Annual Report 1982
NORTHWESTERN UTILITIES LIMITED

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Vice-President and General Manager
ATCO Metal Ltd.

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

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A. H. Mitchell, Edmonton
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***A. Schieman,** Calgary
Vice-President, Industrials Group
ATCO Industries (N.A.) Ltd.

***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

* members of Audit Committee

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

W. D. Grace
Vice-President

R. G. Lock
Vice-President and General Manager

W. L. Graburn
Vice-President, Gas Supply

D. B. Mitchell
Vice-President, Human Resources

A. M. Anderson
Secretary/Treasurer

H. R. Lewis
Controller

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
10040 - 104 Street, Edmonton, Alberta, Canada T5J 2S3

NORTHWESTERN UTILITIES LIMITED

Report to the Shareholders

The downturn experienced in the Alberta economy during 1982 resulted in adjustments in the operations of Northwestern Utilities Limited. As the housing industry and other business sectors struggled with high interest rates and a lack of consumer confidence, the Company's new customer growth rate was halved. During 1982, 7,617 customers were added, down from 14,363 in 1981. At year-end the Company was serving 298,275 customers. Anticipating slower growth and the financial constraints faced by customers, the Company implemented restraint measures affecting operating and capital expenditures.

Operating under the first year of a two-year agreement with its employees' association, the extent of the Company's restraint measure implementation was limited. Hiring and job reclassifications were restricted and during the year the number of employees was reduced from 1,536 to 1,366. Longer working hours were also introduced for supervisory, management, professional and other staff not included in the scope of the agreements and, in addition, for 1983, this employee group received salary increases consistent with the Federal Government guidelines.

In these difficult times, the Company is especially dependent on the dedication and strengths of its employees. The efforts of employees in providing a high level of safe and reliable service is sincerely appreciated. During the year the Company staff provided an excellent demonstration of these efforts. After fire destroyed the Customer Information Centre with more than $500,000 damage, the staff was able to restore service within 24 hours operating from the basement of the Milner Building. Demonstrating the unique comradeship and dedication that has characterized the Company's employees for 60 years, they performed their duties in an outstanding manner.

Earnings are directly dependent on investment in facilities required to serve customers and the effects of weather. Historically, the Company has been able to achieve earnings consistent with the rate of asset growth and changes in the costs of capital. During 1982, the Company's capital assets required to serve customers increased by 24.4% to $355.9 million. In terms of degree days — a measure of space heating requirements — 1982 was 31% colder than 1981. The degree days experienced in 1982 were 6,025 compared to 4,595 in 1981. Earnings attributable to common shares were $21.3 million ($8.77 per common share) compared to $13.1 million ($5.54 per common share) in 1981.

The Company applied to the Alberta Public Utilities Board for three rate increases during 1982. The first change, effective February 1, 1982, was requested to recover higher costs resulting from an increase in the price of gas under the Federal-Provincial Energy Pricing Agreement and an increase in the Federal excise tax. The second change in rates, effective August 1, 1982, was requested to recover higher costs resulting from a further increase in the price of gas under the Federal-Provincial Energy Pricing Agreement. Prompt approval was granted by the Board in these two applications. The third increase, effective September 1, 1982 on an interim refundable basis, was the first since August 1980 due to higher costs in areas such as financing, labour and materials related to both growth and general inflation. The Company's application, filed in June 1982, was heard before the Public Utilities Board during a two-week intensive public hearing in December. A decision on the first phase concerning the amount of revenue required in both 1982 and 1983 by the Company is anticipated in the second quarter of 1983.

The British Columbia Utilities Commission finalized rates for Northland Utilities (B.C.) Limited, which had been approved on an interim basis in August 1981. The Commission also acted expeditiously to approve the passing on of costs relating to the increase in Federal excise tax and the introduction of a surcharge on natural gas by the British Columbia Government.

The combined total of natural gas sold and transported was 261,537 terajoules (TJ), down from 265,710 TJ in 1981. Sales to residential and commercial customers were substantially higher in 1982 over 1981 because of colder than normal temperatures. During 1981, the Company experienced the warmest temperatures recorded by government documents kept over the past 100 years, whereas the year 1982 was the coldest on record since 1955. Sales to temperature sensitive customers attributable to the weather effects between the two years grew by 21,902 TJ. In spite of these increases in sales to residential and commercial customers, overall sales declined from 224,316 TJ in 1981 to 193,815 TJ in 1982, due in part to reduced purchases by Edmonton Power and other industrial customers. As well, 1981 sales included non-recurring short-term sales to some industrial customers. The impact of the sales decline has been partially offset by an increase in the amount of gas transported by the Company for others. During 1982, gas transported for exporting companies for delivery to the Nova system, and for industrial customers for delivery to their plant sites, was 67,722 TJ compared to 41,394 TJ in 1981.

A sales decline in all sectors because of increased energy conservation was partly offset by the growth experienced in the residential and commercial market sectors.

Consolidated revenues for 1982 were $517.7 million, $59.1 million higher than in 1981. Operating expenses, including the cost of natural gas, operations, maintenance, depreciation, taxes other than income tax and income taxes, amounted to $480.8 million, compared to $433.4 million in 1981. The Company's largest expense items were the cost of natural gas and related taxes.

As the volume of gas sold by the Company declined from the previous year, gas costs decreased by $26.8 million to $244.0 million net of rebates. Rebates received from the Alberta Government under the Natural Gas Price Protection Plan, of $49.6 million compared to $46.2 million in 1981, shielded eligible Alberta consumers from the full cost of natural gas purchased.

Total taxes paid to all levels of government increased $61.0 million to $169.6 million in 1982, and amounted to 32.8 per cent of total Company revenue compared to 23.7 per cent in 1981. Federal taxes resulting from the National Energy Program amounted to $130.4 million, an increase of $49.0 million from 1981. This increase results from adjustments in two of the three Federal energy taxes:

— The Natural Gas and Gas Liquids Tax which was implemented at 28¢ per gigajoule (GJ) in November, 1980, was increased to 42¢ per GJ on July 1, 1981 and further increased to 63¢ per GJ on February 1, 1982.

— The Petroleum and Gas Revenue Tax of 8% of net production revenues, which was implemented January 1, 1981, was increased to 12% on January 1, 1982 and was decreased to 11% on June 1, 1982.

The Company continues to pay to the Federal Government the Canadian Ownership Tax of 14¢ per GJ implemented May 1, 1981. Municipal and franchise taxes paid to municipalities were $27.8 million, an increase of $7.3 million over 1981. Provincial mineral taxes increased from $0.8 million to $1.3 million in 1982.

The Company's capital expenditures to provide for customer growth were reduced from the prior year because of the decline in customer additions. However, other projects necessary to assure security of supply during peak demand periods pushed total capital expenditures to a record $81.6 million. The capital program was partially financed by an issue of preferred shares in the amount of $12.0 million, two long-term debt issues totalling $30.0 million and a common share issue of $21.0 million, all issued to the parent company, Canadian Utilities Limited.

During the year, land was purchased and construction commenced on the salt cavern gas peaking project near Fort Saskatchewan. The project will result in the most cost effective method of meeting future peaking requirements. Development of the first phase, which includes four caverns and related gas handling facilities, will be completed in time to meet the peak load projected for the 1984-1985 heating season at a total cost of $32.2 million. The Clover Bar Lateral, a major transmission project completed during the year, consists of 27 km of 610-mm pipeline and 10 km of 762-mm pipeline. This $17.5 million project will serve the expanded Celanese petrochemical complex and in the future will be an integral part of the salt cavern peaking facilities serving the City of Edmonton. In Grande Prairie, a new $1.7 million service centre was completed providing space for the Company which had outgrown facilities previously shared with Alberta Power Limited.

The Company participated in the drilling of 62 wells and the purchase of an additional five. Of the wells drilled, 48 were successful and one was in progress at year-end. The Company negotiated farmouts on certain of its lands and 14 farmout wells have been drilled of which seven were successful. The cost of successful wells was added to assets and the cost of unsuccessful projects will be recovered from border flowback funds, with Public Utilities Board approval.

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.

In 1982, the British Columbia Utilities Commission granted Northland Utilities (B.C.) Limited a certificate of Public Convenience and Necessity, which will allow Northland to construct facilities and provide natural gas to the new coal mining community of Tumbler Ridge in northeastern British Columbia.

The Company looks to 1983 with cautious optimism. Markets for Alberta petrochemical products have dwindled as competition at the international level and the high cost of domestic raw materials have reduced margins substantially. Several Alberta petrochemical projects scheduled for the mid-1980's have been deferred pending a more favourable economic climate. The limited growth expected in 1983 is predicated on the construction of petrochemical projects already committed, programs offered by Federal and Provincial governments for subsidization of new home construction and residential mortgages, and the current lower interest rates.

On April 14, 1982, W. D. Grace and R. G. Lock were elected to the Company's Board of Directors.

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 9, 1983

NORTHWESTERN UTILITIES LIMITED

Highlights in Review

	1982	1981	1980	1979	1978	1972
STATISTICAL						
Customers at year-end	**298,275**	290,658	276,295	260,133	241,606	169,094
Natural gas sales — TJ	**193,815**	224,316	231,944	231,258	208,020	146,249
Transportation of natural gas — TJ	**67,722**	41,394	37,091	27,629	13,892	14,750
Total sales and transportation — TJ	**261,537**	265,710	269,035	258,887	221,912	160,999
Kilometres of pipeline	**15,818**	15,163	14,474	13,613	12,673	8,580
Maximum daily demand — TJ	**1,149**	1,258	1,179	1,132	1,210	702
Communities served	**171**	161	161	160	153	153
Population served	**988,000**	948,000	906,000	870,000	824,000	690,000
Degree days — % normal	**108**	82	97	102	100	106
Owned gas reserves* — PJ	**746**	731**	790	790	799	676
FINANCIAL (thousands of dollars except per share data)						
Revenue	**517,715**	458,619	341,105	276,676	241,988	43,965
Earnings attributable to common shares	**21,295**	13,062	10,391	10,363	8,468	3,987
Earnings per common share	**8.77**	5.54	4.44	4.54	3.84	2.21
Gross additions to plant	**81,646**	48,402	45,075	42,979	28,185	8,276
Gross plant	**453,417**	373,254	325,515	280,916	283,895	131,245

* Revised to reflect reserves in the Company's Craigend and Westlock Fields.

** 1981 reserves reappraised.

Auditors' Report

To the Shareholders of
Northwestern Utilities Limited:

We have examined the consolidated balance sheet of Northwestern Utilities Limited as at December 31,1982 and the consolidated statements of earnings, 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, 1982 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, 1983

NORTHWESTERN UTILITIES LIMITED

Consolidated Statement of Earnings

	Year ended December 31	
	1982	1981
	(Thousands)	
Revenues	**$517,715**	$458,619
Operating Expenses		
Natural gas supply (Note 1)	**244,037**	270,876
Operating and maintenance	**56,550**	45,809
Taxes — other than income (Note 2)	**159,437**	102,671
Taxes — income (Note 3)	**10,149**	5,896
Depreciation	**10,665**	8,172
	480,838	433,424
	36,877	25,195
Allowance for Funds Used During Construction	**2,982**	2,274
Dividend Income from Affiliate	**550**	
Interest Income	**3,531**	642
	43,940	28,111
Interest on Loans from Parent Company	**11,341**	9,143
Interest Expense	**2,232**	1,763
	13,573	10,906
Income before Preferred Dividend Requirements	**30,367**	17,205
Preferred Dividend Requirements	**9,072**	4,143
Earnings Attributable to Common Shares	**$ 21,295**	$ 13,062
Earnings per Common Share	**$ 8.77**	$ 5.54

NORTHWESTERN UTILITIES LIMITED

Consolidated Statement of Retained Earnings

	Year ended December 31	
	1982	1981
	(Thousands)	
Balance at Beginning of Year	**$51,442**	$45,533
Add		
Income before preferred dividend requirements	**30,367**	17,205
	81,809	62,738
Deduct		
Dividends — preferred shares	**9,072**	4,143
— common shares	**10,775**	7,153
	19,847	11,296
Balance at End of Year	**$61,962**	$51,442

Consolidated Balance Sheet

	December 31 1982	December 31 1981
	(Thousands)	
ASSETS		
Current Assets		
Accounts receivable (Note 4)	**$ 86,646**	$ 78,013
Owing by parent and affiliated companies	**29,750**	11,160
Materials and supplies	**4,387**	4,564
Income tax recoverable	**142**	334
Prepaid expenses	**1,040**	576
	121,965	94,647
Investment in Affiliated Company — at cost	**2,158**	2,158
Property, Plant and Equipment (Note 5)	**355,873**	286,163
Deferred Expenses (Note 6)	**26,142**	25,000
	$506,138	$407,968
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Due to bank	**$ 15,797**	$ 11,788
Accounts payable and accrued liabilities	**64,225**	62,302
Income and other taxes	**27,974**	24,938
Dividends payable	**1,870**	1,537
Owing to parent and affiliated companies	**9,678**	4,307
Long-term debt — current maturities	**4,914**	2,222
Deposits	**1,037**	907
	125,495	108,001
Long-Term Debt (Note 7)	**118,844**	94,433
Contributions for Extensions to Plant	**47,232**	39,385
Deferred Income Taxes	**357**	242
Deferred Credits (Note 8)	**27,161**	21,513
Preferred Shares (Note 9)	**83,411**	72,276
Common Shareholders' Equity		
Common shares (Note 10)	**41,676**	20,676
Retained earnings	**61,962**	51,442
	103,638	72,118
	$506,138	$407,968

Approved by the Board:

E. W. King

E. W. King/Director

John L. Schlosser

J. L. Schlosser/Director

Consolidated Statement of Changes in Financial Position

	Year ended December 31	
	1982	1981
	(Thousands)	
Sources of Funds		
Internal Sources		
Income before preferred dividend requirements	**$30,367**	$17,205
Depreciation	**10,665**	8,172
Other	**861**	333
Allowance for equity funds used during construction	**(1,892)**	(1,454)
Provided by operations	**40,001**	24,256
Deduct preferred and common dividends	**19,847**	11,296
Provided internally	**20,154**	12,960
External Sources		
Issue of long-term debt	**30,000**	5,000
Issue of preferred shares	**12,000**	42,000
Issue of common shares	**21,000**	
Contributions for extensions to plant	**8,920**	6,913
Disposition of property, plant and equipment	**198**	49
Other	**5,703**	6,471
Provided externally	**77,821**	60,433
	$97,975	$73,393
Disposition of Funds		
Purchase of property, plant and equipment	**$81,646**	$48,402
Increase in deferred expenses for gas exploration — net	**464**	8,971
Allowance for equity funds used during construction	**(1,892)**	(1,454)
	80,218	55,919
Reduction in long-term debt	**3,508**	2,828
Preferred shares purchased for cancellation	**865**	854
Increase in other deferred expenses	**3,560**	964
Increase in working capital	**9,824**	12,828
	$97,975	$73,393

Summary of Significant Accounting Policies

December 31, 1982

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. Since the companies are regulated utilities, their accounting records and policies reflect decisions made by regulatory bodies, principally the Public Utilities Board of Alberta, as part of the rate making process. Revenues are recognized on the basis of cycle billing and are recorded when customers are billed.

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.

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 2.2% to 6.6%. 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 and market. Costs for materials and supplies are determined on an average basis, whereas costs for natural gas stored are determined using the first in, first out basis.

Deferred expenses

The Company includes in gas exploration all costs, including an allowance for cost 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 monies, 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

The Company follows the "Flow Through" method of income tax accounting under which income taxes currently payable are recorded in its accounts. Deductions claimed in calculating the amount of current taxes exceed costs charged in the accounts, with the result that income taxes payable are reduced and unrecorded deferred taxes are increased.

Since the income tax component of rates is designed only to recover taxes currently payable, the customer in future years will bear an additional charge when recorded expenses exceed deductions for income tax purposes.

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 and held in trust by the Company for rebate to its customers.

The Company is permitted to record deferred income taxes with respect to deferred gas costs and share issue costs.

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, 1982

1. Natural gas supply

The natural gas supply expense is net of an Alberta Government rebate of $49,595,000 (1981 — $46,168,000).

2. Taxes — other than income

	Year ended December 31	
	1982	1981
	(Thousands)	
Federal natural gas and gas liquids taxes	**$102,482**	$ 64,471
Federal petroleum and natural gas revenue taxes	**4,010**	2,637
Federal Canadian ownership taxes	**23,917**	14,258
	130,409	81,366
Franchise taxes	**25,063**	18,200
Property taxes	**2,705**	2,273
Provincial mineral taxes	**1,260**	832
	$159,437	$102,671

3. Taxes — income

The actual income tax rate differs from the rate that would be expected as follows:

	Year ended December 31	
	1982	1981
Expected income tax rate	**48.8%**	48.8%
Capital cost allowance and resource expenditures claimed in excess of depreciation	**(16.9)**	(14.6)
Allowance for funds used during construction	**(3.6)**	(4.8)
Crown royalties and other non-deductible Crown payments	**17.5**	25.5
Earned depletion and resource allowance	**(10.8)**	(17.3)
Investment tax credit	**(1.7)**	(2.9)
Other	**(8.3)**	(9.1)
	25.0%	25.6%

Income tax expense is net of a deferred tax credit of $889,000 (1981 — an expense of $2,604,000).

A provision for certain deferred taxes is not included in the consolidated financial statements. Unbooked deferred taxes increased during the year by $8,058,000 (1981 — $4,433,000) to an accumulated amount of $34,388,000.

4. Accounts receivable

	December 31	
	1982	1981
	(Thousands)	
Customer accounts	**$56,039**	$42,264
Receivable from the Province of Alberta	**24,797**	28,265
Other receivables and deposits	**5,810**	7,484
	$86,646	$78,013

5. Property, plant and equipment

	December 31			
	1982		1981	
	Cost	Accumulated Depreciation	Cost	Accumulated Depreciation
	(Thousands)		(Thousands)	
Plant and equipment	**$439,958**	**$97,544**	$368,316	$87,091
Construction work in progress	**9,067**		3,621	
Land	**4,392**		1,317	
	$453,417	**$97,544**	$373,254	$87,091
Net property, plant and equipment	**$355,873**		$286,163	

6. Deferred expenses

	December 31	
	1982	1981
	(Thousands)	
Gas exploration — net	**$22,939**	$22,475
Unamortized debt and preferred share issue expenses	**2,869**	2,479
Other	**334**	46
	$26,142	$25,000

7. Long-term debt

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

	December 31	
	1982	1981
	(Thousands)	
First mortgage sinking fund bonds 5⅜% to 9¾% due to 1994	**$ 13,669**	$17,072
Sinking fund debentures 7¼% due 1985	**2,176**	2,282
Sinking fund debentures payable to parent company 8.57% to 17.50% due to 2002	**102,999**	75,079
	$118,844	$94,433

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

	Maturing Issues	Sinking Fund Requirements	Sinking Fund Purchased in Advance	Total
		(Thousands)		
1983	$2,785	$ 2,840	$(710)	$ 4,915
1984		3,489	(39)	3,450
1985	2,070	4,183		6,253
1986		5,083		5,083
1987		25,083		25,083

The bond and debenture indentures place limitations on the Company, including restrictions on the payment of dividends. Consolidated retained earnings in the amount of $18,912,000 were free from such restrictions.

8. Deferred credits

	December 31 1982	1981
	(Thousands)	
Funds received under the Natural Gas Price Administration Act — net	**$24,374**	$20,099
Other	**2,787**	1,414
	$27,161	$21,513

During the year an application was made to the Public Utilities Board to apply $1,577,000 of unsuccessful gas exploration costs, net of related income taxes, against monies received under the Natural Gas Price Administration Act. Approval of this application is expected in 1983. During 1981, $832,000 of unsuccessful gas exploration costs, net of related income taxes, were applied with Public Utility Board approval.

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			
		1982		1981	
		Number	Amount (Thousands)	Number	Amount (Thousands)
Cumulative Redeemable Preferred Shares 4%		**105,000**	**$10,500**	105,000	$10,500
Cumulative Redeemable Second Preferred Shares					
10¼%	Series A	**105,950**	**2,649**	110,640	2,766
9.24%	Series B	**455,000**	**11,375**	470,000	11,750
7.30%	Series C	**211,040**	**5,276**	217,800	5,445
10.12%	Series E	**465,186**	**11,629**	472,604	11,815
14.00%	Series F	**1,199,280**	**29,982**	1,200,000	30,000
14.50%	Series G	**480,000**	**12,000**		
			$83,411		$72,276

Stated Values, Redemption Premiums and Dividends:

		Stated Value	Maximum Redemption Premium	Dividends Year ended December 31 1982	1981
				(Thousands)	
Cumulative Redeemable Preferred Shares 4%		$100	4%	**$ 420**	$ 420
Cumulative Redeemable Second Preferred Shares					
10¼%	Series A	$ 25	5%	**276**	290
9.24%	Series B	$ 25	5%	**1,064**	1,101
7.30%	Series C	$ 25	4%	**389**	404
10.12%	Series E	$ 25	4%	**1,185**	938
14.00%	Series F	$ 25	4%	**4,198**	990
14.50%	Series G	$ 25	4%	**1,540**	
				$9,072	$4,143

During 1982 the Company issued for cash $12,000,000 Series G Cumulative Redeemable Second Preferred Shares.

Redemption

The Cumulative Redeemable Preferred Shares and the Cumulative Redeemable Second Preferred Shares may be redeemed at the option of the Company after specified dates subject to premiums listed plus accrued dividends.

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 number of shares of the corresponding issue that the parent company has been able to acquire.

		Current Purchase Obligation	Purchased in 1982 Number	Amount (Thousands)
10¼%	Series A	4,800	4,690	$117
9.24%	Series B	15,000	15,000	375
7.30%	Series C	7,200	6,760	169
10.12%	Series E	9,600	7,418	186
14.00%	Series F	48,000	720	18
14.50%	Series G	19,200		
				$865

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

10. Common shares

Authorized:

An unlimited number of shares without nominal or par value.

Issued:

	Number	Amount (Thousands)
Common shares at beginning of year	2,337,676	$20,676
Issued during the year for cash	562,852	21,000
	2,900,528	$41,676

11. Commitments

Minimum yearly non-capitalized lease payments are $1,975,000, $1,775,000, $1,538,000, $1,304,000 and $1,072,000 for the years 1983-1987, respectively. Leases range in length from three to ten years.

The Company has a retirement pension fund covering substantially all employees. The contribution to the pension fund for the year amounted to $3,205,000 (1981 — $2,528,000). The plan has an unfunded past service liability amounting to approximately $9,700,000 which will be funded over a period not exceeding 14 years.

12. 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 $7,057,000 (1981 — $5,540,000). The above charges and intercompany financing transactions are subject to review by the Public Utilities Board.

Transactions with affiliated companies include purchase of natural gas of $1,206,000 (1981 — $269,000), revenue from the sale of natural gas of $16,665,000 (1981 — $17,475,000), engineering services of $823,000 (1981 — $323,000) and management fees of $169,000 (1981 — $109,000). The Company also participates in numerous oil and natural gas joint ventures. When the Company acts as operator it has, in some instances, contracted ATCO subsidiaries for well drilling and servicing, equipment purchases and related services, the total amount being approximately $4,000,000. A portion of these expenditures are reimbursed by the other participants in the joint ventures. These related party transactions are considered to be in the normal course of business and at fair value.

13. Amounts held in trust

Amounts held in trust for Income Tax Rebates, which are not shown in the consolidated financial statements, are $3,798,000 (1981 — $2,115,000).

14. Financial statements

Certain of the 1981 figures have been reclassified to conform with the consolidated financial statement presentation adopted in 1982.

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.

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

Three non-management directors of the Company serve as the Audit Committee. The Board of Directors, through its Audit Committee, 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 financial matters and to gain assurance that they are carrying out their responsibilities. The internal auditors and the independent auditors have full and free access to the Audit Committee.

TRANSFER AGENTS AND REGISTRARS

Montreal Trust Company
Edmonton/Calgary
Toronto/Montreal

Canada Permanent Trust Company
Edmonton/Toronto/Vancouver

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 13, 1983.

NORTHWESTERN UTILITIES LIMITED

A Subsidiary of Canadian Utilities Limited
An ATCO Company

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