PanCanadian

Annual Report 1981

PanCanadian Petroleum Limited

COMPANY PROFILE

PanCanadian Petroleum Limited, headquartered in Calgary, Alberta, is one of the largest Canadian-owned hydrocarbon companies. It is engaged in exploration, production, transportation and wholesale marketing of oil, natural gas, natural gas liquids and sulphur. PanCanadian has approximately 1 160 employees.

Shareholders' Meeting

The Annual Meeting of Shareholders will be held in the Marquis Room of the Palliser Hotel, Calgary, Alberta at 10:00 a.m. local time on Thursday, April 1, 1982. Notice of meeting, information circular and form of proxy are being mailed to each Shareholder with this report.

In April, each year, PanCanadian Petroleum Limited publishes a supplementary report entitled "Financial and Operating Information." The report contains more detailed information than is possible to include in the Annual Report, and is mainly provided for the use of security analysts. Any shareholder requiring a copy may obtain one by directing a request to the Coordinator — Budgetary Control & Statistics.

The Cover

The Ram Range overlooking the North Saskatchewan River near its headwaters.

Contents

Highlights	1
Directors and Senior Management	2
Corporate	3
To the Shareholders	4
Exploration	7
Production	13
Reserves	16
Financial	18
Auditors' Report	21
Financial Statements	22-28
Reserve Recognition Accounting	29
Government Policies and Legislation	31
Ten Year Statistical Review	32

HIGHLIGHTS

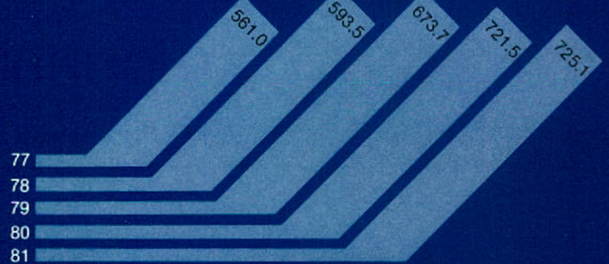
Financial

(Dollar amounts in thousands except per share figures)

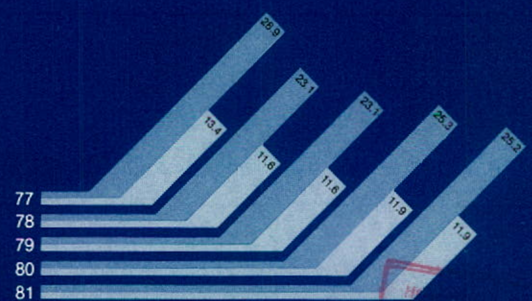
	1981	1980
Gross Income	$641 922	$574 687
Funds from Operations	362 728	367 312
Per Share	11.62	11.76
Net Income	203 737	241 367
Per Share	6.52	7.73
Dividends	112 399	99 909
Per Share	3.60	3.20
Capital Expenditures	347 275	269 960
Long-Term Debt at end of year	247 210	176 425
Working Capital at end of year	49 351	27 151

Operating

	1981	1980
Daily Production (After Royalty)		
Natural Gas – million cubic feet	279.8	281.4
Crude Oil and Natural Gas Liquids – barrels	52 140	50 807
Synthetic Oil – barrels	2 776	2 875
Drilling Statistics – Working Interest Wells		
Exploratory Wells Drilled	311	356
Indicated Successes	202	250
Development Wells Drilled	219	430
Indicated Successes	206	418
Net Working Interest Acreage (thousand acres)	11 851	11 935



TOTAL RESERVES *(million BOE after royalty)*
Six thousand cubic feet of gas equals one barrel of oil equivalent (BOE)



LAND HOLDINGS *(millions of acres)*
GROSS NET

DIRECTORS AND SENIOR MANAGEMENT

CORPORATE DIRECTORS

Robert W. Campbell Calgary, Alberta	*	Chairman of the Board and Chief Executive Officer of PanCanadian Petroleum Limited; Director and Vice Chairman of Canadian Pacific Enterprises Limited; Director of AMCA International Limited and Cominco Ltd.
Albert D. Cohen Winnipeg, Manitoba	†	President and Chief Executive Officer of General Distributors of Canada Ltd.
Jock K. Finlayson Toronto, Ontario		President of the Royal Bank of Canada
G. Donald Love Edmonton, Alberta	†	Chairman and President of Oxford Development Group Ltd.
Hugh A. Martin Vancouver, B.C.	†	President of Western Construction & Engineering Research Ltd.
Paul A. Nepveu Montreal, Quebec		Chairman of the Board of CIP Inc.
Bartlett B. Rombough Calgary, Alberta	*	President of PanCanadian Petroleum Limited; Director of Panarctic Oils Ltd.
John C. Ross Lethbridge, Alberta	†	Rancher; President of the Milk River Cattle Company Limited
Ian D. Sinclair Montreal, Quebec		Chairman and Chief Executive Officer of Canadian Pacific Enterprises Limited
W.J. Stenason Montreal, Quebec		President of Canadian Pacific Enterprises Limited
Marshall M. Williams Calgary, Alberta	*	President and Chief Executive Officer of TransAlta Utilities Corporation

* Member of Executive Committee † Member of Audit Committee

CORPORATE OFFICERS AND SENIOR MANAGEMENT

Robert W. Campbell	Chairman of the Board and Chief Executive Officer
Bartlett B. Rombough	President
Ian D. Sinclair	Vice President
Charley H. Stevens	Senior Vice President — Finance
Richard C. Verner	Senior Vice President — Operations
C. Barrie Clark	Vice President — Administration and Assistant Secretary
Kenneth B. Cusworth	Vice President — Corporate Research
Arthur W. Groll	Vice President — Industry Relations
C. Rolf V. Thomson	Vice President — Exploration
George E. Little	Corporate Secretary
Donald N. Maxwell	Comptroller
Keith A. Wurzer	Treasurer
William S. Bishai	General Manager — Production
Guido A. Montemurro	General Manager — Development
William C. Reinwart	General Manager — Marketing
Virginia M. James	Assistant Secretary
Victor B. Watson	Assistant Treasurer

CORPORATE

Offices

HEAD OFFICE
2000 - One Palliser Square
Calgary, Alberta

UNITED STATES
700 Trinity Place Building
Denver, Colorado

1500 - One Houston Center
Houston, Texas

UNITED KINGDOM
62/65 Trafalgar Square
London, England

Shares listed

Alberta Stock Exchange
Montreal Stock Exchange
Toronto Stock Exchange
Vancouver Stock Exchange

Registrar and Transfer Agent

Guaranty Trust Company of
Canada – Calgary, Montreal,
Toronto, Vancouver

Banker

The Royal Bank of Canada

Auditors

Price Waterhouse
Chartered Accountants
Calgary, Alberta

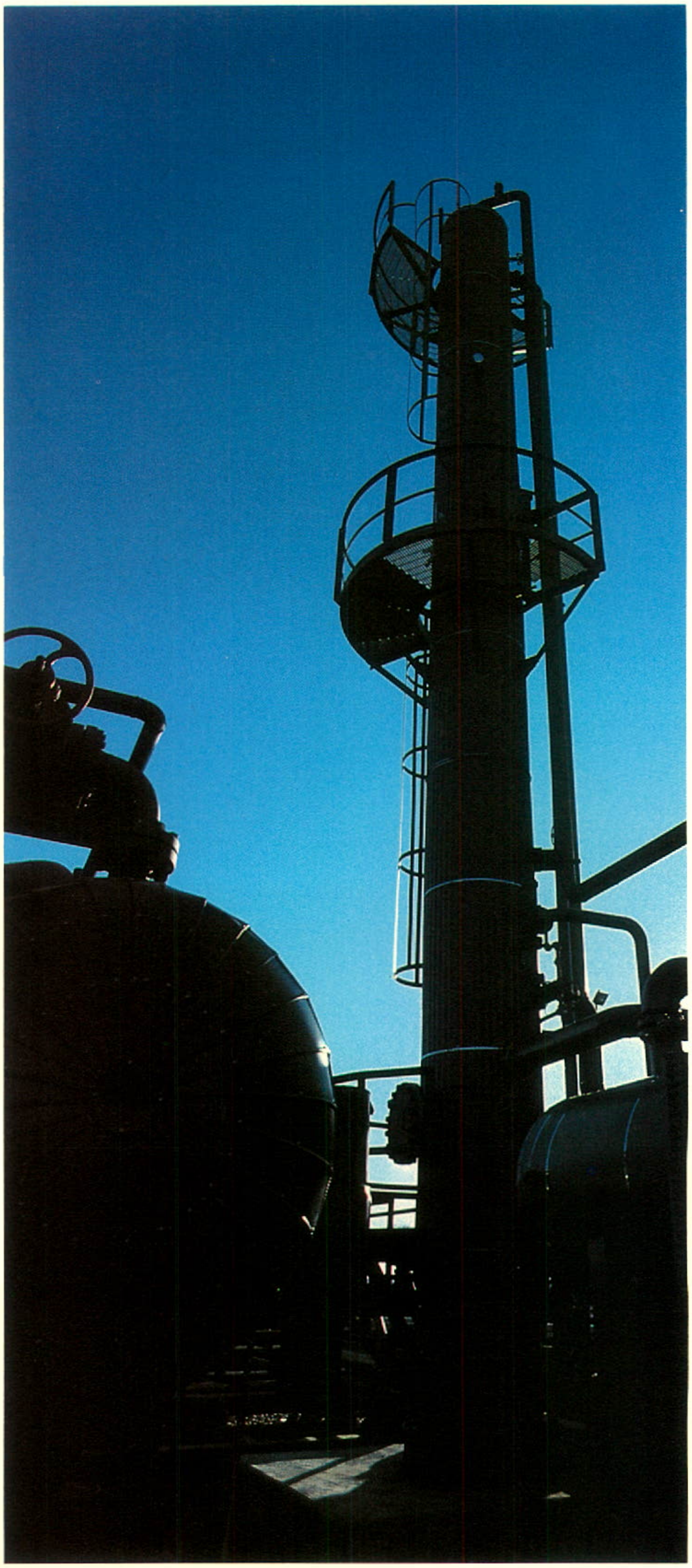
Subsidiary and Affiliate Companies

Wholly Owned

Blackfoot Pipelines Ltd.
Canadian Pacific Oil and Gas of Canada Limited
Canadian Pacific Oil and Gas Nederland B.V.
PanCanadian Gas Products Ltd.
PanCanadian Petroleum Company
PanCanadian Petroleum (U.K.) Limited
PanCanadian Kerrobert Pipeline Ltd.

Other

Minerals Ltd. — 50%
Panarctic Oils Ltd. — 7.99%
Syncrude Canada Ltd. — 4%



TO THE SHAREHOLDERS

Robert W. Campbell

The Canadian petroleum industry operated in an uncertain environment in 1981. Intergovernmental negotiations resulted in pricing and taxation agreements late in the year, without significantly improving industry outlook. Under the various legislative proposals and energy agreements, the industry will operate in a more complex environment. Because of the number and complexity of these changes, discussed elsewhere in this report, it will be some time before the total impact on the industry and the Company can be fully assessed.

Gross revenues in 1981 reached $641.9 million, which represents a 12% increase over $574.7 million last year. Despite these record revenues, net income decreased 16% to $203.7 million from $241.4 million, or $6.52 and $7.73 per share, respectively. Funds generated from operations were $362.7 million or $11.62 per share, compared to $367.3 million or $11.76 per share in 1980. Significant tax changes, including the 8% Petroleum and Gas Revenue Tax, and higher costs of operations exceeded the revenue gains resulting from increased product prices.

Capital expenditures of $347.3 million, before deduction of anticipated federal incentive payments, were 29% higher than $270.0 million reported in 1980. Exploration expenditures, including the investment in Panarctic Oils Ltd., were $145.3 million, compared with $184.7 million last year. The Company's exploration was concentrated in Alberta, but included important programs elsewhere in Canada, in the United States, and in the United Kingdom and Netherlands sectors of the North Sea. Expenditures on development projects, excluding investment in a methanol plant, were $111.8 million in 1981, an increase of $26.5 million over the 1980 expenditures of $85.3 million. Major expenditures were made for facilities to put contracted new gas on production at Hoadley, Countess-Makepeace and Wilson Creek.

Daily production of crude oil and natural gas liquids, after royalties, averaged 54 916 barrels, despite temporary cutbacks in Alberta and Saskatchewan. This was a 2% increase over the 1980 daily average of 53 682 barrels due to higher sales of natural gas liquids from the Empress plants. Sales of natural gas, after royalties, averaged 279.8 million cubic feet a day compared to 281.4 million cubic feet in 1980. These natural gas sales were well below production capability as a result of depressed natural gas demand.

Reserves additions replaced production of conventional crude oil, natural gas liquids and natural gas in 1981. Remaining reserves of crude oil and natural gas liquids, before royalty, are 156.8 million barrels compared to 156.2 million barrels in 1980. Natural gas reserves, before royalty, of 3 782 billion cubic feet at year-end are essentially unchanged from 3 761 billion cubic feet in 1980.

A two-tier crude oil pricing structure has been introduced effective January 1, 1982. Oil produced from pools found after 1980 will qualify for a new oil price, being the lesser of scheduled or actual international prices. The old oil price initially will be approximately one half of the new oil price, escalating to 75% of international prices. Any improvement in the industry share of revenues arising from the energy pricing agreements will come primarily from new oil production. The Company's share of the daily allowable production from discoveries of new oil made in 1981, which will qualify for the new oil prices commencing in 1982, is approximately 3 000 barrels.

The Company is active in new oil development in several areas of Alberta, including Alderson, Lindbergh and Thorsby-Genessee. PanCanadian's land holdings in western Canada position it favourably for further new oil discoveries.

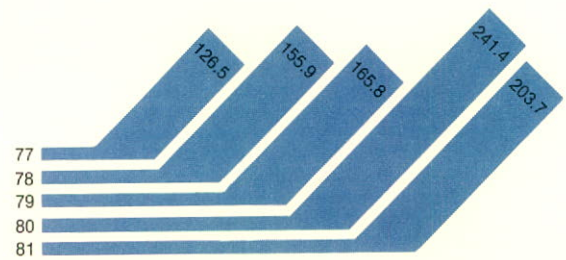
It is the expectation of the governments that the new oil prices will permit high cost projects to proceed, be they oil sands, enhanced recovery, low productivity heavy conventional oils or offshore developments. Under present revenue sharing between government and industry, the realization of these high prices is crucial to the success of these undertakings. It is the view of the Company, and the industry in general, that international prices will be significantly less than those forecast by governments. Given this outlook, certain of these projects are clearly in jeopardy, as are the attendant economic benefits for the country.

Pricing for Alberta natural gas has been revised such that a schedule of Alberta border prices will apply to gas sold outside the province. While producers will continue to share the price differential realized on Alberta natural gas sold in the United States markets, it is expected that a portion of the differential will be used by government to subsidize development of domestic markets. The transfer of the reference point for pricing from the Toronto City Gate to the Alberta border, coupled with the market development subsidy, appears to address our concern that the subsidy for developing new natural gas markets not be borne entirely by the producer.

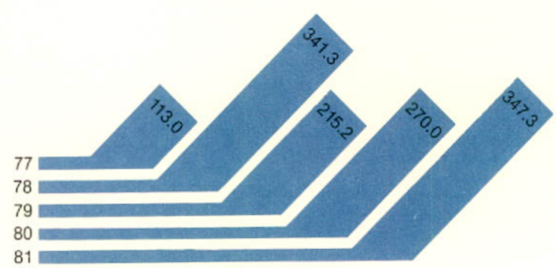
In mid-1981 the National Energy Board concluded that no surplus of exportable natural gas existed. Under continuing pressure from industry that such a surplus does exist, the Board has called for new hearings commencing in March, 1982. Re-examination of the present methods of calculating the amount of gas surplus to Canada's needs, as well as other matters relating to gas exports, will be considered. These hearings will be of particular significance to Alberta producers.

The Company will benefit from any expansion in the domestic and export markets for natural gas. With sizeable natural gas reserves and surplus installed production capacity, increased gas sales can be accommodated without substantial investment in production facilities.

Late in 1981, PanCanadian sold $65 million of 16½% Canadian dollar debentures in the European market. The debentures mature in 1988. As a result of this transaction, approximately 54% of the Company's long-term debt at December 31, 1981 was at fixed interest rates.



NET INCOME *(millions of dollars)*



CAPITAL EXPENDITURES *(millions of dollars)*

The Company entered the growing Alberta petrochemical industry by acquiring a 35% interest in a world-scale methanol plant, under construction near Edmonton, Alberta, in September of 1981. The cost to PanCanadian is expected to be approximately $130 million, of which $90.2 million was incurred in 1981. Celanese Canada Inc., the operator, has a 35% interest with the remaining 30% owned by one of its United States affiliates, Celanese Company of America, Inc. The Celanese group is one of the world's largest producers and marketers of methanol. The plant has a design capacity of 2 100 tonnes of methanol a day and start-up is scheduled for the last half of 1982. Natural gas feedstock for the plant has been contracted on a long-term basis from several

Alberta producers. The methanol is to be initially sold 25% in Canada, 50% in the United States and 25% in Japan.

In August, the Board reluctantly accepted the resignation of Mr. J. Wallace Madill who resigned because of other business interests. His valued contributions to the Board's deliberations will be missed and we wish him continued success.

We thank our employees for their continued and valued efforts on the Company's behalf. We are looking forward to relocating all head office staff in PanCanadian Plaza, our new corporate headquarters in downtown Calgary, later this year.

Submitted on behalf of the Board of Directors,

Robert W. Campbell

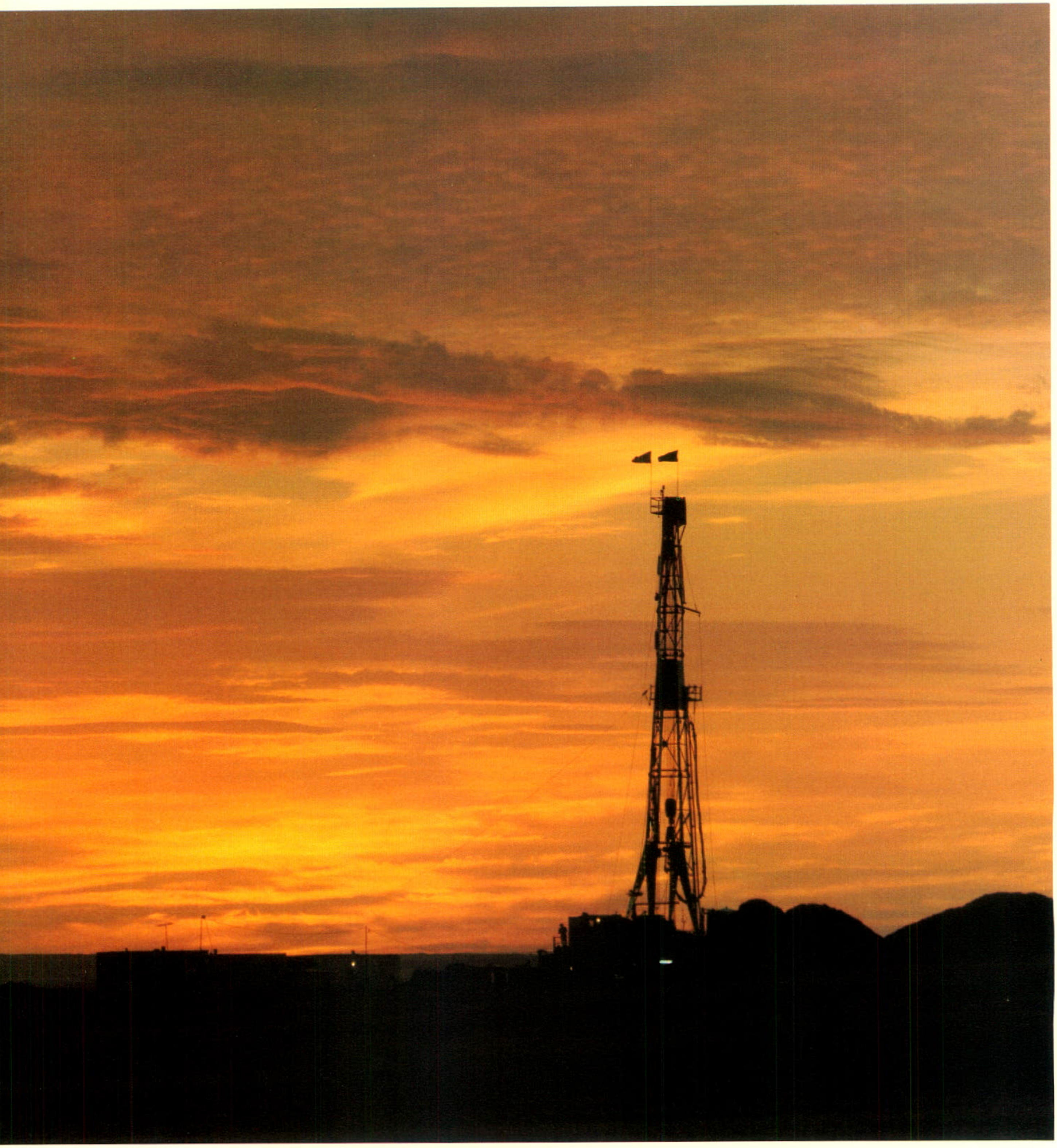
Robert W. Campbell
Chairman of the Board and
Chief Executive Officer

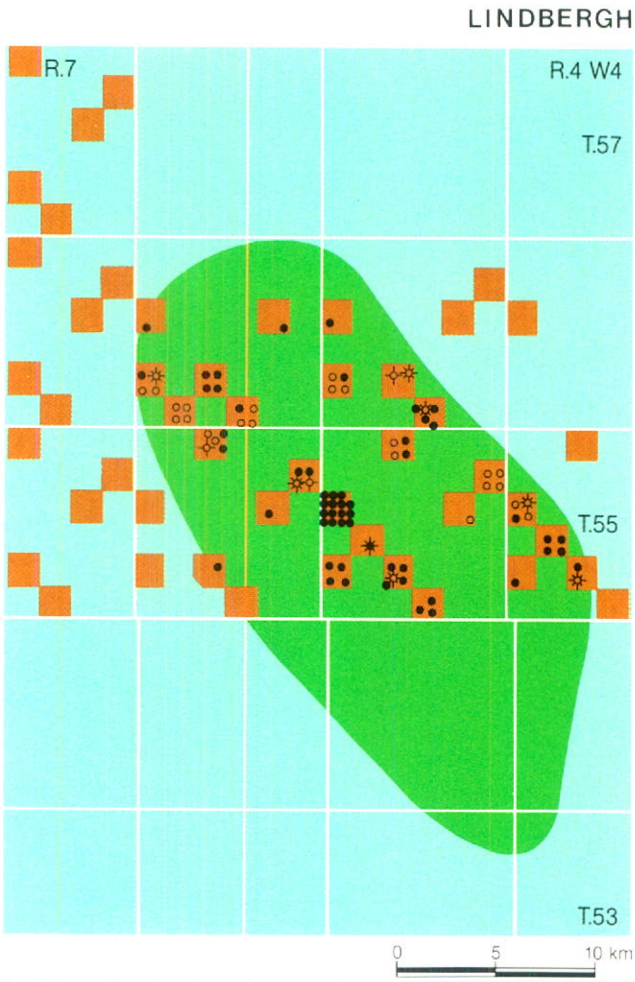
Bartlett B. Rombough

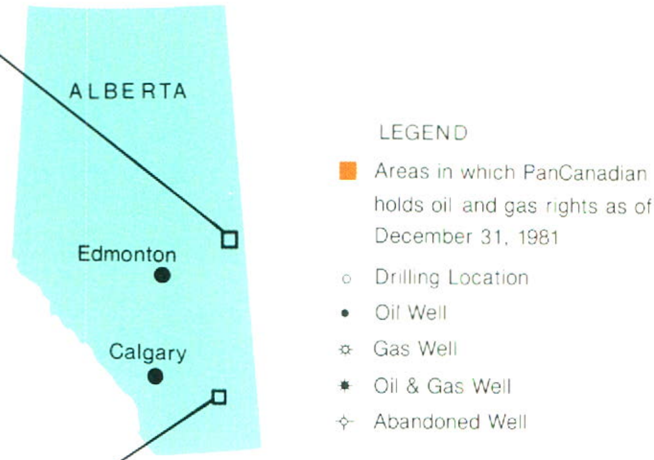
Bartlett B. Rombough
President

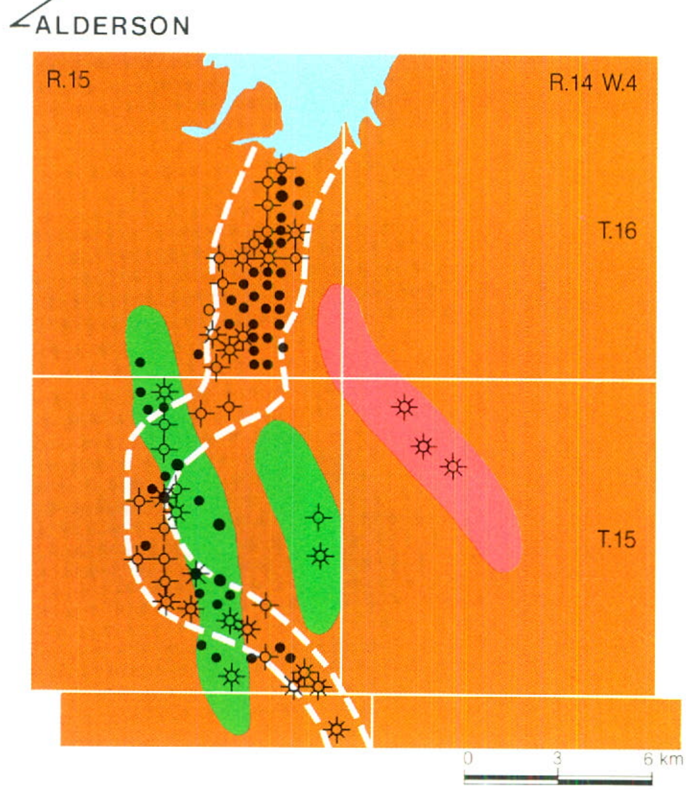
Calgary, Alberta
February 12, 1982

EXPLORATION









PanCanadian had an interest in 1 082 wells drilled during 1981, comprising 492 exploratory and 590 development wells. In 1980, 570 exploratory and 873 development wells were drilled, totalling 1 443 wells.

In Canada, the Company had an interest in 977 wells drilled in 1981, of which 418 were exploratory and 559 were development. Exploratory drilling resulted in 112 oil and 194 gas wells, yielding a success rate of 73%. An additional 108 oil and 435 gas wells resulted from development drilling. The 1981 shallow gas drilling program was less intensive than in 1980, resulting in a lower number of wells. Of the 220 oil wells drilled in 1981, the production from 98 exploratory and 73 development wells will qualify for the New Oil Reference Price (New Oil).

The total number of wells drilled by industry in western Canada in 1981 decreased by 25% from 1980. PanCanadian had an interest in 14% of these wells, compared to 15% last year.

ALBERTA

Exploration in Alberta continued to be active, focusing on the search for oil. Encouraging results were achieved and oil discoveries were made in many areas. In the Thorsby-Genesee area, 35 miles southwest of Edmonton, PanCanadian drilled nine New Oil wells and one gas well and had a 50% interest in four additional New Oil wells. Exploration activity will be maintained in this oil-prone area, with several wells planned for 1982. In the Lindbergh area where the Company's land holdings total 17 280 gross or 12 480 net acres, exploratory drilling resulted in 14 heavy New Oil wells. Exploratory drilling in the Irrigation Block of southern Alberta has continued to provide encouragement and a high level of activity was maintained. In the Alderson West area, 11 New Oil wells and three gas wells were drilled, with an average interest of 82%. Four of these oil wells each discovered a new pool. In the Badger-Enchant area, one gas and three New Oil discoveries were drilled and the Company has a 53.12% interest in a multi-zone New Oil and gas discovery at Tide Lake.

Forty miles northwest of Calgary, in the Rocky Mountain foothills, the Company holds a 62.75% interest in PCP et al Benjamin 10-07-29-07 W5M, which was drilled to a total depth of 12 100 feet. The well flowed gas at a stabilized rate of 5.5 million cubic feet a day on extended production tests of the Mississippian.

In the Grande Prairie - Deep Basin area, PanCanadian participated in the drilling of five New Oil and nine gas wells. PCP et al Wembley 08-28-71-07 W6M production tested 695 barrels of oil a day from 20 feet of net pay in the Halfway Formation. The well also tested eight million cubic feet of gas a day from the Paddy Formation. At year-end, three wells were drilling in this area and further wells are scheduled.

Drilling at Tangent, in northwestern Alberta, led to a Devonian New Oil discovery which production tested 618 barrels of oil a day. Production from the well is royalty free for five years. Several gas wells were also drilled and an active exploration program, in which PanCanadian has a 50% working interest, will continue in 1982. At Shekilie, in the northwest corner of Alberta, industry activity levels have been high. The Company is participating in this promising oil-prone area and, after obtaining seismic data, acquired interests in several parcels of land. Although the Company's first well in this area was dry, further drilling is planned.

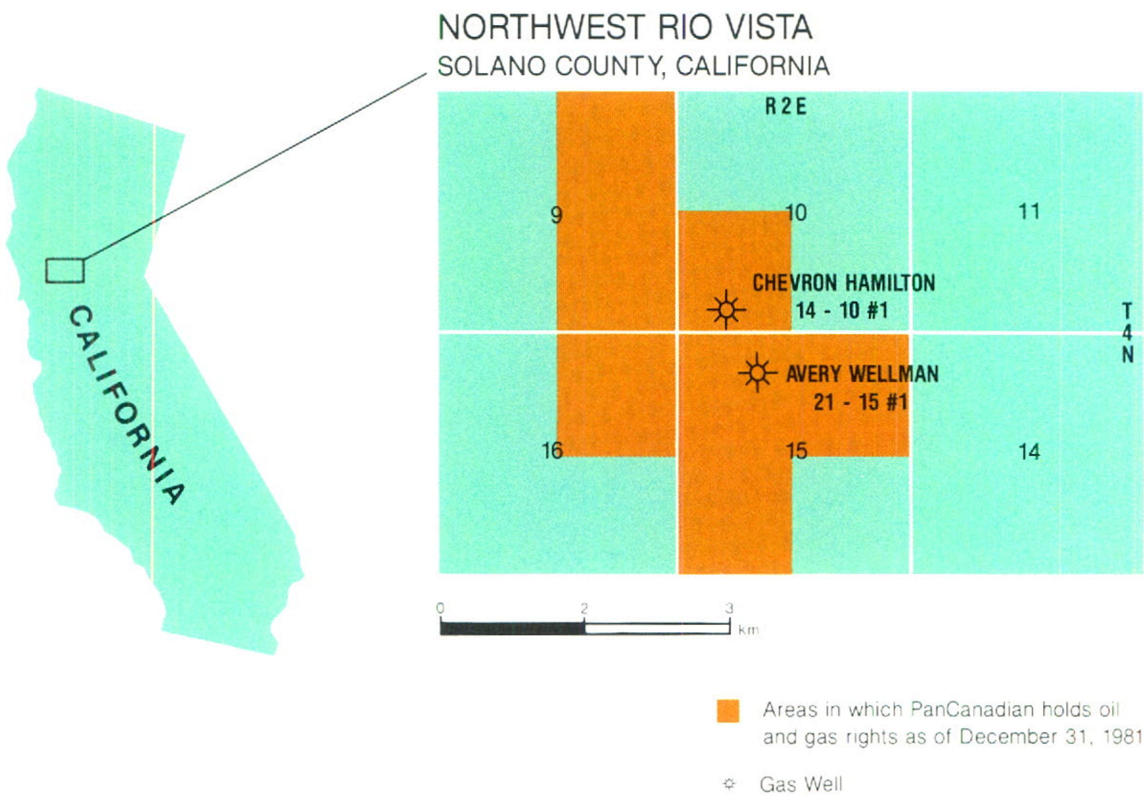
BRITISH COLUMBIA

PanCanadian purchased 26 960 gross acres at Crown land sales in British Columbia during 1981. A gas discovery was made at July Lake in the northeastern part of the province. The well flowed gas on drillstem test at a rate of eight million cubic feet a day, and a second well in the area spudded in January, 1982.

EAST COAST CANADA - OFFSHORE

Offshore Newfoundland and Labrador, the Company's activities accelerated with the formation of the East Coast III group in March, 1981. PanCanadian was designated project leader of the group, with two other Canadian companies as partners. The group contracted a ship which shot 2 175 miles of proprietary seismic data during 1981. In addition, 2 485 miles of seismic data were purchased. The group is evaluating a number of farm-out proposals and may submit work programs for selected land parcels as they are offered.

Further north, in the Baffin Island area, the Company participated in a marine seismic survey to define the Raleigh prospect, 28 miles southeast of the 1980 Hekja O-71 discovery. PanCanadian currently holds a 7.5% working interest in this two million acre permit.



UNITED STATES

Efforts in the United States were directed toward increasing land holdings in areas of exploratory interest. The Company invested a total of $4.8 million for land acquisitions, mainly in Texas, Louisiana, Wyoming, Colorado and California. Total acreage held in the United States is 3.6 million gross acres. The Company had an interest in 105 wells drilled during the year, of which 74 were exploratory and 31 development.

A gas discovery in the Northwest Rio Vista area of Solano County, California was tested at an initial daily rate of two million cubic feet. The Company has a 25% interest in this prospect and participated in a successful offsetting well late in 1981. Further drilling to evaluate the discovery is planned for 1982.

At Alkali Creek in Fisher County, Texas, 11 wells were drilled in 1981 as a follow-up to exploratory successes in 1980, resulting in six additional producers. The Company has a 50% interest in 11 producing wells and unitization of the field is planned in the near future.

Offshore Louisiana on federal lands, the drilling of High Island Block A-351/A-368 unit resumed in 1981 with the deepening of one well and the drilling of another. The 1982 development program has six wells scheduled. The Company holds a 5% working interest in the unit. Development of the remaining portion of Block A-368 will be pursued in 1982.

Evaluation of East Cameron Block 65 began in 1981 with the drilling of a gas well which will be followed-up with a second well early in 1982. On Eugene Island Block 43, where the Company has a one-third interest in a producing gas well, the drilling of an additional well from the platform is planned in 1982.

NORTH SEA

In the outer Moray Firth area of the United Kingdom sector of the North Sea, a wildcat well was drilled on the Sixth-Round Block 13/29, approximately 30 miles northeast of Peterhead, Scotland. The well discovered oil, flowing 4 142 barrels a day of 40 degree API oil during production tests of a 54-foot Jurassic sandstone interval. Further drilling is planned to evaluate the discovery. PanCanadian pays one-third of exploration costs, including the first exploratory well and first appraisal well drilled on the block, following which the Company's interest will be 16⅓ %.

On Block 29/5b, awarded during the Seventh Round, a seismic survey was conducted and a proposed 1982 drilling location was selected. PanCanadian has a 25% interest in this block.

Over the northwest area of Block Q/7, in the Netherlands sector of the North Sea, detailed seismic data was acquired in 1981. An exploratory well was spudded in February of 1982 on the block in which the Company has a 5% working interest.

CHINA

The seismic programs conducted in the Yellow Sea and west of Hainan Island, offshore the People's Republic of China, have been interpreted. The Company has identified areas of interest and is waiting for a call for tenders.

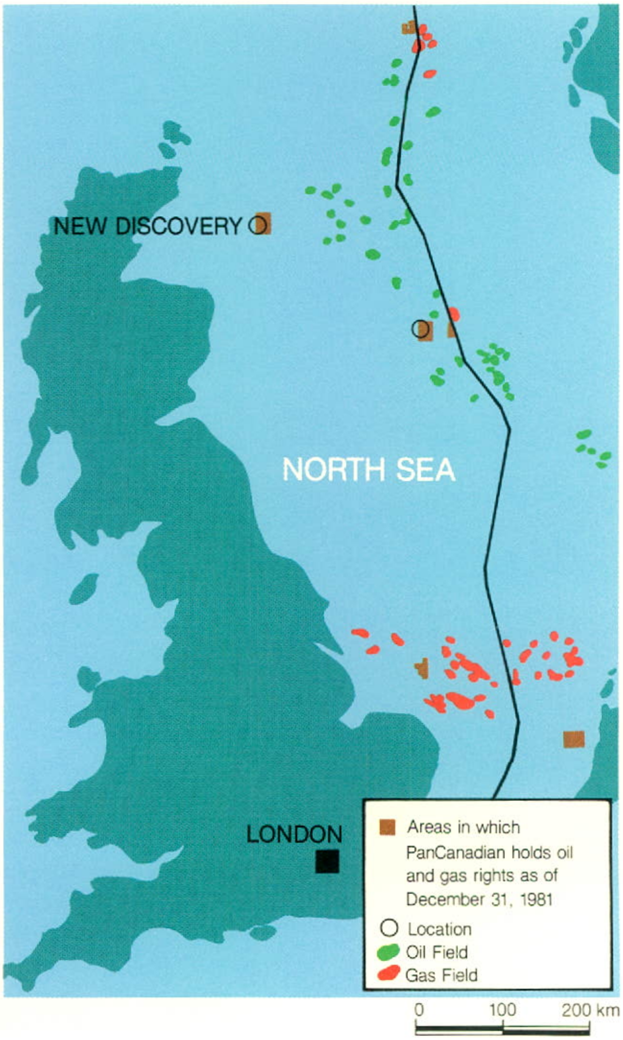
AUSTRALIA

On Block WA-93-P, additional seismic was conducted and evaluated during 1981. The Company has a 28.57% interest in this block, which covers eight million gross acres offshore northwestern Australia.

In August, 1981, PanCanadian and partners participated in bidding for acreage offshore northwestern Australia, but the work program bid was unsuccessful.

PANARCTIC

Through its 8% investment in Panarctic Oils Ltd., PanCanadian participated in three Arctic Islands oil and gas discoveries offshore Lougheed Island: Cisco B-66, Skate B-80 and Maclean I-72. An accelerated drilling program is planned by Panarctic for 1982 to appraise these discoveries.



COAL

During 1981 PanCanadian negotiated a long-term lease, covering 46 million short tons of surface-recoverable coal in the Keephills area of Alberta, through which the Company will receive royalty income.

PanCanadian continued its coal exploration in 1981 and participated in 372 test holes totalling 80 974 feet. These programs delineated 57 million short tons of additional underground bituminous coal and 17 million short tons of surface-recoverable subbituminous coal.

Working Interest Holdings in Petroleum & Natural Gas Rights

	December 31, 1981		December 31, 1980	
	Gross Acres	Net Acres	Gross Acres	Net Acres
CANADA				
Alberta	8 076 656	6 317 798	8 255 553	6 273 148
Arctic Islands	575 921	67 308	575 921	67 308
Baffin Bay	2 010 081	150 756	2 010 081	150 756
British Columbia	899 275	390 222	921 194	382 602
Manitoba	276 781	268 622	292 934	288 363
Northwest Territories and Yukon Territory	930 618	569 291	716 929	550 354
Quebec	—	—	162 770	14 801
Saskatchewan	539 664	508 535	556 364	510 130
	13 308 996	8 272 532	13 491 746	8 237 462
UNITED STATES				
California	32 936	10 735	33 257	27 380
Colorado	181 302	47 691	178 703	46 560
Kansas	96 969	69 425	119 169	85 873
Mississippi	69 000	23 700	84 459	28 134
Montana	154 253	91 150	150 602	94 010
Nebraska	24 120	17 707	24 520	17 907
Nevada	106 214	106 214	106 307	106 307
North Dakota	1 775 392	432 530	1 719 049	572 808
Offshore	82 267	18 700	107 173	15 788
Texas	221 000	88 000	191 819	69 395
Utah	807 918	302 534	730 573	280 188
Wyoming	64 963	36 377	67 833	37 090
Other	11 666	10 729	10 539	3 162
	3 628 000	1 255 492	3 524 003	1 384 602
INTERNATIONAL				
Australia	8 000 000	2 285 712	8 000 000	2 285 600
North Sea (Netherlands)	103 537	5 177	103 537	5 177
North Sea (United Kingdom)	183 871	32 541	141 616	21 977
	8 287 408	2 323 430	8 245 153	2 312 754
TOTAL	25 224 404	11 851 454	25 260 902	11 934 818
Non-working interest acreage under lease or sub-lease, reserving to PanCanadian, or its subsidiaries, royalties or overriding royalties		3 331 919		3 377 671

NOTE: Does not include PanCanadian's interest in Minerals Ltd. or Panarctic Oils Ltd.

PRODUCTION

The Company's net daily production of conventional and synthetic crude oil and natural gas liquids averaged 54 916 barrels in 1981. This represents a 2% increase over 1980. Sales of natural gas decreased marginally from 1980 levels, with daily average production of 279.8 million cubic feet (mmcf).

CONVENTIONAL CRUDE OIL

Net daily production of conventional crude oil for 1981 averaged 31 633 barrels which is a 5% reduction from 1980. The decrease resulted mainly from curtailment of production in Saskatchewan to approximately 25% of normal for a six-month period, because of unfavorable economics. Full production was resumed in December following an assessment of the agreement between the federal and Saskatchewan governments.

In the Alderson West area of Alberta, a battery consolidation project involving the tie-in of 11 wells and a solution gas conservation scheme was completed. The Company is involved in heavy oil development in Alberta through its participation in several projects. At Lindbergh, of 31 wells with interests varying from 50% to 100% drilled in 1981, 22 were on production by year-end. Long-term enhanced recovery development in this heavy-oil area is under consideration. In the Countess area, an enhanced recovery scheme to utilize fireflood techniques is now being investigated. PanCanadian has a 50% interest in this venture.

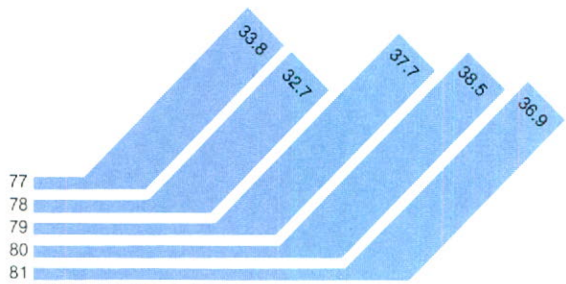
SYNTHETIC CRUDE OIL

PanCanadian's share of net daily production of synthetic crude oil from the Syncrude plant averaged 2 776 barrels in 1981 compared to 2 875 in the previous year. Syncrude's gross daily production averaged 81 600 barrels in 1981 compared to 80 800 barrels in 1980. Production problems, mostly in the first quarter, limited volumes shipped and increased operating expenses.

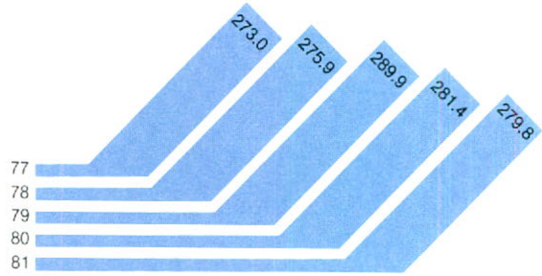
NATURAL GAS

Net daily natural gas sales for 1981 averaged 279.8 mmcf, compared with the 1980 average of 281.4 mmcf. Production was restricted to approximately 75% of capacity during the year due to reduced market demand in both Canada and the United States.

Payments were received under take-or-pay provisions of certain gas purchase contracts when the purchasers were unable to take minimum contract volumes during 1981. These volumes will be delivered at a later date. Although approximately 85% of the Company's proven and probable natural gas reserves are under sales contracts, the ability of the purchasers to take this gas may continue to be restricted because of market constraints.



NET CRUDE OIL & NGL PRODUCTION *(thousand barrels a day)*



NET NATURAL GAS SALES
(million cubic feet a day)

Shallow gas development continued, with projects completed in the Verger area and nearing completion in the Rosemary area in southeast Alberta. The installation of compression facilities and the tie-in of 200 wells resulted in an additional daily contract quantity of 19.5 mmcf from these projects. Work is also in progress to tie in another 116 shallow gas wells in the Gem area with completion scheduled for the first half of 1982. Contract rates were maintained in a number of other shallow gas areas with the tie-in of 36 wells.

In central Alberta, gas projects were completed in the Wilson Creek and Hoadley areas where compression facilities were installed and 27 wells tied in to the Rimbey gas processing plant. PanCanadian's share of the daily contract volume from these two areas is approximately 22 mmcf. The Countess-Makepeace expansion was also completed, which more than doubled the daily producing capacity to 38 mmcf.

NATURAL GAS LIQUIDS

Natural gas liquids sales from the Empress extraction plants averaged 18 017 barrels a day, a 19% increase over 1980. The major factor in this increase was the higher volume of inlet gas, and the liquid content of the gas was also slightly greater than in 1980.

Daily average liquid sales from the Company's natural gas production decreased to 2 490 barrels a day from 2 504 barrels a day in 1980.

SULPHUR

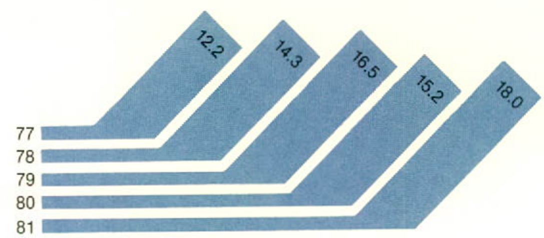
Sulphur sales in 1981 averaged 430 long tons a day compared to 436 long tons a day in 1980. Year-end working interest sulphur inventories, before royalties, totalled 127 726 long tons.

During 1981 two sulphur-forming projects, in which PanCanadian is participating, commenced operations. These facilities will pelletize approximately 24 000 long tons of sulphur a year from PanCanadian's stockpile and its share of Syncrude production. The sulphur will be marketed overseas.

10 Year Production Review
After Royalty

Year	Oil* (thousand barrels)	Natural Gas Liquids (thousand barrels)	Oil* and NGL (thousand barrels)	Natural Gas (million cubic feet)
1972	11 381	1 061	12 442	73 025
1973	14 810	1 076	15 886	76 727
1974	13 289	1 046	14 335	82 594
1975	11 199	1 046	12 245	81 622
1976	10 141	984	11 125	84 799
1977	11 398	952	12 350	99 658
1978	10 949	987	11 936	100 689
1979	12 826	943	13 769	105 797
1980	13 178	916	14 094	102 975
1981	12 560	909	13 469	102 143

* Includes conventional and synthetic crude oil.

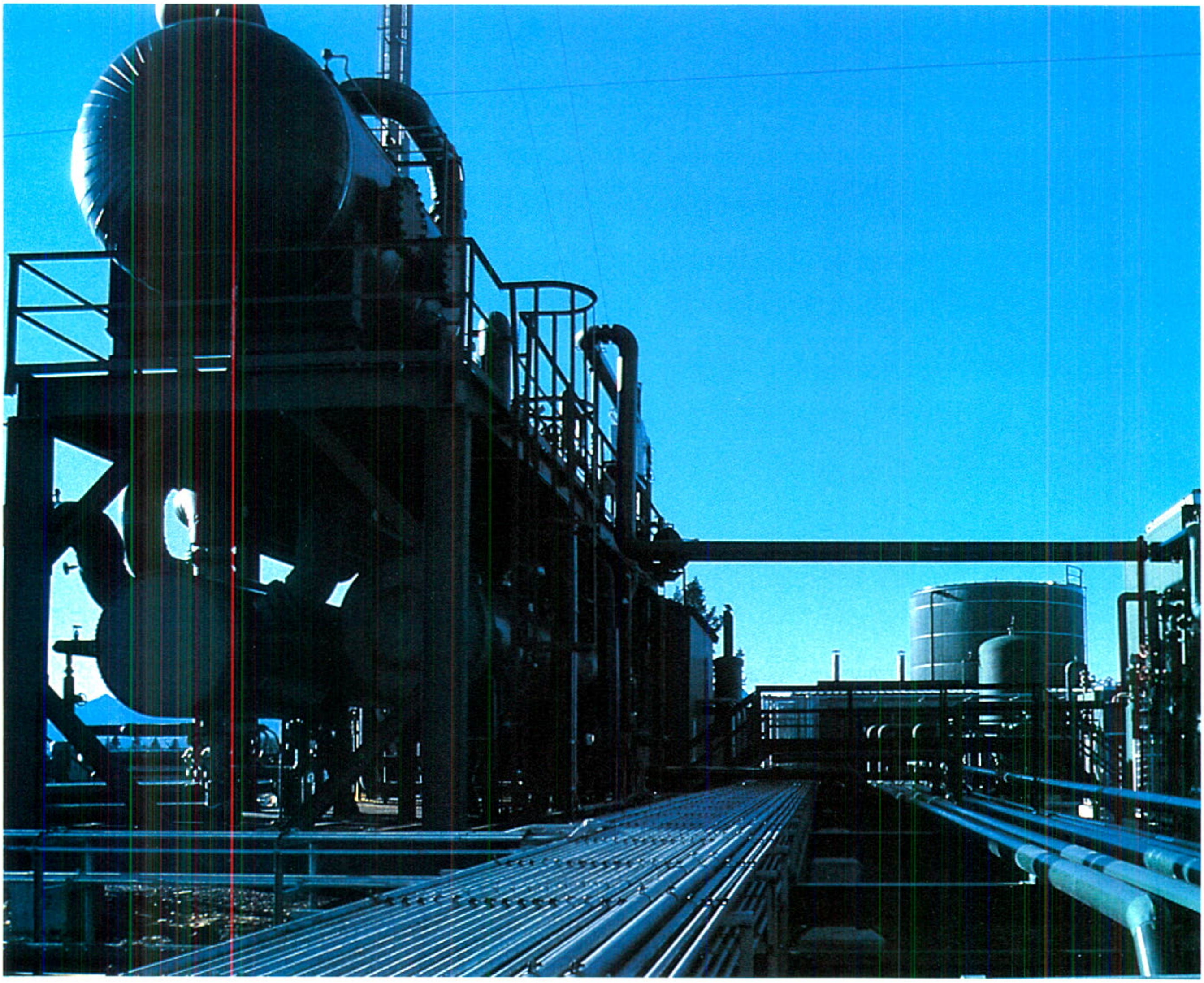


EMPRESS PLANTS
NATURAL GAS LIQUIDS SALES
(thousand barrels a day)

SI Conversion Table

To Convert From	To	Multiply by
Acre (ac)	hectare (ha)	0.404 69
Foot (ft)	metre (m)	0.304 80
Barrel (bbl)	cubic metre (m^3)	0.158 91
Thousand Cubic Feet (mcf)	cubic metre (m^3)	28.173 99
Long Ton (l.t.)	tonne (t)	1.016 05
Short Ton (s.t.)	tonne (t)	0.907 18

RESERVES



At year-end the Company's proven and probable reserves, before royalty, were 3 782 billion cubic feet (bcf) of natural gas, 156.8 million barrels of conventional crude oil and natural gas liquids and three million long tons of sulphur. In addition, the Company's share of permitted Syncrude reserves was 43.4 million barrels of synthetic crude oil.

NATURAL GAS

Proven and probable natural gas reserves, before royalty, increased slightly to a year-end total of 3 782 bcf. The 1981 drilling program added reserves of 161 bcf, primarily at Benjamin Creek, Grande Prairie, Hussar-Crowfoot and Tangent, representing approximately 148% of the year's production. These additions were offset by production of 109 bcf and engineering reviews of 31 bcf. At 1981 production levels, the reserve life index is 34.7 years.

CONVENTIONAL CRUDE OIL AND NATURAL GAS LIQUIDS

Reserves of conventional crude oil and natural gas liquids, before royalty, were 156.8 million barrels compared to 156.2 in 1980. Although the increase is modest, it does represent the first increase in the Company's proven and probable reserves since 1971. This can be attributed largely to drilling at Alderson West, Grande Prairie, Lindbergh, Pembina-Genesee and Tangent. Drilling successes added 7.7 million barrels to reserves while engineering reviews added a further 6.2 million barrels. Drilling replaced approximately 57% of the year's production of 13.4 million barrels. Based on 1981 production rates, the reserve life index is 11.7 years.

COAL

Proven and probable reserves of coal, before royalty, increased by seven million short tons in 1981 and now total 1 999 million short tons. Of these reserves, 1 059 million short tons are surface-recoverable and 940 million short tons are underground-recoverable. The addition of 74 million short tons from 1981 exploration was offset by downward engineering revisions and the impact of a long-term leasing arrangement.

Proven and Probable Reserves

	Marketable Natural Gas (billion cubic feet)	Crude Oil & Natural Gas Liquids (thousand barrels)	Sulphur (thousand long tons)	Coal (million short tons)	Synthetic Oil (thousand barrels permitted) (restated)*
Reserves at January 1, 1981	3 761	156 220	2 994	1 992	45 330
Reserves Added	130	13 927	155	7	
Less Production	109	13 381	128	—	
Reserves at December 31, 1981 (before royalty)	3 782	156 766	3 021	1 999	43 442
Less Royalty Deductions	273	16 534	180	10	
Reserves at December 31, 1981 (after royalty)	3 509	140 232	2 841	1 989	
Proven Reserves at December 31, 1981					
Before Royalty	2 684	119 034	2 203	928	
After Royalty	2 473	104 469	2 046	921	
Probable Reserves at December 31, 1981					
Before Royalty	1 098	37 732	818	1 071	
After Royalty	1 036	35 763	795	1 068	

NOTES:

Reserves figures are calculated by Company engineers. For Reserve Recognition Accounting, as shown on pages 29 and 30 of this report, proven reserves figures used were calculated by independent consultants.

Volumes do not include the Company's interest in Panarctic Oils Ltd., Minerals Ltd., or sulphur from the Syncrude project.

Proven reserves are those quantities of crude oil, natural gas, natural gas liquids and sulphur which analysis of geological and engineering data demonstrates with reasonable certainty to be recoverable from known oil or gas fields under existing economic and operating conditions.

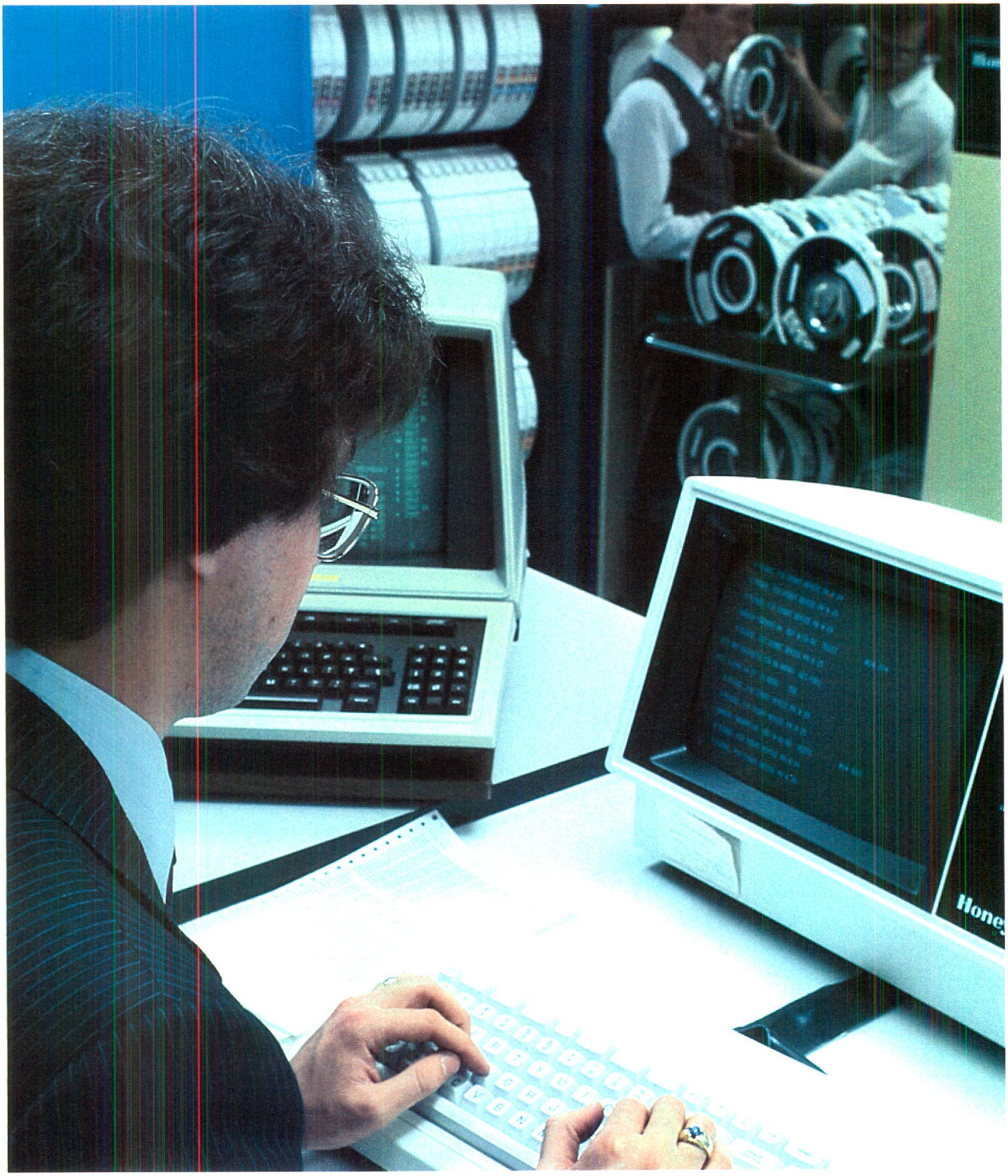
Probable reserves are those additional quantities estimated to be commercially recoverable from known oil and gas fields, as a result of the effect of the future installation of secondary recovery methods or future improvements in the existing recovery mechanism.

Marketable natural gas comprises gases from which certain hydrocarbon and non-hydrocarbon compounds have been removed or partially removed by processing where necessary to meet pipeline or other market specifications, and are measured at a base pressure of 14.65 psia and base temperature of 60°F.

Surface recoverable coal reserves include coal to a maximum strip ratio of 15 cubic yards of overburden to one ton of coal, to a maximum depth of 150 feet.

*Synthetic oil quantities represent the Company's share, at the respective dates, of permitted synthetic crude oil restated to conform with the amended Alberta Energy Resources Conservation Board permit.

FINANCIAL



EARNINGS

Net income for 1981 was $203.7 million, a decrease of 16% from 1980 earnings of $241.4 million. Net income per share decreased to $6.52 from $7.73 in 1980.

REVENUES

Revenue components in thousands of dollars are tabulated below.

Revenue from natural gas liquids extracted from the Company's natural gas production increased $2.5 million. The average price realized in 1981 was $17.70 a barrel, up from $14.85 a barrel in 1980.

The increase in sulphur revenue was due to higher prices. The average sulphur price was $68.18 a long ton compared to $43.96 in 1980 as a result of strong export demand.

	1981		1980		% Increase
	Amount	%	Amount	%	From 1980
Crude Oil	$252 940	39.4	$218 787	38.1	15.6
Natural Gas	248 419	38.7	240 131	41.8	3.5
Empress Plants – Natural Gas Liquids Sales	91 931	14.3	76 191	13.2	20.7
Natural Gas Liquids	16 092	2.5	13 605	2.4	18.3
Sulphur	10 711	1.7	7 006	1.2	52.9
Other	21 829	3.4	18 967	3.3	15.1
	$641 922	100.0	$574 687	100.0	11.7

Of the 1981 crude oil sales revenue, $210.7 million was derived from conventional oil and $42.2 million from synthetic crude oil production at Syncrude. This represents increases of 17% for conventional oil and 9% for synthetic crude over revenues generated in 1980, as a result of higher prices. The average prices received for conventional and synthetic oil were $18.25 and $41.64 a barrel, respectively. This compares to the 1980 average prices of $14.86 a barrel for conventional and $36.64 for synthetic oil. The wellhead price of conventional crude oil increased $1.00 a barrel effective January 1, 1981, with further increases of $1.00 on July 1 and $2.50 on October 1, 1981.

The natural gas sales revenue increase was attributable to higher prices. The average price received for natural gas was $2.43 a thousand cubic feet compared to $2.33 the previous year.

Natural gas liquids revenues from the Empress extraction plants and related operations increased $15.7 million primarily due to higher volumes. The 1981 average product price rose to $13.17 a barrel from $12.39 a barrel the previous year.

EXPENSES

Total expenses, exclusive of income and revenue taxes, were $260.1 million, a 22% increase over the 1980 amount of $213.8 million. Operating expenses accounted for $134.7 million of the total, an increase of 26% over the previous year.

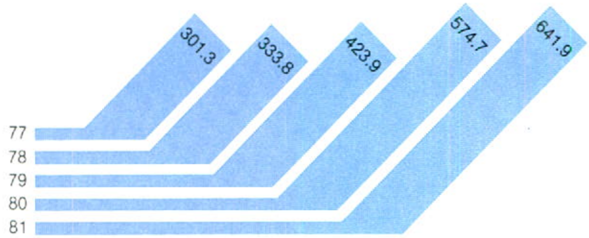
Oil operating expenses, excluding Syncrude, increased to $25.5 million in 1981 or 15% above the $22.2 million recorded for 1980. Syncrude expenses increased 42% to $29.5 million for 1981 from $20.8 million the previous year. This was mainly due to increased maintenance and salaries, and a partial Syncrude plant shutdown during the first half of 1981. Operating expenses for gas and related products were $32.9 million in 1981, an increase of 21%. This was caused by higher salaries and maintenance, and an increase in the number of producing properties.

Operating expenses for the Empress extraction plants amounted to $46.8 million compared to $36.7 million in 1980. The 27% increase was largely due to higher volumes.

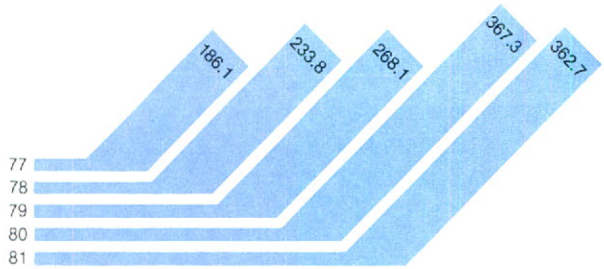
Administrative expenses totalled $20.6 million, a 29% increase over the $16.0 million recorded in 1980. Company growth and inflation accounted for this increase. Interest expense rose 28% to $32.4 million, as a result of increases in the prime lending rate. Depreciation increased 21% to $28.2 million from $23.3 million the previous year because of additional production facilities. Depletion expense was $44.2 million in 1981 compared to $42.1 million in 1980, a 5% increase.

TAXES

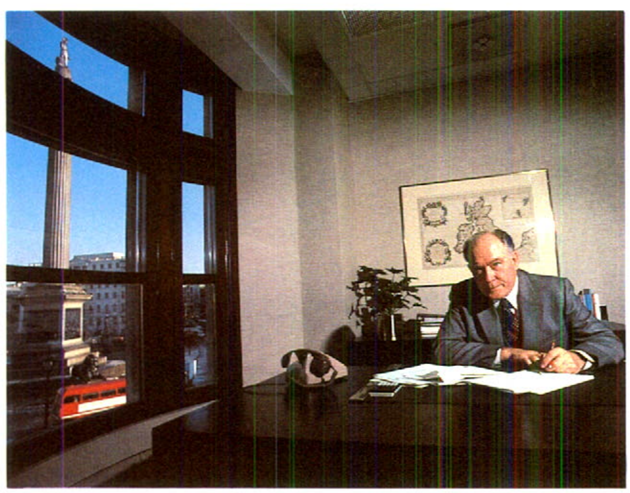
Provision for current and deferred income taxes was $141.9 million in 1981 compared to $119.6 million in 1980. This represents an effective income tax rate of 37% in 1981 compared with 33% in 1980. Provision for the new Petroleum and Gas Revenue Tax effective January 1, 1981 amounted to $36.1 million. The addition of this tax increased the 1981 overall tax rate to 47%.



GROSS INCOME *(millions of dollars)*



FUNDS FROM OPERATIONS *(millions of dollars)*



CAPITAL EXPENDITURES

During 1981, total capital expenditures amounted to $347.3 million of which $312.3 million or 90% was expended on Canadian operations. Of the balance, $33.6 million was spent in the United States and $1.4 million was spent on other foreign operations. The reinvestment rate, representing capital expenditures as a percentage of cash flow, was 96% in 1981 compared to 73% in 1980.

Capital expenditures for land, exploration, drilling and investment in Panarctic totalled $171.4 million or 47% of funds from operations, compared to $219.5 million or 60% in 1980. Capital expenditures on plant, production and other equipment amounted to $85.7 million or 24% of funds from operations compared to $50.5 million or 14% of funds from operations in 1980. The 1981 expenditures include $11.3 million for conversion from gas turbine to electric motor drives for compression facilities at one of the Empress plants.Investment in the methanol venture required $90.2 million in 1981.

The 1981 capital expenditures are before provision for Petroleum Incentive Program grants of approximately $37.9 million recorded with respect to certain eligible exploration and development expenditures.

FINANCIAL POSITION

At December 31, 1981, working capital was $49.4 million compared to $27.2 million at the end of 1980. Funds from operations declined 1% to $362.7 million or $11.62 per share. Deferred production income, resulting from take-or-pay provisions of gas purchase contracts, increased from $33.0 million at the end of 1980 to $40.5 million at December 31, 1981. These funds will be taken into income when actual production of the gas occurs. During 1981, PanCanadian's internal sources of working capital were supplemented through the issuance of $65 million of 16½% Canadian dollar debentures, due 1988, in the European market and by a $90.5 million term bank loan.

The number of outstanding common shares remained unchanged from prior years at 31 224 979. Shareholders' equity increased to $794.8 million, resulting from $203.7 million in earnings less $112.4 million in dividends. At year-end, long-term debt of $247.2 million represented 15% of total liabilities and shareholders' equity, compared to 13% in 1980.

AUDITORS' REPORT

To the Shareholders of
PanCanadian Petroleum Limited:

We have examined the consolidated balance sheet of PanCanadian Petroleum Limited as at December 31, 1981 and the consolidated statements of income and retained income 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, 1981 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.

Calgary, Alberta
February 12, 1982

PRICE WATERHOUSE
Chartered Accountants

CONSOLIDATED STATEMENT OF INCOME AND RETAINED INCOME

For the Year Ended December 31, 1981

	1981	1980
	(thousands of dollars)	
Income:		
Operating revenue	$621 496	$557 367
Interest income from affiliated company	13 783	10 689
Miscellaneous	6 643	6 631
	641 922	574 687
Expenses:		
Operating	134 702	107 030
Administrative	20 574	15 967
Interest on long-term debt	32 417	25 373
Depreciation	28 245	23 254
Depletion	44 183	42 126
	260 121	213 750
Income before income and revenue taxes	381 801	360 937
Provision for income and revenue taxes:		
Income taxes		
Current	55 539	58 192
Deferred	86 389	61 378
Petroleum and gas revenue tax	36 136	—
	178 064	119 570
Net income	203 737	241 367
Retained income at beginning of year	630 415	488 957
	834 152	730 324
Dividends – $3.60 per share (1980 - $3.20)	112 399	99 909
Retained income at end of year	$721 753	$630 415
Earnings per share	$6.52	$7.73

CONSOLIDATED STATEMENT OF CHANGES IN FINANCIAL POSITION

For the Year Ended December 31, 1981

	1981	1980
	(thousands of dollars)	
Source of working capital:		
Net income	$203 737	$241 367
Expenses not requiring a current outlay of funds –		
Depreciation	28 245	23 254
Depletion	44 183	42 126
Deferred income taxes	86 389	61 378
Other	174	(813)
Funds from operations	362 728	367 312
Issue of debentures	65 000	—
Term bank loan	90 500	—
Deferred production income	7 458	16 792
Other	3 354	6 104
	529 040	390 208
Application of working capital:		
Petroleum, natural gas and mineral properties	169 207	219 319
Petroleum incentives (Note 3)	(36 382)	—
Plant, production and other equipment		
Petroleum and natural gas	71 796	43 772
Syncrude	2 540	4 287
Methanol	90 232	—
Empress	11 292	2 428
	308 685	269 806
Investment in Panarctic Oils Ltd.	2 208	154
Petroleum incentives (Note 3)	(1 552)	—
Reduction of long-term debt	84 715	27 965
Dividends	112 399	99 909
Other	385	3 273
	506 840	401 107
Increase (decrease) in working capital	22 200	(10 899)
Working capital at beginning of year	27 151	38 050
Working capital at end of year	$ 49 351	$ 27 151

CONSOLIDATED BALANCE SHEET – DECEMBER 31, 1981

Assets

	1981	1980
	(thousands of dollars)	
Current assets:		
Cash	$ 174	$ 546
Deposits with affiliated company (Note 2)	53 935	98 156
Accounts receivable	100 346	90 987
Income taxes recoverable	1 808	—
Petroleum incentives receivable (Note 3)	14 513	—
Inventories, at average cost –		
Products	16 894	11 412
Materials	6 181	4 356
	193 851	205 457
Property, plant and equipment, at cost:		
Petroleum, natural gas and mineral properties	1 198 438	1 065 613
Less: Accumulated depletion	(295 070)	(251 077)
Plant, production and other equipment		
Petroleum and natural gas	280 921	210 211
Syncrude	151 840	152 797
Methanol (Note 4)	90 232	—
Empress	46 117	34 825
	569 110	397 833
Less: Accumulated depreciation	(129 353)	(102 465)
	1 343 125	1 109 904
Investment in Panarctic Oils Ltd., at cost	22 902	22 246
Long-term notes receivable (Note 5)	32 927	32 927
Other assets	11 242	11 433
	$1 604 047	$1 381 967

Liabilities and Shareholders' Equity

	1981	1980
	(thousands of dollars)	
Current liabilities:		
Accounts payable and accrued liabilities	$ 125 535	$ 121 973
Income taxes payable	—	29 118
Current portion of long-term debt	18 965	27 215
	144 500	178 306
Long-term debt (Note 6)	247 210	176 425
Deferred credits:		
Deferred production income	40 483	33 025
Deferred rentals	360	444
Deferred income taxes	376 688	290 299
	417 531	323 768
Shareholders' equity		
Capital stock –		
Issued –		
31 224 979 shares	31 225	31 225
Paid in surplus	41 828	41 828
Retained income	721 753	630 415
	794 806	703 468
	$1 604 047	$1 381 967

APPROVED BY THE BOARD:

Robert W. Campbell Director

Bartlett B. Rombaugh Director

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

December 31, 1981

1. SIGNIFICANT ACCOUNTING POLICIES:

a) Consolidation of Accounts

The consolidated financial statements include the accounts of PanCanadian Petroleum Limited and its subsidiaries, all of which are wholly-owned and are presented in accordance with Canadian generally accepted accounting principles.

b) Foreign Currency Translation

Foreign currency balances included in the consolidated financial statements have been expressed in Canadian dollars on the following basis:

Current assets and liabilities – at the year-end rate of exchange

Other assets and liabilities – at historical rates of exchange

Income and expenses – at monthly rates of exchange except provisions for depreciation and depletion which are translated on the same basis as the related assets.

All gains or losses on conversion to Canadian dollars are included in income.

c) Full Cost Method of Accounting

The Company follows the full cost method of accounting for oil and gas properties whereby all costs relating to the exploration and the development of oil and gas reserves are capitalized on a world-wide cost centre basis. Such costs include lease acquisition costs, geological and geophysical expenditures, carrying charges on non-producing properties, costs of drilling both productive and non-productive wells and overhead expenses related to exploration activities. These costs are depleted by the unit of production method based on estimated proven oil and gas reserves.

d) Depreciation of Property, Plant and Equipment

Depreciation is being provided at rates which will amortize original costs over the estimated useful lives of the respective assets. The diminishing balance method is applied to all plant, production and other equipment at rates varying from 5% to 20%, except for the Empress gas processing facilities and Syncrude which are depreciated on the straight-line basis at 4% per annum.

e) Deferred Production Income

Pursuant to take-or-pay provisions included in certain gas purchase contracts, payments were received during the year for gas to be delivered at future dates. The Company records these payments as deferred production income and takes them into income when the gas is delivered or the contracts expire, whichever first occurs.

f) Capitalization of Interest

Interest related to financing arrangements on major projects is capitalized during the construction period.

2. RELATED PARTY TRANSACTIONS:

Substantially all of the Company's funds which were surplus to its day to day requirements were invested in deposits of Canadian Pacific Enterprises Limited. These deposits carry interest at rates at least equal to the interest rates paid from time to time by a leading Canadian chartered bank on equivalent deposits.

In the normal course of business the Company purchases materials, utilizes services and leases office space from other companies with which it is affiliated. All such transactions have been conducted at arm's length during the year.

3. PETROLEUM INCENTIVES:

On October 28, 1980 the Federal Government, as part of the National Energy Program, proposed a system of incentives, to be effective January 1, 1981, with respect to certain qualifying exploration and development expenditures. Although the enabling legislation has not yet been introduced, provision for the receipt of these incentives has been included in the 1981 financial statements.

4. METHANOL PLANT ACQUISITION:

Effective September 18, 1981 the Company acquired a 35% interest in a world-scale methanol plant now under construction near Edmonton, Alberta. The Company's share of the total construction cost of this plant, which is scheduled to commence production in 1982, is estimated at $130 000 000. The Company has expended $90 232 000 to December 31, 1981 including capitalized interest of $6 571 000.

5. LONG-TERM NOTES RECEIVABLE:

Under the terms of the agreement for sale of its investment in an ammonia plant project the Company received notes which are payable in U.S. funds in four equal annual instalments commencing December 31, 1986. Interest after December 31, 1980 accrues at 10⅞% and is payable semi-annually commencing June 30, 1981.

6. LONG-TERM DEBT:

Details of long-term debt outstanding at December 31, 1981 and 1980 are set forth hereunder:

	1981	1980
	(thousands of dollars)	
Bank loans due 1982 – 1991	$121 925	$123 140
8⅛% secured debentures due March 1, 1992, sinking fund payments 1982 – 1991, secured by a first mortgage upon certain producing properties	21 250	22 000
8¾% secured debentures due November 1, 1992, sinking fund payments 1982 – 1991, secured by a first mortgage upon certain producing properties	23 000	23 500
9¾% unsecured debentures due November 15, 1983	35 000	35 000
16½% unsecured debentures due December 15, 1988	65 000	—
	266 175	203 640
Less: Current portion	18 965	27 215
	$247 210	$176 425

The bank loans bear interest at rates which fluctuate with the lender's prime commercial rate.

The Company has agreed that the assets of the Company and its subsidiaries will not be encumbered nor will it dispose of any assets other than in the ordinary course of business without the consent of the bankers.

With regard to the $35 000 000 9¾% and the $65 000 000 16½% unsecured debentures, the Company has agreed that it and, subject to certain exceptions, its subsidiaries will not create any mortgage or other charge on their assets to secure any loan or other indebtedness which at the time of issue are intended to be traded on any stock exchange or publicly traded in the over-the-counter market in any part of the world unless the debentures then outstanding are similarly secured.

The annual maturities for long-term debt for each of the five years ending December 31, are as follows:

	(thousands of dollars)
1982	$18 965
1983	50 085
1984	1 375
1985	14 304
1986	14 304

7. SEGMENTED INFORMATION:

The Company's only business segment is the exploration for and the development and production of petroleum, natural gas and related products. The major geographic segments for 1981 are as follows:

	Canada	United States & Other	Total
	(thousands of dollars)		
Income	$ 624 258	$ 17 664	$ 641 922
Segment operating income	$ 444 084	$ 14 317	$ 458 401
Interest expense			(32 417)
Depletion			(44 183)
Income and revenue taxes			(178 064)
Net income			$ 203 737
Identifiable assets	$1 413 855	$190 192	$1 604 047

RESERVE RECOGNITION ACCOUNTING

PanCanadian's financial statements are prepared on the "Full Cost" method of accounting as described in Note 1c to the financial statements. The Securities and Exchange Commission (SEC) in the United States concluded that historical cost methods (Full Cost and Successful Efforts) do not provide sufficient information on operating results and financial position of oil and gas producers. As a result, the SEC has mandated Reserve Recognition Accounting (RRA) which can be applied uniformly to all producers. Although PanCanadian is not subject to SEC reporting requirements, it has prepared the RRA information for those investors who may wish to have access to such information.

RRA statements are not prepared in accordance with generally accepted accounting principles and thus are not prepared on the same basis as the financial statements or notes thereto. Inclusion of RRA information is not intended to express an opinion of PanCanadian that oil and gas prices or production and development costs will remain constant or will change at the same rates or that existing economic conditions will continue, all of which are assumed in preparing such statements. Their inclusion should not be interpreted as indicating that PanCanadian believes that valid inferences as to PanCanadian's probable future net revenues or pre-tax earnings can be derived therefrom.

Under the RRA method, proved reserves of oil and gas are recorded as "assets" upon discovery. The valuation of these assets is based on the present value of future net revenues to be derived from producing the reserves. Current year additions to proved reserves and revisions to the valuation of the reserves are reflected in the RRA Income Statement, along with all costs associated with finding, developing and producing new reserves.

PanCanadian's estimated future net revenues from proved oil and gas reserves for 1982 through 1984 and all remaining years based on estimated reserves at December 31, 1981, are as follows:

	1982	1983	1984	All Remaining Years	Total
			(thousands of dollars)		
Estimated future net revenues from proved reserves* (not discounted)	$456 873	$576 591	$649 729	$10 879 280	$12 562 473

* Prices utilized in estimating future net revenues from Canadian production were escalated in accordance with the provisions of the federal – provincial energy pricing and taxation agreements. These agreements provide that the Canadian price of old oil will not exceed 75% of the world price. No increase in world oil prices beyond those established at December 31, 1981 has been anticipated in this projection.

The present value of estimated future net revenues from proved reserves, discounted at 10%, was $5 205 674 000 at December 31, 1981, $2 627 506 000 at December 31, 1980 and $1 936 500 000 at December 31, 1979.

The following table is a summary of oil and gas producing activities in 1981, 1980 and 1979 on the basis of RRA.

	1981	1980	1979
	(thousands of dollars)		
Present value of gross additions to proved reserves	$ 162 783	$ 63 158	$ 98 725
Revisions to estimates of reserves proved in prior periods:			
Changes in price	2 783 564	721 161	533 598
Changes in operating expense forecasts for proved reserves	(138 066)	41 885	(249 264)
Changes in production timing and engineering review of proved reserve quantities	(134 793)	(7 718)	157 571
Accretion of discount	262 751	193 650	151 797
	2 936 239	1 012 136	692 427
Acquisition, exploration, development and production costs:			
Costs incurred, including impairments	80 406	157 698	134 649
Present value of estimated future development and production costs	15 354	8 541	17 147
	95 760	166 239	151 796
Additions and revisions to proved reserves over related costs*	2 840 479	845 897	540 631
Provision for income and revenue taxes:			
Income taxes (at historical effective rate)	1 008 863	284 136	172 948
Petroleum and gas revenue tax	784 659	—	—
Incremental oil revenue tax	78 766	—	—
	1 872 288	284 136	172 948
Results of oil and gas producing activities on the basis of reserve recognition accounting	$ 968 191	$ 561 761	$367 683

* The corresponding pre-tax profit contribution in the reported historical financial statement is $362 902 in 1981 ($333 652 in 1980 and $249 490 in 1979).

The following table summarizes the changes in the present value of estimated future net revenues from proved reserves during 1981, 1980 and 1979. All amounts included in this table are prior to income and revenue taxes.

	1981	1980	1979
	(thousands of dollars)		
Balance at January 1	$2 627 506	$1 936 500	$1 517 960
Additions and revisions less related estimated future development and production costs of $15 354 (1980 – $8 541 and 1979 – $17 147)	2 920 885	1 003 595	675 280
Expenditures that reduced estimated future development costs	83 541	78 098	42 444
	3 004 426	1 081 693	717 724
Less: Sales and transfers of oil and gas, net of production costs and mineral reserve taxes of $58 426 (1980 – $49 468 and 1979 – $40 683)	426 258	390 687	299 184
	2 578 168	691 006	418 540
Balance at December 31	$5 205 674	$2 627 506	$1 936 500

For the purpose of RRA, PanCanadian has used proved reserve estimates as determined by McDaniel Consultants (1965) Ltd. for Canada and Ryder Scott Company for the United States.

A report dated February 8, 1982 has been prepared by McDaniel Consultants (1965) Ltd., Calgary, Alberta, independent oil and gas reserve evaluators, estimating PanCanadian's net share of remaining proved crude oil, natural gas and natural gas liquids reserves in Canada. Net reserves shown by the report are included in the table which follows. Also included is PanCanadian's net share of remaining proved crude oil, natural gas liquids, and natural gas reserves in the United States, as estimated by Ryder Scott Company, Houston, Texas, independent petroleum engineers. "Net" reserves are the gross reserves underlying the properties in which PanCanadian has either a working interest or a royalty interest, less all royalties and interests owned by others.

	Oil (including natural gas liquids) (thousands of barrels)			Natural Gas (mmcf)		
	Canada	United States	Total	Canada	United States	Total
Net proved reserves:						
December 31, 1981	91 736	697	92 433	2 478 505	13 032	2 491 537
December 31, 1980	95 922	996	96 918	2 205 046	24 073	2 229 119
December 31, 1979	104 564	787	105 351	2 054 531	15 143	2 069 674

Net reserves and changes in net proved reserves of oil (including natural gas liquids) and natural gas during the years ended December 31, 1981, 1980 and 1979 were as follows:

	Oil (including natural gas liquids) (thousands of barrels)	Natural Gas (mmcf)
Net reserves – December 31, 1978	112 579	1 899 575
Revisions of previous estimates	4 180	135 848
Extension, discovery and other additions	1 908	140 048
1979 production	(13 316)	(105 797)
Net reserves – December 31, 1979	105 351	2 069 674
Revisions of previous estimates	4 222	193 478
Extension, discovery and other additions	387	68 942
1980 production	(13 042)	(102 975)
Net reserves – December 31, 1980	96 918	2 229 119
Revisions of previous estimates	7 002	281 744
Extension, discovery and other additions	968	82 817
1981 production	(12 455)	(102 143)
Net reserves – December 31, 1981	92 433	2 491 537

Proved reserves are considered to be those reserves which geological and engineering data demonstrate with a high degree of certainty to be recoverable in the future at commercial production rates under present depletion methods and current operating conditions, prices and costs. Essentially all of PanCanadian's proved crude oil reserves are considered to be developed and recoverable through existing wells with existing facilities. In the case of PanCanadian's proved natural gas and associated liquids reserves, sufficient wells exist in most instances to meet required initial withdrawal rates from the respective reservoirs. As a result, the natural gas and natural gas liquids reserves are considered to be developed even though additional drilling will be required in certain cases to drain effectively the respective reservoirs in a desirable length of time.

At December 31, 1981, PanCanadian had estimated proved reserves of 43 442 000 barrels of crude oil attributable to the Syncrude Project which are not included in the above table.

GOVERNMENT POLICIES AND LEGISLATION

The National Energy Program outlined direct incentive payments for exploration and development programs which will depend upon the Canadian Ownership Rate (COR) of the applicant, measured according to such formulae as are to be prescribed by the federal government. In addition, such payments depend on whether the applicant is Canadian controlled, whether the expenditure is for exploration or development, and whether the expenditure is incurred on federal or provincial lands. The Alberta government agreed to fund and administer the incentive program in that province, including enforcement of the COR and eligiblity rules as established by the federal government. The enabling legislation for the incentive program and the Canadian ownership requirements has yet to be enacted although guidelines outlining the proposed general rules have been published by Ottawa.

Until the final rules are known and the legislation is passed, the Company is not able to determine its COR, which depends largely on the residence and citizenship of shareholders of not only the Company but also Canadian Pacific Enterprises Limited and Canadian Pacific Limited. Based on its interpretation of the published guidelines, the Company has recorded estimated incentives of approximately $37.9 million attributable to its 1981 exploration and development expenditures. These incentives are more than 90% attributable to provincial lands, primarily in Alberta. If the final rules on incentives and Canadian ownership are similar to the published guidelines, the Company anticipates receiving these incentives, following necessary application, in the last half of 1982.

The pricing and taxation agreements which were concluded by Canada and the producing provinces late in 1981 introduced a two-tier oil pricing system for "old" and "new" oil effective January 1, 1982 through 1986 and established a schedule of price increases. However, new oil prices are not permitted to exceed international prices and old oil prices cannot exceed 75% of such prices, all based on a landed price in Montreal. "Old oil" refers to oil produced from discoveries made prior to January 1, 1981. "New oil" is conventional oil produced from pools discovered after December 31, 1980, from extensions of old oil pools and incremental production from approved enhanced recovery projects. A New Oil Reference Price (NORP) will be received for new oil. This NORP base price is higher than the price of conventional old oil and will increase every six months from January 1982 until 1986, contingent upon the world price. The January 1, 1982 price for new oil was less than the amount provided for in the agreements because of the international price ceiling.

The agreements also introduced significant changes to the taxation of the industry commencing in 1982. The Petroleum & Gas Revenue Tax (PGRT) will increase from 8% to 16%. The revenues subject to PGRT can be reduced by a 25% resource allowance if such revenues are subject to a disallowance of provincial levies for income tax purposes. Similarly, the resource allowance for income tax purposes will also be allowed only on revenues subject to disallowance of provincial levies. A new Incremental Oil Revenue Tax (IORT) was also introduced. This IORT provides for a tax of 50% on the incremental revenues, after deduction of related provincial royalties and other levies, received from conventional old oil as a result of the pricing agreements over what would have been received under the National Energy Program. The incremental revenues subject to IORT will be excluded from income for the purposes of income taxes but will be subject to PGRT. The Natural Gas and Gas Liquids Tax, an excise tax imposed on all gas and liquids produced in Canada, was continued on all domestic sales of such products. The rate of this tax on export sales of gas and ethane was set at zero for the term of the agreements and the rate on exports of propane and butane is to be set at the rate equal to that to be imposed on these products sold domestically.

In January, 1982, the Federal Government announced that, as a further incentive directed at marginal producing wells, the IORT applicable to revenues from wells producing less than 20 barrels a day will be reduced. This Low Productivity Well Allowance will permit a reduction in the amount of IORT applicable to such marginal wells which is to be equivalent to 5% for each barrel a day that the well's production is below the 20 barrel threshold and is to be achieved by raising the base price that would have been received for oil from these marginal wells under the National Energy Program.

TEN YEAR STATISTICAL REVIEW

(Dollar amounts in thousands except per share figures)

		1981	1980
Earnings	Gross Income	$ 641 922	$ 574 687
	Funds from Operations	362 728	367 312
	Per Share	11.62	11.76
	Net Income	203 737	241 367
	Per Share	6.52	7.73
Balance Sheet	Working Capital (Deficiency)	49 351	27 151
	Property, Plant & Equipment — Net	1 343 125	1 109 904
	Investments & Other Assets	67 071	66 606
	Long-Term Debt	247 210	176 425
	Deferred Income Taxes	376 688	290 299
Capital Expenditures	Exploration	143 049	184 514
	Development	26 158	34 805
	Production Facilities & Equipment	83 088	46 200
	Syncrude Project	2 540	4 287
	Methanol Plant	90 232	—
	Investment in Panarctic Oils Ltd.	2 208	154
	Petroleum Incentive Program Grants	(37 934)	—
Proven & Probable Reserves (after royalty except Synthetic Oil)	Natural Gas (billion cubic feet)	3 509	3 499
	Crude Oil & Natural Gas Liquids (thousand barrels)	140 232	138 381
	Synthetic Oil (thousand barrels before royalty)	43 442	43 827
	Sulphur (thousand long tons)	2 841	2 949
	Coal (million short tons)	1 989	1 979
Production (after royalty)	Natural Gas Sales (thousand cubic feet a day)	279 844	281 351
	Crude Oil & Natural Gas Liquids Production (barrels a day)	34 123	35 632
	Synthetic Oil (barrels a day)	2 776	2 875
	Empress Plants Natural Gas Liquids Sales (barrels a day)	18 017	15 175
	Sulphur Sales (long tons a day)	430	436
Acreage	Gross (thousand acres)	25 224	25 261
	Net (thousand acres)	11 851	11 935
Shares & Dividends	Number of Shares Outstanding	31 224 979	31 224 979
	Number of Shareholders	4 266	4 581
	Dividends	112 399	99 909
	Per Share	3.60	3.20
	Market Price Per Share — High	97½	98
	— Low	65	60¼

Valuation Day (December 22, 1971) Share Price $15¼

PANCANADIAN PLAZA

PanCanadian Plaza, to the right of the Calgary Tower, stands out as a handsome addition to the downtown skyline. The building is uniquely eight-sided in shape and will be fronted by a tree-lined plaza on the corner of Ninth Avenue and First Street Southwest. The new corporate headquarters will be occupied in mid-1982.

PanCanadian Petroleum Limited

P.O. Box 2850, Calgary, Alberta, Canada T2P 2S5

lawson graphics western limited
PRINTED IN CANADA

1979	1978 (Restated)	1977	1976	1975	1974	1973	1972
$ 423 905	$ 333 762	$ 301 346	$ 206 941	$ 159 590	$ 130 572	$ 75 374	$ 47 271
268 107	233 797	186 096	134 440	99 756	74 557	49 872	34 965
8.59	7.49	5.96	4.31	3.20	2.39	1.60	1.12
165 830	155 883	126 546	85 033	68 663	46 243	21 300	12 544
5.31	4.99	4.05	2.72	2.20	1.48	0.68	0.40
38 050	72 393	57 816	25 327	(9 625)	11 748	10 900	29 896
906 246	804 114	504 765	428 327	342 957	278 626	249 356	203 112
67 495	33 619	31 955	29 328	25 996	23 696	22 242	9 058
204 390	271 855	119 632	130 447	81 429	89 946	93 468	71 979
228 921	181 144	144 174	118 723	101 302	89 317	81 367	71 086
153 892	131 878	74 645	57 032	30 980	30 285	22 934	22 756
13 245	16 200	18 941	14 923	13 622	9 675	4 385	1 985
33 595	28 657	16 444	45 081	38 510	9 356	4 695	5 597
13 095	163 046	—	—	—	—	—	—
—	—	—	—	—	—	—	—
1 364	1 536	3 014	2 876	3 155	1 764	1 705	1 812
—	—	—	—	—	—	—	—
3 174	2 683	2 448	2 366	2 384	2 298	2 225	1 627
144 746	146 336	152 963	165 851	185 945	194 493	206 755	215 947
44 879	57 000	—	—	—	—	—	—
2 918	2 990	3 436	3 773	4 756	4 076	3 573	3 871
1 842	1 748	1 490	860	485	—	—	—
289 855	275 861	273 036	231 691	223 623	226 285	210 210	199 522
36 484	32 700	33 834	30 395	33 546	39 273	43 521	33 995
1 238	—	—	—	—	—	—	—
16 465	14 281	12 163	9 980	9 363	11 979	7 065	—
283	246	230	143	139	218	219	154
23 112	23 149	28 905	30 256	31 793	39 686	45 671	20 037
11 596	11 566	13 362	13 059	15 311	16 426	19 705	14 798
31 224 979	31 219 534	31 219 534	31 219 534	31 219 534	31 219 534	31 214 990	31 205 985
4 767	5 119	5 363	5 905	7 170	7 492	7 840	7 881
54 632	35 583	29 653	27 784	26 847	19 355	12 795	9 982
1.75	1.14	0.95	0.89	0.86	0.62	0.41	0.32
67½	38¾	36	25¾	17¼	14	18½	17⅜
38¼	30¾	23¾	15⅞	7⅝	7⅛	11⅜	13