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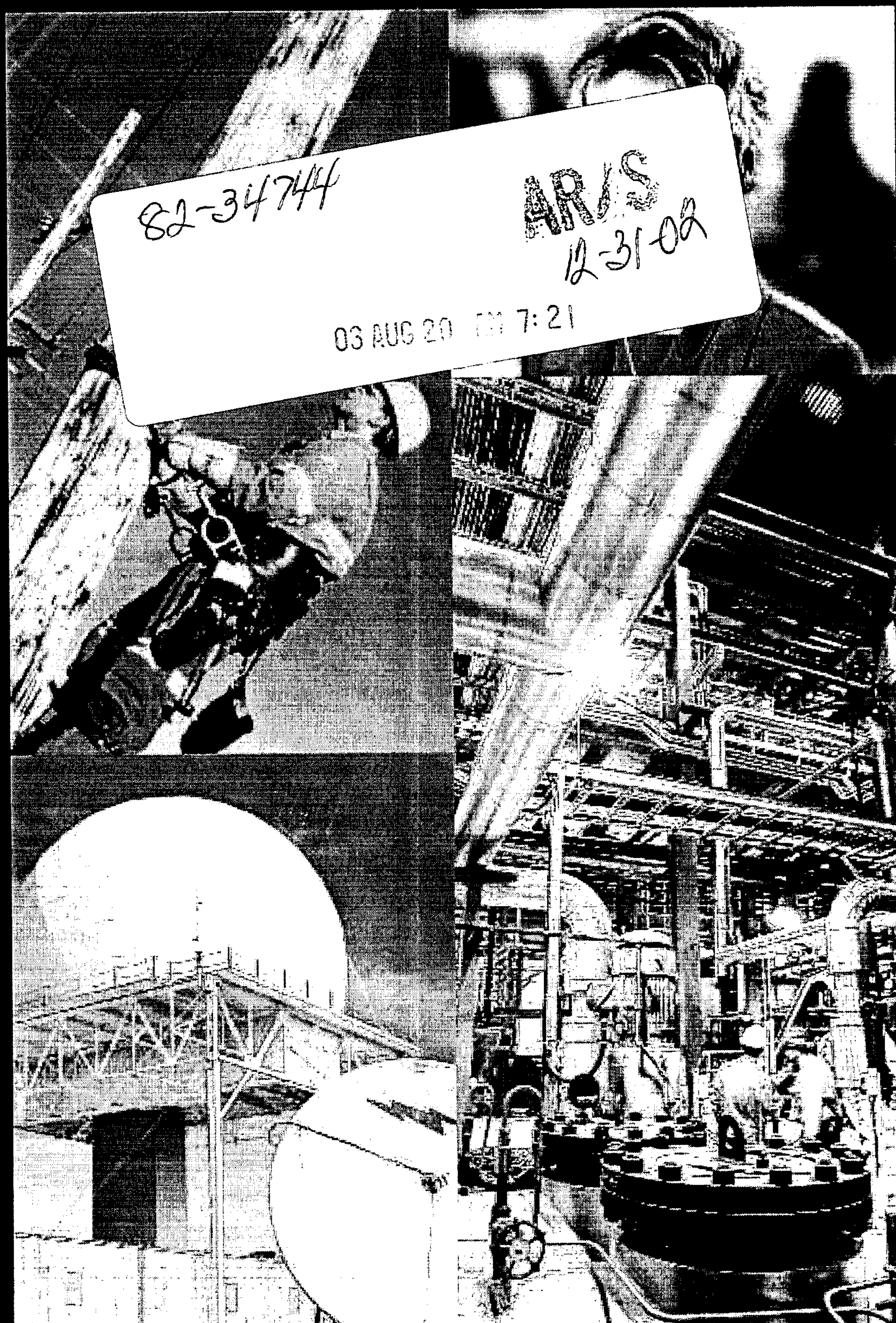
CANADIAN UTILITIES LIMITED 2002 ANNUAL REPORT



CANADIAN UTILITIES LIMITED
An *ATCO* Company

CANADIAN UTILITIES LIMITED
An ATCO Company

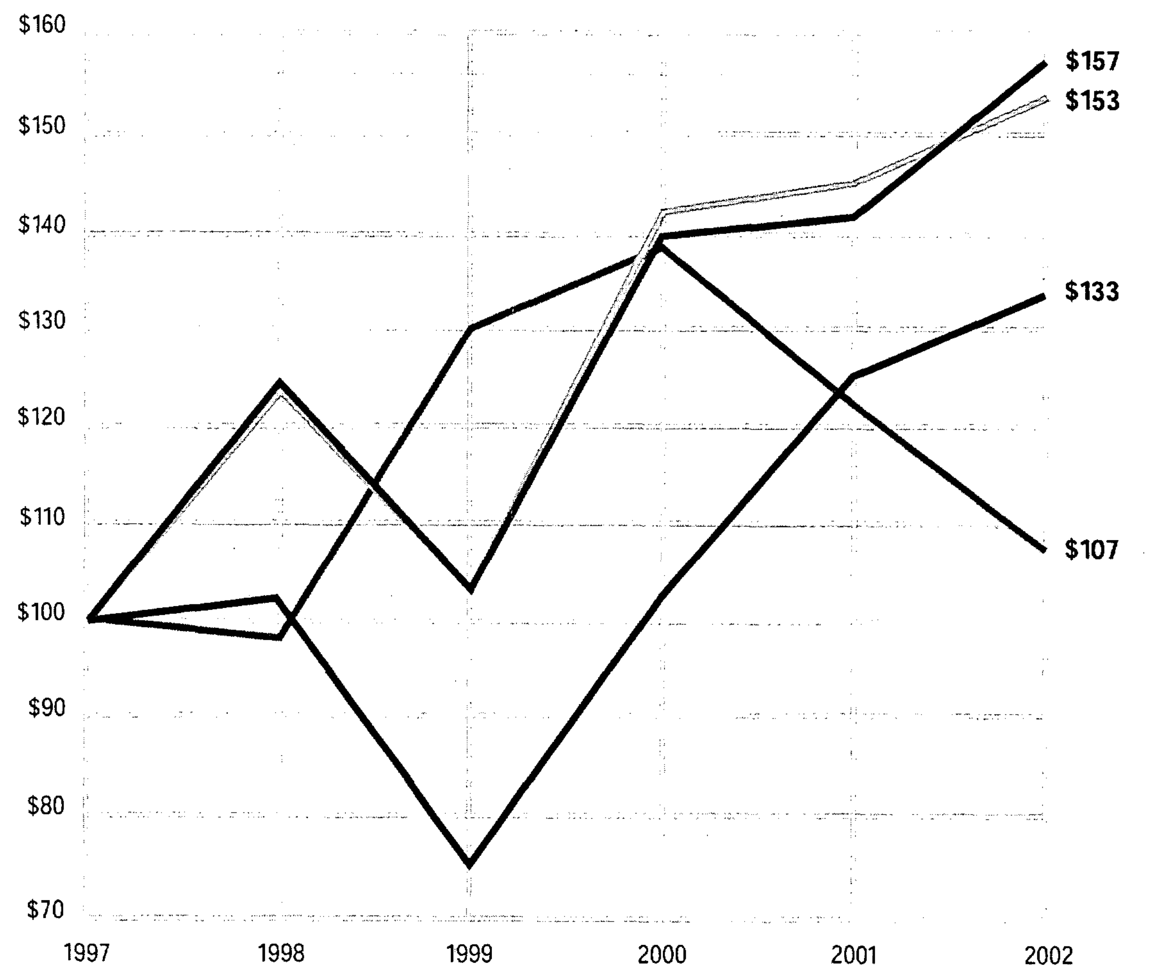
CANADIAN UTILITIES LIMITED IS AN ALBERTA-BASED CORPORATION WITH FOUR PRINCIPAL BUSINESS GROUPS THAT ARE ACTIVE WORLDWIDE IN POWER GENERATION, UTILITIES, LOGISTICS & ENERGY SERVICES AND TECHNOLOGIES.

Table of Contents

CANADIAN UTILITIES LIMITED FIVE YEAR RETURN ON INVESTMENT

THE GRAPH BELOW COMPARES THE CUMULATIVE SHARE OWNER RETURN OVER THE LAST FIVE YEARS ON THE CLASS A NON-VOTING AND CLASS B COMMON SHARES OF THE CORPORATION (ASSUMING A $100 INVESTMENT WAS MADE ON DECEMBER 31, 1997) WITH THE CUMULATIVE TOTAL RETURN OF THE S&P/TSX COMPOSITE INDEX AND THE S&P/TSX UTILITIES INDEX, ASSUMING REINVESTMENT OF DIVIDENDS.

FIVE YEAR TOTAL RETURN ON $100 INVESTMENT



	Cumulative Return	Compound Growth Rate		Cumulative Return	Compound Growth Rate
CU CLASS A non-voting	$153	8.9%	S&P/TSX Composite	$107	1.4%
CU CLASS B Common	$157	9.4%	S&P/TSX Utilities	$133	5.9%

FINANCIAL HIGHLIGHTS

CONSOLIDATED ANNUAL RESULTS

(Millions of Canadian Dollars except per share data)

	2002	2001
Financial		
Revenues	2,975.9	3,513.6
Earnings attributable to Class A and Class B shares	305.0	237.1
Total assets	5,934.4	5,404.0
Class A and Class B Share Owners' equity	1,830.1	1,643.8
Cash flow from operations	500.3	502.3
Purchase of property, plant and equipment	569.8	735.3
Class A Non-Voting and Class B Common Share Data		
Earnings per share	4.81	3.74
Diluted earnings per share	4.79	3.72
Dividends paid per share	1.96	1.88
Equity per share	28.86	25.96
Shares outstanding	63,412,185	63,317,035
Weighted average shares outstanding	63,389,738	63,315,041

CONSOLIDATED QUARTERLY RESULTS [1]

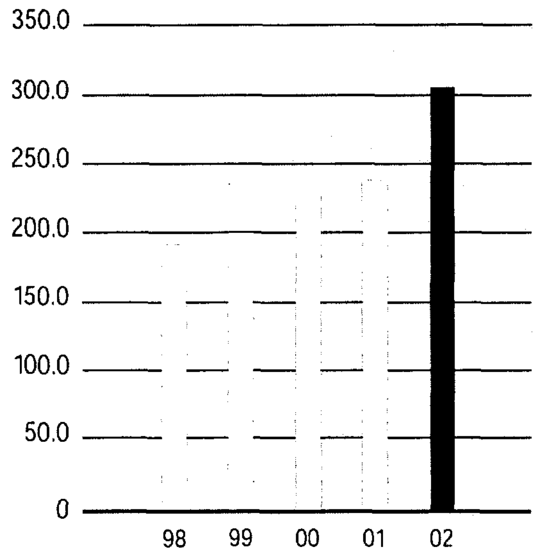
(Unaudited)

(Millions of Canadian Dollars except per share data)

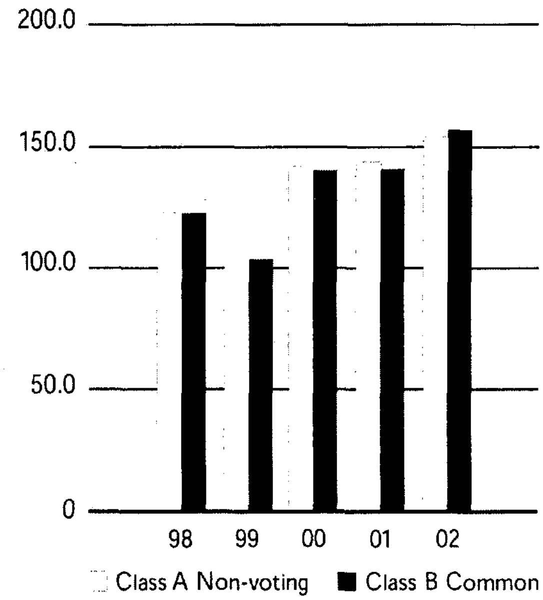
		Three Months Ended				
		March 31	June 30	September 30	December 31	Total
Revenues	2002	863.7	646.3	542.6	923.3	2,975.9
	2001	1,440.7	854.9	582.0	636.0	3,513.6
Earnings attributable to Class A and	2002	144.2	42.9	44.4	73.5	305.0
Class B shares	2001	79.1	45.1	41.2	71.7	237.1
Earnings per Class A and	2002	2.28	0.67	0.70	1.16	4.81
Class B share	2001	1.25	0.71	0.65	1.13	3.74
Diluted earnings per Class A and	2002	2.27	0.67	0.70	1.15	4.79
Class B share	2001	1.24	0.71	0.65	1.12	3.72

[1] *Because of seasonal fluctuations, particularly in the utility operations, quarterly earnings are not indicative of full-year results.*

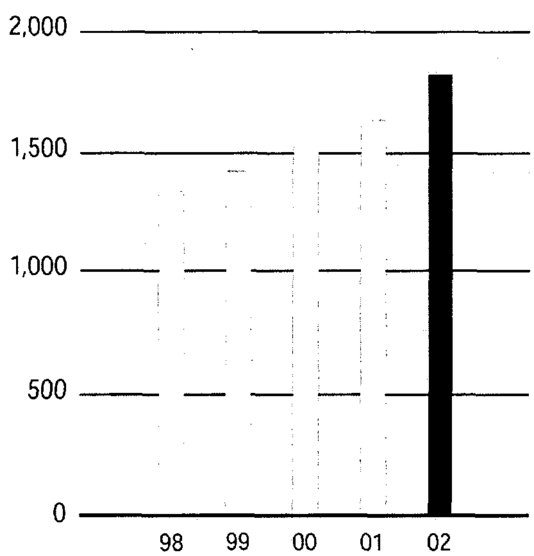
Earnings Attributable to Class A and Class B Shares
(Millions of Dollars)



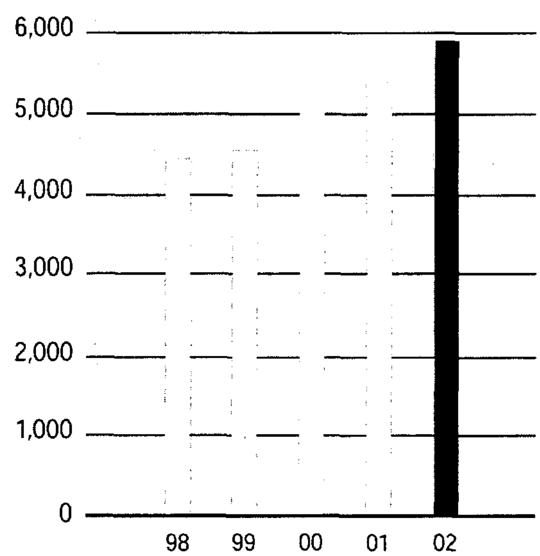
Five Year Total Return on $100 Investment
(Dollars)



Class A and Class B Share Owners' Equity
(Millions of Dollars)



Total Assets
(Millions of Dollars)



R.D. (Ronald) Southern, Chairman

TO THE OWNERS OF OUR CORPORATION

Ladies & Gentlemen,

I am honoured to be named your new non-executive Chairman . . . . and to offer my congratulations to our new President and Chief Executive Officer, Nancy Southern.

Her President's report to you follows and, while I know she does not expect that smooth courses will always lie ahead, you should know your Board of Directors are unanimous in their confidence in her and the first-rank team of Executives she has assembled to sustain and grow the value of your investment in our Company.

2002 has been marked by a weakening economic outlook, especially in our Power Generation business and an unusual amount of focus on Corporate Governance. I will leave it to your President to discuss Canadian Utilities' performance in the problematic economies here and abroad, but I would like to highlight ATCO's governance for you. I trust I will not need to revisit this subject for many years but, against a background of corporate turbulence, it is wholly appropriate that I speak to you on behalf of your Board of Directors with great truth and respect on our ownership, philosophy and governance.

OWNERSHIP It is important for prospective owners to understand that we are a diversified group of companies principally controlled by ATCO Ltd., which in turn is principally controlled by Sentgraf, a Southern Family Holding Company.

It is also important for present and prospective owners to understand that our share registry has both non-voting and voting common shares.

Our performance and record of achievement for building value for our owners shows us to be tied at least equal first with widely held corporations through both short and long business cycles.

PHILOSOPHY We believe our people should be free of duplicity or subterfuge. People whose honesty and integrity compel them to a code of moral and ethical values that produce utter sincerity and candor in everything we do . . . . and . . . . as a result, we believe in **great** transparency, dedication, and sense of duty to you, the owners of our shares, from Directors and Officers alike.

We believe in situational pre-emptive management from time to time by many people in our organization, and we believe in our own definition of Excellence, which measures our performance:

- Going far beyond what anyone might ever expect
- Having the highest standards and always striving for them
- Paying attention to the smallest detail . . . . and caring!

GOVERNANCE Much attention is being given today to the adequacy of Auditing processes and full disclosure of significant developments; therefore, in addition to the Annual Report, may I refer you to our MD&A[1], AIF[2], and Proxy Circular documents for informative and transparent disclosure on the affairs of your Corporation.

In the future, we will support changes proposed for "principle based" regulations that require compliance or explanation ("comply or explain"). We believe this approach offers flexibility and intelligent discretion for our Company, and we are pleased to see a growing number of nations adopting this approach rather than the brittleness and rigidity of rules-based Sarbanes-Oxley type legislation being recommended in the United States, where managers can argue that if they meet the law then everything is alright. This is nonsense of course because no amount of law will ever completely constrain those who wish to circumnavigate it.

As to quality and independence of Directors, it may not be for me to say, but as your Chairman since 1980, I have always understood the need – and my pivotal role – in creating conditions for freedom of expression without limitation – by individual Directors and to have a Board of Directors of great and varied experience that functions as a unified, informed, and judicious body whose collective duty it is to promote the success of your Company.

[1] MD& A – Management's Discussion & Analysis

[2] AIF – Annual Information Form

GOVERNANCE (continued)

Most of what we do today has been in place for many years and our initiatives in some cases, such as our introduction of Lead Directors, Designated Audit Directors and Risk Management Directors, have been pioneering and have marched in the first rank of good corporate practices.

The ATCO Group has developed a unique but effective system of Corporate Governance that has evolved from the challenging requirements to provide oversight to an organization with a diverse number of distinct POSs[3]. The key elements of this system of Corporate Governance are the oversight and diligence provided by the Boards of Directors of the Business Groups, Lead Directors, and the Audit, Risk Review and GOCOM[4] of the Board of Directors, which we have summarized as follows:

- There are four business groups, each comprised of a number of POSs reporting to a Managing Director. Each Business Group has a Board of Directors that is responsible for authorizing and approving the annual business plans, material contracts, strategic transactions, financings and major capital expenditures for each POS within the Business Group.
- Your Company uses Lead Directors to provide more in-depth analysis and knowledge for their colleagues. They often perform special tasks for the Board.
- The Audit Committee of the Board of Directors is comprised of independent Directors with financial expertise chaired by one of our most senior and experienced Directors. Each of the Audit Committee members is designated to report specifically on one or more of the POSs. These Directors are called DADs[5], and they approve audit plans, ensure there is an appropriate system of internal control, and review quarterly and year end financial statements.

[3] POS – Principal Operating Subsidiaries

[4] GOCOM – Corporate Governance, Nomination, Succession and Compensation Committee

[5] DAD – Designated Audit Directors

- The Risk Review Committee of the Board of Directors provides oversight of the Corporation's risk management and control practices and reviews risks that could materially affect its ability to achieve strategic and operating objectives. The President of each POS chairs a Risk Management Committee that reports to the Risk Review Committee. The POS's Risk Management Committee meetings are held at least twice a year attended by senior officers and managers and the subsidiary's DAD.
- Corporate Governance - Oversight of our Corporate Governance rests with GOCOM and is comprised of your Board's most senior and experienced Directors who, in addition to appraising individual and combined Directors' performances, are responsible for succession planning, assessing compensation and performance of officers, and identifying and recommending potential candidates to your Board.

One size does not fit all Corporates, but for us our system is effective. We hope we can streamline it each year to ease the load being carried by our Directors . . . . which is . . . . by any standard . . . . formidable!

In 2002, your 14 outside Directors of CU and its subsidiaries were employed in Board Meetings, Committee Meetings and special assignments such as DADs and Risk Management assessments a total of 1,823 hours for a combined total of 260 days . . . . a noteworthy effort by truly dedicated people!

On your behalf, I want to take this opportunity to thank them for their remarkable contribution to our standards and values.

Respectfully submitted,

Yours sincerely,

R.D. SOUTHERN
CHAIRMAN OF THE BOARD OF DIRECTORS

N.C. (Nancy) Southern, President and Chief Executive Officer

Dear Share Owners:

Stability and prosperity gave way to a global economic slowdown in 2002, with uncertainty and conflict as the dominant features of this past year's stalled economy.

Canadian Utilities is not immune to the volatility of the current environment. In fact, our Group was further challenged by the worldwide recession in the power generation industry. We witnessed formerly creditworthy counterparties fail. Oversupply forced prices down and government intervention altered robust market conditions, that originally prompted power plant investment.

In contrast, the diversity of our Group once again played a significant role in our ability to offset depressed returns in one activity with enhanced profitability in another. This is a unique strength in Canadian Utilities, which also allows us to spread risk across our entire portfolio of enterprise. In addition, the Group's well-developed long-term divesture strategy released significant value for Share Owners through the sale of the Viking gas field, delivering $67.3 million in earnings.

We also made further progress on the divestment of another underutilized asset this year by concluding the key principal agreements with Direct Energy to acquire our Utilities' retail services for gas and electric. Pending Alberta Energy and Utilities Board hearings and other conditions of sale, we expect the transaction to close by mid-2003.

Detailed descriptions of the specific accomplishments our Business Groups achieved in 2002 are provided by our Managing Directors in our operations report. I commend their commentary to you.

As I assume the full responsibility of leading Canadian Utilities as President and Chief Executive Officer in 2003, I want to provide you with a clear understanding of how I intend to proceed.

I am a strong advocate of transparency, the need for real-time significant information flowing up and down the organization. Preemptive identification of risk and opportunities is paramount and even more crucial is the preemptive identification of operating situations which, if left unaddressed, may result in negative surprises for our owners. Indeed, transparency is the fundamental founding trait of not only our operations, but for our governance architecture as referred to by the Chairman in his letter to you.

We believe the test of success for any corporation and the differentiating factor in Canadian Utilities is the ability to give Share Owners sustainable earnings growth through the business cycles. Given the economic climate throughout 2002 and in preparation for the uncertainty of 2003, senior management has and is actively addressing cost improvements and performance enhancements.

Our four Managing Directors are working tirelessly to ensure each of our principal operating subsidiaries is the lowest cost producer in their respective industries, and we expect continuous innovation and determined execution to be their number one priority.

Human resource policies and finance will continue to be centralized core functions. Under the leadership of our Chief Financial Officer, the Group issued $150 million of perpetual preferred shares and $100 million of long-term debt in 2002, which serves to strengthen our balance sheet and provide us with greater flexibility for future opportunities.

We are pleased with our diversity. Our focus for the immediate future is to hone our vigorous executive and administrative base, to assure our controlled growth strategy.

Our Share Owners should know we have no intention of following a high-risk growth strategy and will ignore 'knee jerk' opportunities.

Of course, none of our achievements of the past, nor any we might contemplate in the future, would be possible without our executives, who bring enormous personal energy, balanced resolution and dependability under stress to our plans and I want to thank them most sincerely for their dedication, commitment and loyalty.

In closing, I wish to thank the Board of Directors for their wise, deliberate and steadying counsel.

I also want to thank Craighton Twa, who has recently retired as President and Chief Operating Officer, for his sterling 43-year contribution to our Group of companies.

N.C. South

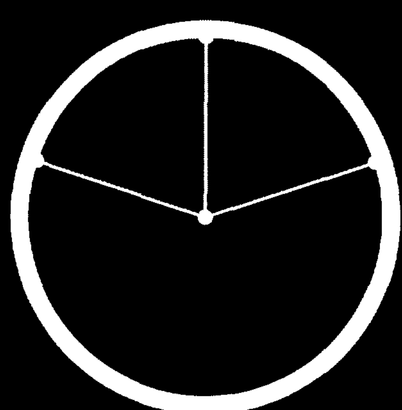
N.C. (NANCY) SOUTHERN
PRESIDENT AND CHIEF EXECUTIVE OFFICER

SEGMENTED FINANCIAL INFORMATION

DURING 2002, THE BUSINESS GROUPS CONTINUED TO BUILD VALUE FOR SHARE OWNERS BY IMPROVING ONGOING OPERATIONS AND CAPTURING NEW BUSINESS OPPORTUNITIES, OFTEN OF A "GREENFIELDS" NATURE.

Revenue

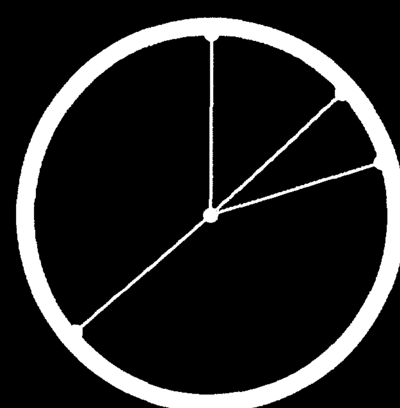
(percentage by segment)



- Utilities 60%
- Logistics & Energy Services 20%
- Power Generation 20%

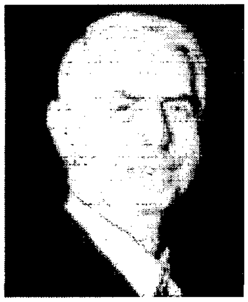
Total Assets

(percentage by segment)



- Utilities 43%
- Power Generation 37%
- Logistics & Energy Services 13%
- Technologies, Other & Corporate 7%

BUSINESS GROUPS[1] MANAGING DIRECTORS



G. K. (Gary) Bauer, Managing Director, Power Generation

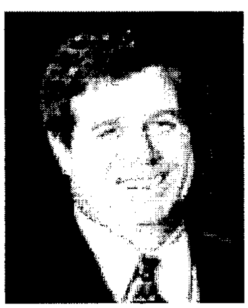
POWER GENERATION

ATCO Power is an international leader in developing, constructing, owning and operating independent, environmentally progressive natural gas fired power projects in Canada, the United Kingdom and Australia. The total capacity of these plants is nearly 5000 MW. The Power Generation Group combines ATCO Power's independent power plants with our regulated "legacy" plants in Alberta.

J. R. (Dick) Frey, Managing Director, Utilities

UTILITIES

ATCO Gas and ATCO Electric, the Utilities Group's two principal operating companies, deliver natural gas and electricity to approximately one million industrial, commercial and residential customers in Alberta, Yukon and the Northwest Territories. ATCO Gas and ATCO Electric have largely moved out of energy production, which enables them to focus on their core business of delivering energy.



M.M. (Michael) Shaw, Managing Director, Logistics & Energy Services

LOGISTICS & ENERGY SERVICES

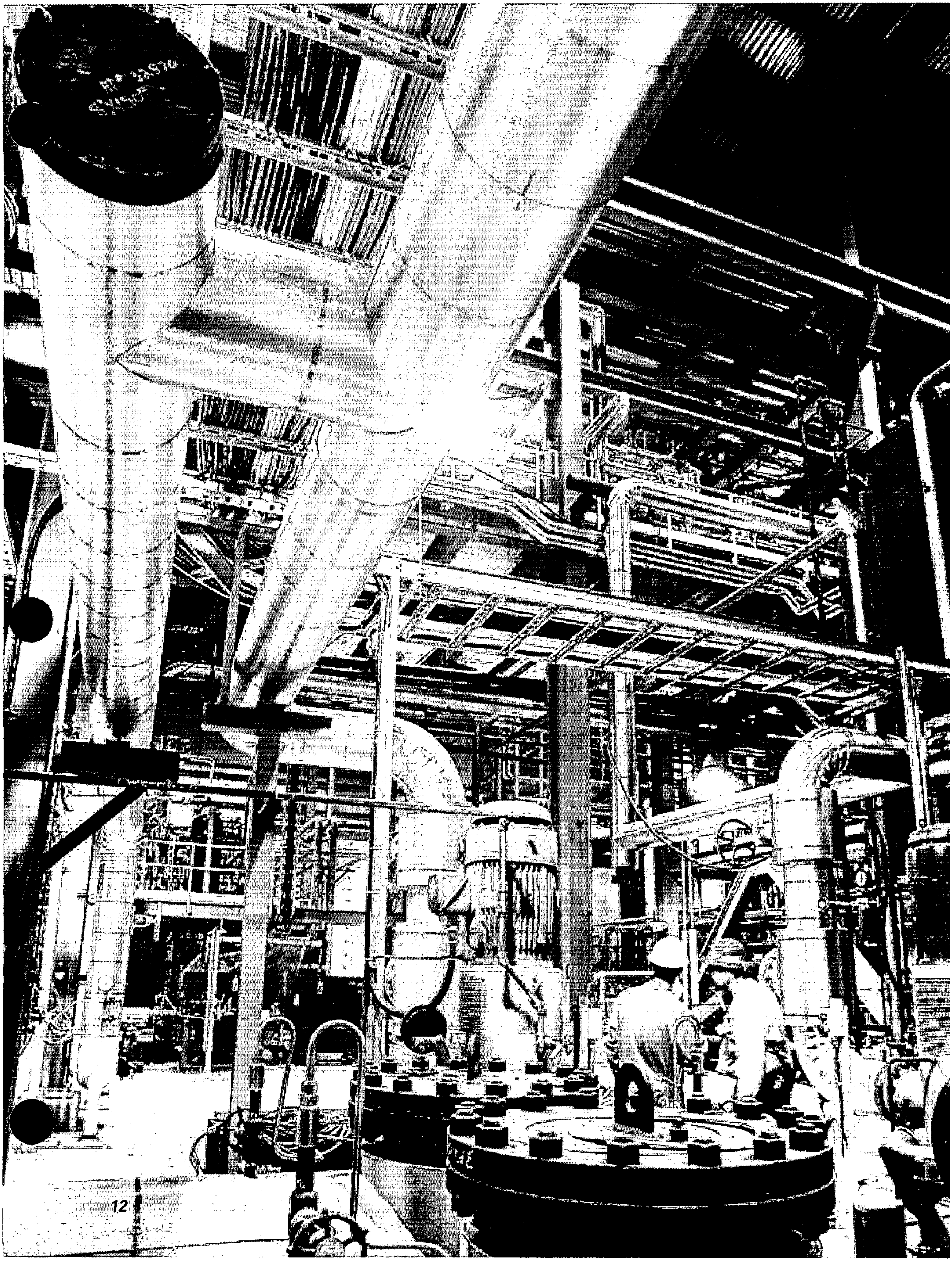
ATCO Frontec provides project management and technical services, operation and maintenance, technology transfer and training services to the defence, telecommunications, resource, transportation and utility sectors. ATCO Pipelines transmits natural gas throughout Alberta to industrial, producer and gas distribution companies using high-pressure pipelines. ATCO Midstream owns and operates natural gas gathering, processing, storage and liquids extraction facilities providing services to Canadian natural gas producers and shippers.

S.W. (Siegfried) Kiefer, Managing Director, Technologies

TECHNOLOGIES

ATCO I-Tek provides billing and customer care services, information technology integration and support, and applications strategy development and implementation to a diverse client group. ATCO Travel provides a wide range of corporate and vacation travel services. ASHCOR Technologies markets coal combustion products. Genics develops, manufactures and markets innovative, environmentally friendly wood preservation products.

[1] Subsidiaries within each Business Group also have separate Boards of Directors



POWER GENERATION GROUP

THE POWER GENERATION GROUP COMBINES THE INDEPENDENT POWER PLANTS BUILT AND OPERATED BY ATCO POWER WITH THE REGULATED LEGACY PLANTS IN ALBERTA PREVIOUSLY OWNED BY ATCO ELECTRIC. THE GROUP OPERATES IN CANADA, THE UNITED KINGDOM AND AUSTRALIA AND IS AN INTERNATIONAL LEADER IN DEVELOPING, CONSTRUCTING AND OPERATING ENVIRONMENTALLY PROGRESSIVE NATURAL GAS FIRED PLANTS.

ATCO Power 2002 was another significant year in the growth of the Power Generation Group. The Group realised strong overall plant performance, progressed construction on five new generation plants (representing more than 1200-MW of capacity) and successfully closed a major financing that raised $403 million of non-recourse long-term debt – the largest non-recourse power plant financing ever closed in Canada.

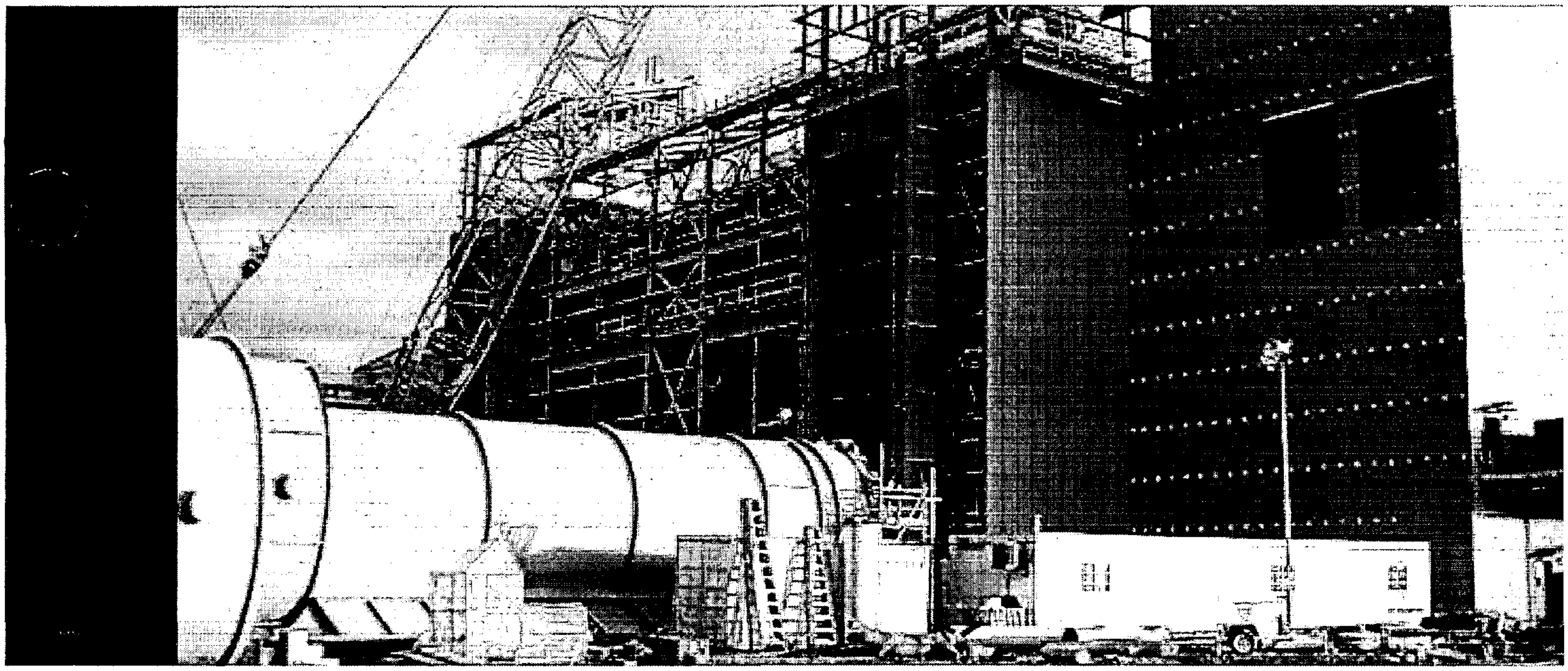
ATCO Power is well positioned to maintain its rank as a leading Canadian based independent power producer. The Group has a wide portfolio of efficient generating assets, with the vast majority of electric and steam output sold under long term contracts and financed with long term non-recourse loans.

CANADA: One of the major new projects under construction is the 580-MW gas-fired combined-cycle Brighton Beach generating plant in Windsor, Ontario. This is ATCO Power's first project in Ontario and demonstrates its successful entry into deregulated power markets following those of the United Kingdom, Australia and Alberta.

In Ontario, the introduction of market deregulation, effective May 1, 2002, allowed ATCO Power and its partner Ontario Power Generation Inc. to develop the Brighton Beach Project by entering into a long-term tolling agreement whereby Coral Energy will deliver natural gas fuel and purchase the entire output of the plant. Construction began in the second quarter of 2002, with completion planned for the second quarter of 2004. The partnership achieved financial close on a $403 million long-term, non-recourse debt financing for the Brighton Beach Project in 2002.

Growth in the Power Generation Group will be significant in the near term as five plants totalling 1200-MW are scheduled for completion during 2003-2004. SaskPower International Inc. is a joint owner of two of these plants. The 260-MW Cory Cogeneration Project at the Potash Corporation of Saskatchewan mine near Saskatoon achieved Commercial Operations on January 15, 2003. This plant is selling all electric energy produced to Saskatchewan Power Corporation and steam to Potash Corporation of Saskatchewan under long term agreements. The 170-MW Muskeg River

Photo: ATCO Power and SaskPower International partnered on this 260-MW cogeneration plant at the Cory Mine site of the Potash Corporation of Saskatchewan. The plant began providing electricity to the Saskatchewan power grid in December of 2002.



The Muskeg River Cogeneration Project is located 75 kilometres north of Fort McMurray in Alberta and is owned 70% by ATCO Power and 30% by SaskPower International. It is a 170-MW high-efficiency cogeneration plant that will supply reliable steam and power to the Athabasca Oil Sands extraction project. The plant achieved completion on January 1, 2003.

Cogeneration Project near Fort McMurray is 70% owned by the ATCO Power Generation Group and 30% owned by SaskPower International Inc. It achieved Commercial Operations in January, 2003. This plant will sell approximately half the electric energy and all the steam to the Muskeg River mine site under a long-term agreement. The balance of the electric energy will be sold into the Power Pool of Alberta.

The Power Generation Group is sole owner of the 170-MW Scotford Upgrader Cogeneration Project, expected to achieve Commercial Operations in the third quarter of 2003. This plant will sell approximately 80% of its electric energy and all the steam to the Scotford Upgrader under a long-term offtake agreement.

Completion of the 32-MW Oldman River Dam Project near Pincher Creek, Alberta, is expected in the second quarter of 2003. The Oldman River Dam Project is the first independent hydroelectric project for the Group. This run-of-river hydro project will provide a new source of clean generation that can be marketed at premium prices in southern Alberta, where additional capacity is required. The Piikani Nation has an option to purchase a 25% interest in the plant following completion.

The power industry in Alberta was deregulated on January 1, 2001. On that date, the output of the legacy plants began to be sold under long-term Power Purchase Arrangements. The main legacy plants are the coal-fired stations at Sheerness and Battle River, whose ownership is held by Alberta Power (2000) Ltd. Sheerness is a 750-MW plant operated by ATCO Power and jointly owned with TransAlta Utilities. The 680-MW Battle River plant is solely owned by Alberta Power (2000).

Both plants achieved high availability operations for the year despite Battle River experiencing severe drought conditions, which caused its cooling water reservoir (created by a 12-metre dam on the Battle River) to fall to record low levels.

Another legacy plant, the 150-MW coal-fired H. R. Milner plant near Grande Cache, was sold to

ONE OF THE MAJOR NEW PROJECTS UNDER CONSTRUCTION IS THE 580-MW GAS-FIRED COMBINED-CYCLE BRIGHTON BEACH GENERATING PLANT IN WINDSOR, ONTARIO.

the Alberta Balancing Pool in early 2001, and ATCO Power has an operating agreement that expires in the fall of 2003.

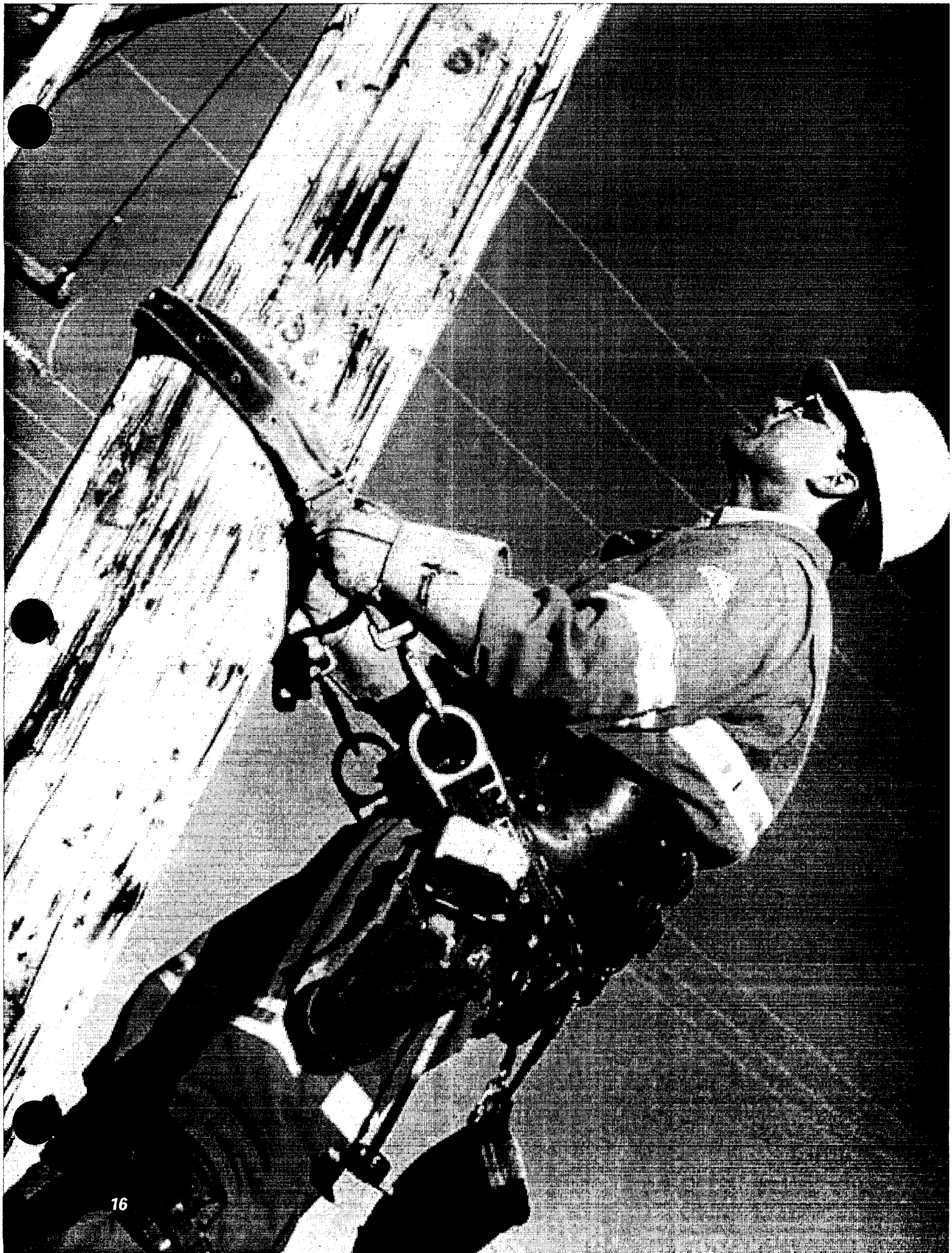
The Group operates a number of proven-technology, state-of-the-art, efficient gas-fired cogeneration and peaking plants. In British Columbia, the 120-MW McMahon cogeneration plant sells all its electric energy under a long-term agreement to BC Hydro and steam to the Westcoast gas plant. In Alberta, the Group's portfolio of plants includes the 480-MW Joffre cogeneration plant, the 85-MW Primrose steam enhancement plant, the 89-MW Rainbow Lake cogeneration and peaking plants, and the 43-MW Poplar Hill and 46-MW Valleyview peaking plants.

UNITED KINGDOM: ATCO Power's principal U.K. asset is the 1,000-MW gas-fired combined-cycle plant at Barking in east London. The company operates the plant and has a 25.5% equity interest. During 2002, TXU Europe, one of the shareholders/offtakers of Barking Power Limited, petitioned the High Court for the appointment of an Administrator. Barking Power Limited is seeking compensation through the Administrator and is seeking a replacement offtaker for the 275 megawatts formerly under long-term contract with TXU Europe.

ATCO Power is a joint owner with London Electricity of a 14-MW cogeneration plant at Heathrow Airport in London.

AUSTRALIA: ATCO Power's largest asset in Australia is the 180-MW Osborne cogeneration plant near Adelaide, commissioned in 1998. The new Bulwer Island Cogeneration Project commenced commercial operation on January 1, 2001. The 33-MW Bulwer Island plant supplies electricity and steam to the British Petroleum's Bulwer Island Refinery in Queensland. Both of these plants are jointly owned with Origin Energy.

G. K. (GARY) BAUER,
MANAGING DIRECTOR, POWER GENERATION



UTILITIES GROUP

THE UTILITIES GROUP COMPANIES DELIVER GAS, ELECTRICITY AND WATER TO MORE THAN ONE MILLION CUSTOMERS ACROSS ALBERTA, YUKON AND THE NORTHWEST TERRITORIES.

In 2002:

• ATCO Gas delivered nearly 232 petajoules of natural gas to consumers

• ATCO Electric and its subsidiaries – Yukon Electrical, Northland Utilities (NWT) and Northland Utilities (Yellowknife) – delivered 10,224 million kilowatt hours of electric energy

• CU Water built a new 50-km pipeline to bring quality water to three more communities in east-central Alberta.

Together, these companies have $2.5 billion in assets. Our 2,539 employees take great pride in our record for safe, reliable delivery of natural gas, electricity, water and our exceptional customer service.

DEREGULATION AND THE SALE OF ATCO'S RETAIL BUSINESS Alberta's continuing transition to a deregulated market for natural gas and electricity formed the backdrop for the Utilities Group operations in 2002. Throughout the year, the Utilities Group provided input on deregulation to the provincial government. In August, the government announced its intended direction for new legislation to be introduced in 2003 to remove barriers to the development of retail competition and bring electricity and natural gas legislation into closer alignment.

The highlight of the year was the December 10 announcement that Direct Energy will purchase the retail energy businesses of ATCO Gas and ATCO Electric. The agreement still requires regulatory approvals.

As Canada's leading provider of retail energy and home services, Direct Energy will assume responsibility for providing natural gas and electricity to ATCO's utility customers once regulatory approval is received. This will enable ATCO Gas and ATCO Electric to focus on their core business of providing safe, reliable delivery of energy to customers.

ATCO and Direct Energy are committed to ensuring a smooth transition for customers. To achieve this goal, the Utilities Group has appointed a Retail Transition Team, which will build on ATCO Electric's successful transition to a retail environment in 2000 by ensuring that systems and procedures are adapted and staff are well trained.

ATCO Gas Consistent with the focus on delivery, ATCO Gas has completed the sale of all production properties owned and operated by ATCO Gas. Early in the year, customers received a rebate from the sale of the Viking-Kinsella property, and ATCO Gas recognised a gain on the sale of $67.3 million after tax. In 2002, ATCO Gas also completed the sale of the Beaverhill Lake and Fort Saskatchewan properties. Customers will receive a rebate from the sale of these properties in 2003.

Photo: ATCO Electric delivers safe, reliable electricity to more than 137,000 homes and farms in more than 200 communities. Through a network of more than 62,000 kms of power lines, ATCO crews are available 24 hours a day, seven days a week to respond to outages and emergencies.

With over 90 years of experience, ATCO Gas delivers safe, reliable natural gas to more than 2.4 million people in 291 communities across Alberta. Our crews are available 24 hours a day, seven days a week to respond to emergencies.

Construction investment hit near-record levels during the year, as almost 25,000 new customers were added to the ATCO Gas delivery system.

Capital investment – which totalled $102.2 million during the year – will continue to be strong. In 2003, significant capital projects include moving approximately 200,000 meters from inside to outside customers' homes over the next five years. This will replace aging infrastructure and facilitate efficient meter reading. To meet the need for accurate monthly billing information for customers and retailers, ATCO Gas is also implementing monthly reading of all meters.

Early in the year, ATCO Gas reorganised into four operating divisions, an initiative that enhances the company's ability to maintain and grow its business by building even stronger relationships with the communities it serves.

In August, ATCO Gas submitted an application to the Alberta Energy and Utilities Board for delivery rates for 2003 and 2004. This application reflects increased investment needed to meet growth in Alberta's robust economy and to provide a natural gas delivery system that addresses the needs of buyers and sellers in the competitive market.

The rate application also reflects the end of a five-year incentive regulation agreement between ATCO Gas and customers, which affected the company's earnings in 2002. The end of the incentive regulation and the re-establishment of a fair and reasonable rate of return should positively impact the company.

ATCO Electric also had an active year responding to growth in its service area. The company invested $83.6 million to build local distribution facilities and $68.5 million to construct transmission facilities.

In 2002, ATCO won the bid to build a third major transmission line between Fort McMurray and the Edmonton area. The provincial Transmission Administrator tendered the contract and ATCO Utility Services, which was established to pursue competitive, non-regulated transmission opportunities, was the successful bidder. Subsequently, the Transmission Administrator

THE HIGHLIGHT OF THE YEAR WAS THE DECEMBER 10 ANNOUNCEMENT THAT DIRECT ENERGY WILL PURCHASE THE RETAIL ENERGY BUSINESSES OF ATCO GAS AND ATCO ELECTRIC.

decided to direct-assign the project to ATCO Electric, and the more than 400-km line will be built as a regulated asset.

Throughout 2002, ATCO Electric continued to provide energy to customers through its regulated rate option (RRO). The company's customers benefited from the lowest RRO of any provider in the province. In December, the Alberta Energy and Utilities Board approved ATCO Electric's application to move to a flow-through of pool price for its RRO customers. The flow-through rate eliminates the risk of building up large deferral accounts and will assist the development of a competitive retail market in Alberta.

In August, ATCO Electric also filed a General Rate Application for the years 2003-2005 with the Alberta Energy and Utilities Board. This application reflects continued high levels of investment for new distribution and transmission facilities.

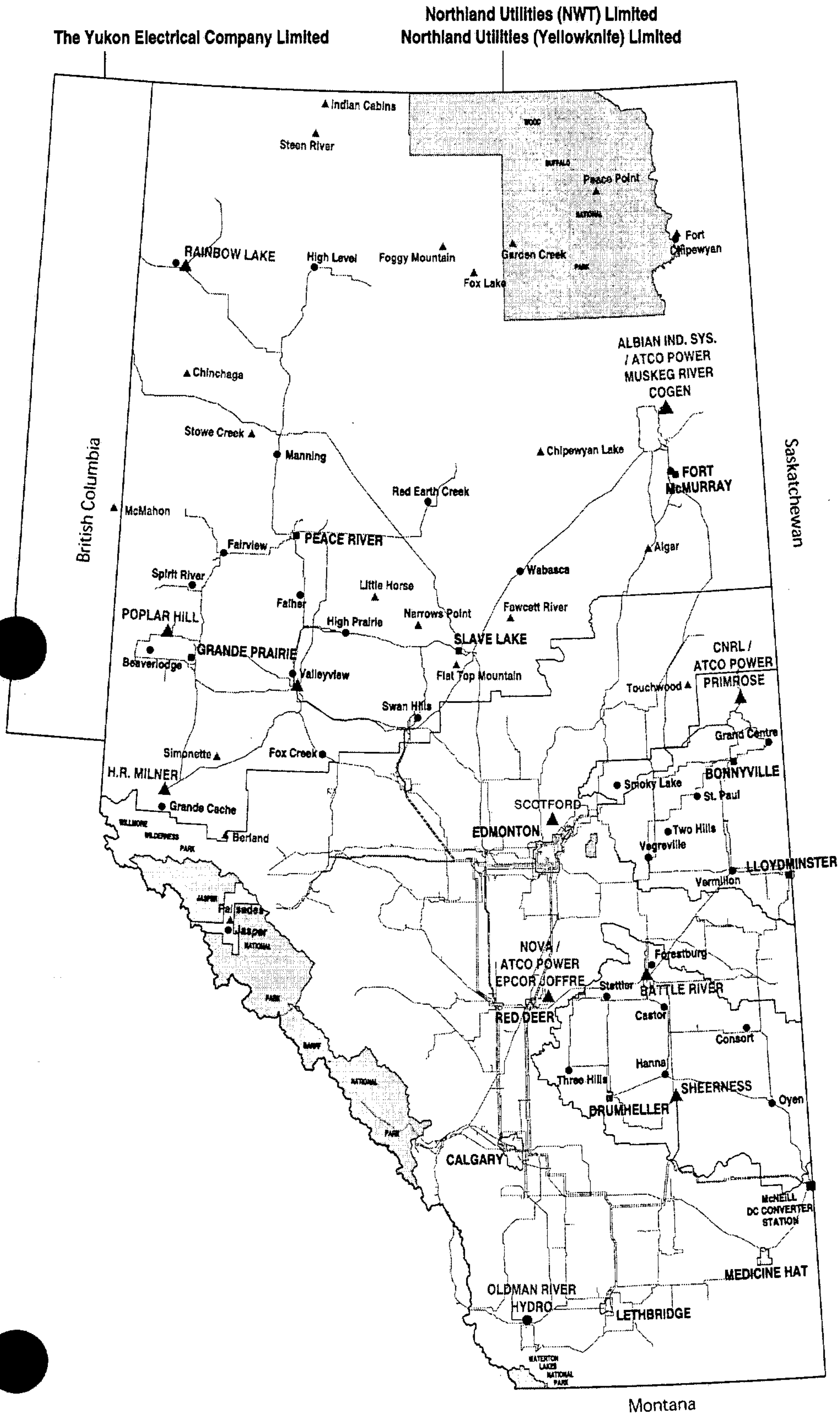
In 2003, ATCO Electric's newest northern subsidiary, Northland Utilities (Yellowknife), will celebrate its 10th anniversary in the ATCO Group. The Yellowknife operation experienced particularly strong growth in 2002, driven largely by expanding diamond mining activity in the Northwest Territories. Northland will conduct a study on upgrading the electrical distribution system in Yellowknife to accommodate growth and provide a higher level of reliability.

CU WATER Through its pipeline system, CU Water offers reliable delivery of safe, high-quality treated water to municipalities and businesses in east-central Alberta. CU Water also owns and operates the municipal water distribution system (including metering and billing) in one community, and it is pursuing the acquisition of other systems.

CU Water extended its system in 2002. A new 50-km pipeline brought water to three communities in east-central Alberta. Construction of the project was fast-tracked to meet the October deadline, a measure much appreciated by residents of the drought-stricken area. CU Water continues to pursue opportunities for growth and investment.

J. R. (DICK) FREY,
MANAGING DIRECTOR, UTILITIES

ELECTRIC POWER SYSTEM



LEGEND

- ATCO Electric Generating Stations
- ATCO Power Generating Stations Connected to Alberta Interconnected System (AIS)
- ATCO Power Generating Stations
- ATCO Power Hydroelectric Projects
- ATCO Electric 240, 144, 72kV Transmission Lines
- Other 500, 240, 144, 72kV Transmission Lines

- ATCO Electric Service Area
- ATCO Electric Division Office
- ATCO Electric Service Point

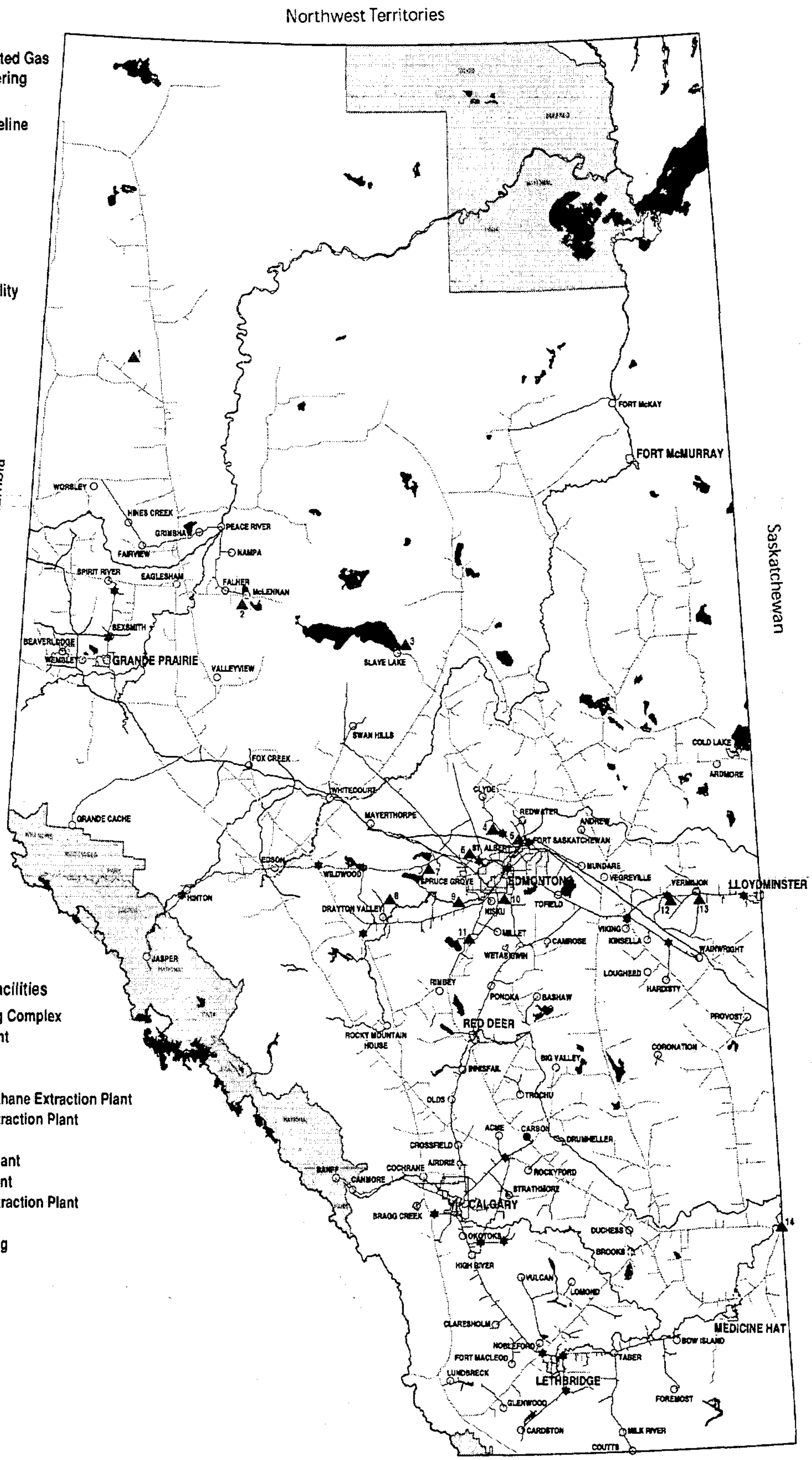
ATCO POWER PLANTS

Rainbow Lake
Muskeg River
McMahon
Primrose
Poplar Hill
Valleyview
H.R. Milner
Scotford
Joffre
Battle River
Sheerness
Oldman River

NATURAL GAS SYSTEM

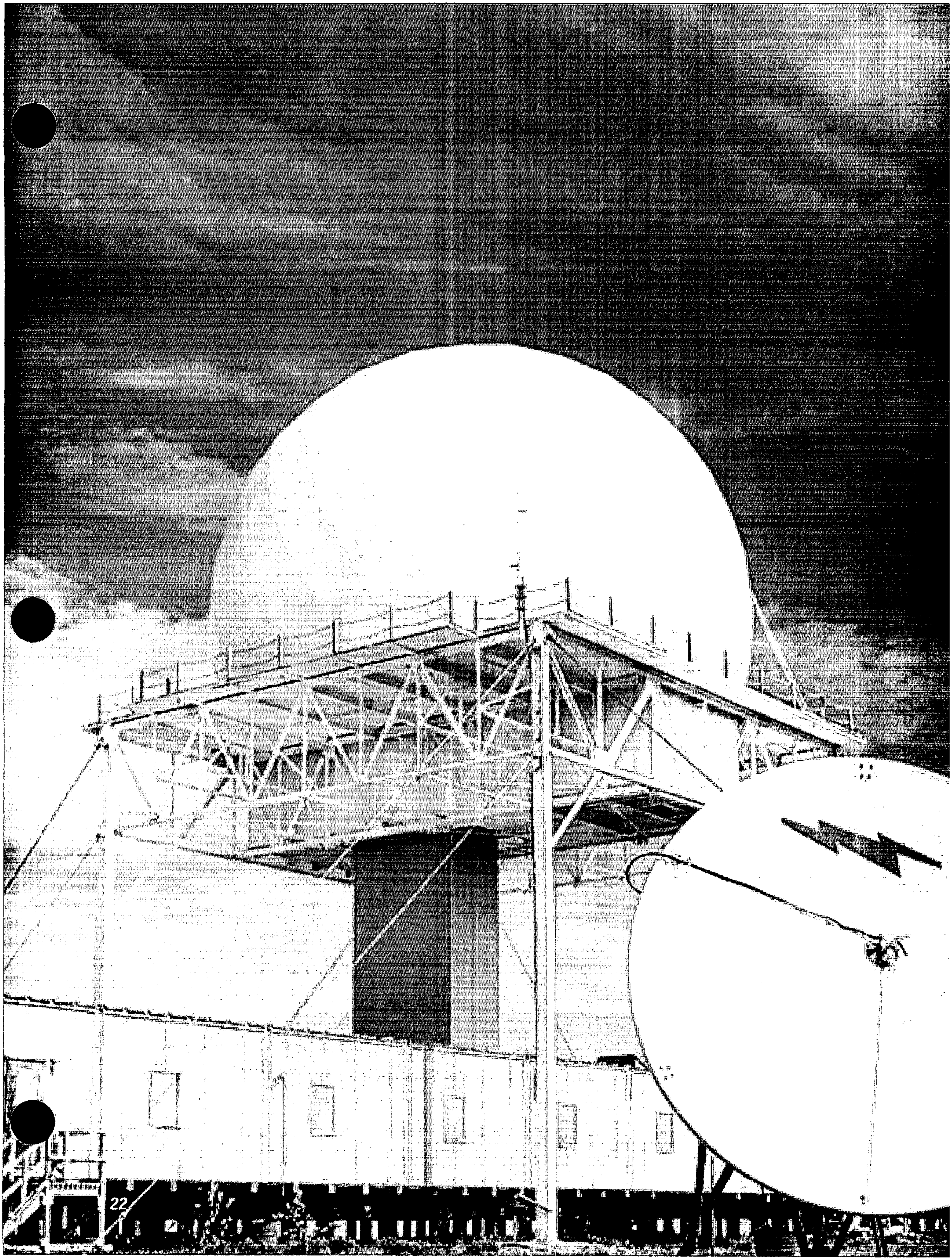
- ATCO Pipelines
- ATCO Midstream Integrated Gas System - Raw Gas Gathering System
- Alliance Partnership Pipeline
- Other Gas Pipelines

- ★ Compressor Stations [ATCO Pipelines]
- ● Carbon Storage Facility - 40 Bcf capacity
- ★ Salt Cavern Storage Facility



▲ ATCO Midstream Facilities

1 Cranberry Processing Complex
2 Puskwaskau Gas Plant
3 Widewater
4 Carbondale Gas Plant
5 Fort Saskatchewan Ethane Extraction Plant
6 Villeneuve Ethane Extraction Plant
7 Riviere Gas Plant
8 West Pembina Gas Plant
9 Golden Spike Gas Plant
10 Edmonton Ethane Extraction Plant
11 Watelet Gas Plant
12 Kinsella Gas Gathering
13 Scovil Lake Gas Plant
14 Empress
15 Wolstitmor



LOGISTICS & ENERGY SERVICES GROUP

THE LOGISTICS AND ENERGY SERVICES GROUP INCLUDES THREE COMPANIES ATCO FRONTEC, ATCO MIDSTREAM AND ATCO PIPELINES, FOCUSED ON PROVIDING ADVANCED LOGISTICS AND ENERGY MANAGEMENT SERVICES TO A DIVERSE CUSTOMER BASE.

ATCO Frontec realised significant accomplishments in 2002, starting with the completion of a five-year contract to continue operation and maintenance of NORAD's North Warning System through Nasittuq Corporation.

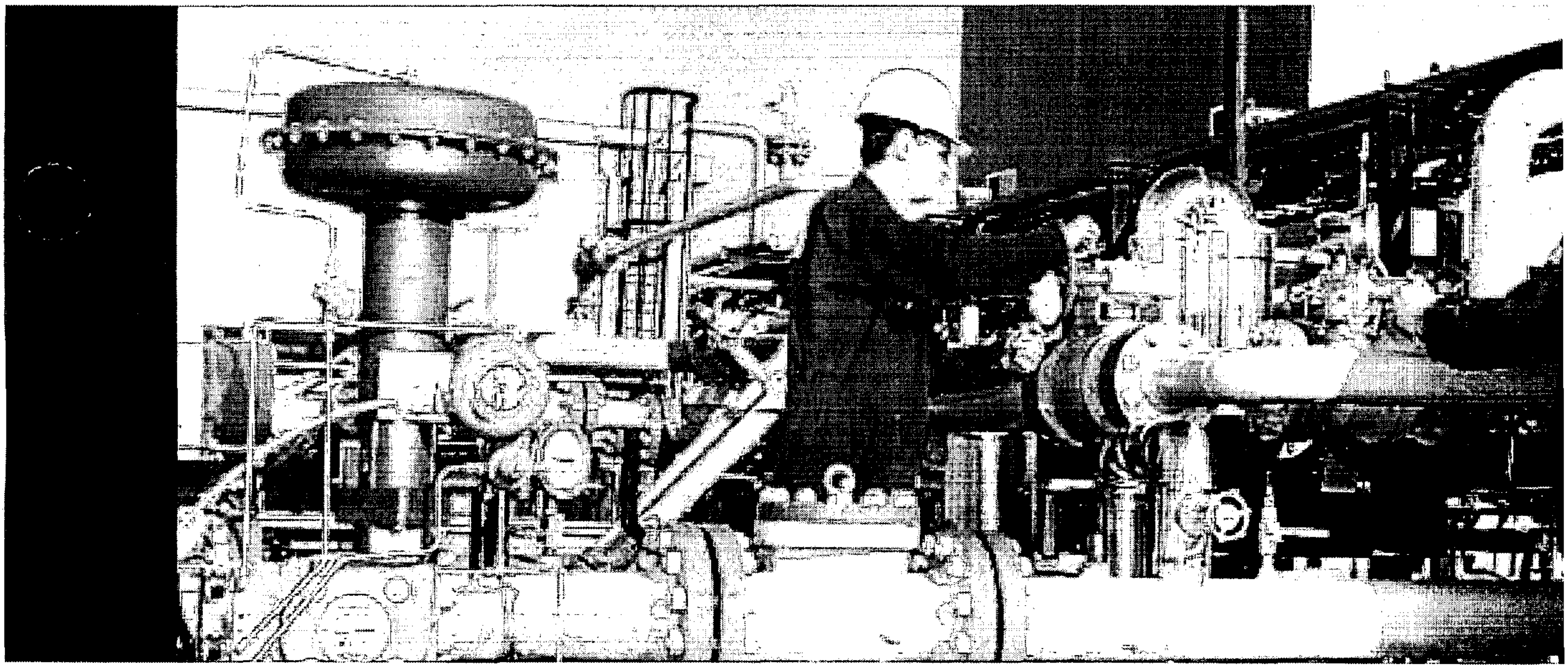
In the first quarter, the Government of Canada exercised a one-year option on the initial two-year contract to extend the Balkan's Contract. Originally awarded to ATCO Frontec in June 2000, this outsourcing contract – designed to allow Canadian soldiers to focus on peacekeeping activities – involves nearly 500 staff supporting five peacekeeping camps and 1,500 Canadian soldiers. ATCO consistently achieved superior ratings during 2002 performance reviews from the Department of National Defence.

In northern Canada, Tli Cho Logistics Inc. – a corporation owned jointly by ATCO Frontec and the Dogrib Rae Band – successfully transitioned its site services contract at the Diavik diamond mine site in the Northwest Territories from a construction/ development phase into an operational phase. Tli Cho has been at the Diavik site since the onset of construction.

During 2002, Voisey's Bay Nickel Company reached agreement for the Voisey's Bay nickel project with the Newfoundland and Labrador provincial government and the Inuit and Innu aboriginal groups. Project development got underway in earnest and activity increased significantly at Torngait Services Inc. (TSI), a joint venture created in 1995 between ATCO Frontec and the Inuit of Labrador in anticipation of Voisey's Bay development. TSI concluded work relating to site logistics including construction camp and utilities and general maintenance, materials handling and security. Additional contracts for construction, communications, marine transportation and site surveying were also undertaken by TSI. For 2003, activity at site will increase significantly, and TSI is well positioned to continue to participate in this mining project.

OPPORTUNITIES ATCO Frontec, on behalf of the Logistics and Energy Services Group, has led efforts to position the ATCO Group of Companies for participation in a northern gas pipeline project. A cross-organisational Northern Pipeline Development Task Force has marketed the northern capabilities of ATCO Frontec, ATCO Pipelines, ATCO Midstream, ATCO Structures, ATCO Noise Management, ATCO Gas, ATCO Electric and ATCO Power to project proponents.

Photo: For over 14 years, ATCO Frontec and its partners have successfully operated and maintained the North Warning System, consistently achieving or exceeding operational availability requirements of 96% on radar and communications systems. This remote radar site at BAR-2, Shingle Point in the Yukon Territory is one of 47 similar installations that span Canada's north.



ATCO Midstream works with producers to gather, process, store and extract liquids from their natural gas. Midstream's Golden Spike Gas Plant, located west of Edmonton, ties into ATCO Pipelines' natural gas transmission network of more than 8,200 kms of pipelines and 200 receipt points.

ATCO Frontec's experience in developing long-term aboriginal relationships, delivering northern logistics and successfully implementing aboriginal training programs is viewed by project proponents as adding significant value.

ATCO Frontec will focus on creating new opportunities in the mining industry, maintaining its presence in the Balkans, and seeking further opportunities with NATO, Department of National Defence and the U.S. Air Force.

ATCO Midstream provides gas gathering and processing, storage, natural gas liquids extraction and energy to a broad customer base. ATCO Midstream is focused on building long-term relationships by providing customers with cost-effective, timely, innovative solutions.

MIDSTREAM GROUP ACTIVITIES The Gas Gathering and Processing group continued to maintain a high standard in 2002 by operating its gas plants at approximately 85% capacity with 97% availability. Reduced industry drilling activity caused throughput to decline in a number of locations; however, the group successfully increased volumes at several plants. In early 2002, additional gas was contracted for the remaining capacity at the Scovil Lake gas plant to Burlington Resources Canada Energy Ltd. In late 2002, the remaining capacity at the Puskwaskau gas plant was contracted with the connection of incremental Anadarko Canada Corporation gas reserves. The Group also contracted additional volumes in southeast Saskatchewan through the expanded Wolstitmor/ Nottingham facility.

The Natural Gas Liquids group successfully managed a volatile year as frac spreads fluctuated considerably. Much of this success is attributed to Midstream's ability to manage its costs and optimise its natural gas liquid infrastructure.

The Storage and Hub Services group made a significant contribution to earnings as a result of gas price volatility and a strong effort to provide value-added services to its customers while minimising operation costs.

GOING FORWARD ATCO Midstream will pursue controlled strategic growth opportunities through new acquisitions, increasing its working interest in joint-venture facilities and developing greenfield opportunities that will allow the company to expand.

ATCO Pipelines continued to grow its natural gas pipeline transportation business in 2002. Total system throughput increased, and on-system producer receipts from natural gas processing plants equalled 1.3 billion cubic feet per day.

SIGNIFICANT ACTIVITIES AND PROJECTS The Alberta Energy and Utilities Board (EUB) released its decision on NOVA Gas Transmission Ltd.'s (NGTL) proposed pipeline into the Fort Saskatchewan industrial area. The Board ruled that the market currently served by ATCO Pipelines does not support the need for additional pipeline capacity. The EUB's decision to deny NGTL's application supported ATCO Pipelines' position at the hearing. We have now signed long-term contracts with the three largest industrial customers in the area.

A new 86-TJ/day delivery station and lateral pipeline was installed to provide natural gas deliveries to the new Shell Scotford Upgrader in the Fort Saskatchewan area under a long-term contract. This facility is an integral component of the overall Athabasca Oil Sands Project.

ATCO Pipelines installed facilities to deliver the total natural gas requirements of the Calpine Calgary Energy Centre in northeast Calgary. This 250-MW power plant will utilise up to 55 TJ/day of natural gas, creating an important new market on the company's south system.

ATCO Pipelines developed a second Alliance Pipeline Interconnect at Paddle River that provides an incremental 40 TJ/day to the Alliance Pipeline system, giving ATCO Pipelines a total deliverability of 150 TJ/day to Alliance.

New transmission agreements were negotiated for the tie-in of two large gas plants in the Wetaskiwin and Edson areas. Facility construction for each was completed in July and August 2002, resulting in an incremental 80-TJ/day flowing on ATCO Pipelines' system.

New and innovative energy projects are an ongoing focus. CanScot, the first coalbed methane producer, was tied into the Swan Hills mainline in October 2002 adding to ATCO Pipelines growing system.

CURRENT BUSINESS ENVIRONMENT ATCO Pipelines operates in a competitive yet regulated environment in Alberta. The company continues to implement initiatives directed at achieving appropriate cost allocation and accountability rules to ensure a level playing field exists for all natural gas transmission pipelines in Alberta. Industrial and producer settlements and regulated transportation rates expired at the end of 2002, providing an opportunity for the design of new rates that are both competitive and value-added for all customers. The Company will continue its aggressive pursuit of opportunities to increase deliveries from its pipeline system, facilitating additional receipt volumes on the system. In addition, we are pursuing opportunities to acquire other pipeline assets both in and outside of Alberta.

Michael M. Shaw

M. M. (MICHAEL) SHAW,
MANAGING DIRECTOR, LOGISTICS & ENERGY SERVICES

TECHNOLOGIES GROUP

IN 2002, ATCO I-TEK, ATCO TRAVEL, GENICS AND ASHCOR TECHNOLOGIES CONTINUED TO EXPAND THEIR MARKETS AND BUILD SOLID REPUTATIONS AS PROVIDERS OF HIGH QUALITY, INNOVATIVE PRODUCTS AND CLIENT-FOCUSED SERVICES.

ATCO I-Tek provides information technology services to a diverse client group throughout Canada, the United States and the United Kingdom. The company offers its services through three business groups:

- Business Services, which provides complete billing, call centre and customer care services to distribution utilities and retail energy service providers
- Technologies, which provides end-to-end computer, network and telephone operations support
- Applications, which provides business application development, integration, maintenance and enhancement services.

BUSINESS SERVICES delivered consistently accurate and timely utility energy bills to more than one million customers, outperforming its competitors in a year of escalated customer concern regarding utility billing accuracy and service. This division has proven its ability to handle the business requirements of the deregulating energy market over the past several years and continues to serve as an industry leader.

In 2002, the utility billing and customer care division delivered more than 12.6 million utility bills, handled 1.7 million customer calls, processed more than $333 million in customer rebates in connection with the Viking Kinsella gas field sale and produced more than 500,000 refund cheques. ATCO I-Tek also collected more than $1.8 billion in revenue on behalf of clients.

The major achievement of 2002 was the December signing of a 10-year agreement between ATCO I-Tek and Direct Energy to provide utility billing and customer care services to Direct Energy, North America's largest energy retailer. Direct Energy is a subsidiary of Centrica plc, a leading U.K.-based supplier of energy and home services with more than 44 million customer relationships worldwide.

Commencement of the contract is conditional upon closing the sale of the ATCO Gas and ATCO Electric retail energy businesses to Direct Energy, expected to occur around the middle of 2003.

APPLICATIONS successfully implemented the Oracle Financial Information System for ATCO Power in 2002. Following the success of this project, ATCO I-Tek will implement Oracle Financials throughout each of the 11 companies in the ATCO Group. Use of this application will streamline financial reporting across the ATCO Group.

TECHNOLOGIES provided 24/7 operations support to the ATCO Group of companies, achieving all service targets and providing a secure technology

Photo: ATCO I-Tek employee, Tom Wheatley making adjustments inside tape storage silo at ATCO's main computer installation in Edmonton, Alberta.

ATCO I Tek call centre employee, Kristina Kuzio responds quickly to inquiries regarding billing or customer service issues.

infrastructure. This division also provided vendor relationship management of more than 30 technology suppliers on behalf of the ATCO Group of companies, ensuring maximum purchasing power and efficiencies for our client companies. This line of business provided technology infrastructure planning, implementation and technical support for more than 3,700 desktop and laptop computers, operated a network connecting more than 130 locations within the ATCO Group and handled more than 67,000 service requests.

The strength of ATCO I-Tek's proven process and controls was reaffirmed when the company was successful in the CICA Section 5900 systems assurance opinion from PricewaterhouseCoopers. This internationally recognised audit assures clients that specific controls for billing, customer care and information technology security services are in place and working effectively.

Overall, 2002 proved very successful for ATCO I-Tek. The company is well positioned for future growth as an IT-based services company.

ATCO Travel is a leader in travel management serving corporate clients, the general travelling public, and ATCO Group of companies and employees. Throughout 2002, ATCO Travel continued to demonstrate solid performance despite the downturn in corporate travel activity and the continued elimination of commissions.

ATCO Travel renewed agreements with all major accounts before the end of 2002, affirming the company's superior customer service.

A major success during 2002 was the awarding to ATCO Travel of a principal Canadian technology corporation's travel management program, which resulted in the creation of a new Ottawa office for ATCO Travel.

As the travel industry continues to experience uncertainty, ATCO Travel's positive results are credited to a strong focus on 'added value' to its corporate and vacation customers.

ATCO Travel is positioned for growth in 2003 and will maintain its four key service models: Corporate Services, Vacation Services, Groups and Meeting Planning and Airline Charter Programs.

THE MAJOR ACHIEVEMENT OF 2002 WAS THE DECEMBER SIGNING OF A 10 YEAR AGREEMENT BETWEEN ATCO I-TEK AND DIRECT ENERGY TO PROVIDE UTILITY BILLING AND CUSTOMER CARE SERVICES TO DIRECT ENERGY, NORTH AMERICA'S LARGEST ENERGY RETAILER.

GENICS INC. develops, manufactures and markets innovative, environmentally friendly wood preservatives for North American utility, commercial and residential markets.

In 2002, Genics continued to strengthen its position in the Canadian marketplace with existing and new customers including Hydro Quebec, which continues to test CobraRod™ on some of its two million wood poles in its service territory.

Genics tripled U.S. sales of its CobraRod™ line of wood preservatives, which extend the life of poles by inhibiting rot. The company grew its U.S. market reach by adding the City of Austin, Texas, several Texas utilities, and companies throughout California, North and South Carolina, Montana, Georgia, Pennsylvania and Wisconsin to its growing client list.

The company also focused on growth and market share of additional products such as its new Genics TM PostGuard™ product for residential, agricultural and commercial use. This product inhibits rot and is intended for use in fence posts, log homes and farm infrastructure.

ASHCOR TECHNOLOGIES markets fly ash and other coal combustion products from ATCO Power's coal-fired generating stations in Alberta. Fly ash is a supplementary cementing material, used as a partial replacement for cement powder in concrete products and in oil well cements.

During 2002, ASHCOR continued to expand its geographic market into British Columbia, northern Alberta and Saskatchewan. ASHCOR continues to demonstrate steady growth.

To broaden its offerings in 2003, ASHCOR is investing in research to develop new value-added uses for fly ash, other coal combustion products, and related products for distribution to its client base.

S.W. Kiefer.

S.W. (SIEGFRIED) KIEFER,
MANAGING DIRECTOR, TECHNOLOGIES

Students dig for fossils in one of the Tyrrell Museum's teaching laboratories. ATCO has provided $1,000,000 for the new ATCO Tyrrell Learning Centre, the largest ever expansion at the world-renowned dinosaur museum in Drumheller.

ENVIRONMENT AND COMMUNITY

ATCO Group and its more than 6,000 employees this year supported hundreds of community endeavours through both financial contribution and volunteer effort.

ATCO companies also protected and enhanced the natural environment where they do business, delivering on historical commitment to maintain a meaningful, on-going dialogue and relationship with communities and residents across Alberta and around the world.

Activity in 2002 builds on ATCO's history of supporting organizations that enrich the quality of life in the communities where employees work and live. Being responsible members of the broader community is a core value endorsed by all levels of ATCO companies.

This attitude of giving starts with employees, and is integral to the ATCO business philosophy. Following are some of this year's community focused activities and programs:

• In the Utilities Group alone, employees volunteered 29,000 hours of their personal time in their communities. Through the **Volunteer Recognition Fund**, employees who annually volunteer more than 50 hours can have the company make a $150 donation on their behalf to a charity of choice.

• Employees financially supported almost **300 health and wellness programs** in communities across Alberta, with a corporate matching program by ATCO. Within ATCO Gas and ATCO Electric this year, the final total after the matching corporate grants exceeded $700,000. Within much smaller ATCO I-TEK, the program resulted in a $47,800 donation to **United Way** campaigns. At ATCO Pipelines, a record 88% of employees participated in the **Employee Community Service Fund**, with donations of almost $133,000.

• ATCO Frontec employees again co-ordinated an internal campaign to seek donations of clothes, games and toys for **families in Bosnia**, where 500 of their employees are providing important support services to Canada's military peacekeepers.

• ATCO Group committed **$1 million** to the development of the **ATCO Tyrrell Learning Centre**, the first new facility built at the world famous dinosaur museum in Drumheller. The donation, the largest in the history of the Royal Tyrrell Museum, will help the museum add much needed physical space while providing the technology to broaden and extend outreach programs to students across Alberta.

• ATCO Gas, the longest-standing corporate sponsor of the **Calgary Stampede**, also supported Edmonton's **Klondike Days** and hundreds of other community-focused events across all regions of the province. Major athletic events that benefited from ATCO support included the **Alberta Summer Games** in Camrose and the **ITU World Triathlon** in Edmonton.

ATCO is a founding sponsor of Alberta Ecotrust, an alliance of business and environmental groups involved in grassroots community projects such as tree planting.

• With drought devastating rural Alberta, both ATCO Gas and ATCO Electric combined to sponsor the "**Say Hay**" benefit concerts, which raised funding to help Alberta's agricultural sector.

• With an eye to the future, ATCO Electric joined a multi-level effort to promote the trades sector. Support for "**Careers - the Next Generation**" will continue for another two years. ATCO supports dozens of other youth, scholarship and education programs, including training programs for Aboriginal and Inuit interested in working in Canada's North.

• Dozens of volunteers from the ATCO Group contributed time, creative talents and workplace experiences teaching Alberta youth about life skills and business through various **Junior Achievement** programs. Business people and students work together in "real world" learning opportunities.

• ATCO Frontec co-chaired the **Pipeline Operations Training Committee**, a cross-organization group of industry, government and community representatives, with a mandate to develop a curriculum-based training program to prepare Northerners for long-term job opportunities.

Following are some environmental protection activities and achievements:

• ATCO Group supported at the Sustainer level Alberta **Ecotrust**, a unique organization that facilitates funding from the corporate sector to environmental groups undertaking progressive, community-based projects across the province. ATCO is an Alberta Ecotrust founding organization.

• ATCO Gas and ATCO Pipelines both earned "**Gold Champion**" recognition for their participation in the federally sponsored **Voluntary Challenge and Registry**, which encourages energy efficiency and conservation measures to reduce greenhouse gas emissions. ATCO Electric earned "**Silver Champion**" in this national program.

• In partnership with Natural Resources Canada, ATCO Gas and ATCO Electric were selected to promote and deliver the **Energuide for Houses** program, assisting homeowners in energy efficiency and reduced energy use.

• ATCO I-Tek marked its second year of participation in the **Alberta Computers for Schools** program, providing more than 700 recycled and refurbished computers to Alberta schools and libraries.

• ATCO Pipelines received a **Platinum Level Stewardship Award** from the Canadian Association of Petroleum Producers (CAPP). The award recognizes the establishment of ATCO Pipelines' Environment, Health and Safety management systems.

• ATCO participated in **Trees Canada**, a working partnership that has Canadians plant and care for trees in our urban and rural environments in an effort to help reduce the harmful effects of carbon dioxide emissions.

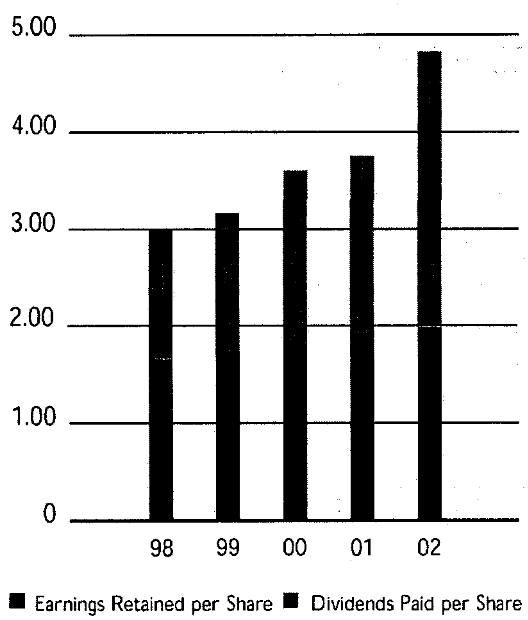
FINANCIAL OVERVIEW

J.A. (James) Campbell, Senior Vice President, Finance & Chief Financial Officer

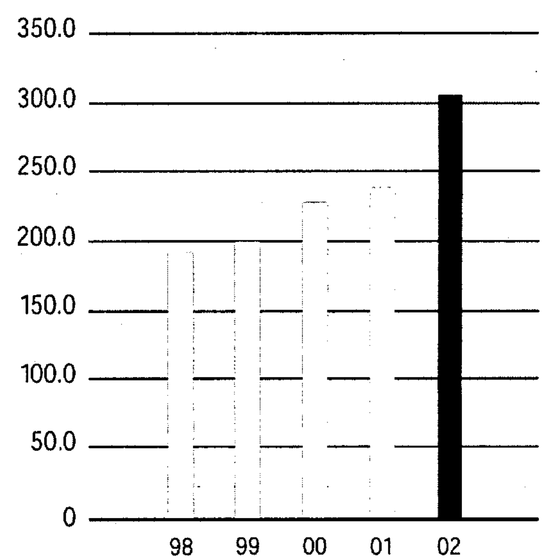
FINANCIAL ACHIEVEMENT IN 2002

- Earnings per share increased to $4.81 from $3.74 in 2001 – the 13th consecutive year of increased earnings per share.
- Dividends per share increased by $0.08 to $1.96 from $1.88 in 2001 – dividends have increased each year since 1972.
- Earnings increased by $67.9 million to $305.0 million compared to $237.1 million in 2001.
- Cash flow from operations decreased by $2.0 million to $500.3 million.
- Total assets increased by $530 million to $5.934 billion compared to $5.404 billion in 2001.
- Capital expenditures decreased by $165 million to $570 million compared to $735 million in 2001.
- Long term debt increased by $61 million to $1.917 billion.
- Long term debt - non-recourse increased by $156 million to $867 million.
- Equity preferred shares increased by $150 million to $487 million.
- Share Owners equity increased by $186 million to $1.83 billion compared to $1.644 billion in 2001.
- Financing activities included $150 million of 15 year, 6.145% debentures; $100 million of 10 year, 6.14% debentures; $50 million of five year, 4.801% debentures; and $150 million of 5.80% equity preferred shares.
- CU redeemed $125 million of 12% debentures, $68 million of 5.42% debentures and $49 million of other debt.
- Non-recourse long term debt of $173 million was issued in 2002, including $111 million for the Brighton Beach Power Project; CU redeemed $44 million of non-recourse long-term debt in 2002.

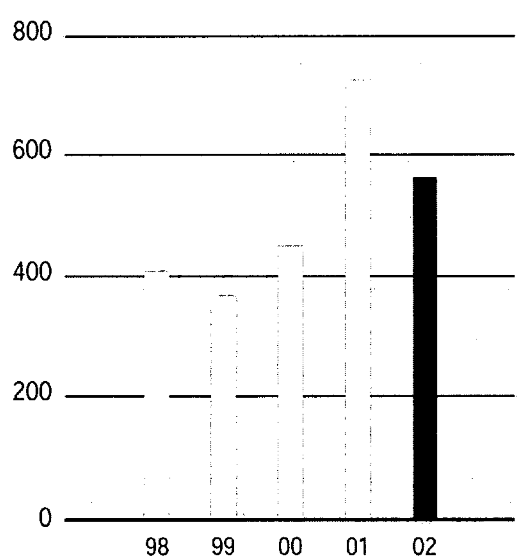
Earnings Per Class A and Class B Share
(Dollars)



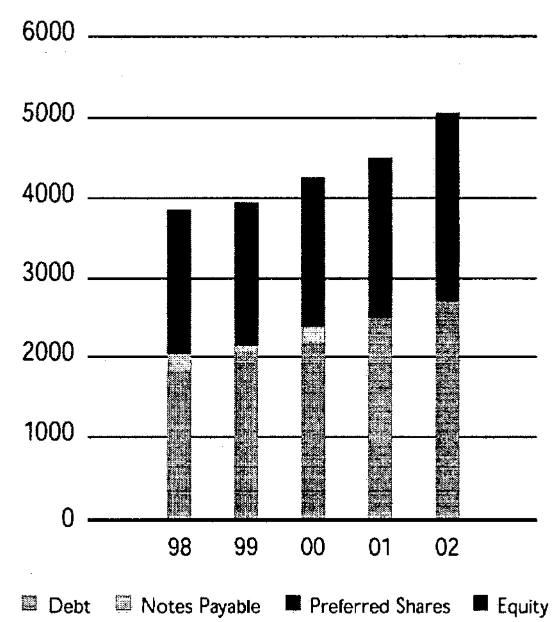
Earnings Attributable to Class A and Class B Shares
(Millions of Dollars)



Purchase of Property, Plant and Equipment
(Millions of Dollars)



Capitalization
(Millions of Dollars)



MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL REPORTING

Management is responsible for the preparation of the consolidated financial statements, management's discussion and analysis 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 of five non-management 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.

J.A. Campbell
Senior Vice President, Finance and Chief Financial Officer

K.M. Watson
Vice President, Finance and Controller

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, 2002 and 2001 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 presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2002 and 2001 and the results of its operations and cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta

February 7, 2003

CONSOLIDATED STATEMENT OF EARNINGS AND RETAINED EARNINGS

Year ended December 31 *(Millions of Canadian Dollars except per share data)*

		2002	2001
Revenues	Note	$ 2,975.9	$ 3,513.6
Costs and expenses			
Natural gas supply		991.7	1,318.6
Purchased power		184.4	366.5
Operation and maintenance		759.9	769.9
Selling and administrative		136.0	123.7
Depreciation and amortization		244.4	241.9
Interest	9	184.1	198.7
Franchise fees		98.5	117.6
		2,599.0	3,136.9
		376.9	376.7
Interest and other income	2	136.2	41.4
Earnings before income taxes		513.1	418.1
Income taxes	3	189.9	164.0
Net earnings		323.2	254.1
Dividends on equity preferred shares		18.2	17.0
Earnings attributable to Class A and Class B shares	2	305.0	237.1
Retained earnings at beginning of year		1,136.9	1,022.6
		1,441.9	1,259.7
Dividends on Class A and Class B shares		124.2	119.0
Direct charges	4	2.8	3.8
Retained earnings at end of year		$ 1,314.9	$ 1,136.9
Earnings per Class A and Class B share	2, 12	$ 4.81	$ 3.74
Diluted earnings per Class A and Class B share	2, 12	$ 4.79	$ 3.72
Dividends paid per Class A and Class B share		$ 1.96	$ 1.88

CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED BALANCE SHEET

Year ended December 31 *(Millions of Canadian Dollars)*

	Note	2002	2001
ASSETS			
Current assets			
Cash and short term investments	15	$ 438.9	$ 254.6
Accounts receivable		459.4	445.4
Inventories		121.7	124.8
Income taxes recoverable		20.2	-
Future income taxes	3	-	1.9
Deferred natural gas costs		31.2	3.9
Deferred electricity costs		20.7	27.4
Prepaid expenses		25.4	16.5
		1,117.5	874.5
Property, plant and equipment	5	4,657.0	4,363.5
Security deposits for debt		26.1	23.6
Other assets	6	133.8	142.4
		$ 5,934.4	$ 5,404.0
LIABILITIES AND SHARE OWNERS' EQUITY			
Current liabilities			
Bank indebtedness	7	$ 5.0	$ 11.7
Accounts payable and accrued liabilities		451.3	463.0
Income taxes payable		-	105.6
Future income taxes	3	16.8	-
Notes payable		-	4.6
Deferred electricity cost obligation	8	51.0	-
Non-recourse long term debt due within one year	9	46.1	37.3
		570.2	622.2
Future income taxes	3	230.8	205.0
Deferred credits	10	78.8	66.8
Long term debt	9	1,916.9	1,855.9
Non-recourse long term debt	9	821.1	673.8
Equity preferred shares	11	486.5	336.5
Class A and Class B share owners' equity			
Class A and Class B shares	12	509.6	506.7
Retained earnings		1,314.9	1,136.9
Foreign currency translation adjustment		5.6	0.2
		1,830.1	1,643.8
		$ 5,934.4	$ 5,404.0

N.C. SOUTHERN
DIRECTOR

B.K. FRENCH
DIRECTOR

CONSOLIDATED STATEMENT OF CASH FLOWS

Year ended December 31 *(Millions of Canadian Dollars)*

	Note	2002	2001
Operating activities			
Earnings attributable to Class A and Class B shares		$ 305.0	$ 237.1
Non-cash items included in earnings:			
Depreciation and amortization		244.4	241.9
Future income taxes		20.7	37.3
Gain on sale of natural gas producing property - net of current income taxes	2	(67.3)	-
Other - net		(2.5)	(14.0)
Cash flow from operations		500.3	502.3
Changes in non-cash working capital	14	(160.0)	245.6
		340.3	747.9
Investing activities			
Purchase of property, plant and equipment		(569.8)	(735.3)
Sale of natural gas producing property - net of current income taxes	2	107.7	-
Proceeds on disposal of other property, plant and equipment		1.7	120.9
Contributions by utility customers for extensions to plant		41.1	38.6
Recovery of non-current deferred electricity costs		18.7	64.4
Changes in non-cash working capital	14	(8.3)	2.2
Other		(10.4)	(8.5)
		(419.3)	(517.7)
Financing activities			
Change in notes payable		(4.6)	(192.5)
Deferred electricity cost obligation	8	51.0	-
Issue of long term debt		300.0	212.9
Issue of non-recourse long term debt		173.0	345.5
Repayment of long term debt		(241.9)	(222.2)
Repayment of non-recourse long term debt		(43.7)	(27.9)
Issue of equity preferred shares		150.0	-
Issue of Class A shares		2.9	0.3
Dividends paid to Class A and Class B share owners		(124.2)	(119.0)
Income tax reassessment	3	-	(12.9)
Changes in non-cash working capital	14	8.7	(14.4)
Other		(6.8)	3.1
		264.4	(27.1)
Foreign currency translation		5.6	2.1
Cash position [1]			
Increase		191.0	205.2
Beginning of year		242.9	37.7
End of year		$ 433.9	$ 242.9

[1] Cash position includes cash and short term investments less current bank indebtedness.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of significant accounting policies

Financial Statement Presentation

The accompanying consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and include the accounts of Canadian Utilities Limited and its subsidiaries, including a proportionate share of joint venture investments ("Canadian Utilities"). Principal operations are Utilities (ATCO Electric, ATCO Gas, ATCO Utility Services, CU Water), Power Generation (ATCO Power, Alberta Power (2000)), Logistics and Energy Services (ATCO Pipelines, ATCO Midstream, ATCO Frontec) and Technologies (ATCO I-Tek Business Services (formerly ATCO Singlepoint), ATCO I-Tek, ATCO Travel, ASHCOR Technologies, Genics). Significant joint venture investments consist principally of power generation plants.

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

Regulation

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

ATCO Electric, ATCO Gas, ATCO Pipelines and CU Water are regulated primarily by the Alberta Energy and Utilities Board ("AEUB"), which administers acts and regulations covering such matters as rates, financing, accounting, construction, operation and service area. The AEUB may approve interim rates, subject to final determination.

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

Use of Estimates

The preparation of Canadian Utilities' 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. Actual results could differ from those estimates.

Revenue Recognition

Revenues are recognized on the accrual basis and include an estimate of services provided but not yet billed.

Revenues resulting from the supply of contracted services are recorded by the percentage of completion method. Full provision is made for any anticipated loss.

Effective January 1, 2002, Canadian Utilities retroactively adopted the Canadian Institute of Chartered Accountants ("CICA") Emerging Issues Abstract on the "Reporting of Revenue Gross as a Principal versus Net as an Agent". This change in accounting resulted in a reduction of revenues and a reduction of operation and maintenance expenses of $22.8 million for the year ended December 31, 2002 (2001 - $14.9 million).

Natural Gas Supply

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

1. Summary of significant accounting policies (continued)

Purchased Power

Purchased power expense is based on the actual cost of electricity purchased, whereas the amount included in customer rates 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 AEUB 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

Certain regulated operations include in capital expenditures an allowance for funds used during construction at rates approved by the AEUB for debt and equity capital. Capital expenditures 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. Property, plant and equipment is disclosed net of unamortized contributions.

Depreciation is provided on assets on a straight-line basis over their estimated useful lives. Depreciation rates for regulated assets are approved by the AEUB or, in the case of Alberta Power (2000)'s generating plants, are determined by the PPA's. These depreciation rates include a provision for future removal costs and site restoration costs. On retirement of depreciable regulated assets, the accumulated depreciation is charged with the cost of the retired unit, net disposal costs and site restoration costs.

Deferred Financing Charges

Issue costs of long term debt are amortized over the weighted average life of the debt and issue costs of preferred shares relating to regulated operations are amortized over the expected life of the issue. 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 various PPA's, Canadian Utilities is subject to an incentive/penalty regime related to generating unit availability. Incentives are paid to Canadian Utilities by the PPA counterparties for availability in excess of predetermined targets, whereas penalties are paid by Canadian Utilities 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 income 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.

1. Summary of significant accounting policies (continued)

Notes Payable

Effective January 1, 2002, Canadian Utilities retroactively adopted the CICA Emerging Issues Abstract on the balance sheet classification of callable debt obligations and debt obligations expected to be refinanced. Notes payable, previously classified as long term, are now classified as current liabilities.

Long Term Debt Due Within One Year

When Canadian Utilities 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 Canadian Utilities' behalf with respect thereto, or sufficient capacity 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, Canadian Utilities 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.

Canadian Utilities designates each derivative instrument as a hedge of specific assets or liabilities on the balance sheet or specific firm commitments or anticipated transactions. Canadian Utilities 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

Canadian Utilities 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 healthcare costs.

Expected return on plan assets for the year is determined 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. Pension plan assets at the end of the year are reported at market value. 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.

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

1. Summary of significant accounting policies (continued)

Stock Based Compensation Plans

Canadian Utilities Limited has a stock option plan and share appreciation rights plans, all of which are described in Note 13.

Effective January 1, 2002, Canadian Utilities prospectively adopted the recommendations of the CICA on accounting for stock-based compensation and other stock-based payments. While the recommendations encourage the adoption of the fair value based method of accounting for stock options, other methods of accounting are permitted.

Canadian Utilities has chosen to retain its existing accounting policy, which is permitted by the recommendations, whereby no compensation expense is recognized upon the granting or exercise of stock options. Any consideration paid by holders of the stock options upon exercise is credited to share capital. While the recommendations require expense recognition for options that may be settled in cash or other assets, Canadian Utilities amended its stock option policy in June 2002 so that stock options will no longer be repurchased. Prior to that date, if stock options were repurchased, the consideration paid to the holders of the options was charged to retained earnings.

No compensation expense is recognized when share appreciation rights are granted. Compensation expense for the share appreciation rights plans is accrued monthly to the date of vesting on the basis of the excess of the market price of the shares over the base value of the rights. Prior to January 1, 2002, compensation expense was determined on the basis of the excess of the greater of the market price of the shares or the 12-month average market price thereof over the base value of the rights. This accounting change increased earnings by $0.9 million and earnings per share by $0.01 for the year ended December 31, 2002.

2. Interest and other income

	2002	2001
Gain on sale of natural gas producing property	$ 110.1	$ -
Interest	17.1	34.7
Allowance for funds used by regulated operations	3.6	5.7
Other	5.4	1.0
	$ 136.2	$ 41.4

On January 3, 2002, Canadian Utilities sold its Viking-Kinsella natural gas producing property, which had a net book value of $40.4 million, for $550 million. In accordance with an AEUB decision, $385.0 million plus related adjustments for future abandonment and future income taxes of $20.6 million, for a total of $405.6 million, was distributed to customers of record as of March 2, 2002 by way of lump-sum payments. Canadian Utilities' share of the net proceeds was $150.5 million, after adjustments, resulting in a gain of $110.1 million. This sale increased earnings by $67.3 million, earnings per share by $1.06 and diluted earnings per share by $1.06.

DECEMBER 31, 2002 (tabular amounts in millions of Canadian dollars)

3. Income taxes

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

	2002		2001	
Earnings before income taxes	$ 513.1	%	$ 418.1	%
Income taxes, at statutory rates	$ 216.7	42.2	$ 180.2	43.1
Federal general tax reduction [1]	(9.1)	(1.8)	(1.9)	(0.5)
Manufacturing and processing tax credit	(7.3)	(1.4)	(4.1)	(1.0)
Resource allowance	(3.3)	(0.6)	(13.5)	(3.2)
Crown royalties and other non-deductible Crown payments	1.8	0.3	9.2	2.2
Large Corporations Tax	7.1	1.4	6.5	1.5
Foreign tax rate variance	(5.2)	(1.0)	(4.3)	(1.0)
Non-deductible interest on foreign financing	1.4	0.3	1.3	0.3
Change in future income taxes resulting from reduction in tax rates	(1.8)	(0.4)	(4.5)	(1.1)
Unrecorded future income taxes	4.9	1.0	(2.9)	(0.7)
Natural gas and other property disposals	(10.8)	(2.1)	2.3	0.6
Other	(4.5)	(0.9)	(4.3)	(1.0)
	189.9	37.0	164.0	39.2
Current income taxes	151.4		183.3	
Future income taxes (recoveries)	$ 38.5		$ (19.3)	
The future income tax liabilities (assets) comprise the following:				
Property, plant and equipment	$ 239.1		$ 210.3	
Deferred costs	46.7		27.8	
Reserves	(22.2)		(17.5)	
Tax loss carryforwards	(0.8)		(0.8)	
Income tax reassessment	(12.9)		(12.9)	
Other	(2.3)		(3.8)	
	247.6		203.1	
Less: Amounts included in current future income taxes	16.8		(1.9)	
	$ 230.8		$ 205.0	

[1] The federal general tax reduction of 3% (2001 – 1%) is applicable to earnings that have not otherwise benefited from the manufacturing and processing tax credit and/or the resource allowance.

Unrecorded future income taxes of the regulated operations amounted to $176.0 million at December 31, 2002. This balance includes $53.2 million in respect of Alberta Power (2000)'s generating plants, which will be recovered through future payments received in respect of the PPA's.

Expected future recoveries relating to tax loss carryforwards, which do not expire, have been recorded in the amount of $0.8 million. In addition, there are tax loss carryforwards of $0.5 million for which no tax benefit has been recorded. These losses begin to expire in 2007.

Income taxes paid amounted to $277.1 million (2001 - $50.6 million).

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

4. Direct charges to retained earnings

	2002	2001
Issue costs of equity preferred shares (after income taxes)	$ 2.8	$ -
Stock options settled (after income taxes)	-	3.8
	$ 2.8	$ 3.8

5. Property, plant and equipment

		2002		2001	
	Composite Depreciation Rates	Cost	Accumulated Depreciation	Cost	Accumulated Depreciation
Utilities	3.6%	$ 4,098.3	$ 1,546.4	$ 3,918.8	$ 1,469.4
Power generation	3.4%	2,588.5	715.7	2,316.5	647.2
Logistics and energy services	4.2%	1,043.9	352.3	1,000.7	316.7
Other	13.4%	62.8	33.1	52.8	26.0
		$ 7,793.5	2,647.5	$ 7,288.8	2,459.3
Property, plant and equipment, less accumulated depreciation			5,146.0		4,829.5
Unamortized contributions by utility customers for extensions to plant			489.0		466.0
			$ 4,657.0		$ 4,363.5

Accumulated depreciation includes amounts provided for future removal and site restoration costs, net of salvage value, of $241.6 million (2001 - $220.7 million).

Composite depreciation rates reflect total depreciation in the year as a percentage of mid-year cost, excluding construction work-in-progress of $550.0 million (2001 - $402.9 million) and non-depreciable assets of $32.7 million (2001 - $28.1 million).

6. Other assets

	2002	2001
Net accrued pension asset (Note 17)	$ 48.0	$ 37.5
Costs deferred for recovery through future regulated rates	27.6	34.1
Deferred financing charges	29.5	26.5
Deferred electricity costs	3.0	21.6
Other	25.7	22.7
	$ 133.8	$ 142.4

DECEMBER 31, 2002 (tabular amounts in millions of Canadian dollars)

7. Bank indebtedness and credit lines

At December 31, 2002, bank indebtedness consists of $5.0 million (2001 - $11.7 million), at an interest rate of 3.76%, secured by a general assignment of accounts receivable.

At December 31, 2002, Canadian Utilities has the following credit lines that enable it to obtain financing for general business purposes:

			2002			2001
	Total	Used	Available	Total	Used	Available
Long term committed	$ 350.0	$ 56.2	$ 293.8	$ 390.5	$ 117.9	$ 272.6
Short term committed	627.7	52.9	574.8	817.9	25.9	792.0
Uncommitted	225.0	10.1	214.9	201.6	5.2	196.4
	$ 1,202.7	$ 119.2	$ 1,083.5	$ 1,410.0	$ 149.0	$ 1,261.0

8. Deferred electricity cost obligation

In December 2000, the Province of Alberta issued regulations providing for the deferral of price and volume variance in excess of forecast amounts in respect of the supply of electricity by distributors to their customers for the year ended December 31, 2000. In June 2002, the AEUB issued decisions approving the collection by ATCO Electric of its deferred costs from customers over a period that is expected to end in July 2003, and permitting ATCO Electric to sell these deferred costs and related rights.

On August 14, 2002, ATCO Electric sold deferred costs of $81 million to an unrelated purchaser for equivalent cash consideration. GAAP requires that this transaction be accounted for as a financing arrangement rather than a sale. Accordingly, the cash received results in the recording of a deferred electricity cost obligation rather than a reduction of deferred electricity costs. The obligation bears interest at 3.3975%, which approximates the interest earned on the deferred costs. The obligation principal and interest incurred will be paid to the purchaser as the deferred costs and interest earned are collected from customers. At December 31, 2002, $51.0 million of the obligation remained outstanding.

ATCO Electric serves as agent for the purchaser in billing, collecting and remitting amounts due in respect of the deferred costs.

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

Long term debt	2002	2001
CU Inc. debentures - unsecured		
1997 Medium Term Note 5.42% due November 2002	$ -	$ 68.0
1993 Series 7.25% due September 2003	60.0	60.0
1994 Series 8.73% due June 2004	100.0	100.0
1995 Series 8.43% due June 2005	125.0	125.0
2001 4.84% due November 2006	175.0	175.0
1987 Series 12% due October 2007, redeemable October 2002	-	125.0
2002 4.801% due November 2007	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
2002 6.145% due November 2017	150.0	-
1999 Series 6.8% due August 2019	300.0	300.0
1990 Second Series 11.77% due November 2020	100.0	100.0
1991 Series 9.92% due April 2022	125.0	125.0
1992 Series 9.40% due May 2023	100.0	100.0
Canadian Utilities Limited debentures - unsecured		
2002 6.14% due November 2012	100.0	-
	1,835.0	1,728.0
ATCO Power Australia Pty Ltd. credit facility, at Bank Bill rates, due July 2003, payable in Australian dollars, unsecured (1)	21.4	24.7
ATCO Midstream Ltd. credit facility, at BA rates, due June 2005, unsecured (1)	8.0	45.0
ATCO Power Canada Ltd. credit facility, at BA rates, due March 2007, secured by a pledge of cash (1)	48.0	48.0
Other long term obligation, at 4.35%	4.5	10.2
	$ 1,916.9	$ 1,855.9

BA – Bankers' Acceptance

Non-recourse long term debt	2002	2001
McMahon plant term facility, at 8.26%	$ -	$ 9.7
Barking Power Limited project financing, payable in British pounds:		
At fixed rates averaging 7.95%, due to 2010	97.1	95.7
At LIBOR, due to 2010 (1)	159.2	157.0
Osborne Cogeneration Pty Ltd. project financing, payable in Australian dollars:		
At Bank Bill rates, due to 2013 (1)	2.6	2.6
At 6.825%, due to 2013 (1)	48.9	49.6
ATCO Power Alberta Limited Partnership ("APALP") project financing:		
At 7.29% to 2008, at LIBOR thereafter, due to 2016 (1)	7.7	9.0
At 7.067% to 2008, at LIBOR thereafter, due to 2016 (1)	10.8	12.5
At 7.25% to 2011, at LIBOR thereafter, due to 2016 (1)	95.6	98.5

DECEMBER 31, 2002 (tabular amounts in millions of Canadian dollars)

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

Non-recourse long term debt	2002	2001
Joffre project financing:		
At BA rates	-	0.9
At 7.161%, due to 2012 [1]	35.6	37.3
At 6.435% to 2004, at BA rates thereafter, due to 2012 [1]	3.6	5.3
At 8.59%, due to 2020	32.0	32.0
Scotford project financing:		
At BA rates, due to 2014 [1]	54.7	29.0
At LIBOR, due to 2014 [1]	13.9	7.3
At 7.93%, due to 2022	28.4	28.4
Muskeg River project financing:		
At BA rates, due to 2014 [1]	-	22.2
At LIBOR, due to 2014 [1]	-	5.5
At 5.147%, due 2007, at BA rates thereafter, due to 2014 [1]	53.1	-
At 7.56%, due to 2022	35.8	35.8
Brighton Beach project financing:		
At 6.924%, due to 2024	110.6	-
Cory project financing:		
At 6.450%, due to 2011 [1]	4.8	-
At 7.586%, due to 2024	38.8	38.8
At 7.601%, due to 2026	34.0	34.0
	867.2	711.1
Less: Amounts due within one year	46.1	37.3
	$ 821.1	$ 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 1.0%.

Canadian Utilities has fixed interest rates, either directly or through interest rate swap agreements, on 89% 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, 2002 was $1,203.8 million (2001 - $954.8 million).

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

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) **Equity contributions** – Represents equity funding requirements needed to complete construction of the project being built. At December 31, 2002, the maximum value of the obligations under these guarantees is anticipated to be:

Project		Amount
Scotford project financing	$	4.5
Brighton Beach project financing	$	49.1

b) **Completion of construction** – Represents completion guarantees associated with project financing whereby non-completion of a project by a certain date will require the repurchase of all or a portion of the project debt. At December 31, 2002, the maximum value of the obligations under these guarantees is:

Project		Amount	Expiry Date
APALP project financing: Oldman River project	$	16.8	May 31, 2003
Brighton Beach project financing	$	161.2	September 30, 2006

c) **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 will become 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, 2002, no amounts were payable as the Scotford and Muskeg River projects had not yet reached commercial operation.

d) **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, 2002, the amount of the obligations under these guarantees is:

Project	Major Maintenance		Debt Service
APALP project financing	Nil [1]	$	6.6
Joffre project financing	Nil [2]	$	4.0

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

e) **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 theproject debt is to be fully repaid. At December 31, 2002, the maximum value of the guarantee is $34.8 million.

DECEMBER 31, 2002 (tabular amounts in millions of Canadian dollars)

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

f) **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, 2002, no such events have occurred.

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. 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.

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.

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
2003	$ 81.4	$ 46.1	$ 127.5
2004	104.5	51.8	156.3
2005	133.0	61.5	194.5
2006	175.0	62.8	237.8
2007	98.0	58.1	156.1
	$ 591.9	$ 280.3	$ 872.2

Of the $127.5 million due in 2003, $81.4 million is to be refinanced and is, therefore, excluded from long term debt due within one year in the balance sheet.

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

Interest expense

Interest on debt is as follows:	2002	2001
Long term debt	$ 145.8	$ 151.7
Non-recourse long term debt	49.8	37.4
Notes payable	0.6	6.2
Current bank indebtedness	8.5	11.7
Amortization of financing charges	2.2	2.6
Less: Capitalized on non-regulated projects	(22.8)	(10.9)
	$ 184.1	$ 198.7

Interest paid amounted to $207.6 million (2001 - $205.5 million).

Fair values

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

	2002	2001
Long term debt		
Fixed rate	$ 2,155.0	$ 1,982.4
Floating rate	77.4	117.7
	$ 2,232.4	$ 2,100.1
Non-recourse long term debt		
Fixed rate	$ 597.8	$ 502.3
Floating rate	283.6	221.9
	$ 881.4	$ 724.2

10. Deferred credits

	2002	2001
Deferred availability incentives	$ 45.0	$ 29.9
Accrued equipment repairs and maintenance	13.1	16.3
Net accrued post employment benefits (Note 17)	6.0	3.8
Other	14.7	16.8
	$ 78.8	$ 66.8

DECEMBER 31, 2002 (tabular amounts in millions of Canadian dollars)

11. Equity preferred shares

Authorized and issued

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

Issued:	Stated Value	Redemption Dates	2002 Shares	2002 Amount	2001 Shares	2001 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	-	-
Perpetual Cumulative Second Preferred Shares						
5.05% Series O	$25.00	December 2, 2006	1,600,000	40.0	1,600,000	40.0
5.05% Series T	$25.00	December 2, 2006	1,600,000	40.0	1,600,000	40.0
5.05% Series U	$25.00	December 2, 2006	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
				$ 486.5		$ 336.5

On December 3, 2002, Canadian Utilities Limited issued $150.0 million of Cumulative Redeemable Second Preferred Shares Series W for cash. The dividend rate has been fixed at 5.8%.

The dividends payable on the Perpetual Cumulative Second Preferred Shares Series O, T, U and V are fixed until the redemption dates specified above, at which time a new dividend rate may be established by negotiation 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 $472.9 million (2001 - $323.4 million).

Redemption privileges

The preferred shares, except for Series W, 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.

12. Class A and Class B shares

Authorized and issued

	Class A Non-Voting		Class B Common		Total	
	Shares	Consideration	Shares	Consideration	Shares	Consideration
Authorized:	Unlimited		Unlimited			
Issued and Outstanding:						
December 31, 2000	39,627,613	$ 356.4	23,678,222	$ 150.0	63,305,835	$ 506.4
Stock options exercised	11,200	0.3	-	-	11,200	0.3
Converted:						
Class B to Class A	237,956	1.6	(237,956)	(1.6)	-	-
December 31, 2001	39,876,769	358.3	23,440,266	148.4	63,317,035	506.7
Stock options exercised	95,150	2.9	-	-	95,150	2.9
Converted:						
Class B to Class A	149,875	0.9	(149,875)	(0.9)	-	-
December 31, 2002	40,121,794	$ 362.1	23,290,391	$ 147.5	63,412,185	$ 509.6

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 common shares outstanding. Diluted earnings per share is calculated using the treasury stock method, which reflects the exercise of stock options on the weighted average shares outstanding. The average numbers of shares used to calculate earnings per share are as follows:

	2002	2001
Weighted average shares outstanding	63,389,738	63,315,041
Effect of dilutive stock options	311,187	300,123
Weighted average diluted shares outstanding	63,700,925	63,615,164

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 takeover 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 takeover 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, 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. The complete text of the rights of exchange attached to the Class A non-voting shares is set out in a Certificate of Amendment dated September 10, 1982 issued to Canadian Utilities Limited.

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12. Class A and Class B shares (continued)

Normal course issuer bid

On May 20, 2002, 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 offer will expire on May 19, 2003. No shares were purchased in 2002.

13. Stock based compensation plans

Stock option plan

Canadian Utilities Limited has a stock option plan under which 3,200,000 Class A non-voting shares are reserved for issuance in respect of options. 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:

	2002		2001	
	Class A Shares	Weighted Average Exercise Price	Class A Shares	Weighted Average Exercise Price
Options at beginning of year	991,550	$35.72	1,129,100	$34.54
Granted	52,500	51.51	-	-
Exercised	(95,150)	30.05	(11,200)	29.89
Settled	(1,100)	41.93	(126,350)	25.72
Options at end of year	947,800	$37.15	991,550	$35.72

Information about stock options outstanding at December 31, 2002 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
$23.76 - $30.08	281,700	3.2	$27.26	281,700	$27.26
$34.46 - $37.74	308,700	6.9	$35.65	197,500	$35.60
$41.29 - $57.29	357,400	6.9	$46.24	195,400	$45.65
$23.76 - $57.29	947,800	5.8	$37.15	674,600	$35.03

In 2002, Canadian Utilities Limited granted 52,500 options to purchase Class A non-voting shares to officers and certain key employees at a weighted average exercise price of $51.51 per share. The options have a term of 10 years and vest in equal amounts over the first five years.

13. Stock based compensation plans (continued)

Had Canadian Utilities adopted the fair value based method of accounting for stock options granted in 2002, earnings would have been reduced by $0.1 million, but there would have been no effect on earnings per share. The reduction in earnings was determined using the Black-Scholes option pricing model, which estimated the weighted average value of the options granted during the year at $7 per option using the following assumptions:

Risk-free interest rate	4.7%
Expected holding period prior to exercise	5.7 years
Share price volatility	14.1%
Estimated annual common share dividend	3.8%

Subsequent to December 31, 2002, 40,000 options were granted at a weighted average exercise price of $51.81 per share.

Share appreciation rights plan

Directors, officers and key employees of Canadian Utilities may be granted share appreciation rights under the share appreciation rights plans of Canadian Utilities Limited and 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 the Class I Non-Voting shares, respectively, over the base value of the share appreciation rights exercised.

Share appreciation rights expense amounted to $0.9 million (2001 - $0.8 million).

14. Changes in non-cash working capital

	2002	2001
Operating activities, changes related to:		
Accounts receivable	$ (20.0)	$ 196.9
Inventories	5.8	6.9
Deferred natural gas costs	(27.3)	131.2
Deferred electricity costs	6.7	60.4
Prepaid expenses	(10.5)	6.9
Accounts payable and accrued liabilities	(7.4)	(229.7)
Income taxes	(126.0)	130.1
Future income taxes	18.7	(57.1)
	$ (160.0)	$ 245.6
Investing activities, changes related to:		
Inventories	$ (2.0)	$ 14.5
Prepaid expenses	2.0	(7.2)
Accounts payable and accrued liabilities	(8.3)	(5.1)
	$ (8.3)	$ 2.2
Financing activities, changes related to:		
Accounts receivable	$ 7.7	$ (10.3)
Accounts payable and accrued liabilities	1.0	(4.1)
	$ 8.7	$ (14.4)

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15. Joint ventures

Canadian Utilities' interest in joint ventures is summarized below:

	2002	2001
Statement of earnings		
Revenues	$ 378.1	$ 382.7
Operating expenses	269.5	257.5
Depreciation and amortization	25.8	24.6
Interest	25.8	30.3
	57.0	70.3
Interest and other income	4.8	5.2
Earnings from joint ventures before income taxes	$ 61.8	$ 75.5
Balance sheet		
Current assets	$ 160.2	$ 182.8
Current liabilities	(112.7)	(144.6)
Property, plant and equipment	949.9	792.3
Deferred items - net	(83.3)	(76.7)
Non-recourse long term debt	(625.8)	(494.6)
Investment in joint ventures	$ 288.3	$ 259.2
Statement of cash flows		
Operating activities	$ 55.3	$ 76.6
Investing activities	(141.5)	(176.7)
Financing activities	74.4	139.0
Foreign currency translation	4.5	1.5
Increase (decrease) in cash position	$ (7.3)	$ 40.4

Current assets include cash of $76.6 million (2001 - $88.7 million), which is only available for use within the joint ventures.

16. Related party transactions

In the normal course of business with affiliate corporations, Canadian Utilities sold natural gas in the amount of $3.2 million (2001 - $4.1 million), recovered administrative expenses and business development costs totaling $2.9 million (2001 - $3.3 million) and incurred administrative expenses and corporate signature rights totaling $6.6 million (2001 - $6.1 million). Canadian Utilities also incurred advertising and promotion expenses from a related entity totaling $1.2 million (2001 - $1.5 million).

17. Employee future benefits

Canadian Utilities 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 dependents. The defined benefit pension plans, which provide for pensions based on length of service and final average earnings, are for the most part contributory, with the balance of funding the responsibility of Canadian Utilities on the advice of an independent actuary. Plan assets are comprised of Canadian and foreign equities, fixed income and other marketable securities and real estate. As of 1997, new employees automatically participate in the defined contribution pension plans and employees participating in the defined benefit pension plans may transfer to the defined contribution pension plans at any time.

17. Employee future benefits (continued)

Information about Canadian Utilities' benefit plans, in aggregate, is as follows:

	2002 Pension Benefit Plans	2002 Other Post Employment Benefit Plans	2001 Pension Benefit Plans	2001 Other Post Employment Benefit Plans
Market value of plan assets				
Beginning of year	$ 1,322.6	$ -	$ 1,381.4	$ -
Actual return on plan assets	(94.9)	-	(29.2)	-
Employee contributions	5.2	-	5.3	-
Benefit payments	(34.2)	-	(32.5)	-
Payments to defined contribution plans	(3.7)	-	(2.4)	-
End of year	$ 1,195.0	$ -	$ 1,322.6	$ -
Accrued benefit obligations				
Beginning of year	$ 884.8	$ 44.8	$ 836.5	$ 40.8
Current service cost	17.6	1.3	16.8	1.3
Interest cost	59.4	3.0	58.0	2.9
Employee contributions	5.2	-	5.3	-
Benefit payments	(35.8)	(1.8)	(33.9)	(1.6)
Experience losses	20.8	0.6	2.1	1.4
End of year	$ 952.0	$ 47.9	$ 884.8	$ 44.8
Funded status				
Excess (deficiency) of assets over obligations	$ 243.0	$ (47.9)	$ 437.8	$ (44.8)
Amounts not yet recognized in financial statements:				
Unrecognized net experience losses	265.4	3.4	50.2	2.8
Unrecognized net transitional liability (asset)	(351.8)	29.9	(382.7)	32.2
Accrued asset (liability)	156.6	(14.6)	105.3	(9.8)
Regulatory asset (liability) [(1)]	(108.6)	8.6	(67.8)	6.0
Net accrued asset (liability)	$ 48.0	$ (6.0)	$ 37.5	$ (3.8)
Weighted average assumptions				
Expected rate of return on plan assets for the year	8.0%	-	8.1%	-
Liability discount rate at December 31	6.5%	6.5%	6.9%	6.9%
Average compensation increase for the year	3.0%	-	3.0%	-

The assumed annual healthcare cost rate increases used in measuring the accumulated post-employment benefit obligation in 2002 and thereafter were 4.0% for drug costs and 3.5% for other medical and dental costs.

Included in the accrued benefit obligations are certain supplementary defined benefit pension plans that are paid by Canadian Utilities out of general revenues. These supplementary plans had accrued benefit obligations of $58.7 million at December 31, 2002 (2001 - $53.9 million).

At December 31, 2002, plan assets include long term debt of CU Inc. having a market value of $1.7 million (2001 - $1.4 million), Class A non-voting and Class B common shares of Canadian Utilities Limited having a market value of $10.3 million (2001 - $9.9 million) and Class I Non-Voting shares of ATCO Ltd. having a market value of $7.8 million (2001 - $8.5 million).

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17. Employee future benefits (continued)

	2002 Pension Benefit Plans	2002 Other Post Employment Benefit Plans	2001 Pension Benefit Plans	2001 Other Post Employment Benefit Plans
Components of benefit plan expense (income)				
Current service cost	$ 17.6	$ 1.3	$ 16.8	$ 1.3
Interest cost	59.4	3.0	58.0	2.9
Expected return on plan assets	(99.5)	-	(94.8)	-
Amortization of net transitional liability (asset)	(30.9)	2.3	(30.9)	2.3
Defined benefit plans expense (income)	(53.4)	6.6	(50.9)	6.5
Defined contribution plans expense	5.5	-	3.7	-
Total expense (income)	(47.9)	6.6	(47.2)	6.5
Less: Capitalized	0.6	1.5	0.6	1.3
Less: Unrecognized defined benefit plans expense (income) [1]	(41.3)	1.5	(37.4)	4.4
Net expense (income)	$ (7.2)	$ 3.6	$ (10.4)	$ 0.8

[1] The regulatory asset (liability) and the unrecognized defined benefits plan expense (income) reflect an AEUB decision to record costs of employee future benefits in the regulated operations when paid rather than accrued.

18. Risk management and financial instruments

Canadian Utilities 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 Logistics and Energy Services segment is affected by the cost of natural gas and the price of natural gas liquids. In conducting its business, Canadian Utilities 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 at December 31 2002	2001
8.370%	90 day BA	December 2002	$ -	$ 3.2
8.260%	90 day BA	September 2003	-	8.4
6.435%	90 day BA	December 2004	3.6	5.3
5.147%	90 day BA	December 2007	53.1	-
7.290%	90 day BA	November 2008	7.7	9.0
7.067%	90 day BA	December 2008	10.8	12.5
6.450%	90 day BA	March 2011	4.8	-
7.250%	6 month LIBOR	December 2011	95.6	98.5
7.161%	90 day BA	September 2012	35.6	37.3
6.825%	Bank Bill Bid rate	June 2013	AUD 55.4 / CDN 48.9	AUD 60.8/ CDN 49.6
6.450% [2]	90 day BA	March 2019	9.2	-
			$ 269.3	$ 223.8

BA – Bankers' Acceptance LIBOR – London Interbank Offered Rate AUD – Australian Dollar CDN – Canadian Dollar

[1] The above swap fixed interest rates include any long term debt margin fees (Note 9).
[2] This swap was placed in November 2002 for Brighton Beach project financing and is expected to be drawn in 2003.

18. Risk management and financial instruments (continued)

Foreign exchange rate risk

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

Canadian Utilities 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 operational cash flows denominated in EUROs. At December 31, 2002, the contracts consist of purchases of $3.1 million U.S. dollars (2001 - $3.6 million U.S. dollars), sales of $0.4 million U.S. dollars (2001 – nil) and purchases of 4.1 million EUROs (2001 - 3.7 million EUROs).

Energy commodity price risk

Canadian Utilities has entered into certain energy contracts to fix the price of electricity and natural gas for the customers of the Utilities segment. These contracts have been approved by customers and the AEUB and, accordingly, Canadian Utilities does not bear any risk for any price fluctuations. At December 31, 2002, the contracts consist of natural gas sales of 3,774.4 terajoules ("TJ") for $22.4 million (2001 – 1,079.5 TJ for $4.1 million), natural gas purchases of nil (2001 - 119.7 TJ for $0.4 million) and electricity purchases of nil (2001 – 1,422.0 megawatt hours for $64.9 million).

Fair Values

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

	2002			2001		
Contracts	Notional Principal	Fair Value (Payable) Receivable	Maturity	Notional Principal	Fair Value (Payable) Receivable	Maturity
Interest rate swaps	$ 269.8	$ (14.0)	2004 - 2019	$ 223.7	$ (5.4)	2003 - 2013
Foreign exchange forward contracts	$ 11.3	$ 1.0	2003	$ 10.4	$ 0.5	2002

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.

19. Commitments and contingencies

Commitments

Canadian Utilities has contractual obligations in the normal course of business and in respect of long term operating leases for office premises and equipment. Future minimum lease payments are as follows:

2003	2004	2005	2006	2007	Total of All Subsequent Years
$12.6	$10.8	$10.2	$9.7	$9.2	$18.4

19. Commitments and contingencies (continued)

Contingencies

Canadian Utilities is party to a number of disputes and lawsuits in the normal course of business. Management is confident that the ultimate liability arising from these matters will have no material impact on the consolidated financial statements.

Canadian Utilities has a number of regulatory filings and regulatory hearing submissions before the AEUB for which decisions have not been received. The outcome of these matters cannot be determined.

20. Regulatory matters

On July 26, 2002, the AEUB issued a decision regarding affiliate transactions within the ATCO Group. In addition, on July 30, 2002, the AEUB issued a decision regarding Canadian Utilities' application to remove the Carbon, Alberta storage facility from regulated service. Both decisions dealt with pricing for services between affiliate corporations. The effect of these decisions was to reduce earnings attributable to Class A and Class B shares by $11.1 million, of which $8.4 million was provided for in 2000 and 2001. Furthermore, the AEUB determined that the Carbon storage facility should remain a regulated asset.

21. Segmented information

Description of segments

Canadian Utilities 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, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical, the regulated transmission and distribution of water by CU Water, and the non-regulated engineering, procurement and construction services for customers in the utility, energy and telecommunications sectors by ATCO Utility Services.

The Power Generation Business Group includes the non-regulated supply of electricity and cogeneration steam by ATCO Power and the regulated supply of electricity by Alberta Power (2000).

The Logistics and Energy Services Business Group includes the regulated transportation of natural gas by ATCO Pipelines, the non-regulated gathering, processing, storage, purchase and sale of natural gas by ATCO Midstream and project management and technical services for customers in the industrial, defence and transportation sectors by ATCO Frontec.

The Technologies Business Group and Other Businesses includes the development, operation and support of information systems and technologies by ATCO I-Tek, the billing services, payment processing, credit, collection and call centre services by ATCO I-Tek Business Services, the sale of fly ash and other combustion byproducts produced in coal-fired electrical generating plants by ASHCOR Technologies, the manufacture of wood preservation products by Genics and the sale of travel services to both business and consumer sectors by ATCO Travel. In addition, Canadian Utilities Limited owns commercial real estate in Fort McMurray, Alberta.

21. Segmented information (continued)

Segmented results

2002 2001	Utilities	Power Generation	Logistics & Energy Services	Technologies & Other Businesses	Corporate	Intersegment Eliminations	Consolidated
Revenues –	$ 1,781.1	$ 584.6	$ 597.9	$ 12.1	$ 0.2	$ -	$ 2,975.9
external	$ 2,256.1	$ 632.9	$ 615.3	$ 9.3	$ -	$ -	$ 3,513.6
Revenues –	86.1	-	335.8	89.8	10.9	(522.6)	-
intersegment[1]	112.5	-	300.5	95.1	11.7	(519.8)	-
Revenues	1,867.2	584.6	933.7	101.9	11.1	(522.6)	2,975.9
	2,368.6	632.9	915.8	104.4	11.7	(519.8)	3,513.6
Operating	1,516.7	336.0	765.7	74.9	11.8	(534.6)	2,170.5
expenses	2,028.6	346.1	761.4	80.9	11.3	(532.0)	2,696.3
Depreciation and	126.8	68.2	42.1	7.3	0.4	(0.4)	244.4
amortization	128.5	65.0	41.0	7.4	0.4	(0.4)	241.9
Interest expense	96.3	68.4	24.6	0.8	144.1	(150.1)	184.1
	109.0	71.1	28.7	0.8	160.5	(171.4)	198.7
Interest and other	(121.1)	(8.5)	(5.1)	(0.1)	(151.5)	150.1	(136.2)
income	(28.6)	(14.4)	(3.8)	(0.2)	(165.8)	171.4	(41.4)
Earnings before	248.5	120.5	106.4	19.0	6.3	12.4	513.1
income taxes	131.1	165.1	88.5	15.5	5.3	12.6	418.1
Income taxes	92.4	41.8	40.3	7.9	3.2	4.3	189.9
	48.9	67.0	35.4	6.6	2.2	3.9	164.0
Net earnings	156.1	78.7	66.1	11.1	3.1	8.1	323.2
	82.2	98.1	53.1	8.9	3.1	8.7	254.1
Dividends on equity	8.4	3.4	1.7	-	4.7	-	18.2
preferred shares	8.3	3.4	1.6	-	3.7	-	17.0
Earnings attributable to Class A and	$ 147.7	$ 75.3	$ 64.4	$ 11.1	$ (1.6)	$ 8.1	$ 305.0
Class B shares	$ 73.9	$ 94.7	$ 51.5	$ 8.9	$ (0.6)	$ 8.7	$ 237.1
Total assets	$ 2,561.9	$ 2,174.7	$ 794.6	$ 47.4	$ 379.6	$ (23.8)	$ 5,934.4
	$ 2,486.4	$ 2,020.7	$ 861.1	$ 36.7	$ 40.4	$ (41.3)	$ 5,404.0
Purchase of property, plant and	$ 274.5	$ 236.0	$ 48.9	$ 10.0	$ 0.4	$ -	$ 569.8
equipment	$ 238.9	$ 384.2	$ 101.9	$ 10.0	$ 0.3	$ -	$ 735.3

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

DECEMBER 31, 2002 (tabular amounts in millions of Canadian dollars)

21. Segmented information (continued)

Geographic segments

	Domestic		Foreign		Consolidated	
	2002	2001	2002	2001	2002	2001
Revenues	$ 2,699.4	$ 3,237.9	$ 276.5	$ 275.7	$ 2,975.9	$ 3,513.6
Property, plant and equipment	$ 4,250.0	$ 3,973.9	$ 407.0	$ 389.6	$ 4,657.0	$ 4,363.5

22. Sale of Retail Operations

On December 10, 2002, Canadian Utilities announced that Direct Energy Marketing Limited has agreed to purchase the retail energy businesses of ATCO Gas and ATCO Electric. The transaction is subject to the satisfaction of certain conditions, including the receipt of required regulatory approvals and the Alberta Legislature passing amendments to Alberta's Natural Gas and Electricity Legislation that reflect the market refinements announced by the Minister of Energy in August 2002. The purchase consideration will be based on the number of customers at closing and is estimated to be $128.5 million, of which $54.4 million is payable on closing, $39.5 million will be payable one year after closing and the balance will be payable two years after closing. Closing is anticipated to occur in mid-2003.

Assuming the sale closes as anticipated, ATCO Gas and ATCO Electric will no longer be involved in arranging for the supply and sale of natural gas and electricity to customers, but will continue to provide transportation and distribution services under AEUB approved rates that provide for a recovery of costs of service and a fair return. The sale does not include any of the distribution and transmission facilities used to deliver natural gas and electricity to customers.

CONSOLIDATED FIVE-YEAR FINANCIAL SUMMARY

(Dollars in millions, except as indicated)		2002	2001	2000	1999	1998
EARNINGS						
Revenues		2,975.9	3,513.6	2,924.5	2,209.4	1,951.3
Operating expenses		2,170.5	2,696.3	2,088.7	1,427.4	1,192.5
Depreciation and amortization		244.4	241.9	238.9	229.6	208.0
Interest		184.1	198.7	196.2	182.2	173.5
Dividends on preferred shares		-	-	0.6	6.6	18.0
Interest and other income		(136.2)	(41.4)	(23.5)	(23.5)	(21.8)
Income taxes		189.9	164.0	179.4	172.1	180.5
Dividends on equity preferred shares		18.2	17.0	16.8	14.9	10.4
Earnings attributable to Class A and Class B shares		305.0	237.1	227.4	200.1	190.2
SEGMENTED EARNINGS						
Utilities		147.7	73.9	77.2	92.4	N/A
Power generation		75.3	94.7	96.5	67.2	N/A
Logistics and energy services		64.4	51.5	46.8	40.7	N/A
Technologies and other businesses		11.1	8.9	6.3	3.4	N/A
Corporate/eliminations		6.5	8.1	0.6	(3.6)	N/A
Earnings attributable to Class A and Class B shares		305.0	237.1	227.4	200.1	N/A
BALANCE SHEET						
Property, plant, and equipment (net)		4,657.0	4,363.5	4,007.4	3,848.0	3,802.3
Total assets		5,934.4	5,404.0	5,403.9	4,538.5	4,446.6
Capitalization:						
Notes payable		-	4.6	197.1	80.7	186.5
long term debt		1,916.9	1,855.9	1,865.5	1,716.2	1,476.2
Non-recourse long term debt		821.1	673.8	360.0	395.4	422.7
Preferred shares		-	-	-	50.0	200.0
Equity preferred shares		486.5	336.5	336.5	320.6	266.9
Share owners' equity*		1,830.1	1,643.8	1,526.5	1,419.0	1,334.0
Total capitalization		5,054.6	4,514.6	4,285.6	3,981.9	3,886.3
CASH FLOWS						
Operations		500.3	502.3	490.2	465.2	425.8
Purchase of property, plant and equipment		569.8	735.3	451.3	367.3	405.3
Financing (excluding Class A and B dividends)		388.6	91.9	189.5	39.8	112.9
Class A and B dividends		124.2	119.0	114.0	109.0	103.9
CLASS A & B SHARES						
Shares outstanding at end of year* (thousands)		63,412	63,317	63,306	63,349	63,362
Return on equity*		17.6%	15.0%	15.4%	14.5%	14.8%
Earnings per share* ($)		4.81	3.74	3.59	3.16	3.00
Dividends paid per share* ($)		1.96	1.88	1.80	1.72	1.64
Equity per share* ($)		28.86	25.96	24.11	22.40	21.05
Stock market record -						
Class A non-voting shares ($)	High	60.10	56.05	51.45	49.35	48.85
	Low	48.80	44.50	31.00	32.35	38.00
	Close	51.21	49.75	51.00	39.00	48.00
Stock market record -						
Class B common shares ($)	High	60.50	54.20	51.15	49.25	49.00
	Low	49.00	44.95	31.10	32.50	38.25
	Close	52.65	49.00	50.55	39.25	48.40

* Includes Class A non-voting shares and Class B common shares.

CONSOLIDATED FIVE YEAR OPERATING SUMMARY

(Dollars in millions, except as indicated)	2002	2001	2000	1999	1998
Utilities					
Natural gas operations					
Purchase of property, plant and equipment	103.1	84.6	87.6	86.9	N/A
Pipelines (thousands of kilometres)	33.7	33.5	33.5	33	N/A
Maximum daily demand (terajoules)	1,670	1,470	1,737	1,595	1,696
Sales (petajoules)	201	187	209	192	N/A
Transportation (petajoules)	31	22	18	13	N/A
Total system throughput (petajoules)	232	209	227	205	N/A
Average annual use per residential customer (gigajoules)	136	131	148	138	144
Degree days - Edmonton *	4,274	3,661	4,210	3,774	3,898
- Calgary **	4,470	3,994	4,441	3,869	4,160
Customers at year-end (thousands)	862.0	837.7	816.1	798.4	779.9
Electric operations					
Purchase of property, plant and equipment	162.4	154.1	114.4	100.3	100.9
Power lines (thousands of kilometres)	67.1	64.2	58.6	57.9	55.3
Retail sales (millions of kilowatt hours)	10,224	10,108	10,392	10,068	10,188
Average annual use per residential customer (kWh)	7,445	7,270	7,444	7,367	7,274
Customers at year-end (thousands)	197.8	192.0	191.0	186.8	186.4
Power Generation					
Purchase of property, plant and equipment	236.0	384.2	155.5	119.8	142.8
Generating capacity (thousands of kilowatts)	2,036	2,036	668	514	482
Logistics and Energy Services					
Purchase of property, plant and equipment	48.9	101.9	84.7	51.4	N/A
Pipelines (thousands of kilometres)	8.3	8.2	7.9	7.9	N/A
Contract demand for pipelines system access (terajoules/day)	4,890	4,876	4,559	4,378	N/A
Natural gas processed (Mmcf/day)	420	429	366	332	330
Natural gas gathering lines (thousands of kilometres)	940	940	670	500	500

* Degree days - Edmonton - are defined as the difference of the mean daily temperature from 14.5 degrees Celsius.

** Degree days - Calgary - are defined as the difference of the mean daily temperature from 15.5 degrees Celsius.

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

The following discussion and analysis of financial condition and results of operations of Canadian Utilities Limited (the "Corporation") should be read in conjunction with the Corporation's comparative financial statements for the year ended December 31, 2002, which include the accounts of Canadian Utilities Limited and all of its subsidiaries. This discussion and analysis of financial condition and results of operations may contain forward-looking statements. These statements are not guarantees of future performance and are subject to risks and uncertainties that could cause actual results to differ materially from those in the forward-looking statements.

The Corporation's financial statements are consolidated from four Business Groups: Utilities, Power Generation, Logistics and Energy Services, and Technologies. For the purposes of financial disclosure, the Technologies Business Group is accounted for as Technologies and Other Businesses and corporate transactions are accounted for as Corporate. (Refer to Note 21 of the comparative financial statements). Transactions between Business Groups are eliminated in all reporting of the Corporation's consolidated financial information.

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, Northland Utilities (Yellowknife), Northland Utilities (NWT) and Yukon Electric, the regulated transmission and distribution of water by CU Water and the non-regulated engineering, procurement and construction services for customers in the utility, energy and telecommunications sectors by ATCO Utility Services.

The Power Generation Business Group includes the non-regulated supply of electricity and cogeneration steam by ATCO Power and the regulated supply of electricity by Alberta Power (2000).

The Logistics and Energy Services Business Group includes the regulated transmission of natural gas by ATCO Pipelines, the non-regulated gathering, processing, storage, purchase and sale of natural gas by ATCO Midstream and project management and technical services for customers in the industrial, defence and transportation sectors by ATCO Frontec.

The Technologies Business Group and Other Businesses includes the development, operation and support of information systems and technologies by ATCO I-Tek, the billing services, payment processing, credit, collection and call centre services by ATCO I-Tek Business Services, the sale of fly ash and other combustion byproducts produced in coal-fired electrical generating plants by ASHCOR Technologies, the manufacture of wood preservation products by Genics, and the sale of travel services to both business and consumer sectors by ATCO Travel. The Corporation also owns commercial real estate in Fort McMurray, Alberta.

RESULTS OF OPERATIONS

Consolidated Operations

Segmented revenues and earnings attributable to Class A non-voting shares ("Class A shares") and Class B common shares ("Class B shares") for the years 2002 and 2001 were as follows:

Business Groups	**Revenues**		**Earnings**	
	2002	2001	2002	2001
	($ Millions)			
Utilities	1,867.2	2,368.6	147.7	73.9
Power Generation	584.6	632.9	75.3	94.7
Logistics and Energy Services	933.7	915.8	64.4	51.5
Technologies and Other Businesses	101.9	104.4	11.1	8.9
Corporate	11.1	11.7	(1.6)	(0.6)
Intersegment	(522.6)	(519.8)	8.1	8.7
Total	2,975.9	3,513.6	305.0	237.1

Earnings attributable to Class A and Class B shares rose $67.9 million to $305.0 million in 2002 and earnings per share increased in 2002 to $4.81 from $3.74 in 2001. These increases were primarily due to the sale of the Viking-Kinsella natural gas producing property (the "Viking property") on January 3, 2002. The sale of the Viking property increased earnings by $67.3 million, earnings per share by $1.06 and diluted earnings per share by $1.06. The remainder of the increase was primarily due to stronger operational results from the Logistics and Energy Services Business Group, the impact of colder temperatures in ATCO Gas, lower income tax rates and lower interest expense, partially offset by lower prices received for electricity sold to the Alberta Power Pool by ATCO Power and lower interest income on lower cash balances. Return on common equity was 17.6% in 2002.

Revenues in 2002 decreased by $537.7 million to $2,975.9 million. This decrease was primarily the result of lower prices for natural gas and power purchased for customers and lower revenues due to lower customer rates in ATCO Gas and ATCO Electric, and lower prices received for electricity sold to the Alberta Power Pool by ATCO Power, partially offset by the impact of colder temperatures in ATCO Gas.

Operating expenses (consisting of natural gas supply costs, purchased power costs, operating and maintenance expenses, selling and administrative expenses and franchise fees costs) decreased by $525.8 million to $2,170.5 million for 2002. This decrease was largely the result of lower prices for natural gas and electricity purchased for customers.

Depreciation and amortization expenses rose $2.5 million to $244.4 million in 2002, primarily due to capital additions in 2002 and 2001, partially offset by depreciation adjustments associated with the sale of the Viking property.

Interest expense for 2002 decreased $14.6 million to $184.1 million. This decrease was principally due to lower interest rates associated with higher cost debt refinanced in 2001 and 2002. $22.8 million of interest was capitalized for projects under construction in power generation operations.

Interest and other income for 2002 increased by $94.8 million to $136.2 million, primarily due to a $110.1 million gain on the sale of the Viking property, partially offset by lower interest income on lower cash balances.

Income taxes for 2002 increased by $25.9 million to $189.9 million. This increase was primarily due to income taxes of $42.8 million on the sale of the Viking property, partially offset by a refund to customers of amounts previously recovered from customers for future income taxes related to the Viking property and lower income tax rates.

Quarterly Financial Information

	1st	2nd	3rd	4th
	($ Millions except per share data) (unaudited)			
2002				
Revenues	863.7	646.3	542.6	923.3
Earnings Attributable to Class A and Class B shares (1) (2)	144.2	42.9	44.4	73.5
Earnings Per Class A and Class B share (1) (2)	2.28	0.67	0.70	1.16
Diluted Earnings Per Class A and Class B share (1) (2)	2.27	0.67	0.70	1.15
2001				
Revenues	1,440.7	854.9	582.0	636.0
Earnings Attributable to Class A and Class B shares (1) (2)	79.1	45.1	41.2	71.7
Earnings Per Class A and Class B share (1) (2)	1.25	0.71	0.65	1.13
Diluted Earnings Per Class A and Class B share (1) (2)	1.24	0.71	0.65	1.12

Notes:

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

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

(3) The first quarter 2002 results reflect the sale of the Viking property.

Utilities

Earnings from the Utilities Business Group for 2002, which amounted to 48.4% of consolidated earnings of the Corporation, increased by $73.8 million to $147.7 million. Of this increase, $67.3 million was due to the sale of the Viking property by ATCO Gas. The property, which had a book value of $40.4 million, was sold for $550 million. In accordance with a decision of the Alberta Energy and Utilities Board ("AEUB"), the proceeds from the sale were shared between ATCO Gas' North division customers and the Corporation. The Corporation's share of the net proceeds was $150.5 million, after adjustments, resulting in a gain of $110.1 million. The balance of the increase in earnings from the Utilities Business Group was primarily due to the impact of colder temperatures, partially offset by lower customer rates and lower interest income. Temperatures in 2002 were 6.3% colder than normal, whereas temperatures in 2001 were 6.9% warmer than normal.

Revenues in 2002 decreased by $501.4 million to $1,867.2 million. This decrease was primarily the result of lower prices for natural gas and power purchased for customers and lower revenues due to lower customer rates, partially offset by the impact of colder temperatures.

Operating expenses for 2002 decreased by $511.9 million to $1,516.7 million. This decrease was primarily due to lower natural gas supply and purchased power costs. Natural gas supply and purchased power costs are recovered in customer rates. The amount of natural gas supply costs recorded as an expense is based on the forecast cost of natural gas included in customer rates. The amount of purchased power costs recorded as an expense is based on the actual cost of electricity purchased, whereas the amount included in customer rates is based on forecast cost. Revenues are adjusted for variances from the forecast cost of electricity. Any variances from forecasted natural gas supply costs or purchased power costs are deferred until the AEUB approves revised customer rates to either refund or collect the variance. As a consequence, changes in natural gas supply and purchased power costs have no effect on the Corporation's earnings. In accordance with recent AEUB decisions, customer rates are now adjusted on a monthly basis (see "Regulatory Matters – ATCO Gas" and "Regulatory Matters – ATCO Electric").

Power Generation

Earnings from the Power Generation Business Group for 2002, which amounted to 24.7% of consolidated earnings of the Corporation, decreased by $19.4 million to $75.3 million. This decrease was primarily due to lower prices received for electricity sold to the Alberta Power Pool.

Revenues in 2002 decreased by $48.3 million to $584.6 million. This decrease was primarily the result of lower prices received for electricity sold to the Alberta Power Pool and lower natural gas fuel supply costs recovered in revenues. Power pool prices averaged $43.94 per megawatt hour in 2002, compared to average prices of $71.29 in 2001. Natural gas prices averaged $3.84 per gigajoule in 2002, compared to average prices of $5.12 in 2001.

Operating expenses for 2002 decreased by $10.1 million to $336.0 million. The decrease was primarily the result of lower fuel costs, partially offset by higher operating and maintenance costs at the Barking power plant and full-year operations at the Rainbow Unit 5 and Valleyview generating plants, which became operational in late 2001.

During the third quarter, Brighton Beach Power L.P., a limited partnership formed by ATCO Power and Ontario Power Generation Inc., completed a $403 million private bond and term debt financing for its 580-megawatt power project under construction at Brighton Beach in Windsor, Ontario.

ATCO Power has an interest in four power projects (Cory, Muskeg River, Scotford and Oldman River) scheduled for completion in the first half of 2003 and having an estimated cost of approximately $750 million, of which ATCO Power's share is approximately $435 million. These costs are approximately 15% above original cost estimates, primarily due to labour and engineering markets in Alberta, which tightened during construction and increased equipment, financing and foreign exchange costs. A significant portion of the increased costs are in dispute. A portion of the additional costs will be recoverable over the term of the commercial contracts.

On November 19, 2002, an administration order was issued by a United Kingdom court for TXU Europe Energy Trading Ltd. ("TXU Europe"), which had a long term offtake agreement for 27.5% of the power produced by the Barking power plant, a 1,000 megawatt plant in London, England, in which the Corporation, through Barking Power Limited, has a 25.5% equity interest. An administration order is similar to a Chapter 11 bankruptcy filing in the United States. Barking Power Limited has filed a claim with the Administrator and is working with the Administrator and Creditors' Committees on liquidation of TXU Europe and settlement of claims. The Barking power plant will continue to supply 725 megawatts of power under long term contracts. It is anticipated that the 275 megawatts of power previously supplied to TXU Europe will be sold under short term bilateral agreements.

A joint venture in which ATCO Power has a 50% interest owns and operates a 180-megawatt cogeneration plant in Osborne, Australia. The joint venture has long term agreements with Flinders Osborne Trading Pty Ltd. ("FOT") to supply gas and to purchase all of the power produced at the plant. In December 2002, the joint venture was advised that FOT's parent corporation would no longer provide financial support to FOT. FOT continues to meet its obligations under its agreements with the joint venture. The government of South Australia has guaranteed the obligations of FOT under these agreements.

Logistics and Energy Services

Earnings from the Logistics and Energy Services Business Group for 2002, which amounted to 21.1% of consolidated earnings of the Corporation, increased by $12.9 million to $64.4 million. The increase was largely due to improved storage operations and lower interest costs in ATCO Midstream.

Revenues in 2002 increased by $17.9 million to $933.7 million. The increase was largely due to higher volumes of natural gas purchased by ATCO Midstream for ATCO Gas and higher storage revenues for ATCO Midstream, partially offset by lower prices for natural gas purchased for ATCO Midstream's and ATCO Pipelines' customers and lower revenues from ATCO Frontec projects, primarily reflecting the terms for a new North Warning System contract which was signed in December 2001 and changes in the contractual arrangements between ATCO Frontec and its North Warning System contract joint venture partner.

Operating expenses for 2002, net of intersegment expenses, decreased by $11.3 million. This decrease was primarily due to the impact of the changes associated with ATCO Frontec's new North Warning System contract, partially offset by higher shrinkage gas costs in ATCO Midstream.

Technologies and Other Businesses

Earnings from technologies and other businesses for 2002, which amounted to 3.6% of consolidated earnings of the Corporation, increased by $2.2 million to $11.1 million. The increase was largely due to improved operating efficiencies and increased business activity.

ATCO I-Tek Business Services Ltd. has entered into a 10-year contract with Direct Energy Marketing Limited ("Direct Energy") to provide billing and customer care services to nearly one million Alberta customers. Commencement of the contract is conditional upon the closing of the sale of ATCO Gas' and ATCO Electric's retail operations to Direct Energy (see "Business Risks – Regulated Operations – Sale of Retail Operations").

REGULATORY MATTERS

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

In July 2002, the AEUB issued decisions regarding affiliate transactions within the ATCO Group and the Corporation's application to remove the Carbon, Alberta storage facility from regulated service. Both decisions dealt with pricing for services between affiliate companies. The effect of these decisions was to reduce earnings attributable to Class A and Class B shares by $11.1 million, of which $8.4 million was provided for in 2000 and 2001. Furthermore, the AEUB determined that the Carbon storage facility should remain a regulated asset.

In August 2002, the Government of Alberta announced further changes to utility legislation in order to improve the environment for retail competition in the Province. The Government announced it intends to introduce a new Electric Utilities Act and revise the Gas Utilities Act and Regulations in the spring of 2003. These changes are designed to bring customer choice for both gas and electricity into closer alignment, as well as to move towards consistent regulatory treatment of investor-owned and municipally-owned utilities.

In September 2002, the AEUB established a process to consider the use of a generic cost of capital methodology for electric and natural gas utilities in Alberta. The first phase of this process is to explore the feasibility and appropriateness of applying a standardised approach for all major gas pipeline and major gas and electric utilities under the jurisdiction of the AEUB. The AEUB has received submissions from interested parties but has not established any further schedule for this process.

ATCO Electric

In December 2000, the Province of Alberta issued regulations providing for the deferral of price and volume variance in excess of forecast amounts in respect of the supply of electricity by distributors to their customers for the year ended December 31, 2000. In June 2002, the AEUB issued decisions approving the collection by ATCO Electric of its deferred costs from customers over a period that is expected to end in July 2003, and permitting ATCO Electric to sell these deferred costs and related rights. On August 14, 2002, ATCO Electric sold deferred costs of $81 million to an unrelated purchaser for equivalent cash consideration. Generally accepted accounting principles require that this transaction be accounted for as a financing arrangement rather than a sale. Accordingly, the cash received results in the recording of a deferred electricity cost obligation rather than a reduction of deferred electricity costs. The obligation bears interest at 3.3975%, which approximates the interest earned on the deferred costs. The obligation principal and interest incurred will be paid to the purchaser as the deferred costs and interest earned are collected from customers. ATCO Electric serves as agent for the purchaser in billing, collecting and remitting amounts due in respect of the deferred costs. At December 31, 2002, $51.0 million of the obligation remained outstanding.

In April 2002, the AEUB issued a decision which determined that the electric generation pricing offer strategy utilized by ATCO Electric in 2000 resulted in higher costs to customers than necessary. The decision resulted in a $4.2 million refund to customers. As the decision related to power generation operations, it has been recognized in the Power Generation Business Group, with $3.5 million included in the 2001 results and the balance in 2002.

In August 2002, ATCO Electric filed a general tariff application with the AEUB for the 2003, 2004 and 2005 test years. In a decision dated December 11, 2002, the AEUB approved interim refundable rates effective January 1, 2003.

In December 2002, the AEUB approved an application requesting the implementation on January 1, 2003, of a monthly method of calculating electricity prices for regulated rate option customers. The new methodology is intended to provide greater price transparency for customers and to prevent large collection shortfalls or surpluses that would require subsequent adjustment by the AEUB. In addition, as a result of this decision, ATCO Electric anticipates that in the future its deferred account balance will be reduced as customer rates will be adjusted monthly to refund or collect variances in purchased power costs.

ATCO Gas

In October 2001, the AEUB approved the implementation on April 1, 2002 of a monthly method of adjusting customer rates to recover the cost of natural gas purchased for customers of ATCO Gas. The new methodology is intended to provide greater price transparency for customers. In addition, as a result of this decision, ATCO Gas anticipates that in the future its deferred account balance will be reduced as customer rates will be adjusted monthly to refund or collect variances in natural gas supply costs.

In August 2002, ATCO Gas filed a general rate application for the 2003 and 2004 test years. In December 2002, the AEUB issued a decision approving rates on an interim refundable basis effective January 1, 2003.

In December 2002, the AEUB issued a decision approving the sale of ATCO Gas' Beaverhill Lake and Fort Saskatchewan natural gas producing properties. The properties, located east of Edmonton, were sold to NCE Petrofund on January 1, 2003 for $31.5million. In the decision, the AEUB also approved a settlement to refund $23 million of the sale proceeds to ATCO Gas'

North division customers. The balance of the proceeds will be used to recover ATCO Gas' book value investment in the assets and costs of disposition. The sale has no impact on earnings. ATCO Gas has filed an application with the AEUB seeking approval for the methodology of distributing the proceeds of the settlement. In the same decision, the AEUB also approved final distribution service rates for ATCO Gas' North division for the year 2002, established in a negotiated settlement, which will result in a refund to customers of approximately $2.5 million in 2003.

In September 2002, the AEUB issued a decision with respect to the distribution of $6.4 million of proceeds associated with the Westlock et al and Lloydminster production assets sold by ATCO Gas in 2001. ATCO Gas has withdrawn the application for leave to appeal filed in respect of the level of proceeds allocated to customers.

In October 2001, the AEUB approved the sale by ATCO Gas of certain properties located in the City of Calgary, known as the Calgary Stores Block, for $6.6 million and subsequently issued a decision allocating $4.1 million of the proceeds to customers. A leave to appeal this decision was granted on July 12, 2002. The appeal was heard on December 6, 2002, with the Court's decision reserved.

ATCO Pipelines

In July 2002, the AEUB issued a decision denying NOVA Gas Transmission Ltd.'s application to construct and operate a natural gas pipeline into the Fort Saskatchewan industrial area, an area currently served by ATCO Pipelines. The AEUB found, among other things, that the proposed facilities were not needed and were not the least cost alternative.

On February 14, 2003, ATCO Pipelines filed a general rate application for the 2003 and 2004 test years.

LIQUIDITY AND CAPITAL RESOURCES

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

Cash flow from operations decreased by $2.0 million to $500.3 million in 2002. This decrease was principally due to lower earnings in the Power Generation Business Group and a refund of $20.6 million to customers of amounts previously recovered from customers for future abandonment costs and future income taxes related to the Viking property, partially offset by higher earnings in the Logistics and Energy Services Business Group, the impact of colder temperatures in ATCO Gas, lower income tax rates and lower interest expense.

Investing decreased by $98.4 million to $419.3 million in 2002. Capital expenditures decreased by $165.5 million to $569.8 million in 2002. This decrease was primarily due to lower investment in power generation, regulated natural gas transmission and unregulated natural gas gathering and processing projects, partially offset by increased investment in regulated natural gas and water distribution projects.

To finance 2002 operations, the Corporation issued $300.0 million of long term debt, including $150.0 million of 6.145% Debentures due November 22, 2017 for ATCO Electric, ATCO Gas, ATCO Pipelines and CU Water, and $50.0 million of 4.801% Debentures due November 22, 2007 for Alberta Power (2000). In addition, $100.0 million of 6.14% Debentures due November 22, 2012 and $150.0 million of 5.80% Cumulative Redeemable Second Preferred Shares Series W were issued for general corporate purposes. During 2002, the Corporation issued $173.0 million of non-recourse long term project debt, including $110.6 million for the Brighton Beach project. The Corporation also issued $81.0 million of the deferred electricity cost obligation. The deferred electricity cost obligation was reduced by $30.0 million, which represents the amount of the deferred electricity cost obligation collected and remitted during the period August 14, 2002 to December 31, 2002.

During 2002, the Corporation redeemed: $241.9 million of long term debt consisting of $125.0 million of 12.00% Debentures 1987 Series, $68.0 million of 5.42% Debentures and $48.9 million of other debt. In addition, the Corporation redeemed $43.7 million of non-recourse long term project debt and $4.6 million of notes payable. Total debt redeemed had interest rates ranging from 2.18% to 12.00%.

The Corporation's cash position (defined as cash and short term investments less current bank indebtedness) increased by $191.0 million to $433.9 million in 2002. This increase was primarily due to the issue of $100 million of 6.14% Debentures due November 22, 2012 and $150.0 million of 5.80% Cumulative Redeemable Second Preferred Shares Series W.

At December 31, 2002, the Corporation had the following credit lines that enable it to obtain funding for general corporate purposes.

	Total	Used	Available
		($ Millions)	
Long term committed	350.0	56.2	293.8
Short term committed	627.7	52.9	574.8
Uncommitted	225.0	10.1	214.9
Total	1,202.7	119.2	1,083.5

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

Current and long term future income tax liabilities of $247.6 million at December 31, 2002 are attributable to differences between the financial statement carrying amounts of assets and liabilities and their tax bases. These differences result primarily from recognising 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 realisation of assets.

On May 20, 2002, the Corporation commenced a Normal Course Issuer Bid for the purchase of up to 3% of the outstanding Class A shares. The offer will expire on May 19, 2003. To date, no shares have been purchased.

It is the policy of the Corporation to pay dividends quarterly on its Class A and Class B shares. In 2002, the Corporation increased the dividends on Class A and Class B shares by $0.08 per share, the same increase as in 2001. 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 2003, the quarterly dividend payment has been increased by $0.02 to $0.51 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.

The current ratings on the Corporation's and CU Inc.'s securities are as follows:

	DBRS	S&P
Canadian Utilities Limited:		
Debentures	A	A
Commercial paper	R-1 (low)	A-1 (mid)
Preferred shares:		
-Obligations of CU Inc. [3]	Pfd-2 (high)	P-1 (low)
-Obligations of CU	Pfd-2	P-1 (low)
CU Inc.:		
Debentures	A (high)	A+
Commercial paper	R-1 (low)	A-1 (mid)
Preferred shares	Pfd-2 (high)	Not rated

Notes:
[1] Dominion Bond Rating Service Limited ("DBRS") maintains a stable trend on the above securities.
[2] Standard and Poor's ("S&P") has announced that it has placed several Canadian utility companies (including Canadian Utilities Limited and CU Inc.) on credit watch with negative implications, pending a review of the various regulatory environments in which the utilities operate.
[3] Refers to the Cumulative Redeemable Second Preferred Shares Series Q, R and S and the Perpetual Cumulative Second Preferred Shares Series U and V which were issued by Canadian Utilities Limited prior to the creation of CU Inc. on March 12, 1999.

BUSINESS RISKS

During 2002, the Government of Canada ratified the Kyoto Protocol. The Corporation is unable to determine what impact, if any, the ratification will have on its operations as the implementation plan has not yet been released by the Government. It is anticipated that the Corporation's power purchase arrangements ("PPA's") relating to its coal-fired generating plants will allow the Corporation to recover any increased costs associated with the implementation of the protocol.

Regulated Operations

ATCO Electric, ATCO Gas, ATCO Pipelines and CU Water 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, 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.

Sale of Retail Operations

On December 10, 2002, the Corporation announced that Direct Energy has agreed to purchase the retail energy businesses of ATCO Gas and ATCO Electric. The transaction is subject to the satisfaction of certain conditions, including the receipt of required regulatory approvals and the Alberta Legislature passing amendments to Alberta's Natural Gas and Electricity Legislation that reflect the market refinements announced by the Minister of Energy in August 2002. The purchase consideration will be based on the number of customers at closing and is estimated to be $128.5 million, of which $54.4 million will be payable on closing, $39.5 million will be payable one year after closing and the balance will be payable two years after closing. Closing is anticipated to occur in mid-2003.

Assuming the sale closes as anticipated, ATCO Gas and ATCO Electric will no longer be involved in arranging for the supply and sale of natural gas and electricity to customers, but will continue to provide transportation and distribution services under AEUB approved rates that provide for a recovery of costs of service and a fair return. The sale does not include any of the distribution and transmission facilities used to deliver natural gas and electricity to customers.

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

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 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 various 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 income 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, 2002, the Corporation had recorded $45.0 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.

As a result of unprecedented drought conditions, the water level in the cooling pond used by the Battle River plant in its production of electricity is now at an all-time low. If the water level continues to fall, production from this plant could be curtailed in 2003. Should production be curtailed at the plant, the Corporation expects to make a claim under the force majeure provisions contained in the plant PPA.

Non-Regulated Operations

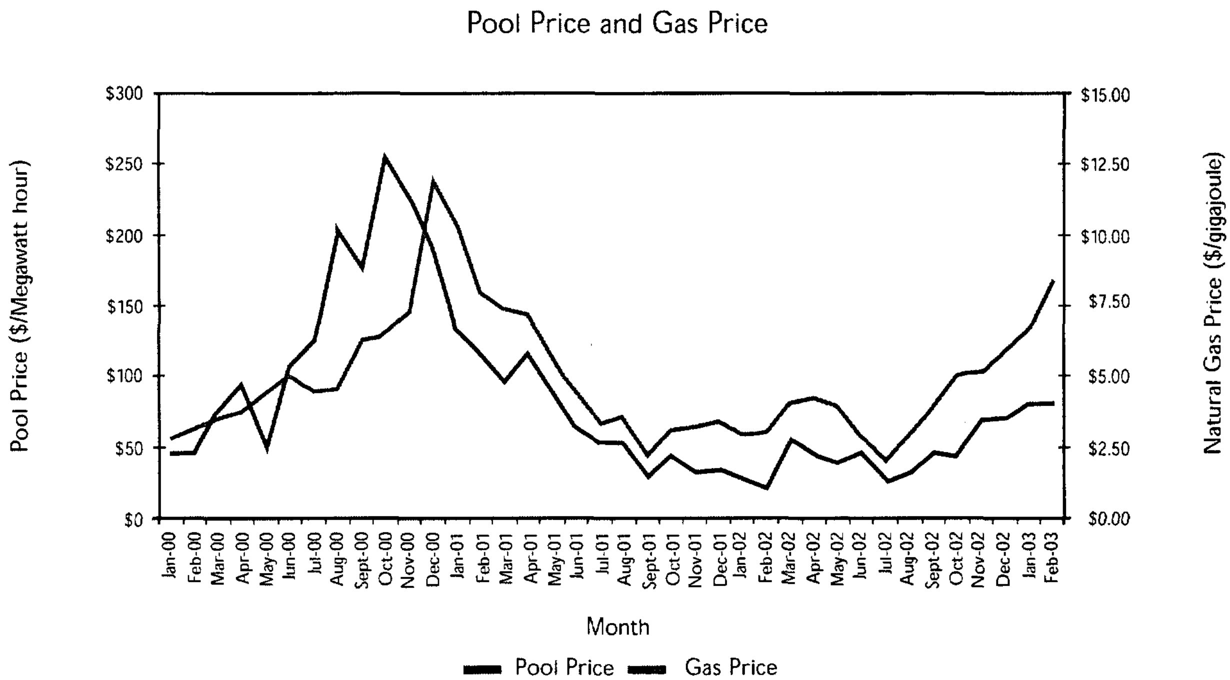
The Corporation's non-regulated operations are complementary to its traditional regulated businesses and are related to them in terms of skills, knowledge and experience. The Corporation accounts for its non-regulated operations separately from its regulated operations. The Corporation's non-regulated operations are subject to the risks faced by any commercial enterprise in those industries and in those countries in which they operate.

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

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 plants with underlying transmission support agreements. In 2002, sales from approximately 69% of ATCO Power's generating capacity were subject to long term agreements, while the remaining 31% consisted primarily of sales to the Alberta Power Pool. In 2003, the portion of generating capacity subject to long term agreements is expected to be approximately 65% while the remaining 35% is expected to consist primarily of sales of electricity to the Alberta Power Pool. These sales are dependent on prices in the Alberta electricity spot 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 strong 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.

Electricity pool prices and gas prices can be very volatile, as shown in the following graph, which illustrates a range of prices experienced during the period January 2000 to February 2003.



Changes in electricity pool prices and gas prices 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.

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. These guarantees cover the following items:

a) **Equity contributions** – Represents equity funding requirements needed to complete construction of the project being built. At December 31, 2002, the maximum value of the obligations under these guarantees is anticipated to be:

Project	**Amount** ($ Millions)
Scotford project financing	4.5
Brighton Beach project financing	49.1

b) **Completion of construction** – Represents completion guarantees associated with project financing whereby non-completion of a project by a certain date will require the repurchase of all or a portion of the project debt. At December 31, 2002, the maximum value of the obligations under these guarantees is:

Project	**Amount** ($ Millions)	**Expiry Date**
ATCO Power Alberta Limited Partnership ("APALP") project financing:		
Oldman River project	16.8	May 31, 2003
Brighton Beach project financing	161.2	September 30, 2006

c) **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 for the Scotford project and 48 megawatts for the Muskeg River project. These guarantees will become 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, 2002, no amounts were payable as the Scotford and Muskeg River projects had not yet reached commercial operation.

d) **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, 2002, the amount of the obligations under these guarantees is:

Project	**Major Maintenance**	**Debt Service**
	($ Millions)	
APALP project financing	NIL [1]	6.6
Joffre project financing	NIL [2]	4.0

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

e) **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, 2002, the maximum value of the guarantee is $34.8 million.

f) **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, 2002, no such events had occurred.

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

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.

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

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.

February 26, 2003


Robert T. Booth

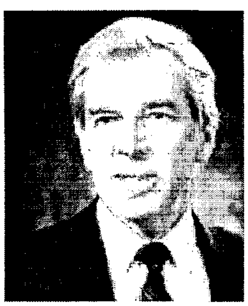
Robert T. Booth [2] [3]
Partner, Bennett Jones LLP, Calgary, Alberta

Mr. Booth is a partner in the law firm Bennett Jones, 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.


William L. Britton

William L. Britton, Q.C. [1]
Partner, Bennett Jones LLP, Calgary, Alberta

Mr. Britton is a Partner at Bennett Jones LLP, Calgary, Alberta, and was Chairman and/or Managing Partner of Bennett Jones from 1981 to 1997. Mr. Britton was first elected to the Board of Directors of ATCO Ltd. and Canadian Utilities Limited in September 1975 and became a Director of Canadian Utilities Limited in June 1980. He is Vice Chairman and Lead Director of ATCO Ltd. and Canadian Utilities Limited and Chairman of the Corporate Governance, Nomination, Succession and Compensation Committee. He is a Director of all ATCO and Canadian Utilities subsidiaries and the five ATCO Business Groups. Mr. Britton's other directorships include Akita Drilling Ltd., Forest Oil Ltd., Hanzell Vineyards Ltd., Geary-Market Investment Company and the Denver Broncos Football Club.


Brian P. Drummond

Brian P. Drummond [1] [4]
Corporate Director, Montréal, Québec

Mr. Drummond is a Corporate Director based in Montréal, Québec and most recently was Vice Chairman, Richardson Greenshields of Canada Limited. He was also previously Chief Executive Officer of Greenshields Inc. Mr. Drummond is a past Chairman of the Investment Dealers Association of Canada and the Montréal Exchange. Mr. Drummond was first elected to the Board of ATCO Ltd. in 1968, when the company initially went public, and to the Board of Canadian Utilities Limited in 1997.


Basil K. French

Basil K. French [2] [3]
President, Karusel Management Ltd., Calgary, Alberta

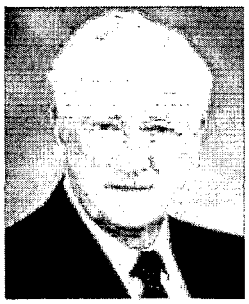
Mr. French is the President of Karusel Management Ltd., a Calgary-based company specializing in management consulting and property management. Prior to the establishment of Karusel Management, Mr. French was with the firms of Buchanan, Barry, Miller and French Chartered Accountants and Price Waterhouse & Co. Mr. French is the Chairman of Canadian Utilities Audit Committee and is a Director of all ATCO and Canadian Utilities subsidiaries and the five ATCO Business Groups. Mr. French was elected to the Boards of ATCO Ltd. in November 1982 and Canadian Utilities Limited in April 1981.

BOARD OF DIRECTORS


Linda A. Heathcott

Linda A. Heathcott [4]
Executive Vice President, Spruce Meadows, Calgary, Alberta

Mrs. Heathcott is Executive Vice President 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. Mrs. Heathcott serves on the Boards of Calgary Olympic Development Association, Sentgraf Enterprises Ltd., Akita Drilling Ltd. and a number of ATCO Group subsidiary Boards. She was elected to the Board of Canadian Utilities Limited in May 2000.


William R. Horton

William R. Horton, P.Eng [2] [3]
Corporate Director, Winfield, British Columbia

Mr. Horton, a Corporate Director, based in Winfield, BC, is Chairman of Horton Engineering Ltd. of Edmonton. He is a life member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta. Mr. Horton was a member of the Alberta Public Utilities Board from 1973 to 1976 and was Chairman from 1976 to 1983. Mr. Horton has been a Director of Canadian Utilities Limited (CU) since 1984 when he joined the Company as Executive Vice President, and President of CU's utility subsidiaries. Mr. Horton is also a Director of the Utilities Business Group.


Helmut M. Neldner

Helmut M. Neldner [1] [2] [3] [4]
Corporate Director, Westerose, Alberta

Mr. Neldner is a Corporate Director based in Westerose, Alberta. He has extensive experience in the telecommunications industry and is the former President & Chief Executive Officer of AGT and Telus Corporation. He serves on several Boards of Directors including ATCO Ltd. and Canadian Utilities Limited as well as the five ATCO Business Groups. He was nominated and elected to the CU Board in May 1991 and the ATCO Ltd. Board in May 1997.


Larry R. Shaben

Larry R. Shaben
Chairman, Western New Ventures Capital Corporation, Edmonton, Alberta

Mr. Shaben is the Chairman of Western New Ventures Capital Corporation, based in Edmonton, Alberta and previously was Vice Chairman, Petrovalve International Inc. In 1989, Mr. Shaben retired from active political life to resume his business activities in the private sector. During his time with the government, he held several ministerial portfolios including Minister of Economic Development & Trade, Minister of Housing, and Minister of Utilities and Telephones. Mr. Shaben was nominated and elected to the Board of Directors of Canadian Utilities Limited in May 1995.

Nancy C. Southern

Nancy C. Southern
President and Chief Executive Officer, Canadian Utilities Limited

Nancy Southern was appointed President & Chief Executive Officer, ATCO Ltd. and Canadian Utilities Limited, effective January 1, 2003. Previously she had been Co-Chairman & Chief Executive Officer since January 2000, Deputy Chief Executive Officer since May 1998 and Deputy Chairman since January 1996 of ATCO Group. She has been a Director of the Corporation since 1990. 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 Canadian Utilities Limited 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.

Ronald D. Southern

Ronald D. Southern, C.B.E., C.M., LL.D.
Chairman of the Board of Directors, Canadian Utilities Limited

Ron Southern is Chairman of the Board, ATCO Ltd., Canadian Utilities Limited and all ATCO Group subsidiary companies. Together with his late father, S.D. Southern, Mr. Southern founded ATCO Group in 1947 and served as the company's President for 47 years. He is credited with transforming the company to what it is today – one of Canada's premier corporations with assets of $5.9 billion and employing more than 6,000 people. Mr. Southern also serves as Chairman of Akita Drilling Ltd. and Sentgraf Enterprises Ltd.

D. Logan Tait

D. Logan Tait, F.R.I., F.C.A. (3) (4)
President, Tait Management Services, Lethbridge, Alberta

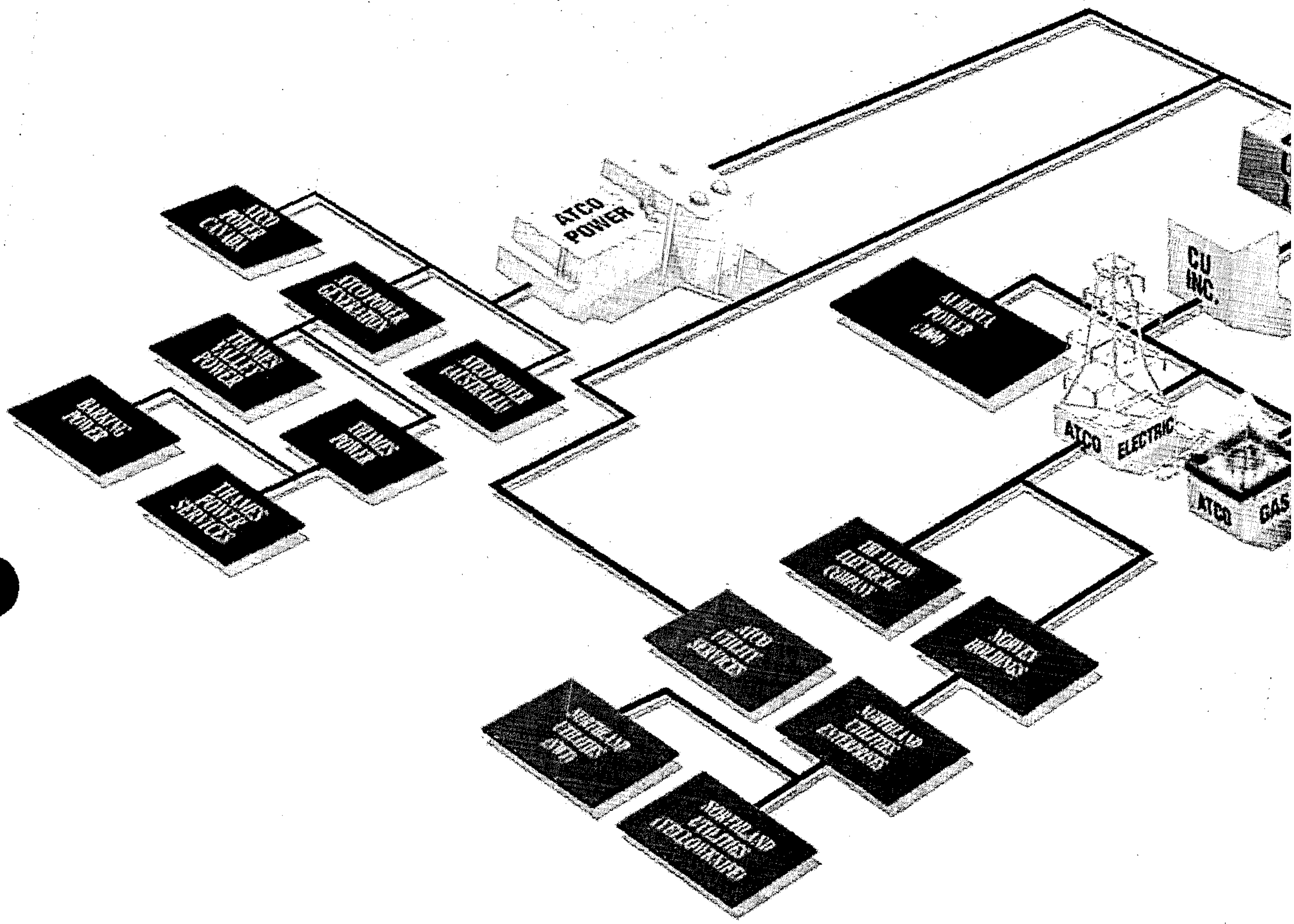
Mr. Tait is the President of Tait Management Services, a Lethbridge-based consulting firm that provides accounting services and tax advice. He has been active in the Alberta Real Estate Association and Junior Achievement of Southern Alberta and was elected a Fellow of Chartered Accountants in 1986. He was elected to the Board of Canadian Western Natural Gas in 1980 and Canadian Utilities Limited in May 1992.

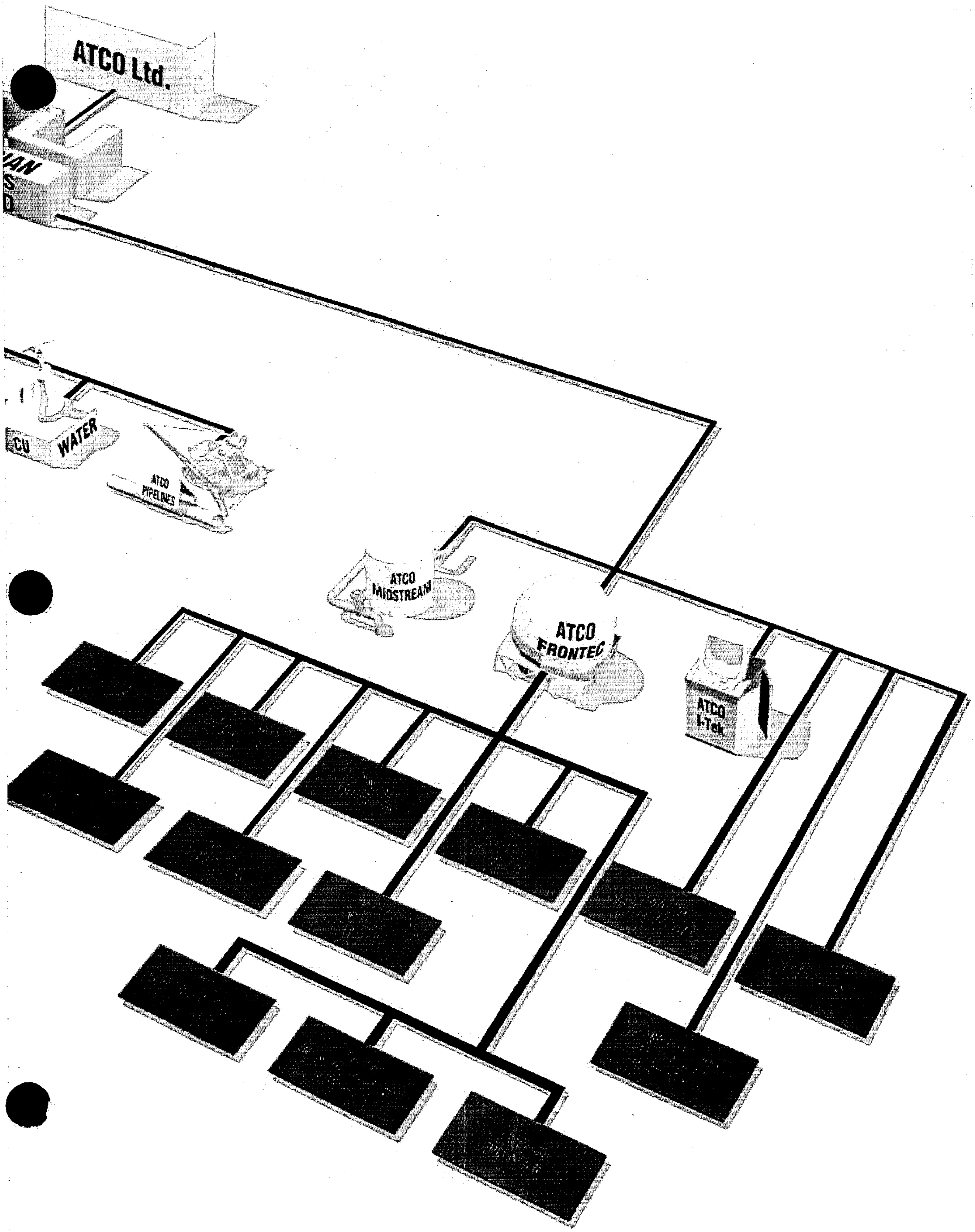
Charles W. Wilson

Charles W. Wilson (2) (3)
Corporate Director, Evergreen, Colorado

Mr. Wilson is former President, Chief Executive Officer and Director of Shell Canada Limited and 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. He was elected to the Boards of Canadian Utilities Limited in May 2000 and ATCO Ltd. in May 2002, and to the Akita Drilling Board and the Talisman Energy Board in 2002. He also serves on the Big Rock Brewery Board.

(1) Member of the Corporate Governance-Nomination, Succession and Compensation Committee
(2) Member of the Audit Committee
(3) Member of the Risk Review Committee
(4) Member of the Pension Fund Committee


ATCO POWER
CU INC.
ATCO ELECTRIC



ATCO Ltd.
WATER
ATCO PIPELINES
ATCO MIDSTREAM
ATCO FRONTEC
ATCO I-Tek

OFFICERS

OFFICERS

Ronald D. Southern
Chairman of the Board

William L. Britton, Q.C.
Vice Chairman of the Board

Nancy C. Southern
President & Chief Executive Officer

James A. Campbell
Senior Vice President, Finance & Chief Financial Officer

Denis M. Ellard
Senior Vice President, Corporate Development

Susan R. Werth
Senior Vice President & Chief Administration Officer

Dale R. Cawsey
Vice President, Human Resources & Corporate Secretary

D. Terrence Davis
Vice President, Internal Audit

Siegfried W. Kiefer
Vice President, Information Technology &
Chief Information Officer

Ladis J. Vegh
Vice President, Insurance

Karen M. Watson
Vice President, Finance & Controller

Walter A. Kmet
Vice President

Charles S. McConnell
Treasurer

Pat Spruin
Assistant Corporate Secretary & Manager
Corporate Secretarial

MANAGING DIRECTORS AND PRESIDENTS OF PRINCIPAL OPERATING SUBSIDIARIES

Gary K. Bauer
Managing Director, Power Generation
President, ATCO Power Ltd.

Paul F. Blaha
President, Genics Inc.

Richard (Rick) J. Brouwer
President, ATCO Midstream Ltd.

Jerome F. Engler
President, ATCO Gas

J. Richard (Dick) Frey
Managing Director, Utilities

J. Douglas (Doug) Graham
President, ATCO Pipelines

Siegfried W. Kiefer
Managing Director, Technologies

Roberta (Bobbi) L. Lambright
President, ATCO I-Tek

R. L. Vaughan Payne
President, ATCO Travel Ltd.

Joseph (Joe) J. Schnitzer
President, ASHCOR Technologies Ltd.

Michael M. Shaw
Managing Director, Logistics & Energy Services
President, ATCO Frontec Corp.

Richard (Dick) H. Walthall
President, ATCO Electric Ltd.

Gerry W. Welsh
President, ATCO Power Canada Ltd.

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. Wednesday, May 7, 2003 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 and W) Shares
CIBC Mellon Trust Company
Montreal/Toronto/Winnipeg/
Calgary/Vancouver

TRUSTEE AND REGISTRAR
Debentures
CIBC Mellon Trust Company
Montreal/Toronto/Calgary/Vancouver

STOCK EXCHANGE LISTINGS
Class A non-voting Symbol CU
Class B common Symbol CU.X
Listing 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
Listing 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
Web site: 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
e-mail: inquiries@cibcmellon.com

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