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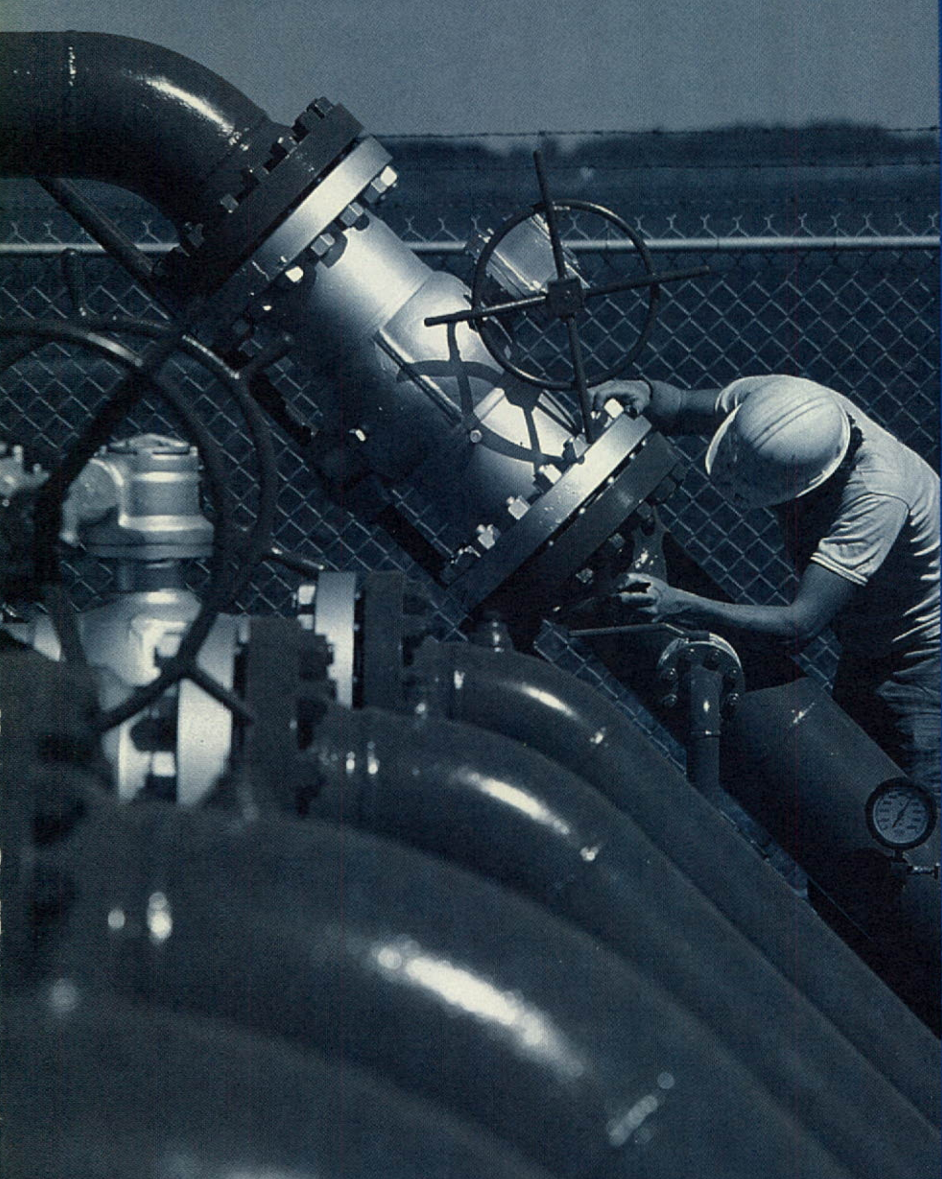

1986 ANNUAL REPORT

NORTHWESTERN UTILITIES LIMITED

Cover

Surface tubing at Northwestern's underground salt cavern natural gas storage facility near Fort Saskatchewan, Alberta.

Report to Shareholders

Lower commodity prices for energy in Canada resulted in a reduced level of activity in Northwestern Utilities' service territory in 1986. Northwestern added 4,710 customers for a growth rate of 1.5%, slightly lower than last year. Northwestern was providing natural gas service to 326,154 customers in 178 communities at the end of 1986.

Earnings attributable to common shares were $23.7 million ($8.16 per common share) compared to $33.9 million ($11.70 per common share) in 1985. Warmer temperatures during the 1986 billing period reduced earnings by $7.5 million. Other contributing factors to the lower earnings included a reduced allowance for funds used during construction, increased operation and maintenance expenses to serve new customers and a higher effective tax rate, partially offset by savings from the purchase of lower priced gas on the spot market.

Total system throughput was 279.5 petajoules (PJ) in 1986, a decrease of 36.0 PJ. Sales and transportation volumes were lower by 25.9 PJ and 10.1 PJ respectively. Temperature sensitive sales were lower by 9.1 PJ while industrial sales declined by 16.8 PJ due mainly to a shift of high volume customers from sales to transportation service. Lower transportation volumes were due primarily to a reduction in requirements of exporting companies and a reduction in natural gas demand for fertilizer production. Northwestern transports gas within Alberta for exporting companies and for large industrial customers who have contracted for their gas supplies directly with brokers or producers.

Consolidated revenues of $380.5 million for 1986 were $83.4 million lower than 1985. Revenues decreased $27.9 million due to the impact of warmer weather on residential and commercial sales, $41.7 million due mainly to the transfer of industrial sales to transportation service and $12.2 million as a rate reduction resulting from the elimination of the Canadian Ownership Special Taxation and the Petroleum and Natural Gas Revenue Tax.

Total operating expenses, which include the cost of natural gas supply, operation and maintenance, depreciation and depletion, taxes other than income taxes and income taxes amounted to $333.0 million, down $73.8 million from 1985. Natural gas costs were reduced by $55.8 million, while taxes other than income were lower by $15.8 million mainly due to the elimination of the Canadian Ownership Special Taxation.

Government administered pricing of natural gas in Canada came to a conclusion on October 31, 1986. With deregulation, the Alberta Border Price has been replaced by negotiated prices. Approximately half of Northwestern's gas supply is subject to price redetermination. If a negotiated settlement is not reached, the price would be subject to arbitration. The Alberta Government proclaimed the Arbitration Amendment Act, 1986, on October 30, 1986. Previously, only the price of alternative fuels could be taken into consideration if contracts were to be arbitrated. Under the new Act, consideration must be given to the prices of other competing natural gas in the buyer's market and to the prices of other Alberta natural gas produced and sold under other natural gas sales contracts.

On December 30, 1986 the Alberta Public Utilities Board released a report on the Natural Gas Transportation Rates Inquiry held earlier in the year with virtually all major Alberta gas producing and consuming interests represented. The Board generally confirmed Northwestern's existing transportation services, rates and contracts and ordered Northwestern, in addition, to provide one, two and three-year transportation services at rates somewhat higher than those charged for longer term service.

In February of 1987 the Alberta Public Utilities Board issued a decision on Northwestern's General Rate Application for 1984 and 1985. The decision approved additional revenues of $2,941,000 to be collected in 1987. The Board also ordered that a schedule of revenue surplus or deficiency is to be filed for 1986 to determine appropriate additional revenues to be collected or refunds to be made in 1987.

Capital expenditures to provide for customer growth and to meet the needs of existing customers amounted to $35.3 million in 1986. At year-end, net property, plant and equipment required to serve customers increased to $492.3 million.

Northwestern continued to take advantage of lower financing rates during 1986, issuing $12.3 million and $32.0 million of 7.70% and 7.08% Cumulative Redeemable Second Preferred Shares and redeemed $11.6 million and $30.0 million of 10.12% and 14.0% Cumulative Redeemable Second Preferred Shares respectively. In addition, Northwestern issued $6.0 million of 9.85% Debentures 1986 Series and $5.0 million of 10.25% Debentures 1986 Second Series to finance the capital program.

The effective management of resources is a high priority of Northwestern. During 1986, the increase in operation and maintenance expense was held to 3.3%, less than the 4.1% increase in the Consumer Price Index.

Operating in the second year of a two-year agreement with the Natural Gas Employees Benefit Association, Northwestern and the Association agreed to go to arbitration to resolve wages in 1986. The arbitration award provided permanent employees with a lump sum payment equivalent to 3½% of base pay.

Effective April 16, 1986 the Board of Directors announced the appointment of the following officers of Northwestern: B. M. Dafoe, President; R. G. Lock, Senior Vice President and General Manager; W. L. Graburn, Vice President and General Manager, Gas Supply; R. Armstrong, Vice President, Engineering and Construction; D. M. Ellard, Vice President, Administration and Marketing; R. M. Massé, Vice President and Controller; G. K. Munk, Vice President, Operations; G. W. Richards, Vice President, Rate Administration and G. W. Welsh, Vice President, Gas Supply Engineering. W. R. Horton, who served as President of Northwestern from June 1, 1984 to April 16, 1986 remains as Executive Vice President, Utilities of Canadian Utilities Limited and a Director of Northwestern. R. D. Southern remains as Chairman of the Board and Chief Executive Officer and J. D. Wood remains as Deputy Chairman of the Board.

Two new members were elected to the Board of Directors at the annual meeting April 16, 1986. Elected were J. E. Lougheed, a member of the Canada Council, and S. D. McGregor, Executive Vice President and a Director of Numac Oil and Gas.

The efforts and dedication of employees made possible the effective performance of the past year. Northwestern gratefully extends its appreciation to employees for their continued commitment to providing safe, efficient natural gas service.

On Behalf of the Board of Directors,

R. D. SOUTHERN
Chairman of the Board
and Chief Executive Officer

B. M. DAFOE
President

February 13, 1987

Highlights in Review

	1986	1985	1984	1983	1982	1976
STATISTICAL						
Customers at year-end	**326,154**	321,444	316,412	306,193	297,557	211,460
Natural gas sales — TJ	**117,431**	143,333	147,257	163,949	193,815	175,890
Transportation of natural gas — TJ	**162,045**	172,183	156,147	113,831	67,722	2,250
Total system throughput — TJ	**279,476**	315,516	303,404	277,780	261,537	178,140
Pipelines — kilometres	**17,704**	17,388	16,952	16,326	15,818	10,931
Maximum daily demand — TJ	**1,324**	1,396	1,309	1,253	1,253	962
Communities served	**178**	178	179	175	171	153
Population served — thousands	**1,055**	1,040	1,035	998	988	789
Degree days — % normal	**88**	97	96	96	108	87
Owned gas reserves — PJ	**641**	654	637	718	746	642
FINANCIAL (thousands of dollars except per share data)						
Revenue	**380,485**	463,898	455,388	487,037	517,715	130,752
Earnings attributable to common shares	**23,655**	33,928	19,601	15,581	21,295	5,833
Earnings per common share — dollars	**8.16**	11.70	6.76	5.37	8.77	3.03
Capital expenditures	**35,321**	38,221	52,081	80,169	81,646	22,174
Gross plant	**646,532**	614,258	580,160	532,000	453,417	189,714

The metric unit for measurement of energy is the joule (J) and its multiples. Large amounts of energy are reported in gigajoules (GJ), billions of joules; in terajoules (TJ), trillions of joules; and in petajoules (PJ) quadrillions of joules. One joule is equivalent to .00095 British Thermal Units.

Auditors' Report

To the Shareholders of
Northwestern Utilities Limited:

We have examined the consolidated balance sheet of Northwestern Utilities Limited as at December 31, 1986 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, 1986 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
January 30, 1987

Consolidated Statement of Earnings and Retained Earnings

	Note	Year ended December 31 1986	1985
		(Thousands)	
Revenues		$380,485	$463,898
Operating Expenses			
Natural gas supply	1	186,945	242,719
Operation and maintenance		70,224	67,949
Taxes — other than income	2	27,952	43,724
Taxes — income	3	29,986	35,159
Depreciation and depletion		17,856	17,169
		332,963	406,720
		47,522	57,178
Allowance for Funds Used During Construction		3,064	4,753
Interest Income		4,196	3,451
		54,782	65,382
Interest on Loans from Parent Company		18,290	18,501
Interest Expense		2,391	1,724
Dividends on Preferred Shares	9	10,446	11,229
		31,127	31,454
Earnings Attributable to Common Shares		23,655	33,928
Retained Earnings at Beginning of Year		93,944	76,288
		117,599	110,216
Dividends on Common Shares		17,287	16,272
Retained Earnings at End of Year		$100,312	$ 93,944
Earnings per Common Share		$ 8.16	$ 11.70

Consolidated Balance Sheet

	Note	December 31 1986	1985
		(Thousands)	
ASSETS			
Current Assets			
Accounts receivable	4	**$ 34,901**	$ 41,773
Owing by parent and affiliated companies		**529**	6,669
Materials and supplies		**4,446**	4,041
Natural gas stored		**11,541**	5,355
Prepaid expenses		**1,088**	631
		52,505	58,469
Property, Plant and Equipment	5	**492,345**	476,815
Deferred Expenses	6	**32,206**	24,941
		$577,056	$560,225
LIABILITIES AND CAPITALIZATION			
Current Liabilities			
Due to bank		**$ 2,940**	$ 1,862
Accounts payable and accrued liabilities		**31,813**	45,143
Income and other taxes		**2,237**	9,261
Dividends payable		**1,171**	2,066
Owing to parent and affiliated companies		**26,671**	11,300
Long-term debt — current maturities	8	**24,560**	4,560
		89,392	74,192
Deferred Credits			
Contributions for extensions to plant		**67,061**	60,669
Deferred income taxes		**727**	517
Other	7	**33,701**	33,804
		101,489	94,990
Capitalization			
Long-term debt	8	**133,342**	147,131
Preferred shares	9	**110,845**	108,292
Common shareholders' equity	10	**141,988**	135,620
		386,175	391,043
		$577,056	$560,225

APPROVED BY THE BOARD:

B. M. Dafoe, Director

R. G. Lock, Director

Consolidated Statement of Changes in Financial Position

	Year ended December 31	
	1986	1985
	(Thousands)	
Cash Provided from Operations		
Earnings attributable to common shares	$ 23,655	$ 33,928
Depreciation and depletion	17,856	17,169
Other	1,177	951
Allowance for funds used during construction — shareholders' equity	(1,203)	(1,866)
	41,485	50,182
Decrease (increase) in working capital	(15,314)	6,869
	26,171	57,051
Dividends on Common Shares	17,287	16,272
	8,884	40,779
Financing		
Issue of short-term notes	9,600	
Issue of long-term debt	11,000	
Reduction in long-term debt	(4,790)	(6,786)
Contributions for extension to plant	7,814	5,604
Issue of preferred shares	44,300	15,000
Preferred shares redeemed	(41,567)	(10,872)
Other	(2,868)	(160)
	23,489	2,786
Total Cash for Investment	32,373	43,565
Investment		
Additions to property, plant and equipment	35,321	38,221
Increase in deferred expenses for natural gas exploration — net	5,455	6,359
Allowance for funds used during construction — shareholders' equity	(1,203)	(1,866)
	39,573	42,714
Disposition of property, plant and equipment	(597)	(1,547)
Increase in other deferred expenses	275	24
	39,251	41,191
Increase (Decrease) in Cash	$ (6,878)	$ 2,374

"Long-term debt — current maturities" and cash are excluded from working capital. Cash is defined as short-term advances to parent company less "Due to bank".

Summary of Significant Accounting Policies

December 31, 1986

Consolidated Financial Statements

The consolidated financial statements have been prepared by management in accordance with 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 the Company and its subsidiary company Northland Utilities (B.C.) Limited.

Regulation

The Company is regulated primarily by the Public Utilities Board of Alberta (the "Board") and the Energy Resources Conservation Board of Alberta, which administer acts and regulations covering such matters as rates, financing, accounting, construction, operation and service area. The Board may award interim rates, subject to final determination. Decisions made by these authorities or management which impact on utility accounting policies are reflected in the consolidated financial statements after the date of decision.

Revenue Recognition

Customers are billed on a cycle billing basis and revenues are recognized when billed. Significant additional revenues or refunds resulting from Board decisions are recorded in the period to which they relate. Other adjustments are recorded in the current period.

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.

Taxes — Income

Income taxes are provided by the Company, using the normalized — all taxes paid method approved by the Board. This method does not result in a deferral of income taxes as any timing differences between accounting earnings and taxable income are eliminated. The major portion of income taxes paid is refunded for rebate to customers under the Public Utilities Income Tax Transfer Act and the Utility Companies Income Tax Rebates Act.

Prior to adoption of this method, the Company provided for income taxes on the flow-through method which resulted in a deferral of income taxes. As the income tax component of rates is designed to recover only income taxes currently payable, no provision has been made in the consolidated financial statements for this deferral of income taxes. The customer in future years will bear an additional charge in the event of a reversal of these unbooked deferred income taxes. Significant reversals are not expected in the foreseeable future. The Company's subsidiary, operating under the jurisdiction of the British Columbia Utilities Commission, is required to provide for deferred income taxes.

Inventories

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

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 Board for debt and equity funds.

Certain additions are made with the 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 Property, Plant and Equipment are gas wells that have been drilled, tested and capped and remain unconnected to the utility system. The 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 5 years, these wells have not been added to the utility system, the costs are written off against funds received under The Natural Gas Pricing Agreement 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 Board varying from 1.8% to 5.5%. All resource properties are depleted on a unit of production basis. Dedicated and shared facilities are depreciated over the life of the contract.

Deferred Expenses

The Company includes in gas exploration all costs, including an allowance for funds, 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 amounts received under The Natural Gas Pricing Agreement Act included in other deferred credits.

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 expected life of the issue. Premiums and unamortized issue costs of redeemed long-term debt and preferred shares are amortized over the life of the issue funding the redemption.

Leases

The 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.

Deferred Credits — Other

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

Preferred Shares

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.

Notes to Consolidated Financial Statements

December 31, 1986

1. Natural gas supply

The natural gas supply expense is net of a rebate from the Province of Alberta of $33,892,000 (1985 — $50,083,000).

2. Taxes — other than income

	Year ended December 31	
	1986	1985
	(Thousands)	
Federal Canadian ownership taxes	**$ —**	$10,170
Federal petroleum and natural gas revenue taxes	**1,693**	3,729
	1,693	13,899
Franchise taxes — City of Edmonton	**16,629**	19,201
Franchise taxes — other	**5,895**	6,668
Property taxes	**3,506**	3,313
Provincial mineral taxes	**229**	643
	$27,952	$43,724

No Canadian ownership taxes and Federal petroleum and natural gas revenue taxes have been levied since June 1, 1985 and October 1, 1986, respectively.

3. Taxes — income

Under the normalized—all taxes paid method of accounting for income taxes the expected rate of income tax on accounting earnings would equal the statutory rate in the absence of permanent differences. The following table describes the permanent differences and their effect on the statutory rate:

	Year ended December 31	
	1986	1985
Statutory income tax rate	**48.8%**	47.9%
Allowance for funds used during construction	**(1.5)**	(1.8)
Crown royalties and other non-deductible Crown payments	**5.6**	6.8
Earned depletion and resource allowance	**(5.2)**	(5.2)
Reassessments	**—**	(3.0)
Other	**(0.9)**	(0.9)
Actual income tax rate	**46.8%**	43.8%

Taxes — income includes deferred income taxes of $210,000 (1985 — $239,000) provided for timing differences in the subsidiary.

The accumulated amount of unbooked deferred income taxes at December 31, 1986 remained unchanged at $37,938,000.

4. Accounts receivable

	December 31 1986	December 31 1985
	(Thousands)	
Customer accounts	$28,338	$37,010
Receivable from the Province of Alberta	4,194	4,208
Other receivables and deposits	2,369	555
	$34,901	$41,773

5. Property, plant and equipment

	December 31 1986 Cost	1986 Accumulated Depreciation	1985 Cost	1985 Accumulated Depreciation
	(Thousands)		(Thousands)	
Plant and equipment	$639,257	$154,187	$606,291	$137,443
Construction work in progress	1,962		2,685	
Land	5,313		5,282	
	$646,532	$154,187	$614,258	$137,443
Net property, plant and equipment	$492,345		$476,815	

Plant held for future use in the amount of $16,591,000 (1985 — $22,191,000) is included in plant and equipment.

6. Deferred expenses

	December 31 1986	December 31 1985
	(Thousands)	
Gas exploration — net	$27,554	$22,099
Unamortized debt and preferred share issue expenses	4,469	2,650
Other	183	192
	$32,206	$24,941

7. Deferred credits — other

	December 31 1986	December 31 1985
	(Thousands)	
Funds received under The Natural Gas Pricing Agreement Act — net	$31,626	$31,423
Other	2,075	2,381
	$33,701	$33,804

During 1986 and 1985 there were no unsuccessful gas exploration costs charged against funds received under The Natural Gas Pricing Agreement Act. No funds have been received since November 1, 1986 as a result of natural gas deregulation.

8. Long-term debt

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

	December 31 1986	December 31 1985
	(Thousands)	
Payable to Parent Company		
Debentures — sinking fund		
8.57% due March 1992	**$ 5,605**	$ 5,985
9.21% due March 1994	**2,060**	2,354
11.74% due October 1994	**2,034**	2,320
11.48% due February 1996	**7,000**	7,500
9.95% due September 2002	**9,880**	10,400
10.62% due July 1999	**13,600**	14,400
12% due July 2000	**16,020**	17,100
17% due December 1996	**3,500**	3,750
17.5% due March 1997	**8,000**	8,500
Debentures — other		
17% due August 1987		20,000
13.10% due June 1994	**44,000**	44,000
9.85% due October 2006	**6,000**	
10.25% due December 2006	**5,000**	
	122,699	136,309
First Mortgage Sinking Fund Bonds		
5¾% due March 1988	**4,250**	4,252
6½% due May 1992	**2,400**	2,530
9¾% due December 1994	**3,993**	4,040
	$133,342	$147,131

During the year, the Company issued for cash $6,000,000 of 9.85% Debentures 1986 Series and $5,000,000 of 10.25% Debentures 1986 Second Series.

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

	Maturing Issues	Sinking Fund Requirements	Sinking Fund Purchased in Advance	Total
		(Thousands)		
1987	$20,000	$5,083	$(523)	$24,560
1988	4,440	4,768	(398)	8,810
1989		4,768	(55)	4,713
1990		4,768		4,768
1991		4,768		4,768

The $44,000,000 13.10% Debentures 1984 Series, due June 1, 1994 grants the holder of the debentures the option of requiring the Company to redeem all or any of the holder's debentures on June 1, 1989 at a price equal to the principal amount plus accrued and unpaid interest to June 1, 1989.

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			
	1986		1985	
	Shares	**Amount**	Shares	Amount
		(Thousands)		(Thousands)
Cumulative Redeemable Preferred Shares				
4%	**105,000**	**$ 10,500**	105,000	$ 10,500
Cumulative Redeemable Second Preferred Shares				
Non-retractable				
7.30% Series C	**184,320**	**4,608**	191,520	4,788
		15,108		15,288
Retractable				
10.12% Series E			463,441	11,586
14.00% Series F			1,199,240	29,981
14.50% Series G	**480,000**	**12,000**	480,000	12,000
8.74% Series I	**869,462**	**21,737**	869,462	21,737
8.375% Series J	**108,000**	**2,700**	108,000	2,700
7.80% Series K	**600,000**	**15,000**	600,000	15,000
7.70% Series L	**492,000**	**12,300**		
7.08% Series M	**1,280,000**	**32,000**		
		95,737		93,004
		$110,845		$108,292

All of the Cumulative Redeemable Second Preferred Shares are held by the parent company, Canadian Utilities Limited.

During 1986, the Company redeemed the 10.12% and 14.00% Cumulative Redeemable Second Preferred Shares Series E and Series F. The redemption prices were $26 per share plus accrued dividends. The Company issued for cash $12,300,000 and $32,000,000 of Cumulative Redeemable Second Preferred Shares 7.70% Series L and 7.08% Series M, respectively.

Stated values, redemption premiums and dividends:

	Stated Value	1987 Redemption Premium	Dividends Year ended December 31	
			1986	1985
			(Thousands)	
Cumulative Redeemable Preferred Shares				
4%	$100	3%	**$ 420**	$ 420
Cumulative Redeemable Second Preferred Shares				
Non-retractable				
9.24% Series B	$ 25			976
7.30% Series C	$ 25	0.8%	**343**	354
			763	1,750
Retractable				
10.12% Series E	$ 25		**200**	1,173
14.00% Series F	$ 25		**3,139**	4,197
14.50% Series G	$ 25	4%	**1,739**	1,740
8.74% Series I	$ 25		**1,899**	1,896
8.375% Series J	$ 25		**226**	226
7.80% Series K	$ 25		**1,168**	247
7.70% Series L	$ 25		**744**	
7.08% Series M	$ 25		**568**	
			9,683	9,479
			$10,446	$11,229

(Note 9 continued)

Redemption privileges

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 commencing at the dates specified and with an initial premium as stated below:

		Redemption Premium
Series G	May 1, 1987	4%
Series I	November 1, 1988	4%
Series J	January 31, 1992	nil
Series K	October 15, 1993	nil
Series L	June 1, 1991	6%
Series M	June 1, 1991	4%

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.

	1986 Share Purchase Obligations	**Purchased in 1986** Shares	**Amount**
			(Thousands)
Series C	7,200	7,200	**$180**
Series G	19,200		
Series I	26,400		
Series K	12,000		
			$180

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 G	May 1, 1987
Series I	November 1, 1991
Series J	January 31, 1992
Series K	October 15, 1993
Series L	June 1, 1994
Series M	June 1, 1993

10. Common shareholders' equity

	December 31 **1986**	1985
	(Thousands)	
Common shares	**$ 41,676**	$ 41,676
Retained earnings	**100,312**	93,944
	$141,988	$135,620

Common shares

Authorized: An unlimited number of shares without nominal or par value.

Issued: 2,900,528 shares.

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 $12,511,000 was free from such restrictions.

11. Amount held in trust

The amount held in trust for income tax rebates, which is not included in the consolidated financial statements, is $7,312,000 (1985 — $6,889,000).

12. Related party transactions

Certain costs of administration, systems development, financial management, equipment, rent and leasehold improvements are incurred 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 $10,558,000 (1985 — $10,688,000).

Transactions with affiliated companies include the purchase of natural gas for $52,904,000 (1985 — $20,607,000), revenue from the sale of natural gas of $2,800,000 (1985 — $9,340,000) and revenue from transportation of natural gas of $7,613,000 (1985 — $7,372,000). The Company participates in 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 $581,000 (1985 — $657,000). 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 construction of an operations base and office leasehold improvements for which fees, including administration costs, amounted to $67,000 (1985 — $87,000).

These transactions are considered to be in the normal course of business, at fair market value and subject to review by the Board.

13. Rate application

The Company has been operating on interim rates since October 1984. The Company filed a rate application for 1984 and 1985 and did not file for 1986 but continued to apply the interim rates approved for 1985. A final decision for 1984 and 1985 was received early in 1987 awarding additional revenues of $2,941,000 which will be recorded in 1987. The Board also ordered that a schedule of revenue surplus or deficiency is to be filed for 1986 to determine appropriate additional revenues or refunds.

14. Employee pension plan

The Company and its subsidiary have a defined benefit pension plan covering substantially all employees. Employees participate through contributions to the plan which provides for pensions based on length of service and final average earnings. During the year, the Company made no changes to the benefits offered by the plan, which uses the accrued benefit cost method with projection of employee compensation levels to determine the costs of the reporting period. Pension costs for the year amounted to $3,451,000 (1985 — $3,479,000). Based on the most recent actuarial evaluation of December 31, 1983 the Company has been amortizing a plan deficit, now calculated to amount to $8,805,000.

The Company is in the process of obtaining an actuarial evaluation as at December 31, 1986 which will incorporate improvements to the plan resulting from changes in pension benefits legislation and revisions to the actuarial assumptions. The significant appreciation in the value of the plan assets since the last evaluation is expected to eliminate the existing plan deficit and cover the revised actuarial liability which results from these changes.

15. Commitments and contingencies

Minimum non-capitalized lease payments, which extend over periods not exceeding ten years, are $228,000, $139,000, $95,000, $95,000 and $36,000 for the years 1987-1991, respectively.

The Company purchases natural gas from approximately 168 producers under approximately 267 purchase contracts. Substantially all of these contracts have provisions requiring payment by the Company when it is unable to nominate specified minimum annual quantities for delivery. The available market has exceeded the minimum contract supply quantities and no "take-or-pay" payments were required.

The Company is currently involved in negotiations with its producers to determine the price to be paid for natural gas deliveries made under existing contracts, subsequent to November 1, 1986. Adequate provision has been made for the costs of natural gas delivered under these contracts.

16. Financial statements

Certain of the 1985 figures have been reclassified to conform with the consolidated financial statement presentation adopted in 1986.

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 financial information contained elsewhere in this annual report is consistent with that in the consolidated financial statements. The consolidated financial statements have been prepared in conformity with generally accepted accounting principles as applied to regulated utilities and conform in all material respects with International Accounting Standards.

Where management makes a choice from acceptable alternatives it uses methods which it believes are prudent. These consolidated financial statements necessarily include some amounts that are based on informed judgements 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 review 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 responsibilities for financial reporting.

Price Waterhouse, the Company's 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.

Board of Directors

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

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

W. A. Elser, Calgary
President and Chief Executive Officer
ATCOR Ltd.

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

W. R. Horton, Edmonton
Executive Vice President, Utilities
Canadian Utilities Limited

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

J. E. Lougheed, Calgary
Member, Canada Council

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

S. D. McGregor, Edmonton
Executive Vice President
Numac Oil & Gas Ltd.

C. S. Richardson, Calgary
Deputy Chairman of the Board and
Chief Financial Officer
Canadian Utilities Limited

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

R. D. Southern, Calgary
Chairman of the Board and
Chief Executive Officer
Canadian Utilities Limited

J. D. Wood, Edmonton
President and Chief Operating Officer
Canadian Utilities Limited

Officers

R. D. Southern
Chairman of the Board
and Chief Executive Officer

J. D. Wood
Deputy Chairman of the Board

B. M. Dafoe
President

R. G. Lock
Senior Vice President and General Manager

W. L. Graburn
Vice President and General Manager,
Gas Supply

R. Armstrong
Vice President,
Engineering and Construction

D. M. Ellard
Vice President,
Administration and Marketing

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Vice President and Controller

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Vice President, Human Resources

G. K. Munk
Vice President, Operations

G. W. Richards
Vice President, Rate Administration

G. W. Welsh
Vice President, Gas Supply Engineering

A. M. Anderson
Secretary/Treasurer

J. H. Cook
Assistant Secretary

C. K. Sheard
Assistant Secretary

D. P. Wood
Assistant Secretary

HEAD OFFICE

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Edmonton, Alberta T5J 2V6
Telephone (403) 420-7211

TRANSFER AGENT AND REGISTRAR

Toronto/Edmonton/Calgary

Preferred Shares
The Royal Trust Company

TRUSTEE AND REGISTRAR

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

Bonds
Montreal Trust Company

STOCK EXCHANGE LISTINGS

Preferred Shares
Toronto and Alberta Stock Exchanges

AUDITORS

Price Waterhouse
2401 Toronto Dominion Tower
Edmonton Centre
Edmonton, Alberta T5J 2Z1

ANNUAL MEETING

The annual meeting of shareholders will be held in Edmonton, Alberta on May 7, 1987.

NORTHWESTERN UTILITIES LIMITED

A Subsidiary of Canadian Utilities Limited
An ATCO Company

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