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Annual report 1983

NORTHWESTERN UTILITIES LIMITED

Board of Directors

J. E. Barrett, Calgary
Vice-President and General Manager
ATCO Metal/ATCO Components

B. M. Dafoe, Edmonton
Senior Vice-President
Northwestern Utilities Limited
and Canadian Western Natural Gas
Company Limited

W. D. Grace, F.C.A., Edmonton
Senior Vice-President, Finance
Canadian Utilities Limited

H. Hole, Edmonton
General Manager,
Lockerbie and Hole Western Limited

E. W. King, Edmonton
President and Chief Executive Officer
Canadian Utilities Limited

R. G. Lock, Edmonton
Vice-President and General Manager
Northwestern Utilities Limited

A. R. McBain, Edmonton
President, McBain Camera Ltd.

A. H. Mitchell, Edmonton
President, Mitchell & Associates Ltd.

A. Schieman, Calgary
Special Assistant to the
Chairman of the Board
Canadian Utilities Limited

J. L. Schlosser, Edmonton
President, Tri-Jay Investments Ltd.

R. D. Southern, Calgary
President and Chief Executive Officer
ATCO Ltd.

J. D. Wood, Calgary
President and Chief Executive Officer
ATCOR Resources Limited

Officers

R. D. Southern
Chairman of the Board

J. D. Wood
Deputy Chairman of the Board

E. W. King
President and Chief Executive Officer

B. M. Dafoe
Senior Vice-President

R. G. Lock
Vice-President and General Manager

W. L. Graburn
Vice-President, Gas Supply

W. D. Grace
Vice-President

D. B. Mitchell
Vice-President, Human Resources

A. M. Anderson
Secretary/Treasurer

H. R. Lewis
Controller

J. H. Cook
Assistant Secretary

C. K. Sheard
Assistant Secretary

Metric Conversion

This annual report presents all measurement statistics using the SI system of units. The following information is provided to assist readers who wish to convert to other units.

Conversion Factors

SI	Equivalent
1 kilometre (km)	0.6214 miles
1 millimetre (mm)	0.0394 inches
1 joule	0.000948 British thermal units (Btu)
1 gigajoule (GJ)	948.2133 cubic feet*
1 terajoule (TJ)	1,000 gigajoules (GJ)
1 petajoule (PJ)	1,000 terajoules (TJ)

* based on 1,000 Btu's per cubic foot.

NORTHWESTERN UTILITIES LIMITED
(Incorporated under the laws of Canada)
and subsidiary: Northland Utilities (B.C.) Limited
10035 - 105 Street, Edmonton, Alberta, Canada T5J 2V6

NORTHWESTERN UTILITIES LIMITED

Report to Shareholders

Northwestern Utilities Limited reached two significant milestones in 1983: The Company observed its 60th anniversary of natural gas service and Northwestern now provides service to more than 300,000 customers. A growth rate of 2½% was achieved in 1983, with 7,385 customers added, up from 6,899 in 1982. This does not include 1,251 new customer accounts which were created when two military bases were converted to individual metering. At year-end, the Company was serving 306,193 customers in 175 communities.

These achievements have been possible through the strengths and dedication of the Company's past and present employees. The tradition of safe and reliable service established by employees is sincerely appreciated. Extra effort and cooperation were demonstrated as employees moved from the Milner Building and Service Centre to the new Canadian Utilities Centre at 10035 - 105 Street, Edmonton. This allowed for consolidation of the Company's engineering, technical and administrative staff. The Centre has the potential to meet future growth requirements.

As adverse economic conditions continued to impact on the Company, restraint measures affecting operating and capital expenditures were maintained. Operating under the second year of a two-year agreement with its employees' association, restrictions on hiring and job reclassifications were continued. Although customer growth continued during the year, the number of employees was further reduced from 1,366 to 1,350. Longer working hours were maintained for supervisory, management, professional and other staff not included within the scope of the agreement.

Earnings are directly dependent on the effects of weather and investment in facilities required to serve customers. Historically, the Company has achieved earnings consistent with the rate of asset growth and changes in the costs of capital. During 1983, the Company's net property, plant and equipment required to serve customers increased by 19.4% to $425.0 million.

In terms of degree days — a measure of space heating requirements — 1983 was 11% warmer than 1982. The degree days experienced in 1983 were 5,362 compared to 6,025 in 1982. In addition, colder temperatures in mid-December resulted in higher natural gas supply expense which will be recovered through customer billings in January 1984. Earnings attributable to common shares were $15.6 million ($5.37 per common share) compared to $21.3 million ($8.77 per common share) in 1982.

The combined total of natural gas sold and transported was 277,780 terajoules (TJ), up from 261,537 TJ in 1982. Within this total, sales alone declined to 163,949 TJ from 193,815 TJ in 1982. Sales to temperature sensitive customers attributable to the warmer 1983 temperatures decreased by 14,882 TJ. The remainder of the decline was largely due to reduced purchases by Edmonton Power and other industrial customers. The growth in customers experienced in the residential and commercial market sectors was largely offset by a sales decline due to increased energy conservation. An increase in the amount of gas transported by the Company for others has more than offset the impact of the sales decline. During 1983, gas transported for exporting companies for delivery to the NOVA system and for industrial customers to meet their process needs was 113,831 TJ compared to 67,722 TJ in 1982.

In June of 1983, the Alberta Public Utilities Board issued its decision for the rate application filed in June of 1982 setting the Company's rate base, rate of return and revenue requirements. The decision was reflected in the interim rates effective August 1, 1983 and resulted in a refund to customers of $12.9 million. Final rates were approved by the Board on January 31, 1984.

Effective February 1 and August 1, 1983 the Board approved reductions in rates as increases in the cost of natural gas supply were offset by increased shielding through the Alberta Natural Gas Price Protection Plan and decreases in the Federal Excise Tax.

Consolidated revenues for 1983 were $487.0 million, $30.7 million lower than in 1982, largely attributable to warmer than normal temperatures and rate reductions. In addition, the substitution of transportation for sales to certain industrial customers resulted in lower expense associated with gas supply and therefore lower revenue. Operating expenses, including the cost of natural gas supply, operations, maintenance, taxes other than income, income taxes, and depreciation amounted to $457.4 million, down from $480.8 million in 1982. The Company's largest expense items continue to be the cost of natural gas supply and related taxes.

Natural gas supply costs increased by $23.6 million to $267.6 million net of rebates. Rebates of $48.1 million received from the Alberta Government under the Natural Gas Price Protection Plan shielded eligible Alberta consumers from the full cost of natural gas purchased. Rebates totalled $49.6 million in 1982.

Total taxes paid to all levels of government decreased $50.7 million to $118.9 million in 1983, and amounted to 24.4% of total Company revenue compared to 32.8% in 1982. Federal taxes resulting from the National Energy Program amounted to $79.6 million, a decrease of $50.8 million from 1982. As world energy prices declined, the Federal Natural Gas and Gas Liquids Tax was reduced to allow the price differential between oil and gas to be maintained at the Toronto gate. This tax was decreased to 45¢ per gigajoule (GJ) on February 1, 1983 and further decreased to 15¢ per GJ on August 1, 1983. The Petroleum and Gas Revenue Tax on net production revenue, which was implemented January 1, 1981, was increased to 12% from 11% on June 1, 1983. The Company continues to pay to the Federal Government the Canadian Ownership Tax of 14¢ per GJ implemented May 1, 1981.

Municipal property and franchise taxes paid to municipalities were $26.2 million, a decrease of $1.6 million from 1982 due mainly to reduced sales and rate reductions. Provincial mineral taxes increased from $1.3 million to $1.6 million in 1983.

The Company's capital additions to provide for customer growth decreased slightly from 1982. However, other projects necessary to assure security of supply during peak demand periods brought total capital additions to $80.2 million. The capital program was partially financed by an issue of preferred shares to the parent company, Canadian Utilities Limited, in the amount of $22.0 million.

During 1983, construction of the salt cavern gas peaking project near Fort Saskatchewan continued. Two caverns of the first phase and related gas handling facilities will be available to meet the peak load projected for the 1984-1985 heating season. The project will result in the most cost effective method of meeting current peaking requirements.

The $4.9 million Keephills-Genesee transmission line was completed in 1983. The project will serve the Edmonton Power Genesee and the TransAlta Keephills power plants. Construction commenced on the $3.2 million transmission line to loop the Esso lateral in 1983. This line will serve the Shell Scotford refinery, Shell styrene plant and will connect the existing Esso Chemical lateral to the new salt cavern facilities.

Northland Utilities (B.C.) Limited, which had been providing propane service to the new coal mining community of Tumbler Ridge since 1982, began conversions to natural gas in late 1983. By year-end the Company was serving 547 customers with natural gas or propane. Expenditures for gas processing, transmission and distribution facilities were $5.0 million. The British Columbia Utilities Commission issued a decision on Northland's general rate application establishing the Company's rate of return and authorizing a uniform rate system.

The Company participated in the drilling of 38 wells and the purchase of an additional 3. Of the wells drilled, 21 were successful, 4 were being evaluated and 6 were in progress at year-end. The Company negotiated farmouts on certain of its lands and 11 farmout wells have been drilled of which 8 were successful. The cost of successful wells was added to assets and the cost of unsuccessful projects will be recovered, with Public Utilities Board approval, from border flowback. Under the border flowback program, all Alberta gas producers, including Northwestern, receive a pro rata share of the revenues generated by the differential in price between gas exported to the United States and that marketed in Canada.

During 1984 the Company will continue to seek opportunities for continued growth and expansion. Although a prolonged period of recovery is forecast, assisted by the re-assessment of tar sands and heavy oil projects in Northern Alberta, only moderate growth is expected in the near term. The economic benefits of these projects would be distributed throughout the province, including Edmonton which would serve as the supply base.

On behalf of the Board of Directors,

R.D. Southern
Chairman of the Board

E.W. King

E.W. King
President and Chief Executive Officer

February 16, 1984

NORTHWESTERN UTILITIES LIMITED

Highlights in Review

	1983	1982	1981	1980	1979	1973
STATISTICAL						
Customers at year-end	**306,193**	* 297,557	290,658	276,295	260,133	178,123
Natural gas sales — TJ	**163,949**	193,815	224,316	231,944	231,258	162,613
Transportation of natural gas — TJ	**113,831**	67,722	41,394	37,091	27,629	9,057
Total sales and transportation — TJ	**277,780**	261,537	265,710	269,035	258,887	171,670
Kilometres of pipeline	**16,326**	15,818	15,163	14,474	13,613	8,784
Maximum daily demand — TJ	**1,175**	1,235	1,258	1,179	1,132	706
Communities served	**175**	171	161	161	160	153
Population served — thousands	**998**	988	948	906	870	709
Degree days — % normal	**96**	108	82	97	102	97
Owned gas reserves — PJ	**718**	746	731	790	790	667
FINANCIAL (thousands of dollars except per share data)						
Revenue	**487,037**	517,715	458,619	341,105	276,676	47,811
Earnings attributable to common shares	**15,581**	21,295	13,062	10,391	10,363	4,000
Earnings per common share	**5.37**	8.77	5.54	4.44	4.54	2.21
Capital additions	**80,169**	81,646	48,402	45,075	42,979	8,941
Gross plant	**532,000**	453,417	373,254	325,515	280,916	139,092

* Revised to delete inactive premises.

Auditors' Report

To the Shareholders of
Northwestern Utilities Limited:

We have examined the consolidated balance sheet of Northwestern Utilities Limited as at December 31, 1983 and the consolidated statements of earnings and retained earnings and changes in financial position for the year then ended. Our examination was made in accordance with generally accepted auditing standards, and accordingly included such tests and other procedures as we considered necessary in the circumstances.

In our opinion, these consolidated financial statements present fairly the financial position of the Company as at December 31, 1983 and the results of its operations and the changes in its financial position for the year then ended in accordance with generally accepted accounting principles applied on a basis consistent with that of the preceding year.

Price Waterhouse

Chartered Accountants

Edmonton, Canada
February 1, 1984

Consolidated Statement of Earnings and Retained Earnings

	Note	1983	1982
		Year ended December 31	
		(Thousands)	
Revenues		$487,037	$517,715
Operating Expenses			
Natural gas supply	1	267,646	244,037
Operation and maintenance		61,107	56,550
Taxes — other than income	2	107,317	159,437
Taxes — income	3	11,601	10,149
Depreciation		9,763	10,665
		457,434	480,838
		29,603	36,877
Allowance for Funds Used During Construction		8,630	2,982
Dividend Income from Affiliate		184	550
Interest Income		2,208	3,531
		40,625	43,940
Interest on Loans from Parent Company		13,440	11,341
Interest Expense		2,054	2,232
Dividends on Preferred Shares	9	9,550	9,072
		25,044	22,645
Earnings Attributable to Common Shares		15,581	21,295
Retained Earnings at Beginning of Year		61,962	51,442
		77,543	72,737
Deduct			
Dividends on common shares		10,501	10,775
Retained Earnings at End of Year		$ 67,042	$ 61,962
Earnings per Common Share		$ 5.37	$ 8.77

Consolidated Balance Sheet

	Note	December 31 1983	1982
		(Thousands)	
ASSETS			
Current Assets			
Accounts receivable	4	**$ 72,210**	$ 86,646
Owing by parent and affiliated companies		**109**	29,750
Materials and supplies		**5,047**	4,387
Income tax recoverable		**1,137**	142
Prepaid expenses		**678**	1,040
		79,181	121,965
Investment in Affiliated Company — at cost		**2,158**	2,158
Property, Plant and Equipment	5	**425,000**	355,873
Deferred Expenses	6	**20,384**	26,142
		$526,723	$506,138
LIABILITIES AND CAPITAL			
Current Liabilities			
Due to bank		**$ 7,354**	$ 15,797
Accounts payable and accrued liabilities		**72,666**	65,262
Income and other taxes		**13,924**	27,974
Dividends payable		**2,196**	1,870
Owing to parent and affiliated companies		**11,626**	9,678
Long-term debt — current maturities		**3,050**	4,914
		110,816	125,495
Deferred Credits			
Contributions for extensions to plant		**53,963**	47,232
Deferred income taxes		**2,437**	357
Other	7	**30,583**	27,161
		86,983	74,750
Capitalization			
Long-term debt	8	**115,280**	118,844
Preferred shares	9	**104,926**	83,411
Common shareholders' equity	10	**108,718**	103,638
		328,924	305,893
		$526,723	$506,138

Approved by the Board:

E.W. King

E.W. King, Director

R.G. Lock

R.G. Lock, Director

NORTHWESTERN UTILITIES LIMITED

Consolidated Statement of Changes in Financial Position

	Year ended December 31	
	1983	1982
	(Thousands)	
Sources of Funds		
Internal sources		
Earnings attributable to common shares	**$15,581**	$21,295
Depreciation	**9,763**	10,665
Other	**1,754**	861
Allowance for funds used during construction — shareholder's equity	**(3,349)**	(1,484)
Provided by operations	**23,749**	31,337
Deduct dividends on common shares	**10,501**	10,775
Provided internally	**13,248**	20,562
External sources		
Issue of long-term debt		30,000
Issue of preferred shares	**22,000**	12,000
Issue of common shares		21,000
Contributions for extensions to plant	**7,418**	8,920
Disposition of property, plant and equipment	**78**	198
Other	**5,164**	5,703
Provided externally	**34,660**	77,821
	$47,908	$98,383
Disposition of Funds		
Purchase of property, plant and equipment	**$80,169**	$81,646
Increase (decrease) in deferred expenses for natural gas exploration — net	**(7,659)**	464
Allowance for funds used during construction — shareholders' equity	**(3,349)**	(1,484)
	69,161	80,626
Reduction in long-term debt	**3,564**	3,508
Preferred shares purchased for cancellation	**485**	865
Increase in other deferred expenses	**2,804**	3,560
Increase (decrease) in working capital	**(28,106)**	9,824
	$47,908	$98,383

NORTHWESTERN UTILITIES LIMITED

Summary of Significant Accounting Policies

December 31, 1983

Consolidated Financial Statements

The consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles and conform in all material respects with the International Accounting Standards adopted by the International Accounting Standards Committee.

The consolidated financial statements include the accounts of Northland Utilities (B.C.) Limited.

The preferred dividends are recorded in the same manner as interest expense in the consolidated statement of earnings and retained earnings. The capitalization segment of the consolidated balance sheet and the consolidated statement of earnings and retained earnings reflect the financing and cost of capital policies of the Company as a regulated utility in Alberta. Revenues are recognized on the basis of cycle billing and are recorded when customers are billed.

Regulation

The Company is regulated primarily by the Public Utilities Board of Alberta and the Energy Resources Conservation Board of Alberta, which administer acts and regulations covering such matters as rate design, rate making, financing, accounting, construction, operation and service area. Decisions made by these authorities which impact on operating results or accounting policies are reflected in the accounts from the date of decision. Customer refunds are recorded when known.

Property, Plant and Equipment

The Company includes in the cost of additions, an allowance for funds used during construction, at a rate approved by the Public Utilities Board for debt and equity funds.

Certain additions are made with assistance of cash contributions where 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.

On retirement of depreciable assets, the accumulated depreciation is charged with the cost of the retired unit less net salvage. Gains and losses on extraordinary retirements are recognized in earnings as extraordinary items.

Included in the Company's Property, Plant and Equipment are gas wells that have been drilled, tested and capped and remain unconnected to the utility system. The Public Utilities Board has directed that the costs of such wells, including an allowance for funds, be accounted for as plant held for future use. If, after a period of five years, these wells have not been added to the utility system, the costs will be written off against funds received under The Natural Gas Price Administration Act.

If at a future date a gas well is placed in service or is required to be used, the amount written off will be reinstated in Property, Plant and Equipment.

Depreciation is provided on assets on a straight-line basis over their estimated useful lives. The major assets are depreciated using rates approved by the Public Utilities Board varying from 1.8% to 8.3%. All resource properties are depreciated on a unit of production basis.

Leases

The Public Utilities Board requires that application be made for the capitalization of leases in the determination of customer rates. Prior to such approval, leases that would otherwise be treated as capital leases are accounted for as operating leases.

Inventories

Inventories are valued at the lower of cost or market. Costs for materials and supplies are determined on an average basis, whereas the cost of natural gas stored is determined on a first in, first out basis.

Deferred Expenses

The Company includes in gas exploration all costs, including an allowance for costs of capital, related to the development of gas reserves. These costs are recorded net of income taxes. Costs related to a successful venture are capitalized as plant and equipment. The costs of an unsuccessful venture are charged against deferred credits, as noted below.

Expenses of issue of long-term debt are amortized over the weighted average life of the debt and expenses of issue of preferred shares are amortized over the lesser of the expected life of the issue or 30 years.

Deferred Credits

As an Alberta gas producer, the Company receives a pro rata share of monies available under The Natural Gas Price Administration Act. The amounts received, net of royalties and income taxes, are deferred and, subject to Public Utilities Board approval, are reduced by the costs of unsuccessful gas exploration.

Taxes — Income

In determining the provision for income taxes the Company follows the normalization — all taxes paid method as approved by the Public Utilities Board. Under this method, there is no deferral of income taxes as capital cost allowance is claimed in the same amount as depreciation net of other items which give rise to timing differences between accounting and taxable income. Prior to adoption of this method, the Company followed the flow-through method and deductions claimed in calculating taxable income exceeded the expenses recorded in the accounts, thereby reducing income taxes otherwise payable. As the income tax component of rates only recovers income taxes currently payable, no provision has been made in the consolidated financial statements for the deferred taxes accumulated in prior years when the Company used the flow-through method. The customer in future years will bear an additional charge in the event that expenses exceed deductions for income tax purposes. The unbooked deferred tax balance is not expected to change significantly in the foreseeable future.

Under The Public Utilities Income Tax Transfer Act and The Utility Companies Income Tax Rebates Act the major portion of income taxes paid are refunded for rebate to customers.

Natural Gas Supply

The Province of Alberta enacted The Natural Gas Rebates Act effective January 1, 1974 to shelter the majority of Alberta natural gas customers from the full impact of significant price increases for natural gas. Under the provisions of the Act, the Company incurs a lower effective cost for natural gas in that it is reimbursed for the portion of the price paid to its suppliers which exceeds the support price.

Notes to Consolidated Financial Statements

December 31, 1983

1. Natural gas supply

The natural gas supply expense is net of a rebate from the Province of Alberta of $48,126,000 (1982 — $49,595,000).

2. Taxes — other than income

	Year ended December 31	
	1983	1982
	(Thousands)	
Federal natural gas and gas liquids taxes	**$ 53,129**	$102,482
Federal petroleum and natural gas revenue taxes	**5,570**	4,010
Federal Canadian ownership taxes	**20,880**	23,917
	79,579	130,409
Franchise taxes	**23,314**	25,063
Property taxes	**2,870**	2,705
Provincial mineral taxes	**1,554**	1,260
	$107,317	$159,437

3. Taxes — income

The actual income tax rate differs from the statutory rate as follows:

	Year ended December 31	
	1983	1982
Statutory income tax rate	**47.9%**	48.8%
Capital cost allowance and resource expenditures claimed in excess of depreciation	**(1.4)**	(16.9)
Allowance for funds used during construction	**(9.6)**	(3.6)
Crown royalties and other non-deductible Crown payments	**23.3**	17.5
Earned depletion and resource allowance	**(18.9)**	(10.8)
Investment tax credit	**(.9)**	(1.7)
Alberta royalty tax credit	**(7.2)**	(6.2)
Other	**(1.6)**	(2.1)
Actual income tax rate	**31.6%**	25.0%

The income tax provision is derived by applying the actual income tax rate to earnings attributable to common shares increased by dividends on preferred shares and taxes — income.

Income tax expense includes deferred taxes of $1,310,000 (1982 — a deferred tax credit of $889,000).

A provision for certain deferred taxes is not included in the consolidated financial statements. Unbooked deferred taxes increased during the year by $1,134,000 (1982 — $8,058,000) to an accumulated amount of $35,522,000. Effective January 1, 1983 the Company changed from the flow-through method to the normalization — all-taxes-paid method of income tax accounting.

4. Accounts receivable

	December 31	
	1983	1982
	(Thousands)	
Customer accounts	**$51,807**	$56,039
Receivable from the Province of Alberta	**17,330**	24,797
Other receivables and deposits	**3,073**	5,810
	$72,210	$86,646

5. **Property, plant and equipment**

	December 31			
	1983		1982	
	Cost	**Accumulated Depreciation**	Cost	Accumulated Depreciation
	(Thousands)		(Thousands)	
Plant and equipment	**$508,931**	**$107,000**	$439,958	$97,544
Construction work in progress	**18,148**		9,067	
Land	**4,921**		4,392	
	$532,000	**$107,000**	$453,417	$97,544
Net property, plant and equipment	**$425,000**		$355,873	

Plant held for future use in the amount of $20,226,000 is included in plant and equipment at December 31, 1983.

6. **Deferred expenses**

	December 31	
	1983	1982
	(Thousands)	
Gas exploration — net	**$16,999**	$22,939
Unamortized debt and preferred share issue expenses	**2,852**	2,869
Other	**533**	334
	$20,384	$26,142

7. **Other deferred credits**

	December 31	
	1983	1982
	(Thousands)	
Funds received under The Natural Gas Price Administration Act — net	**$27,936**	$24,374
Other	**2,647**	2,787
	$30,583	$27,161

During the year $1,577,000 (1982 — $NIL) of unsuccessful gas exploration costs, net of related income taxes, were charged against monies received under The Natural Gas Price Administration Act.

8. **Long-term debt**

Long-term debt outstanding, net of current maturities, is as follows:

	December 31	
	1983	1982
	(Thousands)	
First mortgage sinking fund bonds 5⅜% to 9¾% due to 1994	**$ 12,942**	$ 13,669
Sinking fund debentures 7¼% due 1985	**2,070**	2,176
Sinking fund debentures payable to parent company 8.57% to 17.50% due to 2002	**100,268**	102,999
	$115,280	$118,844

Annual repayment of maturing issues and sinking fund requirments for each of the following years are:

	Maturing Issues	Sinking Fund		Total
		Requirements	Purchased in Advance	
		(Thousands)		
1984	$	$3,489	$(439)	$ 3,050
1985	2,070	4,183	(114)	6,139
1986		5,083		5,083
1987	20,000	5,083		25,083
1988	4,440	4,768		9,208

9. Preferred shares

Authorized:

105,000 4% Cumulative Redeemable Preferred Shares; voting, non-participating.

An unlimited number of Series Second Preferred Shares, issuable in series, which have been designated as Cumulative Redeemable Second Preferred Shares.

Issued:

		December 31			
		1983		1982	
		Shares	**Amount (Thousands)**	Shares	Amount (Thousands)
Cumulative Redeemable Preferred Shares					
4%		105,000	**$10,500**	105,000	$10,500
Cumulative Redeemable Second Preferred Shares					
Non-retractable					
10¼%	Series A	105,700	**2,643**	105,950	2,649
9.24%	Series B	443,938	**11,098**	455,000	11,375
7.30%	Series C	204,680	**5,117**	211,040	5,276
			29,358		29,800
Retractable					
10.12%	Series E	463,441	**11,586**	465,186	11,629
14.00%	Series F	1,199,280	**29,982**	1,199,280	29,982
14.50%	Series G	480,000	**12,000**	480,000	12,000
8.74%	Series I	880,000	**22,000**		
			75,568		53,611
			$104,926		$83,411

During 1983 the Company issued for cash $22,000,000 of Series I Cumulative Redeemable Second Preferred Shares.

Stated Values, Redemption Premiums and Dividends:

		Stated Value	Maximum Redemption Premium	Dividends Year ended December 31 **1983** (Thousands)	Dividends Year ended December 31 1982 (Thousands)
Cumulative Redeemable Preferred Shares					
4%		$100	4%	**$ 420**	$ 420
Cumulative Redeemable Second Preferred Shares					
Non-retractable					
10¼%	Series A	$ 25	2%	**271**	276
9.24%	Series B	$ 25	3%	**1,045**	1,064
7.30%	Series C	$ 25	3.2%	**381**	389
				2,117	2,149
Retractable					
10.12%	Series E	$ 25	4%	**1,174**	1,185
14.00%	Series F	$ 25	4%	**4,198**	4,198
14.50%	Series G	$ 25	4%	**1,740**	1,540
8.74%	Series I	$ 25	4%	**321**	
				7,433	6,923
				$9,550	$9,072

Redemption

The preferred shares of the Company are redeemable subject to premiums listed, above, plus accrued dividends. The Cumulative Redeemable Preferred Shares and the non-retractable Cumulative Redeemable Second Preferred Shares are redeemable at the option of the Company at any time. The retractable Cumulative Redeemable Second Preferred Shares will be subject to redemption at the option of the Company as of the dates specified below:

Series E	March 1, 1986
Series F	October 1, 1986
Series G	May 1, 1987
Series I	November 1, 1988

Purchase Obligations

The Company's parent company, Canadian Utilities Limited, is required in each year to make all reasonable efforts to purchase for cancellation the number of shares of the Cumulative Redeemable Second Preferred Shares listed below at a price not exceeding $25 per share plus costs of purchase. If after all reasonable efforts the parent company is unable to do so, the obligation to purchase shares in such year is extinguished. The Company's requirement to purchase will be limited to its proportionate share of the corresponding issue that the parent company has been able to acquire.

		Current Purchase Obligation	Purchased in 1983 Shares	Purchased in 1983 Amount
				(Thousands)
10¼%	Series A	4,800	250	$ 6
9.24%	Series B	15,000	11,062	276
7.30%	Series C	7,200	6,360	159
10.12%	Series E	9,600	1,745	44
14.00%	Series F	48,000		
14.50%	Series G	19,200		
8.74%	Series I	26,400		
				$485

Retraction Privileges

Certain series of the Cumulative Redeemable Second Preferred Shares have retraction privileges on specified dates at the option of the holder at the stated value plus accrued dividends. The series and retraction dates are shown below:

Series E	March 1, 1988
Series F	September 28, 1984 and September 29, 1989
Series G	May 1, 1987
Series I	November 1, 1991

10. Common shareholders' equity

	December 31 1983	December 31 1982
	(Thousands)	
Common shares	$ 41,676	$ 41,676
Retained earnings	67,042	61,962
	$108,718	$103,638

Common shares

Authorized:

An unlimited number of shares without nominal or par value.

Issued:

	Shares	Amount
		(Thousands)
December 31, 1983	2,900,528	$41,676

Retained earnings

The bond and debenture indentures place certain limitations on the Company which include restrictions on the payment of dividends on common shares. Consolidated retained earnings in the amount of $18,835,000 was free from such restrictions.

11. **Commitments**

Minimum non-capitalized lease payments, which extend over periods not exceeding 10 years are $1,771,000, $1,534,000, $1,300,000, $1,068,000 and $834,000 for the years 1984-1988, respectively.

The Company has a defined benefit pension plan covering substantially all employees. Pension expense for the year amounted to $3,743,000 (1982 — $3,205,000) including past service costs of $1,337,000 (1982 — $1,149,000). Based on the most recent actuarial evaluation, December 31, 1980, the estimated unfunded past service liability at December 31, 1983 amounts to approximately $9,100,000 which will be funded over a period not exceeding 13 years.

12. **Amount held in trust**

The amount held in trust for income tax rebates, which is not included in the consolidated financial statements, is $6,379,000 (1982 — $3,798,000).

13. **Related party transactions**

Certain costs of administration, systems development and financial management are provided by the parent company, Canadian Utilities Limited. These costs are allocated to the Company on the basis of usage and on the basis of assets and employees. Total charges amounted to $7,084,000 (1982 — $7,057,000). The above charges and inter-company financing transactions are subject to review by the Public Utilities Board.

Transactions with affiliated companies include the purchase of natural gas for $3,010,000 (1982 — $1,206,000), revenue from the sale of natural gas of $18,178,000 (1982 — $16,665,000), revenue from transportation of natural gas of $3,999,000 (1982 — $1,423,000) and engineering services of $176,000 (1982 — $823,000) Payments were made to ACTO Ltd., an affiliated company, for management fees of $175,000 (1982 — $169,000). The Company participates in numerous oil and natural gas joint ventures. When the Company acts as operator it has, in some instances, contracted ATCO Ltd. subsidiaries for well drilling and servicing, equipment purchases and related services, the total amount being approximately $1,700,000. A portion of these expenditures is reimbursed by the other participants in the joint ventures. A subsidiary of ATCO Ltd. acted as a general contractor for the construction of a fleet repair shop and an operation warehouse complex. Fees of $159,000 (1982 — $Nil) charged by the subsidiary include the recovery of certain administrative costs. These transactions are considered to be in the normal course of business and at fair value.

14. **Financial statements**

Certain of the 1982 figures have been reclassified to conform with the consolidated financial statement presentation adopted in 1983.

15. **Subsequent events**

The Company entered into an agreement on February 1, 1984 with its parent company, Canadian Utilities Limited, for the sale of 108,000 Cumulative Redeemable Second Preferred Shares Series J of the Company to yield 8.375% at a price of $25 per share, amounting to $2,700,000. The net proceeds to the Company are estimated to be $2,690,000 after deducting expenses of issue.

The Company announced on February 1, 1984 that it will redeem on March 5, 1984 all 10¼% Cumulative Redeemable Second Preferred Shares Series A. The redemption price will be $25.25 per share plus $0.45 of accrued dividends amounting to $2,716,000.

Management's Responsibility for Financial Reporting

The consolidated financial statements and other financial information relating to the Company contained in this annual report have been prepared by management, which is responsible for the integrity and objectivity of this information. The consolidated financial statements have been prepared in conformity with Canadian generally accepted accounting principles as applied to regulated utilities and conform in all material respects with International Accounting Standards. These consolidated financial statements necessarily include some amounts that are based on informed judgments and best estimates of management.

Management depends upon a system of internal accounting controls to meet its responsibility for reliable and accurate reporting, which includes periodic reviews by the internal audit function. Management modifies and improves its system of internal accounting controls in response to changes in business conditions. The Board of Directors oversees management's responsibility for financial reporting.

Price Waterhouse, our independent auditors, are engaged to express a professional opinion on the consolidated financial statements. The examination is conducted in accordance with generally accepted auditing standards and includes tests and other procedures which allow the auditors to report on the fairness of the consolidated financial statements prepared by management.

TRANSFER AGENT AND REGISTRAR

Montreal/Toronto/
Edmonton/Calgary

Preferred Shares
Guaranty Trust Company of Canada

TRUSTEES AND REGISTRARS

Halifax/Montreal/Toronto/
Winnipeg/Regina/Edmonton/
Vancouver

Bonds
Montreal Trust Company

Montreal/Toronto/
Edmonton/Vancouver

Debentures
Canada Permanent Trust Company

AUDITORS

Price Waterhouse
2401 Toronto Dominion Tower
Edmonton Centre
Edmonton, Alberta

ANNUAL MEETING

The annual meeting of shareholders will be held in Edmonton, Alberta on April 18, 1984.

NORTHWESTERN UTILITIES LIMITED

A Subsidiary of Canadian Utilities Limited
An ATCO Company

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