K. operations.

This increase was partially offset by:

- lower Power Purchase Arrangement ("PPA") tariffs due to declining rate bases at Alberta Power (2000)'s generating plants and a decline in the return on common equity rate (2006 – 8.75%, 2005 – 9.49%) that is based on long term Government of Canada bond yields plus 4.5%.

Revenues for the year ended December 31, 2006, **increased** by $28.8 million to $799.5 million, primarily due to:

- improved merchant performance, higher natural gas fuel purchases recovered on a "no-margin" basis, and higher availability (due to a planned outage in 2005) in ATCO Power's U.K. operations; and
- higher revenues in ATCO Power's Alberta generating plants due to higher Alberta Power Pool prices.

This increase was partially offset by:

- impact of lower U.K. and Australia exchange rates on conversion of revenues to Canadian dollars in ATCO Power; and
- lower PPA tariffs due to declining rate bases at Alberta Power (2000)'s generating plants and a decline in the return on common equity rate (2006 – 8.75%, 2005 – 9.49%) that is based on long term Government of Canada bond yields plus 4.5%.

Earnings for the three months ended December 31, 2006, **increased** by $0.2 million to $36.9 million, primarily due to:

- higher earnings in ATCO Power's Alberta generating plants due to higher spark spreads realized on sales of electricity in the Alberta market; and
- improved merchant performance and higher availability (due to a planned outage in 2005) in ATCO Power's U.K. operations.

This increase was partially offset by:

- higher maintenance expenses due to a planned outage in 2006 at Alberta Power (2000)'s Battle River generating plant; and
- a settlement with a supplier was recorded in the fourth quarter of 2005 for damages due to equipment defects in ATCO Power's U.K. operations..

Alberta Power Pool electricity prices for the three months ended December 31, 2006, averaged $116.81 per megawatt hour, compared to average prices of $117.07 per megawatt hour for the corresponding period in 2005. Natural gas prices for the three months ended December 31, 2006, averaged $6.55 per gigajoule, compared to average prices of $10.77 per gigajoule for the corresponding period in 2005. The consequence of these changes in electricity and natural gas prices was an average spark spread of $67.66 per megawatt hour for the three months ended December 31, 2006, compared to $36.31 per megawatt hour for the corresponding period in 2005.

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

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

On January 1, 2006, the Alberta Balancing Pool announced the sale of its interest in the PPA for Alberta Power (2000)'s Sheerness generating plant to TransCanada Energy Ltd. On May 8, 2006, EPCOR Utilities Inc. announced the sale of its interest in the PPA for Alberta Power (2000)'s Battle River generating plant to ENMAX Corporation. These sales are not expected to have a material impact on the Corporation's operations or earnings.

Alberta Power (2000) continued to operate the Rainbow generating plant during 2006 and the electricity generated was sold to the Alberta Power Pool. Alberta Power (2000) had one year after the expiry of the PPA for the Rainbow generating plant (December 31, 2005) to determine whether to decommission the plant in order to fully recover plant decommissioning costs or to continue to operate the plant. The Alberta Electric System Operator ("AESO") and Alberta Power (2000) are currently negotiating a contract that, if executed, will result in Alberta Power (2000) continuing to operate the plant and be responsible for future decommissioning costs. Alberta Power (2000) has filed an application with the AEUB to decommission the plant and thereby preserve Alberta Power (2000)'s rights to fully recover plant decommissioning costs in the event negotiations with the AESO are unsuccessful.

Earnings for the year ended December 31, 2006, **increased** by $14.0 million to $119.2 million, primarily due to:

- higher earnings in ATCO Power's Alberta generating plants due to higher spark spreads realized on sales of electricity in the Alberta market;
- improved merchant performance and higher availability (due to a planned outage in 2005) in ATCO Power's U.K. operations; and
- $7.2 million adjustment in the second quarter of 2006 for ATCO Power to reflect recent tax changes (refer to Recent Changes in Income Taxes and Rates section).

This increase was partially offset by:

- H.R. Milner Income Tax Reassessment (refer to H.R. Milner Income Tax Reassessment section); and
- lower PPA tariffs due to declining rate bases at Alberta Power (2000)'s generating plants and a decline in the return on common equity rate (2006 – 8.75%, 2005 – 9.49%) that is based on long term Government of Canada bond yields plus 4.5%.

Alberta Power Pool electricity prices in 2006, averaged $80.79 per megawatt hour, compared to average prices of $70.36 per megawatt hour in 2005. Natural gas prices in 2006, averaged $6.17 per gigajoule, compared to average prices of $8.27 per gigajoule in 2005. The consequence of these changes in electricity and natural gas prices was an average spark spread of $34.52 per megawatt hour in 2006, compared to $8.32 per megawatt hour in 2005.

Operating expenses for the year ended December 31, 2006, **increased** by $10.9 million to $431.3 million, primarily due to:

- higher fuel costs due to the expiry in December 2005 of the PPA for Alberta Power (2000)'s Rainbow generating plant. Fuel costs were the responsibility of the PPA counterparty.

At December 31, 2006, all of ATCO Power's non-regulated independent generating plants were in service.

During the three months ended December 31, 2006, Alberta Power (2000)'s **deferred availability incentive** account **decreased** by $41.0 million to $39.6 million. The decrease was due to availability penalties paid associated with the planned outage in 2006 for Alberta Power (2000)'s Battle River generating plant which occurred during a period of high Alberta Power Pool electricity prices as well as normal amortization. During the three months ended December 31, 2006, the amortization of deferred availability incentives, recorded in revenues, was **unchanged** at $2.7 million as compared to the same period in 2005.

During the year ended December 31, 2006, Alberta Power (2000)'s **deferred availability incentive** account **decreased** by $20.1 million to $39.6 million. The decrease was due to additional availability penalties paid associated with the planned outage in the fourth quarter of 2006 for Alberta Power (2000)'s Battle River generating plant which occurred during a period of high Alberta Power Pool electricity prices as well as normal amortization. During the year ended December 31, 2006, the amortization of deferred availability incentives, recorded in revenues, **increased** by $1.7 million to $10.6 million as compared to 2005.

Global Enterprises

Revenues from the Global Enterprises Business Group for the three months ended December 31, 2006, **decreased** by $26.0 million to $173.9 million, primarily due to:

- lower recovery of natural gas costs in revenues due to customers supplying shrinkage gas in ethane extraction operations in ATCO Midstream; and
- lower volumes of natural gas purchased and resold for natural gas liquids extraction in ATCO Midstream.

Revenues for the year ended December 31, 2006, **decreased** by $11.8 million to $667.2 million, primarily due to:

- lower recovery of natural gas costs in revenues due to customers supplying shrinkage gas in ethane extraction operations in ATCO Midstream;
- lower volumes of natural gas purchased and resold for natural gas liquids extraction in ATCO Midstream; and
- lower business activity in ATCO Frontec.

This decrease was partially offset by:

- higher storage revenues due to higher capacity leased, and the timing and demand of storage capacity sold, by ATCO Midstream; and
- increased sales of natural gas to affiliates by ATCO Midstream.

Earnings for the three months ended December 31, 2006, were **substantially unchanged.**

Earnings for the year ended December 31, 2006, **increased** by $22.2 million to $101.0 million, primarily due to:

- higher margins received for natural gas liquids, higher storage earnings due to higher capacity leased, and the timing and demand of storage capacity sold by ATCO Midstream.

Operating expenses for the year ended December 31, 2006, **decreased** by $42.6 million to $490.5 million, primarily due to:

- lower volumes of natural gas purchased for natural gas liquids extraction in ATCO Midstream;
- lower natural gas prices for shrinkage gas used in natural gas liquids extraction in ATCO Midstream; and
- lower business activity in ATCO Frontec.

On January 30, 2007, ATCO Frontec announced it had been awarded a contract with the United Nations to provide camp support and food services to the United Nations Mission in Kosovo.

Corporate and Other

Earnings from the Corporate and Other segment for the three months ended December 31, 2006 **increased** by $1.0 million to $(6.5) million, primarily due to:

- higher short term interest rates on larger cash balances.

Earnings for the year ended December 31, 2006 **increased** by $11.8 million to $(11.7) million, primarily due to:

- decreased share appreciation rights expense due to changes in Canadian Utilities Limited Class A share and ATCO Ltd. Class I Non-Voting Share prices since December 31, 2005; and
- higher short term interest rates on larger cash balances.

REGULATORY MATTERS

Regulated operations are conducted by wholly owned subsidiaries of Canadian Utilities' wholly owned subsidiary, CU Inc.:

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

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

- in July 2004, the AEUB issued the generic cost of capital decision which established, among other things:
  - a standardized approach for each utility company regulated by the AEUB for determining the rate of return on common equity;
    - rate of return adjusted annually by 75% of the change in long term Government of Canada bond yield as forecast; and
    - adjustment mechanism similar to the method the National Energy Board uses in determining its formula based rate of return;
  - the capital structure for each utility regulated by the AEUB.
- in November 2005, the AEUB announced a generic return on common equity of 8.93% for 2006;
- in January 2006, the AEUB clarified that the generic return on equity determined on an annual basis in accordance with the generic cost of capital decision should apply to each year of the test period in the companies' applications. If no rate applications are filed for a particular year, then there will be no adjustment to the common equity rate of return for that year; and
- in November 2006, the AEUB announced a generic return on common equity of 8.51% for 2007.

In June 2005, as part of their rate applications, ATCO Electric and ATCO Gas submitted a filing to the AEUB that addressed certain common matters. ATCO Pipelines was also a party to this filing as the concerns were common to all three utilities:

- this filing included evidence regarding:
  - the appropriate ratemaking approach in the determination of utility revenue requirements;
  - treatment of pension costs, executive compensation and head office rent expense; and
  - the continued use of preferred shares as a form of financing for the three utilities;
- AEUB heard this filing in May 2006; and
- on October 11, 2006, the AEUB issued a decision (the "Common Matters Decision") which resulted in no significant impact on earnings. Among other things, the decision upheld ATCO's treatment of pension costs and approved the continued use of preferred shares. In addition, the decision approved minimal changes to head office rent expense and executive compensation.

ATCO Electric

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

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

In May 2006, the AEUB issued a decision on ATCO Electric's 2003-2004 Regulated Rate Option Tariff Non-Energy Rates application dated November 2002:

- this decision approved, on an interim refundable basis, the collection in 2006 of a shortfall of $2.7 million for 2003 and $2.2 million for 2004 that was not previously incorporated into customer rates;
- the amounts approved for collection are subject to the outcome of an existing process regarding the pricing of services provided by ATCO I-Tek; and
- the impact of this decision increased ATCO Electric's 2006 earnings by $1.9 million and was recorded in the second quarter of 2006.

In August 2002, the AEUB issued a decision in which it denied ATCO Electric's application to adjust its 2001 and 2002 transmission and distribution revenue requirements by $4.6 million for changes in the amounts of future income taxes recorded:

- in May 2005, the AEUB changed its August 2002 decision and allowed ATCO Electric to increase its revenues and earnings by $4.6 million. The impact of this decision was recorded in the second quarter of 2005.

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

- AEUB decision grants the AESO approval to assign approximately $300 million in projects to the Transmission Facility Owner, ATCO Electric;
- once assigned by the AESO, ATCO Electric will prepare and file facility applications with the AEUB. Construction will commence once approval to proceed is received from the AEUB; and
- the entire project was originally intended to be completed by 2009, but now is anticipated to be completed by 2011. As a result of price escalation caused by the change in completion date, coupled with the increasing costs of construction in Alberta, the entire project is now estimated to cost $400 million.

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

- requesting, among other things, increased revenues to recover increased financing, depreciation and operating costs associated with increased rate base in Alberta;
- a decision from the AEUB on the general tariff application is not expected until late 2007;

- in November 2006, ATCO Electric filed an application requesting interim refundable rates for transmission and distribution operations, pending the AEUB's decision on the general tariff application; and
- on December 19, 2006, ATCO Electric received a decision from the AEUB approving interim refundable rate increases amounting to 50% of ATCO Electric's requested increases for transmission and distribution operations.

ATCO Gas

In January 2006, the AEUB issued a decision on ATCO Gas' 2005, 2006 and 2007 General Rate Application ("ATCO Gas GRA Decision"):
- which, among other things, established the amount of revenue to be collected over the period 2005 to 2007 from customers for natural gas distribution service and approved a return on common equity as determined by the AEUB's standardized rate of return methodology – 9.5% in 2005, 8.93% in 2006 and 8.51% in 2007;
- the final impact of the decision will not be known until a subsequent regulatory process is finalized; and
- a decision from the AEUB with respect to a second regulatory process that was pending at the end of 2005 was received on October 11, 2006; the effect of this decision on the earnings of the Corporation was not material.

In May 2006, the City of Calgary filed a Review and Variance application with the AEUB for the ATCO Gas GRA Decision:
- the application alleges that the AEUB made errors in the ATCO Gas GRA Decision related to the calculation of working capital needed by ATCO Gas to operate its Carbon natural gas storage facility; and
- the AEUB issued its decision on January 17, 2007, denying the City of Calgary's application.

In October 2006, ATCO Gas also filed a Review and Variance application with the AEUB for the ATCO Gas GRA Decision:
- the application alleges that the AEUB made errors in the ATCO Gas GRA Decision related to the approved level of administrative expenses;
- in December 2006, the AEUB issued a decision in which it acknowledged an error for a portion of the administrative expenses in question; and
- a further AEUB decision on the remainder of this application is expected in the 2nd quarter of 2007.

In October 2001, the AEUB approved the sale by ATCO Gas of certain properties in the City of Calgary, known as the Calgary Stores Block, for $6.6 million (excluding costs of disposition). As a result of this decision (the "Calgary Stores Block Decision"):
- $4.1 million of the proceeds were allocated by the AEUB to customers and $1.8 million to ATCO Gas;
- ATCO Gas appealed the decision to the Alberta Court of Appeal which overturned the decision and directed the AEUB to allocate $5.4 million of the proceeds to ATCO Gas;
- City of Calgary appealed this decision to the Supreme Court of Canada, which also granted ATCO Gas leave to cross-appeal the decision;
- the Supreme Court of Canada rendered its decision on February 9, 2006, dismissing the City of Calgary's appeal and allowing ATCO Gas' cross-appeal. The AEUB was directed to issue a new decision in accordance with the Supreme Court's ruling;
- ATCO Gas requested that the AEUB address the Supreme Court of Canada decision; and
- the AEUB complied with the Supreme Court of Canada decision on August 11, 2006, and ATCO Gas recorded additional net proceeds totaling $4.1 million from the sale and increased earnings of $3.7 million after income taxes in the third quarter of 2006.

ATCO Gas owns a 43.5 petajoule natural gas storage facility located at Carbon, Alberta. ATCO Gas has leased the entire storage capacity of the facility to ATCO Midstream. ATCO Gas has taken the position that the facility is no longer required for utility service and should be removed from regulation. In the process of obtaining AEUB approval, the following events are significant:
- in July 2004, the AEUB initiated a written process to consider its role in regulating the operations of the facility;

- in June 2005, the AEUB issued a decision with respect to this process. In addition to addressing other matters, the decision found that the AEUB has the authority, when necessary in the public interest, to direct a utility to utilize a particular asset in a specific manner, even over the objection of the utility;
- ATCO Gas filed for leave to appeal the decision with the Alberta Court of Appeal;
- in October 2005, the AEUB established processes to review the use of the facility for utility purposes;
- a hearing to review the use of the facility for revenue generation was held in April 2006 and a hearing to review the use of the facility for load balancing was held in June 2006. On October 11, 2006 the AEUB issued a decision confirming ATCO Gas' position that the facility is no longer required for utility service with respect to the use of the facility for load balancing purposes. The City of Calgary has filed a leave to appeal and a review and variance application of this decision; and
- on February 5, 2007, the AEUB issued a decision in which it determined that a legitimate utility use for the facility is that it be used for purposes of generating revenues to offset customer rates. The AEUB has directed ATCO Gas to continue to lease the entire storage capacity of the facility to ATCO Midstream. The AEUB will conduct a further process to determine if it is appropriate that 100% or some lesser portion of this facility should be used to offset customer rates. (Refer to Business Risks - Regulated Operations - Carbon Natural Gas Storage Facility section).

ATCO Gas has filed an application with the AEUB to address, among other things, corrections required to historical transportation imbalances (the process whereby third party natural gas supplies are reconciled to amounts actually shipped in the Corporation's pipelines) that have impacted ATCO Gas' deferred gas account:

- in April 2005, the AEUB issued a decision resulting in a 15% decrease in the transportation imbalance adjustments sought by ATCO Gas. The decision resulted in a decrease to ATCO Gas' 2005 revenues and earnings of $1.8 million and $1.2 million, respectively; and
- City of Calgary filed for leave to appeal the AEUB's decision. ATCO Gas filed a cross appeal of the AEUB's decision. The leave to appeal was heard by the Alberta Court of Appeal on April 18, 2006. On July 7, 2006 the Alberta Court of Appeal issued its decision granting the City of Calgary's leave to appeal on the question of whether the AEUB erred in law or jurisdiction in assuming that it had the authority to allow recovery in 2005, for costs relating to prior years. ATCO Gas' cross appeal was denied. A hearing with the Alberta Court of Appeal has been scheduled for April 13, 2007.

In October 2005, ATCO Gas filed an application with the AEUB to approve the sale of its Red Deer Operating Centre:

- in December 2005, the AEUB approved the sale and deferred its decision on the distribution of net proceeds of $1.0 million until the Supreme Court of Canada rendered a judgment in the appeal regarding the Calgary Stores Block disposition and allocation of proceeds discussed above;
- the Supreme Court of Canada rendered its decision on the Calgary Stores Block matter on February 9, 2006;
- in February 2006, ATCO Gas submitted a filing to the AEUB to approve the allocation of the net proceeds;
- on March 16, 2006, the AEUB suspended the process convened to approve allocation of the net proceeds pending resolution of certain issues arising in connection with the Supreme Court's Calgary Stores Block decision. The net proceeds of the sale remained in trust pending AEUB approval; and
- on August 16, 2006, ATCO Gas requested that the process re-convene in light of the AEUB's approval of the Calgary Stores Block application. The AEUB issued a call for comments which concluded on September 14, 2006 and on December 13, 2006 the AEUB issued a decision approving the distribution of proceeds to ATCO Gas resulting in increased revenue of $1.0 million and earnings of $0.7 million for ATCO Gas.

ATCO Pipelines

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

Other Matters

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

LIQUIDITY AND CAPITAL RESOURCES

Funds generated by operations 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.

Funds generated by operations for the three months ended December 31, 2006, **decreased** by $19.4 million to $168.4 million, primarily due to:

- decreased availability incentives in Alberta Power (2000), primarily due to availability penalties paid associated with the planned outage in 2006 for the Battle River generating plant which occurred during a period of high Alberta Power Pool electricity prices.

This decrease was partially offset by:

- increased earnings.

Funds generated by operations for the year ended December 31, 2006, **decreased** by $1.8 million to $657.5 million, primarily due to:

- lower proceeds received from the TXU Europe Settlement (refer to TXU Europe Settlement section); and
- decreased availability incentives in Alberta Power (2000), primarily due to availability penalties paid associated with the planned outage in 2006 for the Battle River generating plant which occurred during a period of high Alberta Power Pool electricity prices.

This decrease was partially offset by:

- increased earnings.

Investing activities for the three months ended December 31, 2006, **increased** by $0.3 million to $160.6 million, primarily due to:

- changes in non-cash working capital.

This increase was partially offset by:

- increased contributions by utility customers for extensions to plant.

Purchase of property, plant and equipment for the three months ended December 31, 2006, **increased** by $2.8 million to $184.0 million, primarily due to:

- increased investment in regulated electric distribution and transmission projects.

This increase was partially offset by:

- decreased investment in regulated natural gas distribution projects.

Investing activities for the year ended December 31, 2006, **increased** by $57.1 million to $527.5 million, primarily due to:

- 2005 proceeds on the transfer of the retail energy supply businesses;
- increased capital expenditures;
- changes in non-cash working capital; and
- H.R. Milner Income Tax Reassessment (refer to H.R. Milner Income Tax Reassessment section).

This increase was partially offset by:

- increased contributions by utility customers for extensions to plant; and
- changes in non-current deferred electricity costs.

Purchase of property, plant and equipment for the year ended December 31, 2006, **increased** by $41.0 million to $567.7 million, primarily due to:

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

This increase was partially offset by:

- decreased investment in regulated natural gas distribution projects.

During the three months ended December 31, 2006, the Corporation **issued**:

- $160.0 million of 4.801% Debentures due November 22, 2021; and
- $160.0 million of 5.032% Debentures due November 20, 2036.

During the three months ended December 31, 2006, the Corporation **redeemed**:

- $175.0 million of 4.84% Debentures due November 6, 2006; and
- $12.6 million of non-recourse long term debt.

These changes resulted in a **net debt increase** of $132.4 million.

During the year ended December 31, 2006, the Corporation **issued**:

- $160.0 million of 4.801% Debentures due November 22, 2021;
- $160.0 million of 5.032% Debentures due November 20, 2036; and
- $35.5 million of other long term debt.

During the year ended December 31, 2006, the Corporation **redeemed**:

- $175.0 million of 4.84% Debentures due November 6, 2006; and
- $64.6 million of non-recourse long term debt.

These changes resulted in a **net debt increase** of $115.9 million.

Net purchase of Class A non-voting shares for the three months ended December 31, 2006, **decreased** by $4.6 million to $1.9 million, primarily due to decreased share purchases in 2006.

Net purchase of Class A non-voting shares for the year ended December 31, 2006, **increased** by $64.8 million to $67.5 million, primarily due to increased share purchases in 2006.

Foreign currency translation for the three months ended December 31, 2006, positively impacted the Corporation's cash position by $11.4 million to $11.6 million, primarily as a result of:

- changes in the U.K. exchange rate which resulted in an increase in the value of cash balances denominated in U.K. pounds when translated into Canadian dollars.

Foreign currency translation for the year ended December 31, 2006, positively impacted the Corporation's cash position by $27.5 million to $16.3 million, primarily as a result of:

- changes in the U.K. exchange rate which resulted in an increase in the value of cash balances denominated in U.K. pounds when translated into Canadian dollars.

At December 31, 2006, the Corporation had the following credit lines that enable it to obtain funding for general corporate purposes.

($ Millions)	Total	Used	Available
Long term committed	326.0	47.4	278.6
Short term committed	600.0	14.0	586.0
Uncommitted	69.1	7.1	62.0
Total	995.1	68.5	926.6

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

Capital expenditures to maintain capacity, meet planned growth and fund future development activities are expected to be approximately $725 million in 2007. The majority of these expenditures are uncommitted and relate primarily to utility operations.

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)					
Long term debt	2,411.5	54.5	225.0	272.0	1,860.0
Non-recourse long term debt	686.0	59.3	150.3	124.2	352.2
Operating leases	61.6	18.5	24.6	13.7	4.8
Purchase obligations:					
ATCO Gas natural gas purchase contracts (1)	4.5	0.5	1.0	1.0	2.0
Alberta Power (2000) coal purchase contracts (2)	607.7	47.7	99.2	105.2	355.6
ATCO Power natural gas fuel supply contracts (3)	248.1	52.4	104.8	74.0	16.9
ATCO Power operating and maintenance agreements (4)	198.2	21.2	45.3	38.4	93.3
Capital expenditures (5)	45.4	45.4	-	-	-
Other	7.8	7.8	-	-	-
Total	4,270.8	307.3	650.2	628.5	2,684.8

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 primarily to operational contracts pertaining to the Carbon natural gas 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 December 31, 2006, and assumes a remaining life of 10 years for the gas reserves commencing January 1, 2004. DEML has agreed to purchase the natural gas purchased under these contracts at the prices paid by ATCO Gas.*

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

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

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

Current and long term future income tax liabilities of $195.0 million at December 31, 2006, are attributable to differences between the financial statement carrying amounts of assets and liabilities and their tax bases. These differences result primarily from recognizing revenue and expenses in different years for financial and tax reporting purposes. Future income taxes will become payable when such differences are reversed through the settlement of liabilities and realization of assets.

On May 20, 2005, the Corporation commenced a **normal course issuer bid** for the purchase of up to 3% of the outstanding Class A shares. The bid expired on May 19, 2006. Over the life of the bid, 348,100 shares were purchased, of which 195,600 were purchased in 2005 and 152,500 were purchased in 2006. On May 23, 2006, the Corporation commenced a new normal course issuer bid for the purchase of up to 5% of the outstanding Class A shares. The bid will expire on May 22, 2007. From May 23, 2006, to February 16, 2007, 1,679,700 shares have been purchased, all of which were purchased in 2006.

It is the policy of the Corporation to **pay dividends** quarterly on its Class A and Class B shares. For the first quarter of 2006, the quarterly dividend payment on the Corporation's Class A and Class B shares **increased** by $0.01 to $0.285 per share. The quarterly dividend payment for the second quarter remained unchanged at $0.285 per share. For the third quarter of 2006, the quarterly dividend was increased by $0.005 to $0.29 per share. The Corporation also approved a one-time special dividend of $0.25 per share. Both the third quarter dividend of $0.29 per share and the one-time special dividend of $0.25 per share were paid on September 1, 2006, to shareholders of record on August 9, 2006. Based on approximately 126.3 million shares then outstanding, the one-time special dividend totaled approximately $31.6 million. The Corporation has increased its annual common share dividend each year since its inception as a holding company in 1972. The matter of an increase in the quarterly dividend is addressed by the Board of Directors in the first quarter of each year. For the first quarter of 2007, the quarterly dividend payment has been **increased** by $0.015 to $0.305 per share. 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.

On April 12, 2006, CU Inc. filed a **base shelf prospectus** which permits CU Inc. to issue up to an aggregate of $850.0 million of debentures over the twenty-five month life of the prospectus.

- on November 20, 2006, the Corporation issued $160.0 million of 4.801% Debentures due November 22, 2021, at a price of 100 to yield 4.801%, and $160.0 million of 5.032% Debentures due November 20, 2036, at a price of 100 to yield 5.032%. The proceeds of these issues were advanced to ATCO Electric, ATCO Gas and ATCO Pipelines and used to fund capital expenditures, repay indebtedness and for general corporate purposes.

OUTSTANDING SHARE DATA

At February 16, 2007, the Corporation had outstanding 81,462,286 Class A shares and 43,926,484 Class B shares.

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

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

Of the 6,400,000 Class A shares reserved for issuance in respect of options under the Corporation's stock option plan, 2,626,800 Class A shares are available for issuance at December 31, 2006. Options may be granted to directors, officers and key employees of the Corporation and its subsidiaries at an exercise price equal to the weighted average of the trading price of the shares on the Toronto Stock Exchange for the five trading days immediately preceding the date of grant. The vesting provisions and exercise period (which cannot exceed 10 years) are determined at the time of grant. As of February 16, 2007, options to purchase 1,368,900 Class A shares were outstanding.

TRANSACTIONS WITH RELATED PARTIES

The Corporation's transactions with related parties are in the normal course of business and under normal commercial terms. For a description of these transactions, refer to Note 19 to the consolidated financial statements for the year ended December 31, 2006.

BUSINESS RISKS

The current Federal government favours a made in Canada approach to deal with climate change instead of the Kyoto Protocol which the previous government had ratified. The Corporation is unable to determine what impact the Clean Air Act may have on its operations as the Government of Canada has not yet provided industry specific details for its 2006 Climate Change Plan. While it is not certain, it is anticipated that the Corporation's PPA's relating to its coal-fired generating plants will allow the Corporation to recover any increased costs associated with the implementation of the Clean Air Act.

Regulated Operations

ATCO Electric, ATCO Gas and ATCO Pipelines are regulated primarily by the AEUB, which administers acts and regulations covering such matters as rates, financing, accounting, construction, operation and service area. The AEUB may approve interim rates or approve the recovery of costs on a placeholder basis, subject to final determination. These subsidiaries are subject to the normal risks faced by companies that are regulated. These risks include the approval by the AEUB of customer rates that permit a reasonable opportunity to recover on a timely basis the estimated costs of providing service, including a fair return on rate base. The Corporation's ability to recover the actual costs of providing service and to earn the approved rates of return depends on achieving the forecasts established in the rate-setting process.

Carbon Natural Gas Storage Facility

ATCO Gas leases the entire storage capacity of the Carbon natural gas storage facility to ATCO Midstream at AEUB approved placeholder rates. On February 5, 2007, the AEUB issued a decision to ATCO Gas that leaves in question these placeholder rates and the effect that these placeholder rates will have on future ATCO Gas revenues. (Refer to Regulatory Matters – ATCO Gas section).

Weather

Weather fluctuations have a significant impact on throughput in ATCO Gas. Since approximately 50% of ATCO Gas' delivery charge is recovered based on throughput, ATCO Gas' revenues and earnings are sensitive to weather. Weather that is 10% warmer or colder than normal temperatures impacts annual earnings by approximately $10.0 million.

ATCO I-Tek Services

ATCO Electric, ATCO Gas and ATCO Pipelines purchase information technology services, and ATCO Electric and ATCO Gas also purchase customer care and billing services, from ATCO I-Tek. The recovery of these costs in customer rates are subject to AEUB approval. Since 2003, the costs have been approved on a placeholder basis, and are subject to final AEUB approval after completion of an ongoing collaborative benchmarking process.

Transfer of the Retail Energy Supply Businesses

On May 4, 2004, ATCO Gas and ATCO Electric transferred their retail energy supply businesses to Direct Energy Marketing Limited and one of its affiliates (collectively "DEML"), a subsidiary of Centrica plc.

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

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

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

Late Payment Penalties on Utility Bills

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

Alberta Power (2000)

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

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

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

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

At December 31, 2006, the Corporation had recorded $39.6 million of deferred availability incentives.

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

Alberta Environment implemented mercury emission regulations in March 2006 for coal-fired generating plants. Owners of coal-fired generating plants are required to submit by April 1, 2007, proposals on capturing at least 70% of the mercury in the coal burned in their plants. The proposals for mercury emission reduction must be implemented by 2010. While it is not certain, it is anticipated that the Corporation's PPA's relating to its coal-fired generating plants will allow the Corporation to recover most of the costs associated with complying with the new regulation.

Measurement Inaccuracies in Metering Facilities

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

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

Non-Regulated Operations

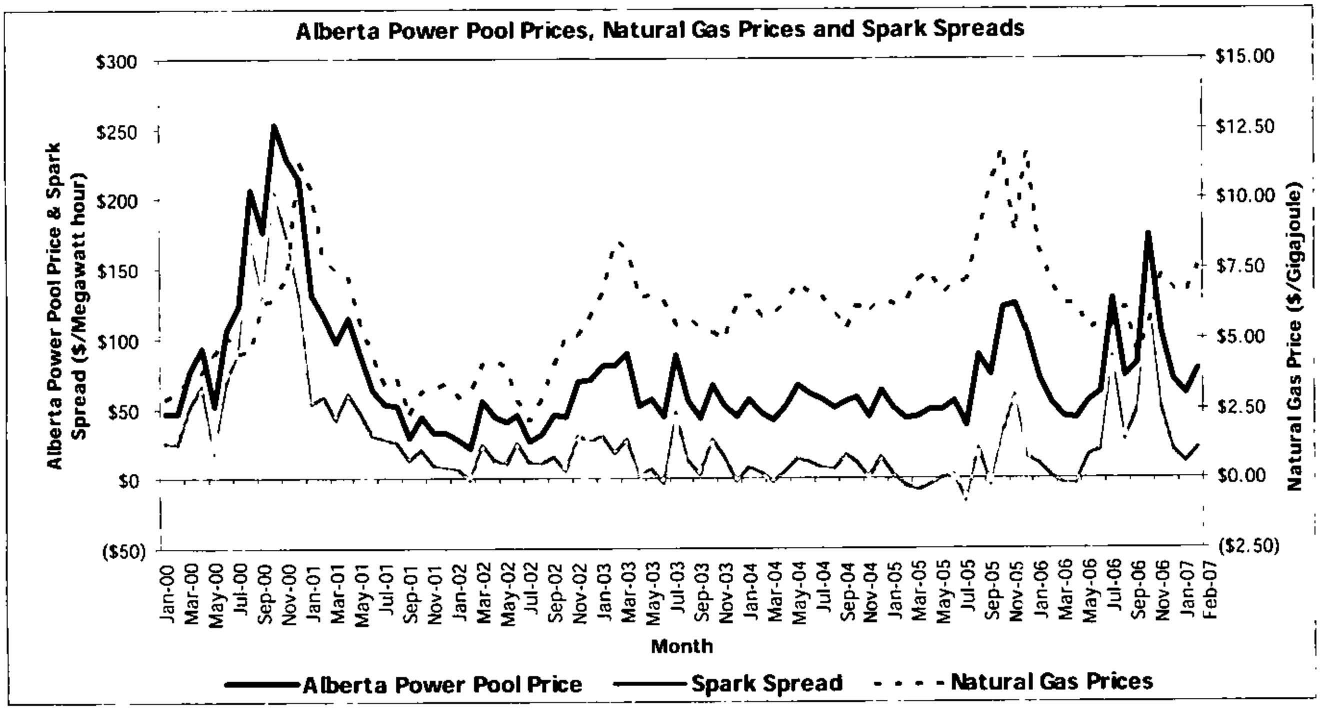
The Corporation's non-regulated operations are complementary to its traditional regulated businesses and are related to them in terms of skills, knowledge and experience. The Corporation accounts for its non-regulated operations separately from its regulated operations. The Corporation's non-regulated operations are subject to the risks faced by any commercial enterprise in those industries and in those countries in which they operate.

ATCO Power

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

ATCO Power's generating plants include high efficiency gas-fired cogeneration plants, with associated on-site steam and power tolling arrangements, and gas-fired peaking and hydroelectric plants with underlying transmission support agreements. In 2006, sales from approximately 71% of ATCO Power's generating capacity were subject to long term agreements, while the remaining 29% consisted primarily of sales to the Alberta Power Pool and the U.K. merchant power market. In 2007, these percentages are expected to be approximately the same. These sales are dependent on prices in the Alberta electricity spot market and in the U.K. merchant power market. The majority of the electricity sales to the Alberta Power Pool are from gas-fired generating plants, and as a result operating income is affected by natural gas prices. During peak electricity usage hours in Alberta, a good correlation exists between electricity spot prices and natural gas spot prices. During off-peak hours, there is less correlation. The correlation is expected to increase in the future as customer load grows and older plants are decommissioned.

Alberta Power Pool electricity prices, natural gas prices and related spark spreads can be very volatile, as shown in the following graph, which illustrates a range of prices experienced during the period January 2000 to February 2007.



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

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

ATCO Power has financed its non-regulated electrical generating capacity on a non-recourse basis. In these projects, the lender's recourse in the event of default is limited to the business and assets of the project in question, which includes the Corporation's equity therein. Canadian Utilities Limited has provided a number of guarantees related to ATCO Power's obligations under non-recourse loans associated with certain of its projects. The guarantees outstanding at December 31, 2006, are described in Note 12 to the consolidated financial statements for the year ended December 31, 2006. To date, Canadian Utilities Limited has not been required to pay any of its guaranteed obligations.

ATCO Midstream

Timing, capacity and demand of ATCO Midstream's storage business as well as changes in market conditions may impact the Corporation's earnings and cash flow from storage operations.

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

ATCO Frontec

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

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

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

CONTINGENCIES

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

HEDGING

In conducting its business, the Corporation uses various instruments, including forward contracts, swaps and options, to manage the risks arising from fluctuations in exchange rates, interest rates and commodity prices. All such instruments are used only to manage risk and not for trading purposes. For details on the financial instruments in place at December 31, 2006, refer to Note 21 to the consolidated financial statements for the year ended December 31, 2006.

OFF-BALANCE SHEET ARRANGEMENTS

At December 31, 2006, unrecorded future income tax liabilities of the regulated operations amounted to $141.3 million and unrecorded future income tax assets of other operations amounted to $0.5 million. The liabilities include $14.6 million in respect of Alberta Power (2000)'s generating plants, which will be recovered through future payments received in respect of the PPA's. There are tax loss carryforwards of $0.4 million for Canadian subsidiary corporations and $7.6 million for a foreign subsidiary corporation for which no tax benefit has been recorded. The losses for Canadian subsidiary corporations begin to expire in 2010 and the losses for the foreign subsidiary corporation do not expire. For additional information on the Corporation's unrecorded future income tax liabilities, refer to Note 7 to the consolidated financial statements for the year ended December 31, 2006.

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

CRITICAL ACCOUNTING ESTIMATES

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

Deferred Availability Incentives

As noted in the Business Risks section, Alberta Power (2000) is subject to an incentive/penalty regime related to generating unit availability. As at December 31, 2006, the Corporation had recorded $39.6 million of deferred availability incentives. The amortization of deferred availability incentives, which was recorded in revenues, amounted to $10.6 million in 2006.

The amount to be amortized is dependent upon estimates of future generating unit availability and future electricity prices over the term of the PPA's. Each quarter, the Corporation uses these estimates to forecast high case, low case and most likely scenarios for the incentives to be received from, less penalties to be paid to, the PPA counterparties. These forecasts are added to the accumulated unamortized deferred availability incentives outstanding at the end of the quarter; the resulting total is divided by the remaining term of the PPA to arrive at the amortization for the quarter.

Compared to the most likely scenario recorded in revenues for the year, the high case scenario would have resulted in higher revenues of approximately $5.0 million, whereas the low case scenario would have resulted in lower revenues of approximately $4.6 million.

Employee Future Benefits

The expected long term rate of return on pension plan assets is determined at the beginning of the year on the basis of the long bond yield rate plus an equity and management premium that reflects the plan asset mix. Actual balanced fund performance over a longer period suggests that this premium is about 1%, which, when added to the long bond yield rate of 5.1% at the beginning of 2006, resulted in an expected long term rate of return of 6.1% for 2006. This methodology is supported by actuarial guidance on long term asset return assumptions for the Corporation's defined benefit pension plans, taking into account asset class returns, normal equity risk premiums, and asset diversification effect on portfolio returns.

Expected return on plan assets for the year is calculated by applying the expected long term rate of return to the market related value of plan assets, which is the average of the market value of plan assets at the end of the preceding three years. The expected long term rate of return has declined over the past five years, from 8.1% in 2001 to 6.1% in the year ended December 31, 2006. The result has been a decrease in the expected return on plan assets and a corresponding increase in the cost of pension benefits. In addition, the actual return on plan assets over the same period has been lower than expected (i.e., an experience loss), which is also contributing to an increase in the cost of pension benefits as losses are amortized to earnings.

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

In accordance with the Corporation's accounting policy to amortize cumulative experience gains and losses in excess of 10 percent of the greater of the accrued benefit obligations or the market value of plan assets, the Corporation began amortizing a portion of the net cumulative experience losses on plan assets and accrued benefit obligations in 2003 for both pension benefit plans and other post employment benefit plans and continued this amortization during the three months and the year ended December 31, 2006.

The assumed annual health care cost trend rate increases used in measuring the accumulated post employment benefit obligations in the three months and the year ended December 31, 2006, are as follows: for drug costs, 8.5% starting in 2006 grading down over 7 years to 4.5%, and for other medical and dental costs, 4.0% for 2006 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).

The sensitivities of key assumptions used in measuring accrued benefit obligations and benefit plan cost (income) for 2006 are outlined in the following table. The sensitivities of each key assumption have been calculated independently of changes in other key assumptions. Actual experience may result in changes in a number of assumptions simultaneously.

	2006 Pension Benefit Plans		2006 Other Post Employment Benefit Plans	
($ Millions)	Accrued Benefit Obligation	Benefit Plan Cost	Accrued Benefit Obligation	Benefit Plan Cost
Expected long term rate of return on plan assets				
1% increase (1)	-	(3.4)	-	-
1% decrease (1)	-	3.4	-	-
Liability discount rate				
1% increase (1)	(79.5)	(6.4)	(3.7)	(0.4)
1% decrease (1)	101.7	7.5	4.7	0.5
Future compensation rate				
1% increase (1)	22.9	2.9	-	-
1% decrease (1)	(20.8)	(2.6)	-	-
Long term inflation rate				
1% increase (1) (2) (3)	34.5	3.9	4.2	0.7
1% decrease (1) (3)	(60.4)	(6.9)	(3.4)	(0.5)

Notes:

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

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

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

CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2007, the Corporation prospectively adopted the recommendations of the Canadian Institute of Chartered Accountants ("CICA") pertaining to financial instruments, hedging and comprehensive income. These recommendations require certain financial instruments and hedge positions to be recorded at their fair value. They also introduce the concept of comprehensive income and accumulated other comprehensive income. Financial instruments designated as "held-for-trading" and "available-for-sale" will be carried at their fair value while financial instruments classified as "loans and receivables" and "held-to-maturity" will be carried at their amortized cost. All derivatives will be carried on the consolidated balance sheet at their fair value, including derivatives designated as hedges. The effective portion of unrealized gains and losses on cash flow hedges and the cumulative foreign currency translation adjustments arising from self-sustaining investments in foreign operations will be carried in Accumulated Other Comprehensive Income, a component of Class A and Class B Share Owners Equity on the consolidated balance sheet. Any ineffective portions of gains and losses on hedges will be taken into earnings immediately. Changes in value of fair value hedges will be recognized in earnings as they occur. The Corporation is unable to determine at this time the impact of adopting these recommendations on earnings or assets of the Corporation.

Effective January 1, 2006, the Corporation retroactively adopted the CICA Emerging Issues Abstract regarding conditional asset retirement obligations. This abstract requires an entity to record a liability for an asset retirement obligation where the timing and/or method of settlement are conditional upon the occurrence of a future event that may or may not be within the control of the entity. Adoption of this abstract had no effect on the consolidated financial statements for the year ended December 31, 2006.

Effective January 1, 2006, the Corporation retroactively adopted the CICA Emerging Issues Abstract regarding stock based compensation for employees eligible to retire before the vesting date. This abstract requires an entity to recognize the compensation cost attributable to such an award over the period from grant date to the date the employee becomes eligible to retire. Since the Corporation does not have stock based compensation plans that contain such provisions, adoption of this abstract had no effect on the consolidated financial statements for the year ended December 31, 2006.

February 21, 2007

CANADIAN UTILITIES LIMITED
CONSOLIDATED FIVE-YEAR FINANCIAL SUMMARY

(Millions of Canadian dollars, except as indicated)		**2006**	2005	2004 [1]	2003	2002 [2]
EARNINGS						
Revenues		**2,430.4**	2,515.8	3,011.4	3,742.6	2,975.9
Operating expenses		**1,390.7**	1,553.9	2,107.5	2,868.7	2,169.8
Depreciation and amortization		**348.5**	311.5	291.5	269.2	243.9
Interest		**222.9**	210.0	203.7	190.3	184.1
Interest and other income		**(58.5)**	(36.6)	(94.1)	(33.4)	(136.2)
Income taxes		**167.1**	175.6	158.0	155.6	190.0
Dividends on equity preferred shares		**35.8**	35.8	35.8	33.1	18.2
Earnings attributable to Class A and Class B shares		**323.9**	265.6	309.0	259.1	306.1
SEGMENTED EARNINGS						
Utilities		**121.2**	106.0	168.7	121.3	177.8
Power generation [3]		**119.2**	105.2	82.0	94.1	77.3
Global enterprises [3]		**101.0**	78.8	70.1	54.8	44.4
Corporate and other/eliminations		**(17.5)**	(24.4)	(11.8)	(11.1)	6.6
Earnings attributable to Class A and Class B shares		**323.9**	265.6	309.0	259.1	306.1
BALANCE SHEET						
Property, plant and equipment		**5,426.1**	5,208.7	5,042.5	4,835.4	4,681.2
Total assets		**6,993.5**	6,817.8	6,617.5	6,237.6	6,075.8
Capitalization:						
Long term debt		**2,411.5**	2,231.0	2,171.0	1,805.3	1,916.9
Non-recourse long term debt		**626.7**	673.8	760.9	806.1	821.1
Equity preferred shares		**636.5**	636.5	636.5	636.5	486.5
Share owners' equity [4]		**2,324.7**	2,223.5	2,117.7	1,948.5	1,827.0
Total capitalization		**5,999.4**	5,764.8	5,686.1	5,196.4	5,051.5
CASH FLOWS						
Funds generated by operations		**657.5**	659.3	538.3	525.8	504.6
Purchase of property, plant and equipment		**567.7**	526.7	535.5	495.7	569.8
Financing (excluding Class A and B dividends)		**44.4**	(2.2)	333.8	(10.6)	384.3
Class A and B dividends		**176.7**	139.6	134.4	129.3	124.2
CLASS A & B SHARES						
Shares outstanding at end of year [4] (thousands)		**125,388**	126,892	126,783	126,767	126,824
Return on equity [4] (%)		**14.3**	12.2	15.2	13.7	17.7
Earnings per share [4] ($)		**2.57**	2.09	2.44	2.04	2.42
Dividends paid per share [4] [5] ($)		**1.40**	1.10	1.06	1.02	0.98
Equity per share [4] ($)		**18.54**	17.52	16.70	15.37	14.41
Stock market record - Class A non-voting shares ($)	High	**48.94**	46.20	32.00	29.80	30.05
	Low	**35.15**	29.55	25.71	22.55	24.40
	Close	**47.73**	43.98	30.16	28.93	25.605
Stock market record - Class B common shares ($)	High	**48.85**	45.82	31.95	29.375	30.25
	Low	**35.72**	29.63	25.70	22.75	24.50
	Close	**47.66**	43.85	31.95	29.00	26.325

(1) *Includes the gain on the transfer of retail energy supply businesses that occurred on May 4, 2004. Revenues and natural gas supply and purchased power costs after May 4, 2004 were reduced accordingly for 2004 and thereafter.*

(2) *Includes the gain on the sale of Viking-Kinsella property.*

(3) *In 2006, ASHCOR Technologies was transferred from the Global Enterprises Business Group to the Power Generation Business Group. Segmented figures for 2002 to 2005 have been reclassified to conform to the current basis of segmentation.*

(4) *Includes Class A non-voting shares and Class B common shares.*

(5) *Dividends paid per share include a Special Dividend of $0.25 paid to Class A and Class B share owners on September 1, 2006.*

CANADIAN UTILITIES LIMITED

CONSOLIDATED FIVE-YEAR OPERATING SUMMARY

(Millions of Canadian dollars, except as indicated)	**2006**	2005	2004	2003	2002
Utilities					
Natural gas distribution operations					
Purchase of property, plant and equipment	**167.4**	174.0	154.3	141.0	103.1
Pipelines (thousands of kilometres)	**35.9**	35.4	34.8	34.2	33.7
Maximum daily demand (terajoules)	**1,861**	1,919	2,049	1,831	1,670
Natural gas sold [1] (petajoules)	**-**	-	103	198	201
Natural gas distributed [1] (petajoules)	**219**	216	120	32	31
Total system throughput (petajoules)	**219**	216	223	230	232
Average annual use per residential customer (gigajoules)	**126**	131	134	134	136
Degree days - Edmonton [2]	**3,819**	3,641	3,985	4,245	4,274
- Calgary [3]	**3,910**	3,934	3,978	4,291	4,470
Customers at year-end (thousands)	**969.9**	939.6	914.3	887.8	862.0
Electric distribution and transmission operations					
Purchase of property, plant and equipment	**238.1**	212.2	223.4	171.6	162.4
Power lines (thousands of kilometres)	**70.1**	69.2	68.0	67.0	67.1
Electricity distributed (millions of kilowatt hours)	**10,286**	9,926	9,910	9,768	10,224
Average annual use per residential customer (kWh)	**7,495**	7,214	7,475	7,261	7,445
Customers at year-end (thousands)	**216.3**	210.9	206.2	202.3	197.8
Natural gas transportation operations					
Purchase of property, plant and equipment	**97.7**	84.3	47.9	33.6	47.3
Pipelines (thousands of kilometres)	**8.4**	8.3	8.3	8.3	8.3
Contract demand for pipelines system access (terajoules/day)	**5,032**	4,830	4,606	4,599	4,890
Power Generation					
Purchase of property, plant and equipment	**48.1**	41.2	77.0	131.7	236.0
Generating capacity (thousands of kilowatts)	**2,474**	2,474	2,474	2,397	2,036
Global Enterprises					
Purchase of property, plant and equipment	**14.2**	11.9	14.5	15.5	11.5
Natural gas processed (Mmcf/day)	**480**	476	427	399	420
Natural gas gathering lines (kilometres)	**1,000**	1,000	1,000	1,000	940

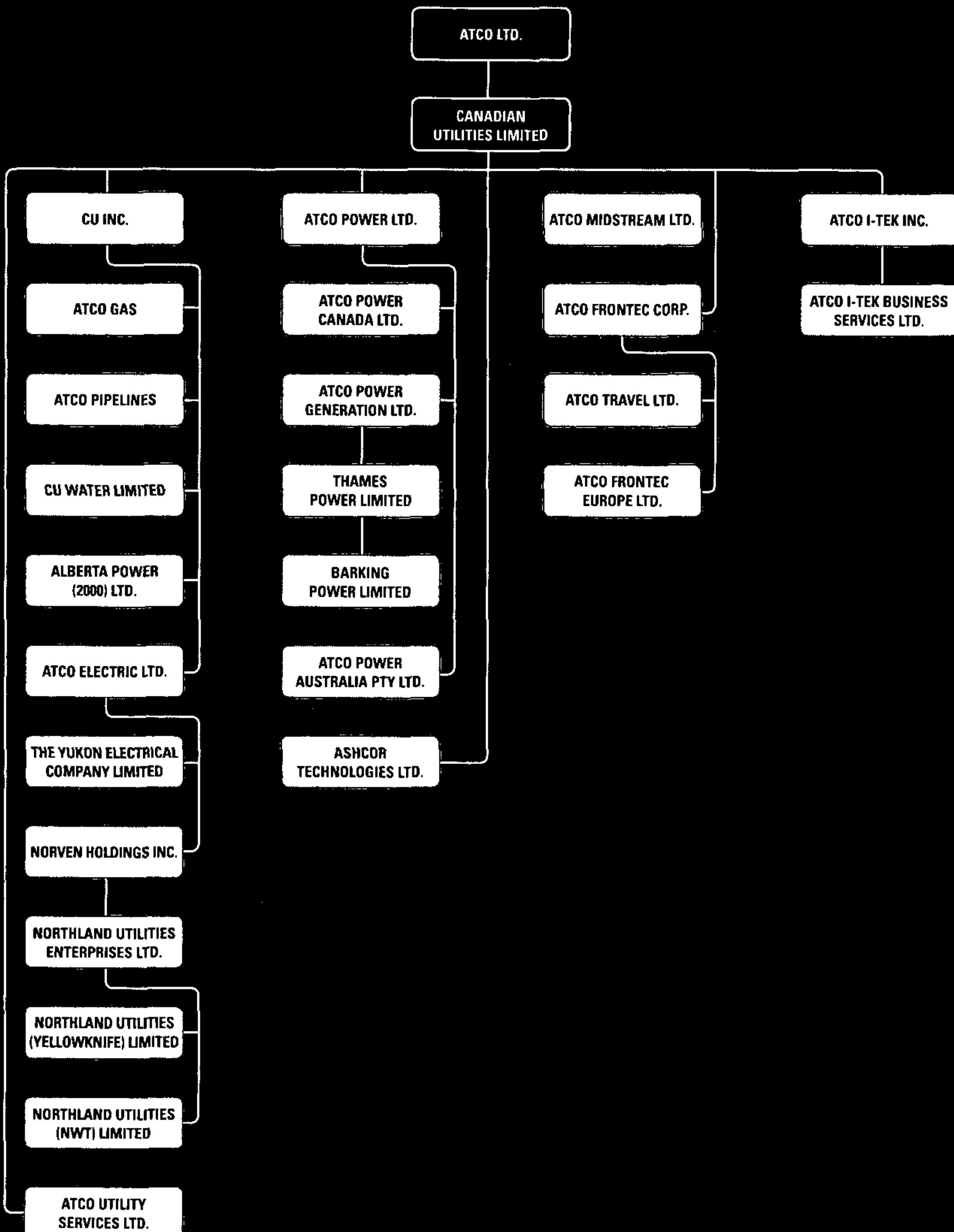
(1) *Effective May 2004, with the transfer of the retail energy supply businesses, ATCO Gas' existing sales service customers became transportation service customers.*

(2) *Degree days – Edmonton – are defined as the difference of the mean daily temperature from 14.5 degrees Celsius.*

(3) *Degree days – Calgary – are defined as the difference of the mean daily temperature from 15.5 degrees Celsius.*

Canadian Utilities Limited

ORGANIZATION CHART



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Corporate Banking, BMO Capital
Markets

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Lead Director

Nancy C. Southern
President & Chief Executive Officer
Canadian Utilities Limited

Ronald D. Southern
Chairman of the Board of Directors
Canadian Utilities Limited

Charles W. Wilson
Corporate Director

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END