prairie oil royalties
1983

PRAIRIE OIL ROYALTIES

COMPANY, LTD.

ANNUAL REPORT 1983

CORPORATE PROFILE

The Company was incorporated July 13, 1951 under the laws of the Province of Saskatchewan, Canada. There are 1,961,520 Common Shares outstanding, of which 74.4% are owned by Norcen Energy Resources Limited of Toronto, Canada. The Company produces and sells crude oil, gas liquids and natural gas in Western Canada and is engaged in oil and gas exploration and development in Western Canada, the Arctic Islands, and the United States. Interests are also held in exploratory lands in the Northwest Territories and the Province of Ontario. Operations in the United States are carried out through a wholly-owned subsidiary, P.O.R. Oil & Gas Inc. The Company is not involved in refining or retail marketing.

Photography

Photographs of drilling and production operations were taken in the Taber North field by The Kelly Group, Calgary.

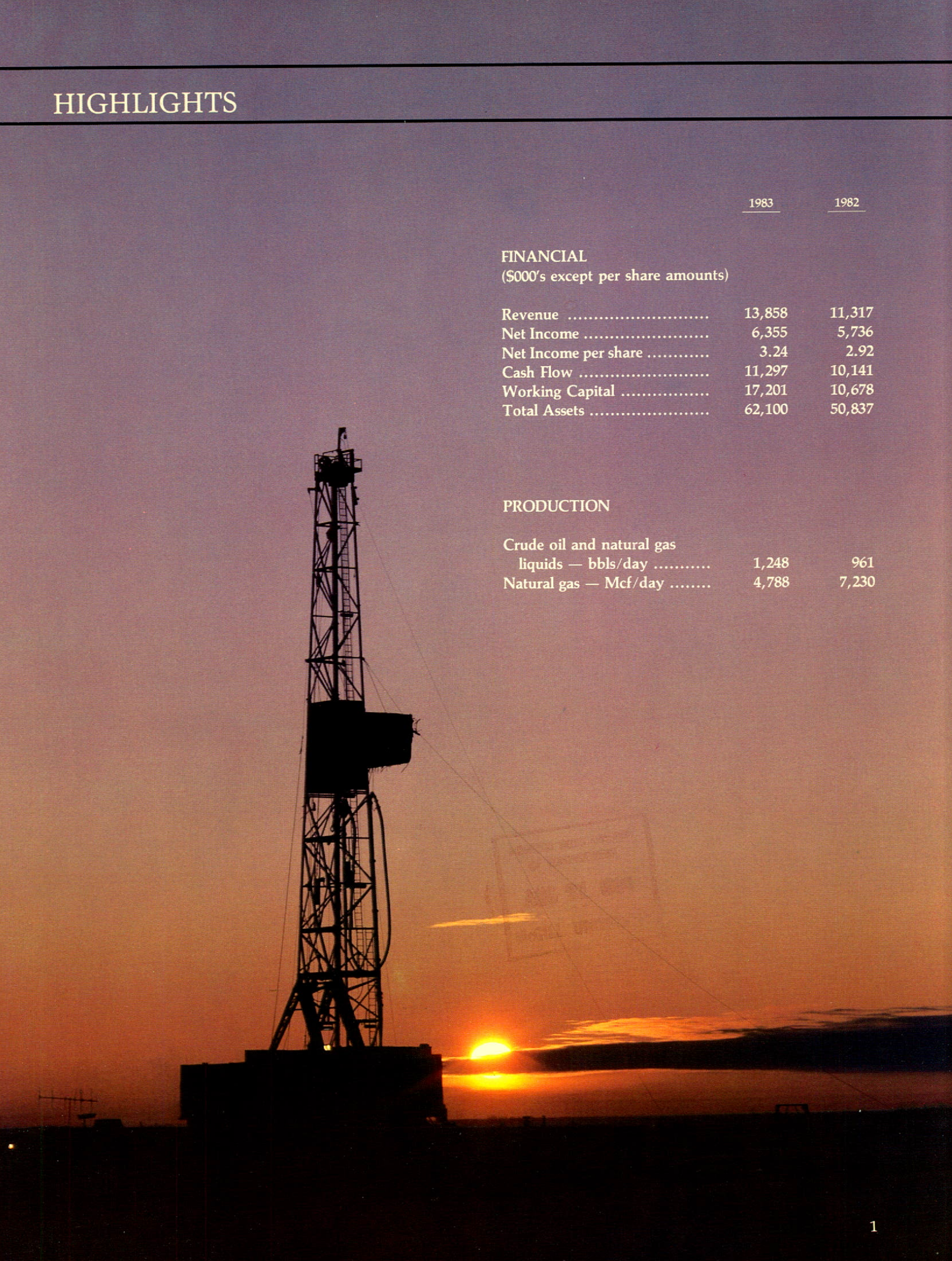
CONTENTS

HIGHLIGHTS

	1983	1982
FINANCIAL (\$000's except per share amounts)		
Revenue	13,858	11,317
Net Income	6,355	5,736
Net Income per share	3.24	2.92
Cash Flow	11,297	10,141
Working Capital	17,201	10,678
Total Assets	62,100	50,837

PRODUCTION

	1983	1982
Crude oil and natural gas liquids — bbls/day	1,248	961
Natural gas — Mcf/day	4,788	7,230



REPORT TO SHAREHOLDERS

Donald D. Barkwell, Chairman

The Company recorded increases in revenue, net income and cash flow in 1983. Revenue from all sources, after deducting production revenue taxes of $2,027,000, was $13,858,000, a 22% increase over 1982 revenue. Net income of $6,355,000 or $3.24 a share was 11% above 1982 net income of $5,736,000 or $2.92 a share. Cash flow from operations increased to $11,297,000 from $10,141,000 in the previous year.

The major factors contributing to the Company's improved financial performance in 1983 were as follows:

- A 30% increase in the average daily production of crude oil and natural gas liquids;
- A further increase in the average price received from the sale of the Company's production of crude oil and natural gas liquids;
- A 30% increase by year-end in the volume of crude oil and natural gas liquids receiving the new oil reference price;
- A substantial increase in interest revenue.

These factors more than offset a further decline in revenue from the sale of natural gas, higher royalty rates and a substantial increase in income taxes. A more detailed review of the Company's 1983 financial performance appears on pages 10 and 11 of this annual report.

Average daily production of crude oil and natural gas liquids before deducting royalties was 1,248 barrels, an increase of 287 barrels a day over the 1982 average. Increases in well allowables in existing fields and production from newly-completed wells at Taber North in Alberta and at Tatagwa-Colgate in Saskatchewan accounted for most of this increase.

Natural gas production declined 34% to 4,788 Mcf a day from 7,230 Mcf a day in 1982, reflecting a further drop in demand in export markets.

The average price received by the Company from the sale of its 1983 production of crude oil and natural gas liquids was $32.97 a barrel compared to $27.58 a barrel in 1982. This increase resulted from a $4.00 a barrel increase on July 1, 1983, the full year effect of a July 1, 1982 increase of $2.25 a barrel and further increases in the volume of production receiving the new oil reference price which is close to the international price of crude oil. On December 31, 1983 the new oil reference price was being received on 567 barrels a day or 45% of the Company's average daily production.

The average price received in 1983 from the sale of natural gas declined slightly to $2.53 an Mcf from $2.62 an Mcf in 1982. This was due to a further reduction in the volume of natural gas exported to the United States resulting in a lower flowback price to producers.

Estimated reserves at December 31, 1983 before royalties were 3.25 million barrels of crude oil and natural gas liquids and 65 billion cubic feet of natural gas. Comparable figures at December 31, 1982 were 2.75 million barrels of crude oil and natural gas liquids and 64.5 billion cubic feet of natural gas. These estimates have been calculated by engineers of the parent company, Norcen Energy Resources Limited, and do not include the

Company's share of natural gas reserves in the Arctic Islands. Further information on the Company's reserves appears in the supplemental information commencing on page 18 of this annual report.

During the past year the federal and provincial governments introduced measures to alleviate some of the difficulties being experienced by the oil and gas industry in Canada since the introduction of the National Energy Program in 1980. Effective July 1, 1983, the inter-governmental energy pricing and taxation agreements were amended to increase the volume of conventional crude oil production receiving the new oil reference price, to fix the price of the remaining production at a minimum of $29.75 a barrel, approximately 80% of the international price, and to regulate the price of natural gas so it will not exceed 65% of the energy-equivalent price of crude oil. These amendments are to remain in effect for a period of eighteen months.

Earlier in the year the federal government cut the price of natural gas exported to the United States from U.S. $4.90 an Mcf to U.S. $4.40 an Mcf and, in July, introduced a volume-related pricing incentive program under which the price of all gas exported above prescribed base volumes was set at U.S. $3.40 an Mcf. The price of base volumes remains at the current price of U.S. $4.40 an Mcf. Further incentives are under consideration by both levels of government.

Royalty and tax holidays, were features of the Oil Industry Recovery Program introduced by the Saskatchewan Government. In Alberta, the government provided cash grants under a Well Servicing and Development Drilling Incentives Program which expired at the end of October, 1983.

The favourable impact of these measures on the Company's 1983 earnings and cash flow will continue into 1984 but will be offset to some extent by a recent downward adjustment in the price of crude oil and an increase in tax expense due to the January 1, 1984 reduction in the Alberta Royalty Tax Credit.

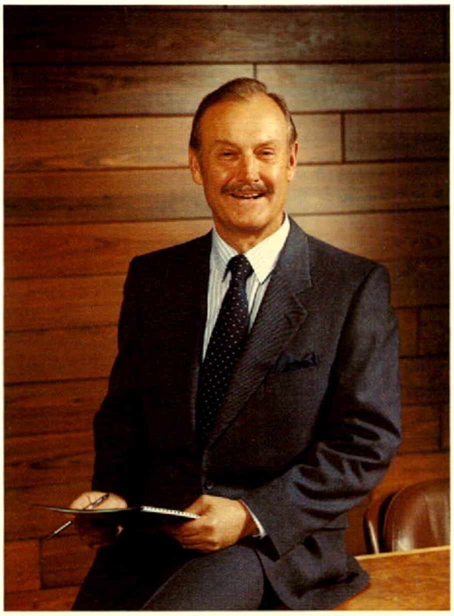
The weak demand for natural gas in export markets continues to be a serious problem for the industry and only a small improvement is anticipated in 1984. However, the recent decision by the federal government to eliminate the natural gas and gas liquids tax in order to maintain the 65% price relationship with crude oil will increase the average price received by the Company from the sale of natural gas.

ON BEHALF OF THE BOARD

DONALD D. BARKWELL
Chairman

WILFRID A. LOUCKS
President

Calgary, Alberta
February 28, 1984



Wilfrid A. Loucks, President

EXPLORATION AND DEVELOPMENT

During 1983 the Company participated in the drilling of 56 (7.8 net) wells resulting in 15 (2.65 net) oil wells and 6 (.47 net) gas wells. In addition, 8 wells were drilled on Company lands under farmout arrangements at no cost to the Company, resulting in 1 (.05 net) oil well and 4 (.53 net) gas wells. The major areas of activity were in the Tatagwa-Colgate fields in Saskatchewan and in the Taber North field in Alberta. Drilling activity in the United States was down from 1982 levels but the success ratio showed marked improvement. Capital expenditures on exploration and development totalled $6,253,000. The following review covers all of the Company's 1983 operations except for minor interests held in gas wells drilled at Calling Lake, Marten Hills, West Pembina and Kakut in Alberta.

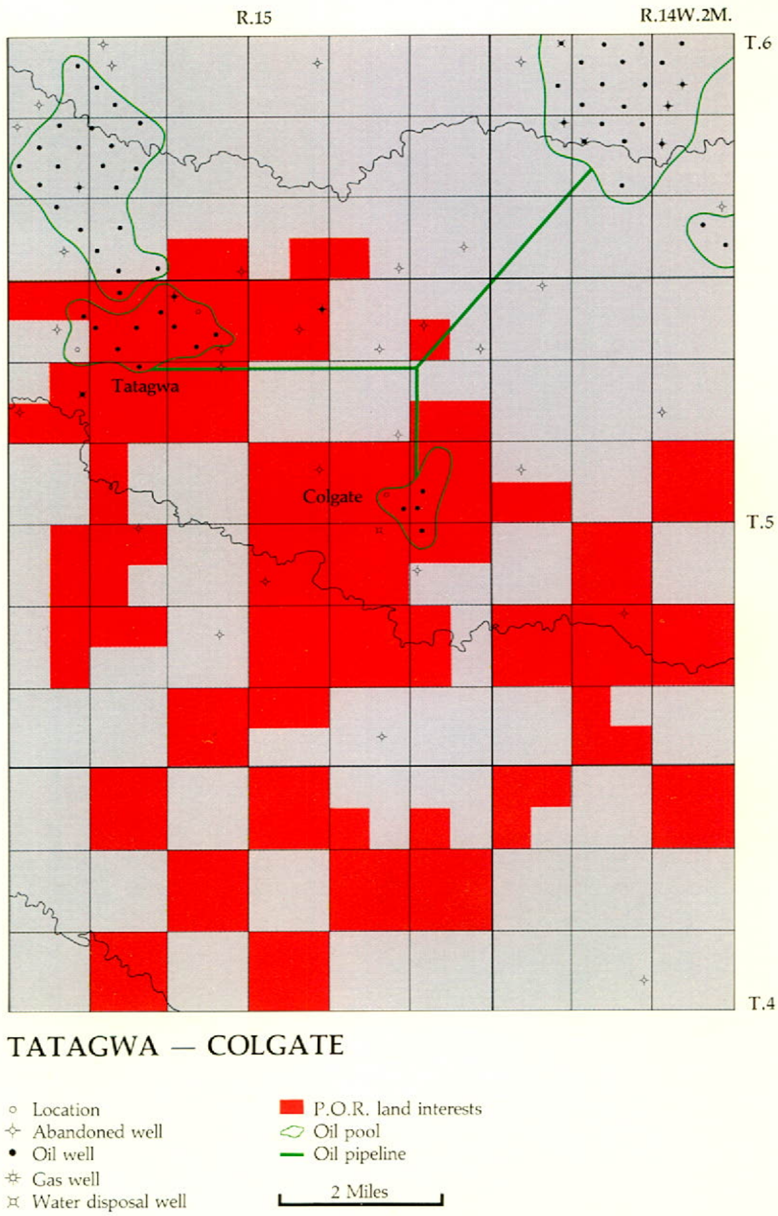
Tatagwa-Colgate

During 1983, the Company continued its participation in an aggressive exploration and development program in the Tatagwa area and the adjacent Colgate area in south central Saskatchewan. The 1983 program included 390 miles of seismic, the drilling of 19 wells of which nine have been completed as oil wells and the acquisition of interests in a further 1,765 net acres of oil and gas rights. The Company now has a 10% interest in nine producing oil wells at Tatagwa and a 7½% interest in four producing oil wells at Colgate. The Company's share of production from these wells is averaging 140 barrels a day.

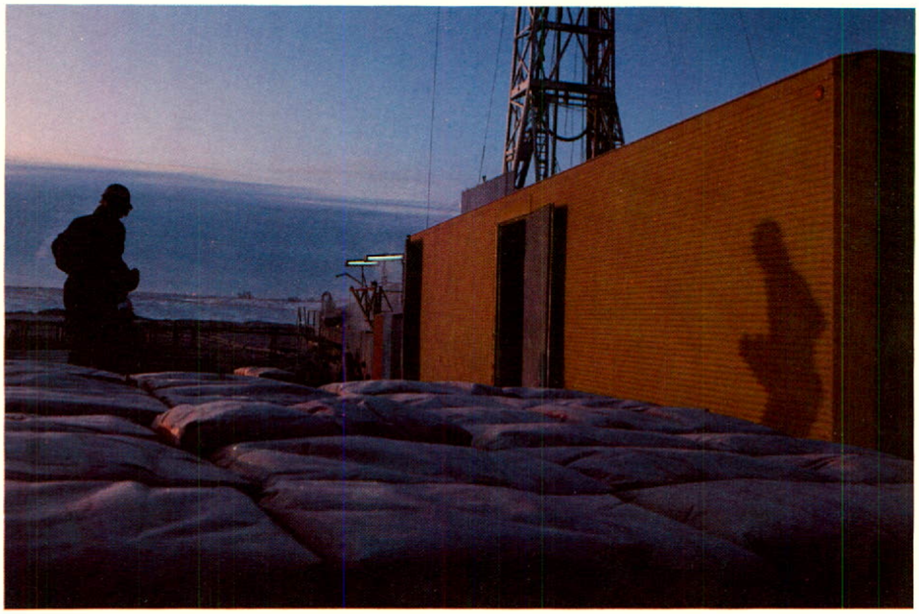
Taber

The Company participated in the drilling of five wells in the Taber North area of southeastern Alberta during 1983. A sixth well was drilled under a farmout at no cost to the Company. Three of these wells were completed as Glauconitic oil wells, two of them being new Glauconitic oil pool discoveries which will require further delineation drilling in 1984. The Company now has interests ranging from 25% to 27½% in six oil wells in this area.

In the small pool known as Taber Southeast, discovered in 1981 approximately 15 miles southeast of the Taber North pools, the producing formation is nearing depletion on primary production and consideration is being given to unitization and installation of an enhanced recovery scheme. The Company's interest in the unitized production will be approximately 15%.



EXPLORATION AND DEVELOPMENT

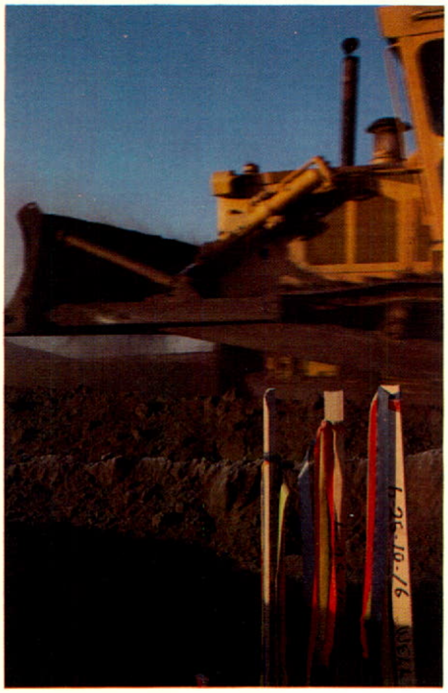


Zama (Gator)

The Company's landholdings in the Zama (Gator) area of northwestern Alberta were increased in 1983 by the acquisition of a 30% interest in a 1,280 acre licence on a seismic reef anomaly. The Company now holds interests ranging from 20% to 30% in a total of 9,280 acres in the area. Further seismic and land acquisitions and the drilling of at least one well are planned for 1984.

Senex

In August 1983 the Company participated in the purchase of a licence covering approximately 5,120 acres on a reefal oil play in the Senex area of north central Alberta. A seismic evaluation of the licence will be carried out in 1984. The Company's interest is 20%.



Rainbow Lake

Major seismic programs are planned for 1984 in the Rainbow Lake area of northwestern Alberta where the Company holds a 10% interest in 1,280 acres acquired at a 1983 government land sale. Drilling plans are dependent on the outcome of the seismic surveys.

Ricinus

A 10% interest in 9,440 acres was acquired in 1983 in the Ricinus area of central Alberta. This is a Cardium formation prospect and the first well will be drilled early in 1984.

Keystone-Pembina

During 1983 the Company, together with two other companies, established an area of mutual interest covering approximately 216 square miles in the Keystone area of central Alberta. Since the end of the year, 3,520 acres have been acquired in this area and the companies will continue to build a land position based on seismic leads. The Company's interest in this project is 15%.

At Pembina, in the same general area, the Company will participate to the extent of a 30% interest in a seismic program to evaluate the multizone potential of the Viking, Pekisko, Basal Quartz and Ostracod formations underlying Cardium production in the Pembina field.

Leedale

A gas well was completed in the Pekisko and Glauconitic formations on a 1,280 acre farmin near Leedale in central Alberta. The Company paid 12% of the costs of this well to obtain a 7⅞% interest in the well and the farmin lands. Attempts are being made to farmin additional land for further drilling.

Ogston

With the 1983 acquisition of another licence in this north central area of Alberta, the Company now has interests of 10% to 12½% in 8,320 acres located immediately north and south of existing Granite Wash production. Seismic work will precede the drilling of a well in 1984. This area has experienced a high rate of activity with a good record of success.

Ferrier

The Company acquired a 7½% interest in 1,280 acres by drilling a successful Glauconitic gas well on a farmin in the Ferrier area of central Alberta. The Company plans to exercise its option on another 640 acres under the farmin agreement and to drill a further well in 1984. Under the terms of the farmin agreement the Company paid 15% of costs to obtain a 7½% interest in the well and the farmin lands.

Westerose

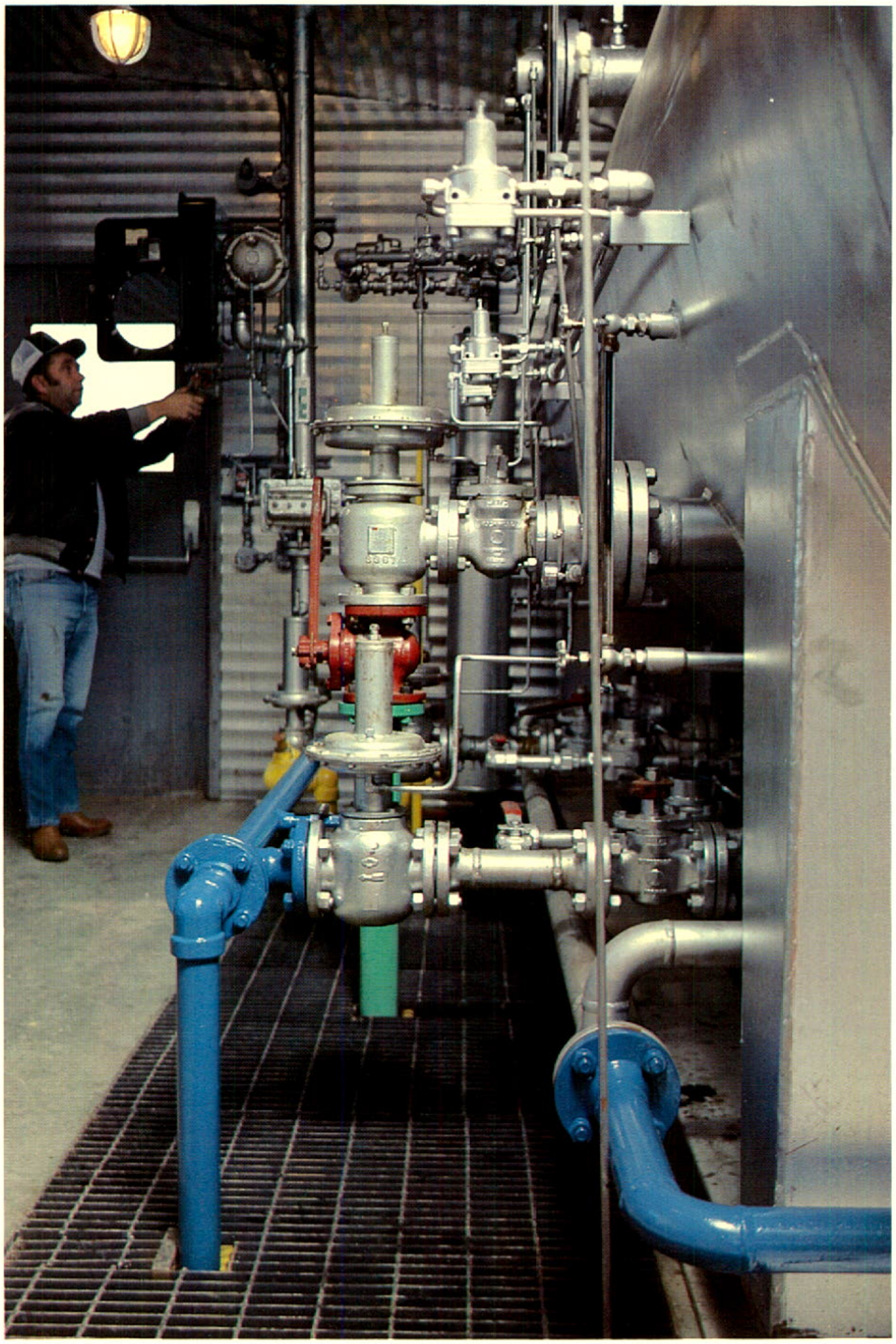
The Company acquired a 10% interest in 1,280 acres in this central Alberta area in 1983 and participated in the drilling of a potential gas well completion. Future drilling plans are uncertain at the present time.

Arctic Islands

The postponement of public hearings by the National Energy Board into the Arctic Pilot Project continues pending establishment of firm markets for liquefied natural gas with prospective customers in western Europe as an alternative to United States markets. Discussions with potential European gas buyers are continuing but the sponsors of the project are not expected to return to the Board for export authorizations for at least eighteen months. The Company has a 3.15% interest in the Drake Point reserves dedicated to the project.

EXPLORATION AND DEVELOPMENT

United States



Through its wholly-owned subsidiary, P.O.R. Oil & Gas Inc., the Company participated in the drilling of ten exploratory wells and two development wells in the United States in 1983. Four of the exploratory wells were completed as oil wells resulting in the discovery of three new fields; the Hitt field in the Powder River Basin in Wyoming, in which the Company has a 5% interest, and two Triassic Spearfish fields in North Dakota, in which the Company's interests are 10%. Both development wells were completed as oil wells. At year-end, the Company had interests in eight oil wells and one gas well and had increased its landholdings to 51,905 gross acres (3,607 net acres). The Company also participated in an extensive seismic exploratory program in Wyoming and North Dakota. During 1984, the Company will be participating in development drilling in the newly-discovered fields and in additional exploratory ventures throughout the Central Rocky Mountain Basin and North Dakota with working interests ranging from 5% to 10%.

1984 Exploration and Development

The directors of the Company have approved capital expenditures of $15,300,000 for exploration and development in 1984. Of this amount, $902,000 has been allocated to operations in the United States. Operations in Canada in 1984 will be centred in Alberta and in the Tatagwa-Colgate area of Saskatchewan.

OIL AND GAS LANDHOLDINGS

At December 31, 1983 the Company owned interests in 4,053,282 gross (319,259 net) acres as shown in detail in the following summary. This compares with 3,918,154 gross (335,288 net) at the end of 1982. In addition, the Company holds royalty interests in 194,076 acres.

	DEVELOPED*		UNDEVELOPED				TOTAL	
	Leases		Leases		Reservations and Permits			
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
British Columbia	30,238	2,015	86,227	4,655	—	—	116,465	6,670
Alberta	243,487	49,894	587,104	94,735	133,280	16,583	963,871	161,212
Saskatchewan	15,172	2,370	87,967	32,192	—	—	103,139	34,562
Manitoba	2,156	578	89,052	25,672	3,200	800	94,408	27,050
Ontario	—	—	3,144	796	99	20	3,243	816
Arctic Islands	92,128	2,352	114,244	2,871	2,488,721	79,333	2,695,093	84,556
Northwest Territories	—	—	25,158	786	—	—	25,158	786
United States	4,038	290	47,867	3,317	—	—	51,905	3,607
	387,219	57,499	1,040,763	165,024	2,625,300	96,736	4,053,282	319,259

*Developed leases are leases upon which one or more productive or potentially productive wells have been drilled.

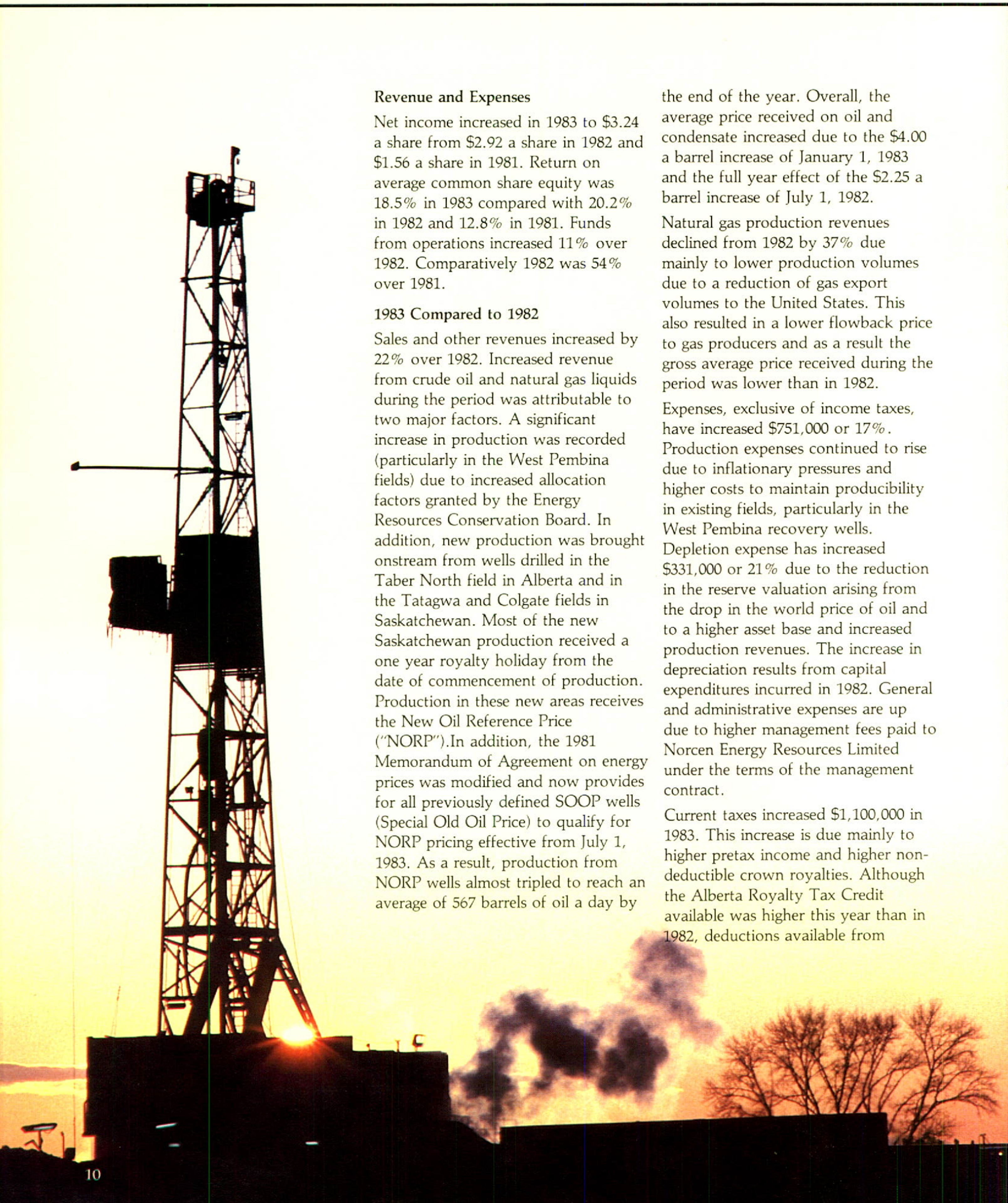
DRILLING SUMMARY

The following table sets forth the gross and net exploratory and development wells in which the Company participated during the five year period ended December 31, 1983.

	Exploratory Wells				Development Wells			
		Net Wells				Net Wells		
Year	Gross Wells	Oil	Gas	Dry Holes	Gross Wells	Oil	Gas	Dry Holes
1979	31	.47	2.34	2.19	19	.05	4.03	—
1980	40	.29	2.19	2.83	14	—	2.17	—
1981	44	.62	.82	3.05	4	.50	.13	.37
1982	52	2.17	.83	4.68	5	.45	—	1.00
1983	43	1.50	.47	4.55	13	1.15	—	.21
	210	5.05	6.65	17.30	55	2.15	6.33	1.58

As at December 31, 1983 the Company had working interests in 635 gross (11.1 net) producing oil wells and 362 gross (58 net) producing gas wells [including 76 gross (14.3 net) shut-in gas wells] all in Western Canada, working interests in 9 gross (.70 net) producing oil and gas wells in the United States and royalty interests in 400 gross (10 net) producing oil wells and 14 gross (.4 net) producing gas wells most of which are in the province of Saskatchewan.

MANAGEMENT'S DISCUSSION AND FINANCIAL REVIEW



Revenue and Expenses

Net income increased in 1983 to $3.24 a share from $2.92 a share in 1982 and $1.56 a share in 1981. Return on average common share equity was 18.5% in 1983 compared with 20.2% in 1982 and 12.8% in 1981. Funds from operations increased 11% over 1982. Comparatively 1982 was 54% over 1981.

1983 Compared to 1982

Sales and other revenues increased by 22% over 1982. Increased revenue from crude oil and natural gas liquids during the period was attributable to two major factors. A significant increase in production was recorded (particularly in the West Pembina fields) due to increased allocation factors granted by the Energy Resources Conservation Board. In addition, new production was brought onstream from wells drilled in the Taber North field in Alberta and in the Tatagwa and Colgate fields in Saskatchewan. Most of the new Saskatchewan production received a one year royalty holiday from the date of commencement of production. Production in these new areas receives the New Oil Reference Price ("NORP").In addition, the 1981 Memorandum of Agreement on energy prices was modified and now provides for all previously defined SOOP wells (Special Old Oil Price) to qualify for NORP pricing effective from July 1, 1983. As a result, production from NORP wells almost tripled to reach an average of 567 barrels of oil a day by the end of the year. Overall, the average price received on oil and condensate increased due to the $4.00 a barrel increase of January 1, 1983 and the full year effect of the $2.25 a barrel increase of July 1, 1982.

Natural gas production revenues declined from 1982 by 37% due mainly to lower production volumes due to a reduction of gas export volumes to the United States. This also resulted in a lower flowback price to gas producers and as a result the gross average price received during the period was lower than in 1982.

Expenses, exclusive of income taxes, have increased $751,000 or 17%. Production expenses continued to rise due to inflationary pressures and higher costs to maintain producibility in existing fields, particularly in the West Pembina recovery wells. Depletion expense has increased $331,000 or 21% due to the reduction in the reserve valuation arising from the drop in the world price of oil and to a higher asset base and increased production revenues. The increase in depreciation results from capital expenditures incurred in 1982. General and administrative expenses are up due to higher management fees paid to Norcen Energy Resources Limited under the terms of the management contract.

Current taxes increased $1,100,000 in 1983. This increase is due mainly to higher pretax income and higher non-deductible crown royalties. Although the Alberta Royalty Tax Credit available was higher this year than in 1982, deductions available from capital cost pools were lower. A summary of the changes to the total tax rate appears in note 4 to the financial statements.

1982 Compared to 1981

Sales and other revenues increased by 50% over the 1981 level. In 1982 there were price increases on crude oil and natural gas liquids of $2.25 a barrel on January 1 and July 1 compared to price increases in 1981 of $1.00 a barrel on January 1 and July 1 and $2.50 a barrel on October 1. The increased revenue from oil and oil and gas liquids was also attributable to increased production levels, especially natural gas liquids in the enhanced recovery well in the West Pembina area. The effect of these increases was offset somewhat by a higher Petroleum and Gas Revenue Tax rate and the introduction on January 1, 1982 of the Incremental Oil Revenue Tax, which was later suspended by the Federal Government for the period from June 1, 1982 to May 31, 1985. Natural gas production revenues increased from 1981 by 10% despite a 15% decline in volumetric sales, due to the impact of the 25¢ an Mcf increases on February 1 and August 1, 1982.

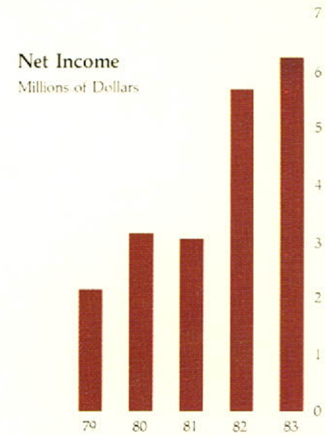
Expenses, exclusive of income taxes, have increased $817,000 or 23%. Production expenses continued to rise due to inflationary pressures and higher costs to maintain producibility in existing fields, particularly in the West Pembina area. Depletion expense has increased $354,000 or 30% due primarily to higher production revenues. The increase in depreciation results from capital expenditures incurred in 1981. General and administrative expenses are up due to higher management fees paid to Norcen Energy Resources Limited under the terms of the management contract. Interest expense decreased by $261,000 or 84% due to greatly reduced requirements for short-term borrowings. Income taxes increased as explained in note 4 to the financial statements.

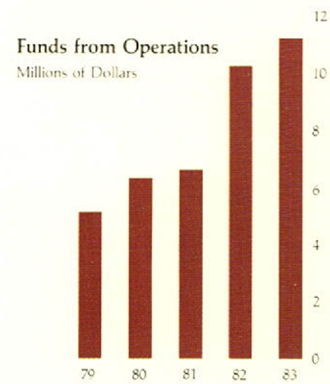
Balance Sheet

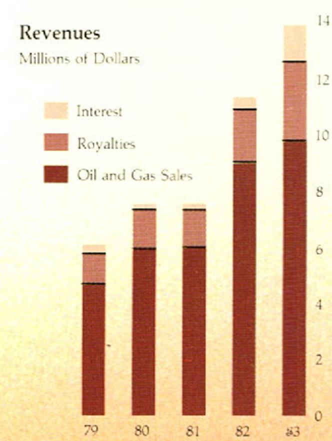
The total cost of assets of the Company has continued to grow to $62.1 million from $50.8 million in 1982 and $39.2 million in 1981. This growth is attributable mainly to the increased balance of internally generated cash and deposits on hand. The other contributing factor remains the capital expenditures program which amounted to $5.6 million, $4.7 million and $4.3 million in the last three years, net of petroleum incentive payments earned.

Financial Position

The funds position of the Company increased $6.5 million in 1983, $9.4 million in 1982 and $3.9 million in 1981. Funds from operations has continued to increase despite reduced gas sales which were more than offset by increased revenues from oil and gas liquids production. The decline in funds generated in 1983 from funds generated in 1982 was caused mainly by reduced deferred gas revenues received during 1983.







CONSOLIDATED BALANCE SHEET

As at December 31, 1983 and 1982 (thousands of dollars)

	1983	1982
Assets		
CURRENT ASSETS		
Cash and deposits	$18,435	$ 5,700
Accounts receivable	3,512	6,155
Income taxes recoverable	—	1,305
Drilling and other deposits	71	57
Portion of note receivable due within one year	622	623
	22,640	13,840
NOTE RECEIVABLE (note 2)	—	622
PROPERTIES, PLANT AND EQUIPMENT (note 3)	39,460	36,375
	$62,100	$50,837
Liabilities		
CURRENT LIABILITIES		
Accounts payable and accrued charges	$ 1,588	$ 2,259
Income taxes payable	2,386	—
Due to parent company	1,465	903
	5,439	3,162
DEFERRED GAS REVENUES	5,546	5,313
DEFERRED INCOME TAXES	13,551	11,153
Shareholders' Equity		
CAPITAL STOCK		
Issued		
1,961,520 Common Shares	1,962	1,962
CONTRIBUTED SURPLUS	574	574
RETAINED EARNINGS	35,028	28,673
	37,564	31,209
	$62,100	$50,837

Approved by the Board

D. O. Barnhart Director

W. A. Loucks Director

ACCOUNTING POLICIES

Years Ended December 31, 1983, 1982 and 1981

The Annual Report and the accompanying consolidated financial statements have been prepared by Management and approved by the Board of Directors. The consolidated financial statements have been prepared in accordance with generally accepted accounting principles applied on a consistent basis and comply with United States disclosure requirements in all material respects. The principles used were those judged by Management to be the most appropriate in the circumstances. Management acknowledges responsibility for the fairness, integrity and objectivity of all financial information contained in the Annual Report including the consolidated financial statements.

Principles of Consolidation

The consolidated financial statements include the accounts of Prairie Oil Royalties Company, Ltd. and its wholly-owned subsidiary, P.O.R. Oil & Gas Inc.

Foreign Currency Translation

Amounts in foreign currency have been translated to Canadian dollars on the following bases: current assets and current liabilities, at the rate of exchange as at the balance sheet date; properties, plant and equipment and related depreciation and depletion, at the rate of exchange at the date of acquisition; revenues and expenses, at the average rate of exchange for the respective year. Gains and losses on currency translation are included in income.

Properties, Plant and Equipment

Oil and gas properties, in accordance with the full cost method of accounting, include all expenditures related to the exploration and development of oil and gas reserves, whether or not potentially productive. These costs are depleted on the net production revenue method based on total estimated future net production revenues from proven recoverable reserves.

Oil and gas production equipment and related facilities are depreciated over their estimated useful service life on the straight-line method at various rates, the application of which is equivalent to a composite rate of approximately 8.6% in 1983, (8.4% in 1982, 7.9% in 1981).

Upon retirement or sale of major items of producing property or equipment, the asset accounts are relieved of the cost of such property together with the applicable accumulated depletion or depreciation. The difference between net book value of such items and the proceeds, if any, is charged or credited to income. Proceeds on sale of non-producing properties are credited to asset costs.

Maintenance and repairs are charged to income when incurred and betterments which extend the serviceable life of properties are capitalized.

Income Taxes

The Company follows the tax allocation method of accounting whereby provisions for income taxes are based on the income reported in the accounts. This method results in the provision of deferred income taxes to the extent that taxes currently payable have been reduced by claiming depletion and depreciation for income tax purposes in amounts differing from those reported in the accounts.

Deferred Gas Revenues

Deferred gas production revenues represents payments received under take-or-pay gas contracts. These amounts will be included in revenue when the gas to which the payments relate is delivered at the purchaser's option. Deliveries are to be made over a ten year period commencing November 1, 1984.

Oil & Gas Sales and Royalty Revenues

Oil and gas sales and royalty revenues are net of the petroleum and gas revenue tax and the incremental oil revenue tax. These production revenue taxes totalled $2,027,000 in 1983 ($1,759,000 in 1982; $815,000 in 1981).

Segmented Information

All of the Company's activities are in one business segment, oil and gas exploration, development and production, and substantially all of the Company's operations are conducted in one geographic segment, Canada. Accordingly, no separate disclosure has been made of financial data by segment.

CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED STATEMENT OF INCOME

Years Ended December 31, 1983, 1982 and 1981 (thousands of dollars except per share amounts)

	1983	1982	1981
SALES AND OTHER REVENUES			
Oil and gas sales	$ 9,959	$ 9,094	$ 6,116
Royalties	2,548	1,962	1,384
Interest	1,351	261	36
	13,858	11,317	7,536
COSTS AND EXPENSES			
Production	1,438	1,266	889
Depletion	1,878	1,547	1,193
Depreciation	666	531	460
General and administrative			
Charges from parent company	1,003	901	599
Other	93	70	96
Interest	36	48	309
	5,114	4,363	3,546
Income before income taxes	8,744	6,954	3,990
Income taxes (note 4)			
Current (recovery)	(9)	(1,109)	(927)
Deferred	2,398	2,327	1,855
	2,389	1,218	928
NET INCOME	$ 6,355	$ 5,736	$ 3,062
EARNINGS PER SHARE	$3.24	$2.92	$1.56

CONSOLIDATED STATEMENT OF RETAINED EARNINGS

Years Ended December 31, 1983, 1982 and 1981 (thousands of dollars)

	1983	1982	1981
BALANCE AT BEGINNING OF YEAR	$28,673	$22,937	$19,875
Net income	6,355	5,736	3,062
BALANCE AT END OF YEAR	$35,028	$28,673	$22,937

CONSOLIDATED STATEMENT OF CHANGES IN FINANCIAL POSITION

Years Ended December 31, 1983, 1982 and 1981
(thousands of dollars)

	1983	1982	1981
SOURCE OF FUNDS			
Net income	$ 6,355	$ 5,736	$ 3,062
Items not requiring an outlay of funds			
Deferred income taxes	2,398	2,327	1,855
Depletion	1,878	1,547	1,193
Depreciation	666	531	460
From operations	11,297	10,141	6,570
Deferred gas revenues	233	3,351	421
Note receivable	622	623	—
Sale of oil and gas properties	—	—	2,489
	12,152	14,115	9,480
APPLICATION OF FUNDS			
Expenditures on properties, plant and equipment	6,253	6,682	4,390
Petroleum incentive payments earned	(624)	(1,998)	(99)
Note receivable	—	—	1,245
	5,629	4,684	5,536
INCREASE IN FUNDS	$ 6,523	$ 9,431	$ 3,944
CHANGES IN COMPONENTS OF FUNDS ARE REPRESENTED BY:			
Cash and deposits	$12,735	$ 5,700	$ —
Accounts receivable	(2,643)	3,795	291
Income taxes recoverable	(1,305)	113	890
Drilling and other deposits	14	—	14
Portion of note receivable due within one year	(1)	1	622
Bank indebtedness	—	1,528	1,084
Accounts payable and accrued charges	671	(1,036)	871
Income taxes payable	(2,386)	—	—
Due to parent company	(562)	(670)	172
INCREASE IN FUNDS	$ 6,523	$ 9,431	$ 3,944

AUDITORS' REPORT

To the Shareholders of Prairie Oil Royalties Company, Ltd.

We have examined the consolidated balance sheet of Prairie Oil Royalties Company, Ltd. as at December 31, 1983 and 1982 and the consolidated statements of income, retained earnings and changes in financial position for each of the three years ended December 31, 1983. 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 1982 and the results of its operations and the changes in its financial position for each of the three years ended December 31, 1983 in accordance with generally accepted accounting principles applied on a consistent basis.

Thorne Riddell

Calgary, Canada
February 1, 1984

Thorne Riddell
Chartered Accountants

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Years Ended December 31, 1983, 1982 and 1981 (thousands of dollars)

1. ACCOUNTING POLICIES

The summary of accounting policies is an integral part of these financial statements.

2. NOTE RECEIVABLE

	1983	1982
Due in equal annual instalments on April 1 each year through 1984	$ 622	$ 1,245
Portion due within one year	622	623
	$ —	$ 622

3. PROPERTIES, PLANT AND EQUIPMENT

	Year Ended December 31,	
	1983	1982
Properties	$45,625	$40,428
Production equipment	8,143	7,711
	53,768	48,139
Accumulated depreciation and depletion	14,308	11,764
Capitalized costs	$39,460	$36,375

4. INCOME TAXES

Deferred income taxes result from timing differences in the recognition of income and expenses for income tax and financial statement purposes. The source of these differences and the tax effect of each are as follows:

	1983	1982	1981
Exploration and development expenditures and capital cost allowances deducted for income tax purposes in excess of depletion and depreciation	$ 2,070	$ 2,387	$ 1,908
Other items	328	(60)	(53)
	$ 2,398	$ 2,327	$ 1,855

The provision for income taxes in the consolidated statement of income varies from the amounts that would be computed by applying the Canadian federal statutory rate of 46% to income before income taxes for the following reasons:

	1983	1982	1981
Income before income taxes	$ 8,744	$ 6,954	$ 3,990
Canadian federal statutory rate of income tax	46.0%	46.0%	46.0%
Computed income tax expense	$ 4,027	$ 3,199	$ 1,835
Increase (decrease) in income tax resulting from:			
Income tax depletion	(118)	(318)	(708)
Non-deductible royalties, Petroleum and Gas Revenue Tax, Incremental Oil Revenue Tax, mineral taxes and other expenses, less federal resource allowance and provincial rebates	(1,761)	(1,369)	(270)
Other, net	241	(294)	71
Actual income tax expense	$ 2,389	$ 1,218	$ 928
Effective income tax rate	27.3%	17.5%	23.3%

SUPPLEMENTAL INFORMATION

Years Ended December 31, 1983, 1982 and 1981 (thousands of dollars except per share amounts)

QUARTERLY AND OTHER FINANCIAL DATA

	Quarter				
	First	Second	Third	Fourth	Year
1983					
Revenue	$ 3,394	$ 3,137	$ 3,321	$ 4,006	$13,858
Income before income taxes	2,090	2,003	2,147	2,504	8,744
Net income	1,641	1,483	1,319	1,912	6,355
Earnings per share	.84	.75	.67	.98	3.24
Market price per common share (i)					
High	20¾	25	22⅝	22½	25
Low	15½	17¾	20¼	19¾	15½
1982					
Revenue	$ 3,038	$ 2,068	$ 3,013	$ 3,198	$11,317
Income before income taxes	1,722	1,169	2,075	1,988	6,954
Net income	1,856	1,064	1,463	1,353	5,736
Earnings per share	.95	.54	.75	.68	2.92
Market price per common share (i)					
High	13½	16¼	14½	18¼	18¼
Low	11	12	11¾	11⅝	11

(i) The market prices are as reported by the American Stock Exchange, the primary market, in U.S. dollars.

OIL AND GAS INFORMATION

The following unaudited supplemental information is disclosed in accordance with the provisions of the Financial Accounting Standards Board ("FASB") Statement No. 69 "Disclosures about Oil and Gas Producing Activities". These new FASB requirements were developed with the support of the United States Securities and Exchange Commission which rescinded certain disclosure requirements, including the experimental reserve recognition accounting.

Exploration and Production Activities

The Company has capitalized property acquisition, exploration and development costs pertaining to its Canadian oil and gas operations as follows:

	December 31,	
	1983	1982
Properties (i)	$45,625	$40,428
Production equipment	8,143	7,711
	53,768	48,139
Accumulated depreciation, depletion and amortization	14,308	11,764
Capitalized costs	$39,460	$36,375

(i) Included in the totals are the Company's unproven properties which were not categorized due to immateriality.

The following table presents information on the Company's oil and gas property acquisition, exploration and development activities.

	1983	1982	1981
Costs capitalized in the year			
Property acquisition	$ 1,230	$ 205	$ (1,857)
Exploration (i)	3,407	2,519	2,433
Development (i)	992	1,960	1,226
Total capitalized	$ 5,629	$ 4,684	$ 1,802

(i) Exploration and development costs are shown net of Petroleum Incentive Payments earned of $624 in 1983, $1,998 in 1982; $99 in 1981.

	1983	1982	1981
Net revenues from producing oil and gas			
Revenue	$19,429	$16,605	$11,890
Production expenses (i)	8,361	6,816	5,279
Depreciation, depletion and amortization expense	2,544	2,078	1,653
	8,524	7,711	4,958
Income Tax Expense	2,169	1,506	1,234
Results of operations from producing activities (excluding corporate overhead and interest costs)	$ 6,355	$ 6,205	$ 3,724

(i) Includes production revenue taxes of $2,027 in 1983 ($1,759 in 1982; $815 in 1981); freehold and crown royalty payments of $4,897 in 1983 ($3,790 in 1982; $3,575 in 1981).

RESERVES

Reserves as determined by company engineers are stated on a before royalty basis and include proven remaining reserves together with probable additional reserves reduced by a risk factor, all in accordance with Canadian practice. The reserve information provided as determined by independent reservoir engineers McDaniels & Associates, Inc., is provided on a proven reserve basis only, after deducting royalty interests of governments and others. All of the Company's proven reserves are developed. The reserve quantity of information summarizes the changes in quantities of net proven Canadian oil and gas reserves.

	Year Ended December 31,					
	1983		1982		1981	
	Oil and Gas Liquids (000's bbls)	Gas (Mmcf)	Oil and Gas Liquids (000's bbls)	Gas (Mmcf)	Oil and Gas Liquids (000's bbls)	Gas (Mmcf)
Beginning of year	1,989	39,406	2,036	36,816	1,833	39,000
Revision of previous estimates	259	(447)	232	1,658	406	(492)
Extensions, discoveries and other additions	159	822	—	2,866	—	316
Production	(346)	(1,253)	(279)	(1,934)	(203)	(2,008)
End of year	2,061	38,528	1,989	39,406	2,036	36,816

SUPPLEMENTAL INFORMATION

Standardized Measure of Discounted Future Net Cash Flows and Changes therein relating to Proved Oil and Gas Reserves

In calculating the standardized measure of discounted future net cash flows, prices and costs in effect at January 1, 1984 were applied to proven reserves and provision was made for estimated future development expenditures that will be required to produce the reserves. Royalty deductions were based on laws, regulations and contracts existing at the end of the fiscal year. The discounted future net cash flows are derived by applying a 10% discount factor, as required by the FASB Statement No. 69 rules, to the future net cash flows. Management believes that this information does not sufficiently reflect the current economic value of the oil and gas producing properties or the present value of estimated future cash flows since no economic value is attributed to potential reserves, the use of a 10% discount rate is arbitrary and prices constantly change from year end levels.

	Year ended December 31, (millions of dollars)		
	1983	1982	1981
Future cash inflows	$ 223.4	$ 218.6	$ 213.7
Future production costs	(107.4)	(99.0)	(111.8)
Future development costs	(2.5)	(2.5)	(2.7)
Future income tax expense	(61.9)	(62.8)	(55.4)
Future net cash flows	51.6	54.3	43.8
Standardized measure of future net cash flows discounted at 10%	$ 27.1	$ 28.0	$ 21.5

The following table sets out principal sources of changes in the standardized measure of discounted future net cash flows during the respective periods:

	1983	1982	1981
		(millions of dollars)	
Sales of oil and gas	$ (11.1)	$ (9.8)	$ (6.6)
Net changes in prices and production costs	(1.3)	10.5	7.3
Extensions, discoveries and improved recovery, less related costs	3.1	.9	.2
Development costs incurred during the period	.2	.6	.9
Revisions of previous quantity estimates and other	4.9	5.9	6.5
Accretion of discount	2.8	2.2	1.9
Net changes in income taxes	.5	(3.8)	(8.0)
Net increase (decrease)	(0.9)	6.5	2.2
Beginning of period	28.0	21.5	19.3
End of period	$ 27.1	$ 28.0	$ 21.5

SELECTED FINANCIAL DATA

(Dollar amounts in thousands except per share amounts)

For the Years Ended December 31	1983	1982	1981	1980	1979
REVENUE - note 1					
Oil Sales	$ 7,175	$ 4,331	$ 2,066	$ 1,520	$ 1,079
Gas Sales	2,784	4,763	4,050	4,463	3,616
Royalties	2,548	1,962	1,384	1,501	1,322
Interest	1,351	261	36	17	149
	13,858	11,317	7,536	7,501	6,166
EXPENSES					
Production	$ 1,438	$ 1,266	$ 889	$ 785	$ 592
Depletion	1,878	1,547	1,193	1,648	1,453
Depreciation	666	531	460	343	262
General and Administrative	1,096	971	695	556	451
Interest	36	48	309	334	395
	5,114	4,363	3,546	3,666	3,153
INCOME BEFORE INCOME TAXES	$ 8,744	$ 6,954	$ 3,990	$ 3,835	$ 3,013
INCOME TAXES					
Current (recovery)	$ (9)	$(1,109)	$ (927)	$ (671)	$ (454)
Deferred	2,398	2,327	1,855	1,356	1,220
	2,389	1,218	928	685	766
NET INCOME	$ 6,355	$ 5,736	$ 3,062	$ 3,150	$ 2,247
CASH FLOW	$11,297	$10,141	$ 6,570	$ 6,496	$ 5,183
CAPITAL EXPENDITURES - note 2					
Exploration and Property Acquisitions	$ 5,197	$ 3,293	$ 1,338	$ 5,815	$12,607
Plant and Equipment	$ 432	$ 1,391	$ 464	$ 1,721	$ 767
TOTAL ASSETS - note 3	$62,100	$50,837	$39,245	$35,236	$30,750
COMMON SHARES					
Issued and Outstanding	1,961,520	1,961,520	1,961,520	1,961,520	1,961,520
Number of Shareholders - note 4	756	950	1,220	1,350	1,340
Earnings per share	$ 3.24	$ 2.92	$ 1.56	$ 1.61	$ 1.15

MARKET PRICES	High	Low	High	Low	High	Low	High	Low	High	Low
American Stock Exchange										
(U.S. $) 1st Quarter	20¾	15½	13½	11	16⅝	14	30¾	15¾	17⅞	13⅛
2nd Quarter	25	17¾	16¼	12	18¼	14⅜	25⅜	17½	22⅝	15⅛
3rd Quarter	22⅝	20¼	14½	11¾	21⅜	11	28⅝	22⅝	21⅜	16⅝
4th Quarter	22½	19¾	18¼	11⅝	16¼	12⅜	27⅝	14⅝	26¼	18⅝
Toronto Stock Exchange										
(CAN. $) 1st Quarter	21	21	no sales		20	20	34	26	21	16
2nd Quarter	30	22	no sales		no sales		30	24	25⅛	20½
3rd Quarter	28	25	22	16½	22⅛	19¾	30	28	24½	19½
4th Quarter	27½	25	22	19	no sales		29	29	24½	22

Long-term obligations, redeemable preferred stock and dividends are not applicable for the disclosed periods.

Notes:

(1) Oil, gas and royalty revenue for years 1981 to 1983 is net of production revenue taxes which became effective in 1981.

(2) Capital expenditures for the year 1981 are net after sales.

(3) Total assets for years 1979 to 1981 have been restated to reflect an income tax reassessment relating to reported capital gains in 1976.

(4) Number of shareholders as at March 1, 1984 - 750.

CORPORATE INFORMATION

BOARD OF DIRECTORS

DONALD D. BARKWELL
Calgary, Alberta
Executive Vice-President
Norcen Energy Resources Limited

*WILFRID A. LOUCKS
Calgary, Alberta
Vice-President
Norcen Energy Resources Limited

CLIFFORD A. RAE, Q.C.
Calgary, Alberta
Barrister & Solicitor
Macleod Dixon

*EDWARD A. GALVIN
Calgary, Alberta
Chairman of the Board
Poco Petroleums Ltd.

*FREDERICK A. McKINNON
Calgary, Alberta
Director of various companies

DAVID M. TYERMAN, Q.C.
Regina, Saskatchewan
Barrister & Solicitor
MacPherson, Leslie & Tyerman

*Member of the Audit Committee

CORPORATE OFFICERS

DONALD D. BARKWELL
Chairman of the Board
Executive Vice-President
Norcen Energy Resources Limited

WILFRID A. LOUCKS
President
Vice-President
Norcen Energy Resources Limited

WILLIAM C. HENNENFENT
Vice-President
Vice-President Exploration
Norcen Energy Resources Limited

GORDON B. SINGER
Vice-President, Comptroller
Vice-President,
Accounting and Services
Norcen Energy Resources Limited

DAVID M. TYERMAN, Q.C.
Secretary
Barrister & Solicitor
MacPherson, Leslie & Tyerman

ALICK S. G. DUGUID
Treasurer
Treasurer
Norcen Energy Resources Limited

WILLIAM T. KILBOURNE
Assistant Secretary
Vice-President, Legal and Secretary
Norcen Energy Resources Limited

RUSSELL G. RENNIE
Assistant Secretary
Assistant Secretary
Norcen Energy Resources Limited

EVELYN M. MACDONALD
Assistant Treasurer
Assistant Treasurer
Norcen Energy Resources Limited

Norcen Tower — location of Company's Executive Office

EXECUTIVE OFFICE
715 Fifth Avenue Southwest,
Calgary, Alberta T2P 2X7

REGISTERED OFFICE
2161 Scarth Street
Regina, Saskatchewan
S4P 2V4

REGISTRARS &
TRANSFER AGENTS

Canada Permanent Trust Company
Regina, Saskatchewan
Toronto, Ontario

Morgan Guaranty Trust Company
of New York
New York, U.S.A.

AUDITORS

Thorne Riddell
Calgary, Alberta

STOCK EXCHANGE LISTINGS

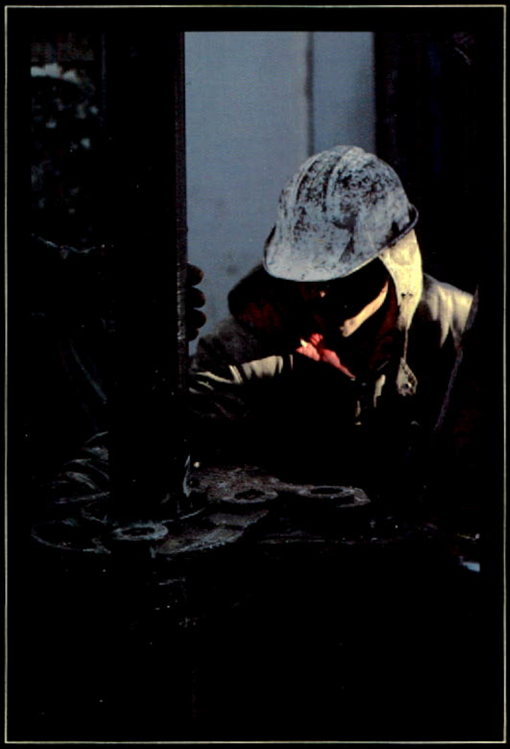
(Symbol — POY)
Toronto Stock Exchange
American Stock Exchange

ANNUAL MEETING

The Annual Meeting of Shareholders of the Company will be held on Friday, April 27, 1984, at 10:30 o'clock in the forenoon, local time, in the Board Room of Norcen Energy Resources Limited, 32nd Floor, 715 Fifth Avenue Southwest, Calgary, Alberta, Canada.

FORM 10-K

Copies of the Annual Report on Form 10-K filed with the Securities and Exchange Commission of the United States are available to shareholders by writing to the Corporate Secretary of the Company.



Prairie Oil Royalties
Company, Ltd.

Annual Report 1983

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