Suncor inc.

Annual Report 1981

Highlights year ended December 31	1981	1980
Revenues ($ millions)	**$1,320.7**	$1,259.4
Earnings ($ millions)	**$ 50.1**	$ 306.4
Earnings per common share	**$ 0.93**	$ 5.83

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Company Profile

Suncor Inc., one of Canada's largest integrated oil and gas companies, was the first in the world to tap the enormous potential of the oil sands on a commercial scale. Today, Suncor operates both mining and steam stimulation projects recovering hydrocarbons from the oil sands of Alberta. The Company explores for, and produces, conventional crude oil and natural gas in Canada's western provinces and participates in the search for oil and gas in the frontier areas of the Arctic Islands, the Beaufort Sea, the Mackenzie Delta and Offshore Labrador. It is also assessing opportunities for coal and other minerals.

Suncor manufactures, distributes and markets gasolines, petrochemicals, home heating oil, heavy fuel oil, lubricants and specialty products under the Sunoco and Sunchem names. The Company owns and operates a refinery in Sarnia, Ontario.

Suncor is independently directed and managed by Canadians and pursues a policy of responding to Canadian needs. About 75 per cent of its common shares are held by Sun Company, Inc. of the United States and approximately 25 per cent are owned by Ontario Energy Resources Ltd., a corporation indirectly owned by the Province of Ontario.

◀ "Tailgunner" Dave Mortenson in the "dog house" of a bucketwheel used to remove overburden.

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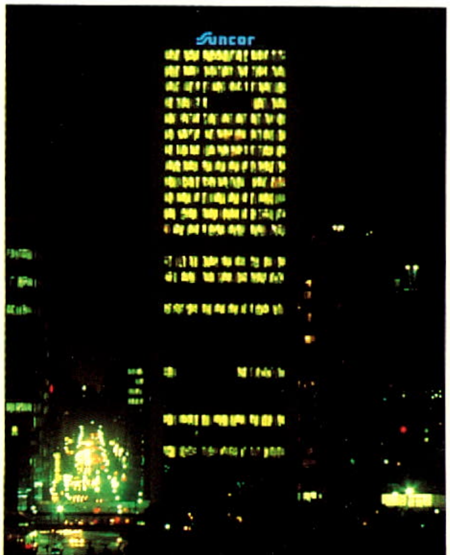
Summary of Results

Financial	($ millions except per share data) **1981**	1980
Revenues	**$1,320.7**	$1,259.4
Earnings		
– for the year	**$ 50.1**	$ 306.4
– per common share	**$ 0.93**	$ 5.83
– as a percentage of capital employed	**3.5%**	24.6%
– as a percentage of shareholders' equity	**4.6%**	32.3%
Funds from operations–for the year	**$ 127.7**	$ 418.0
–per common share	**$ 2.44**	$ 8.00
Capital expenditures	**$ 201.1**	$ 271.9
Dividends–per preferred share	**$ 1.92**	$ 1.92
–per common share	**$ 1.50**	—

Operating	**1981**	1980
Exploration, production and resources development		
Conventional crude oil and natural gas liquids		
–gross production (a)	**833**	940
Natural gas–gross sales (b)	**686**	628
Conventional crude oil and natural gas liquids		
–gross proven reserves (b)	**9.7**	10.3
Natural gas–gross proven reserves (c)	**13.3**	13.3
Oil sands		
Synthetic crude oil		
–gross production (a)	**1 701**	2 716
–gross proven reserves (b)	**54.0**	56.0
Refining, petrochemicals and marketing		
Crude oil processed at Suncor refinery (a)	**4 403**	4 525
Sales of refined products (a)	**4 521**	4 260

(a) thousands of cubic metres
(b) millions of cubic metres
(c) billions of cubic metres

The Suncor Tower in Calgary, headquarters for the Company's Resources Group.



Earnings fell dramatically in 1981, due primarily to the National Energy Program's low price for synthetic crude from our oil sands plant and a sharp decline in production. After months of uncertainty, however, we obtained a higher oil sands price effective January 1, 1982 and Suncor now stands on the brink of a new era of opportunity.

New pricing and tax agreements
Suncor's profitability is in large part tied to oil sands pricing, as the charts shown below demonstrate. In 1980, our synthetic crude selling price averaged $34.53 per barrel. But in 1981, our average price fell to $20.61 per barrel as a result of the National Energy Program (NEP) introduced the previous October and earnings dropped accordingly.

As of January 1, 1982, Suncor's entire oil sands output began receiving the new oil reference price of about $45 per barrel under the terms of an agreement between the Alberta and federal governments signed September 1, 1981. Similar agreements were signed by the other oil-producing provinces. The new oil reference price is determined by a schedule in the agreement or a formula for calculating the international price, whichever is lower. Currently, the international price applies. The price in the schedule increases semi-annually from about $46 per barrel on January 1, 1982 to approximately $78 by July, 1986 and the agreement expires at the end of that year.

Taxes offset some of the benefits of the higher price. Effective January 1, 1982 a new incremental oil revenue tax of 50 per cent applies to revenues in excess of NEP levels for old oil (oil discovered prior to January 1, 1981). This tax affects Suncor's pre-expansion oil sands production, currently deemed to be 75 per cent of total output, but the incremental revenue from this production is exempt from corporate income tax. Furthermore, the petroleum and gas revenue tax, applicable to all production of oil and gas, is up from eight per cent to an effective rate of 12 per cent.

The new oil reference price also applies to conventional oil discovered after December 31, 1980 as well as additional oil obtained by enhanced recovery techniques, production from new oil sands projects commencing operation after December 31, 1980 and production from the frontiers. Our Fort Kent project will be receiving this price, less reductions for lower quality (see page four).

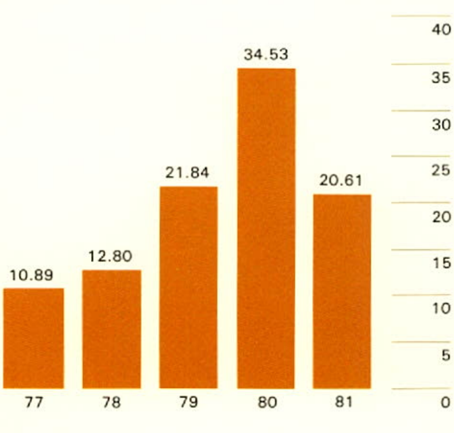
Old oil is scheduled to increase from a January 1, 1982 price of $23.50 to $57.75 per barrel in July, 1986 provided the price does not exceed 75 per cent of the international price. In the short term, tax increases in the federal/provincial agreements actually reduce Suncor's netbacks from old oil below NEP levels, which were already too low. However, the economics of old oil improve marginally in the later years of the price agreements.

The impact of the new price agreements depends in part on the international price which is currently lower than the federal price schedule. Scheduled prices are unlikely to be attained in 1982. The international price is depressed by much reduced demand among non-communist countries– the result of a doubling of the price in 1979/1980 as well as a worldwide recession. Surpluses have developed. However, when the price shock of 1979/1980 has worked its way through the system and the world economy has improved, these surpluses should be absorbed and we expect the upward trend in prices to resume.

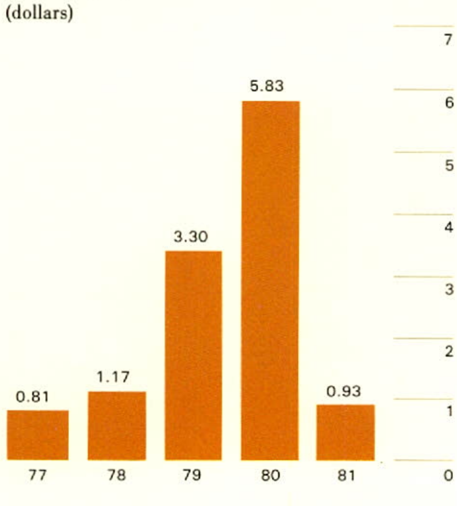
New initiatives being assessed
Higher prices for our synthetic crude should generate the cash flow necessary to increase capital spending. Furthermore, with pricing now clarified for the next five years, we can evaluate which projects will be economic to develop of the many we have identified. We are therefore conducting a Company-wide strategic review of each business unit and its opportunities.

Our main objective is to increase Suncor's oil reserves and production, both conventional and nonconventional. We have therefore decided to proceed with expansion of our experimental in-situ oil sands project at Fort Kent from a little less than 1,200 barrels per day to about 5,000. Another project now awaiting tax decisions from government is the mining of an extended area at our oil sands plant to produce an additional 90 million barrels of synthetic crude considered uneconomic before the new price

Average synthetic crude oil sales price
(dollars per barrel)



Earnings per common share
(dollars)



The charts above show that Suncor's earnings are in large part tied to oil sands pricing.

agreement. These and other projects still in the evaluation stages are described in the section starting on page four.

Canadianization
A major step toward Canadianization was taken in late 1981 with the sale of about 25 per cent of our common shares by our major shareholder, Sun Company, Inc., to Ontario Energy Resources Ltd., a corporation indirectly owned by the Province of Ontario. The price was about $650 million. The purchaser has extended the same offer to owners of 69,885 Suncor common shares not held by Sun Company.

I would like to welcome Pierre Genest, W. Edwin Jarmain and Malcolm Rowan as Suncor directors, nominated to our Board by Ontario Energy Resources Ltd. We now have a majority of independent Canadian directors–that is, directors having no other relationship with Suncor or our major shareholder. To facilitate the work of the Board, our directors have appointed Michael M. Koerner as Suncor's first Chairman. His role is described on page 50.

Our objective is majority Canadian ownership and control of Suncor. To reach this goal, a number of options are being pursued including additional private placements of common shares.

Early in 1982, our Board of Directors established a policy of regular quarterly cash dividends on Suncor's common shares beginning with the first quarter of 1982. The first such payment was 20¢ per share to shareholders of record on February 19, 1982. Suncor also paid $1.50 per common share to shareholders of record on December 22, 1981, the first common share dividend in our 62-year history.

Operating highlights
At the oil sands plant, our $185 million expansion program was completed in 1981, on time and slightly below budget. The expansion adds about 13,000 barrels per day to plant capacity. However, synthetic crude production was down 37 per cent from 1980 due to a planned biennial maintenance shutdown in the second quarter of 1981 and operating problems which developed in the second half of the year. Production difficulties were still being experienced early in 1982.

Conventional crude oil production was also down, primarily because of Alberta Government cutbacks and a maturing of reservoirs, both of which affected the industry as a whole. Natural gas sales were higher as new fields were brought on stream. Three new oil and gas discoveries on Suncor interests in the Arctic Islands highlighted the year's frontier drilling activities.

Downstream, our Sunoco Group enjoyed a good year. Production and sales of both gasolines and petrochemicals were higher in 1981. Our market position for both of these product categories was strengthened during the year.

Outlook
The outlook for Suncor in 1982 is much improved from a year ago. The higher netbacks we expect from our synthetic crude should generate the funds to undertake some exciting new initiatives. However, earnings for the year will be reduced by more than $50 million as a result of a fire at the plant on January 20 (see "Prospects for 1982" on page 23).

I believe Suncor's strengths combine to make us unique among Canada's integrated oil companies. Our commitment to Canadianization–now partially realized–is one of these strengths. Federal government policy very clearly favors Canadian-owned companies by tying its new exploration incentive grants and even project approvals to ownership status. We intend to become eligible for these benefits as fully and as quickly as possible.

We have a growing land position in the western provinces, balanced by significant participation in each of the main frontier areas. And Suncor has well-developed expertise in oil sands technology, with worldwide leadership in such areas as enhanced bitumen recovery and tailings disposal. Because we were the first to develop oil sands production on a commercial scale, we have had to innovate. This innovation has a substantial and growing value, as a recent sale of technology demonstrates (see page 23).

We have a competitive edge in our downstream operations where Sunoco has, for example, consistently registered gains in market share for gasoline over the past several years. Our petrochemical division has solidified its market position and distribution network, thanks in part to purchase of the M.V. Suncor Chippewa, a petrochemical tanker which has improved our delivery capabilities.

But our most valuable resource is our people. The past year was a time of trial. Earnings were down, budgets were cut, takeovers were rumored. Despite this uncertainty, Suncor employees remained dedicated to the Company and worked very hard to maintain its momentum. I am delighted that the qualities exhibited by our people will now be tested by new opportunities.

Suncor is once again a Company with a future, a future dedicated to developing Canadian resources to meet Canadian needs.

Ross A. Hennigar

Ross A. Hennigar
President & Chief
Executive Officer
March 3, 1982

The Task at Hand

Fort Kent production is loaded for shipment to a heavy oil treatment plant where it is upgraded prior to refining.

At Suncor, one of our main tasks is to contribute to Canadian petroleum self-sufficiency. In this section, we take you behind the scenes to discuss some of the new projects we are considering which could help us accomplish this task.

Some of these projects are dependent upon a strategic review of Suncor's investment opportunities. This review was set in motion in the wake of the new price agreements which recently came into effect. It will help us evaluate just what projects should proceed and in what order.

Several of these projects use new technology developed by Suncor. As a Company, we take pride in the fact that we are making a growing contribution to Canada's energy expertise.

Fort Kent expansion

Suncor is operator and 50 per cent owner of an experimental in-situ oil sands project at Fort Kent in the Cold Lake area of northeastern Alberta. Steam and water are forced underground to reduce the viscosity of heavy oil trapped in the sand, inducing it to flow. The oil is then pumped to the surface. Production averaged 182 m^3 per day (1,147 barrels) from 37 wells.

A decision has been made to expand the project to 795 m^3 per day (5,000 barrels). Work has begun and should be completed in 1984. Expansion includes drilling 112 wells and constructing additional steam and production facilities at an estimated cost of $88 million. Suncor's share would be 55 per cent.

The project design includes a number of innovative ideas, two of which will benefit the environment. Waste water from the nearby town of Bonnyville will be used as a source of water to produce the steam, thus conserving valuable water. Also, wells will be clustered and drilled on a slant using specially-developed new equipment so as to access sizable reserves while preserving agricultural land and reducing the cost of surface piping. Meetings were held with local residents who expressed support for these concepts.

Fort Kent's entire production will receive the new oil reference price which, after reductions related to quality, should commence at about $33 per barrel in 1982. The incremental oil revenue tax will not apply. Because of the experimental nature of this project, the Alberta Government has set a favorable royalty rate of five per cent for the first five years of expansion.

If this expansion meets our expectations, we plan to undertake other projects like Fort Kent.

The large-pit project

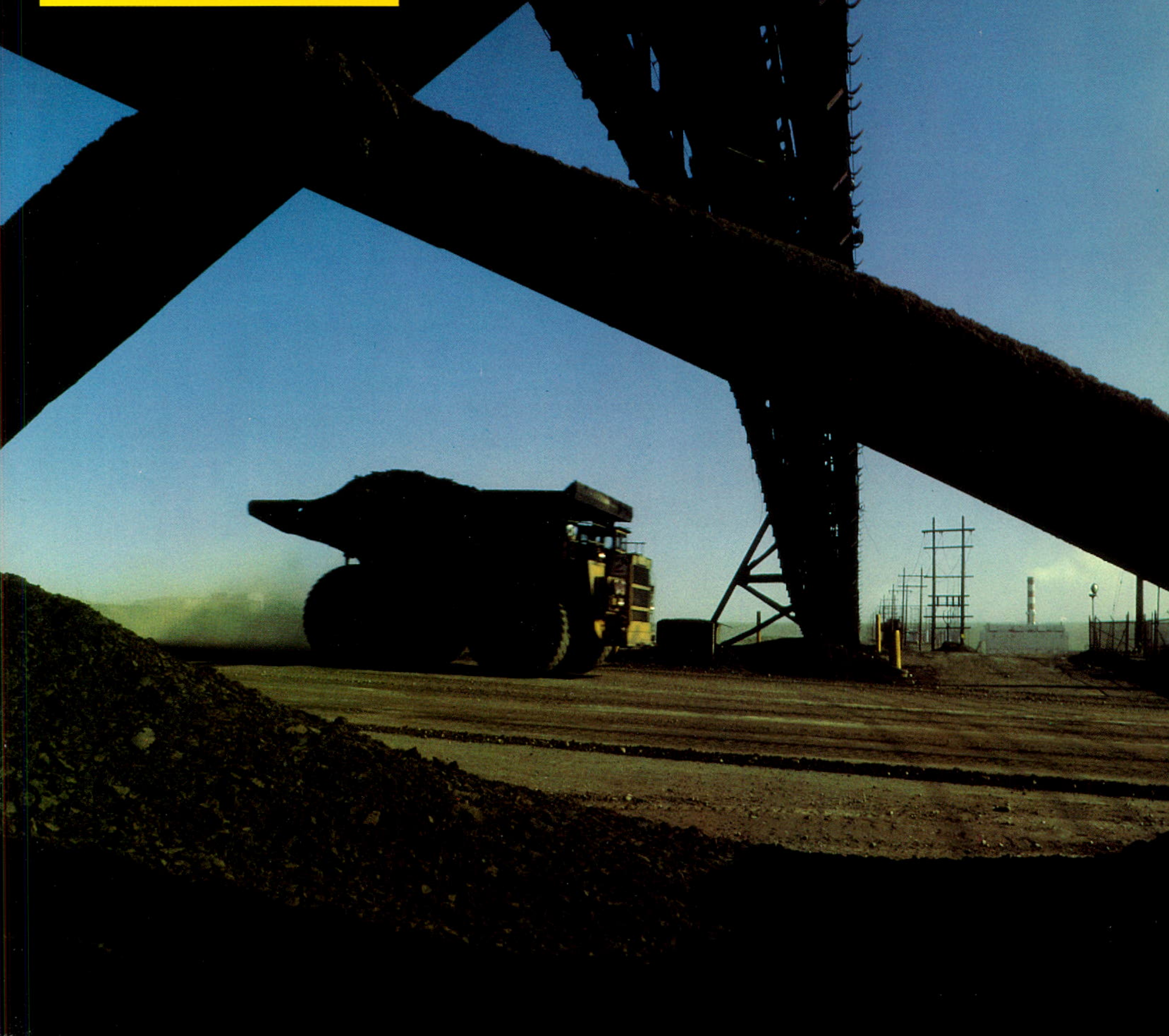
The size of oil sands reserves depends upon the oil price. Under the NEP, our mine plan was limited by the low price in effect. With the new oil reference price, it will now be economic to mine another area of the lease, subject to favorable tax rulings which we are now awaiting. Mining this area expands the size of the pit, which is why we call it the large-pit project.

Our plan to mine the large pit adds about 14.3 million m^3 (90 million barrels) of synthetic crude to reserves, an increase of about 25 per cent, which would extend the life of our oil sands project by over four years.

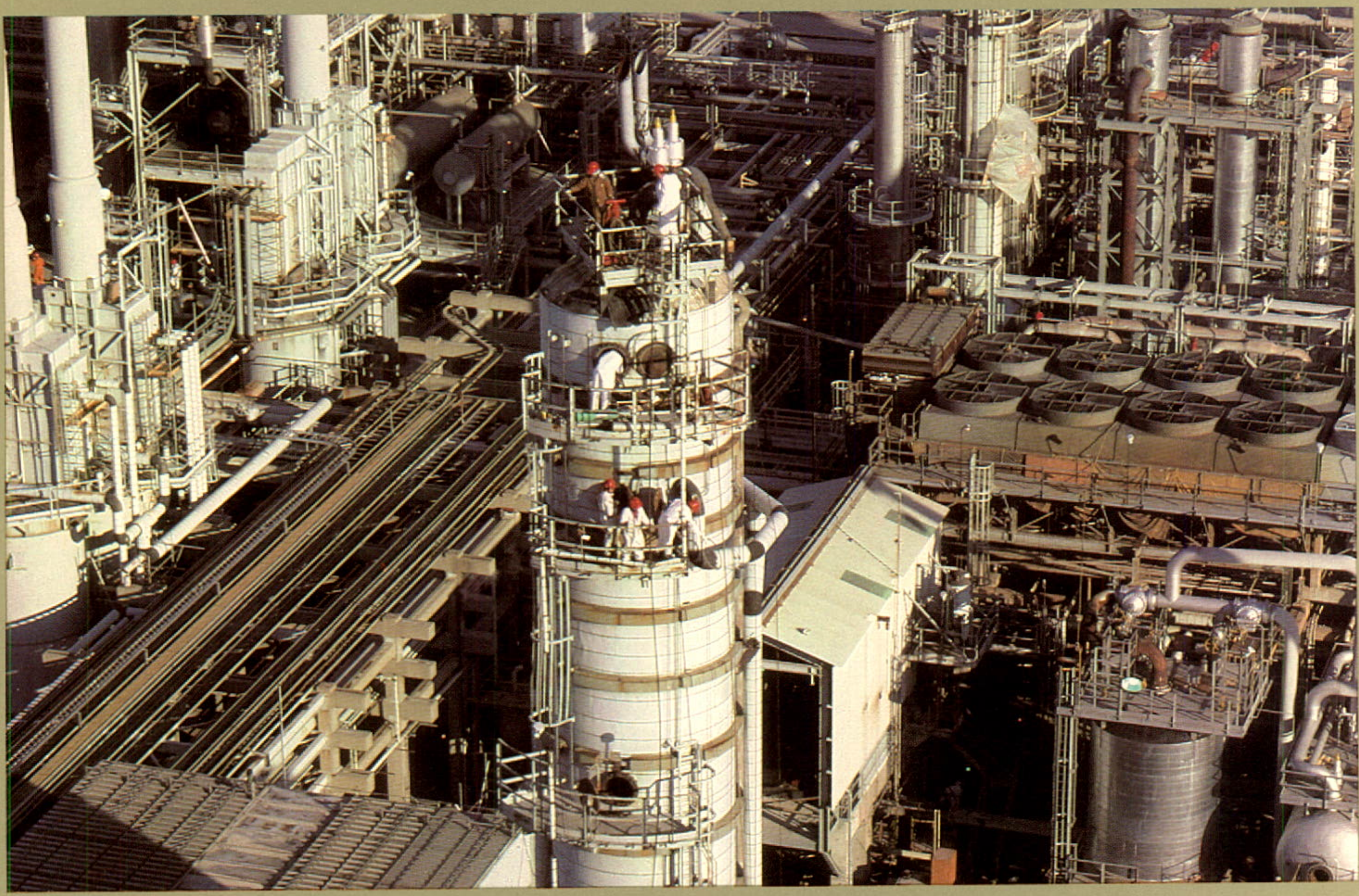
Because of the location of the additional reserves, significant expenditures will be incurred now but the benefit of additional revenues will not begin to be realized until the end of this century when our lease would otherwise have been mined out. The main expenditure is removal of overburden–a layer of muskeg and glacial deposits covering the oil sand. The section of the mine containing the additional 90 million barrels is covered by a thicker layer of this material. Our plan requires that we proceed with removing about 35 million m^3 (46 million cubic yards) of additional overburden over the next five years, at an estimated extra cost of close to $180 million. The total extra cost of mining the large pit could add up to a billion dollars over the life of the project.

Mechanic Harrison Cardinal repairs mining and overburden equipment. The combination of climate, sand and tar puts enormous strains on equipment.

This 170-ton truck, one of 26, carries away overburden so that oil-bearing sand can be mined.



Suncor's Sarnia refinery. A major upgrading program is in the final evaluation stages as one possible response to changing market conditions.



Refinery upgrading

Consumption patterns for refined petroleum products will go through significant changes in the next two decades.

Demand for transportation fuels will subside and there will be a shift from gasoline to diesel. Heating fuel demand will drop precipitously as consumers improve insulation and move to lower-priced energy alternatives such as natural gas and electricity. On the other hand, demand for lubricants and petrochemicals will rise.

To respond to these changes, we are evaluating a number of options which would give us greater flexibility in the mix of refined products we manufacture. One such option is an upgrading of our Sarnia refinery including a hydrocracker, a sulphur plant, a hydrogen plant and related facilities. The hydrocracking process produces less low-grade fuel oils and greater amounts of higher-value transportation fuels and petrochemical feedstocks than the processes now in use at our refinery.

Hydrocracking would dramatically increase our efficiency and conserve Canadian crude oil. We would be able to produce the same volumes of gasoline and petrochemicals as we now do while using approximately 35 per cent less crude oil and virtually eliminating output of heavy fuel oil.

Detailed studies are now in progress and a final decision is imminent. If we proceed, the upgrading would require substantial capital outlays and about three years to complete.

Synthetic gas liquids plant

When bitumen is thermally cracked into coke and distillates at our oil sands plant, gas is produced. This synthetic gas has a number of uses; for example, some of it is desulphurized, mixed with natural gas and used as a fuel at the plant and for the production of hydrogen used in the process area.

The potential value of synthetic gas is not realized by using it as a fuel, however. Its components include ethane/ethylene, propane/propylene and butane. Separated and compressed into liquid form, ethane and propane are valuable as petrochemical feedstocks. Butane can be used to augment synthetic crude production. In total, this project would add about 900 m^3 per day (5,700 barrels) of liquid hydrocarbons to our oil sands output, including approximately 220 m^3 per day (1,400 barrels) of additional synthetic crude.

Proposed construction for this project would include a synthetic gas liquids extraction plant at our Fort McMurray site, a fractionation plant at another location (where liquified gas is separated into various components or fractions), salt-cavern storage for the hydrocarbon components and pipeline facilities at a total cost of perhaps $100 million.

Preliminary engineering is completed but royalty considerations must be resolved before construction can begin. A final decision is expected in 1982 and if positive, the plant could be operational in about three years. Studies are now being carried out to determine optimum uses for the petrochemical feedstocks.

New settling agent

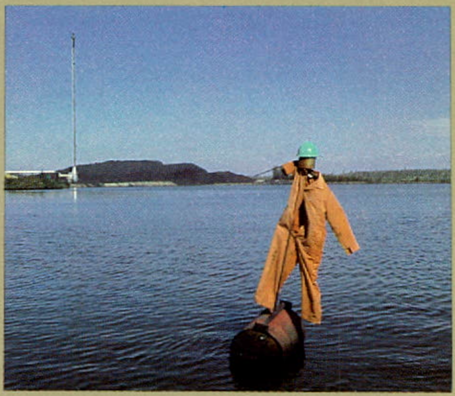
Sludge is one of the most difficult problems facing not only oil sands operations but also industries producing aluminum, iron, phosphate and other resources. These industries produce waste (called tailings) which consist largely of sludge which is a mixture of fine silt and clay, suspended in water.

Sludge is typically stored in large ponds where it settles very slowly. There are two such ponds at our oil sands plant. Using current practices, the solids settle out over a five-year period, forming a gel which is still about 70 per cent water. It has proved very difficult to reduce the water content any further.

Suncor has spent 13 years and more than $7 million researching solutions to this problem. For the past five years, we have worked with McGill University to develop a unique new additive which reduces the surface tension of the water surrounding the particles. This biodegradable agent accelerates settling by a factor of five in lab tests and reduces the amount of water in the gel to 60 per cent. With this additive, it may prove possible to reduce the water content to the point where tailings ponds could be reclaimed as usable land area.

Quantities of the agent have been manufactured by Suncor and are now being tested. Final results are not expected until late 1982. If successful, the agent could be mass-produced and sold to the world market under patents shared by Suncor and the inventor.

▼ Scarecrows keep waterfowl away from our tailings ponds. Suncor is testing a new additive which increases the settling rate for sludge contained in these ponds.

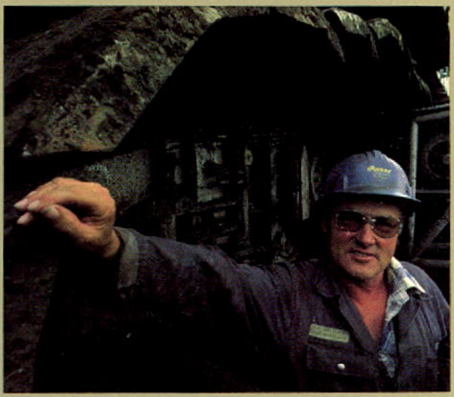


Bitumen from sludge

A little more than five per cent of the bitumen we mine at the oil sands plant ends up in the tailings ponds where it accumulates at the bottom, mixing with sludge. We are currently scheduled to begin moving the sludge to new locations on the plant site in 1984, providing an opportunity to process the sludge and recover the bitumen.

Suncor is experimenting with new technology using mechanical agitation, which could possibly recover up to 80 per cent of the bitumen in the sludge, adding about 6.4 million m^3 (40 million barrels) of synthetic oil to reserves. A pilot plant was constructed in 1981 at a cost of $3 million to test the technology. If these tests demonstrate that the process is economical, we may then proceed to a full-scale plant which could be constructed in time to process the sludge as it is moved. Capital costs would approximate $75 million.

Clarence Little operates a bucketwheel which digs out oil-bearing sand and loads it onto conveyors heading for the extraction plant.



A new bucketwheel costing $21 million was added to the mining operation as part of the plant expansion completed in 1981.

Earnings

Earnings in 1981 were $50.1 million, down $256.3 million or 84 per cent from 1980. This decrease primarily reflected substantially lower synthetic crude oil selling prices, reduced synthetic crude oil sales volumes and higher oil sands operating expenses. The lower sales volumes and a substantial part of the higher operating expenses arose principally from the planned biennial maintenance shutdown of the oil sands plant and operating problems in the second half of the year.

Schedule of segmented data

Exploration, production and resources development

Earnings from this segment declined by $11.3 million to $8.7 million.

Revenues rose by $14.4 million or nine per cent. This included higher crude oil and natural gas selling prices arising from legislated increases ($23 million) and natural gas sales volume increases ($3 million). These were partially offset by a decline in crude oil sales volumes ($11 million) mainly as a result of the Alberta production cutbacks.

Expenses were up by $25.6 million or 22 per cent. Factors contributing to this increase were the new eight per cent petroleum and gas revenue tax ($9 million), higher royalties ($4 million), and other cost increases of $12 million or 18 per cent due mainly to inflation and increased coal and mineral development activities.

Income taxes were essentially unchanged as the reduction in pre-tax earnings was almost entirely attributable to the petroleum and gas revenue tax–a non-deductible expense for income tax purposes.

Oil sands

Earnings from this segment were reduced by $230.6 million to a loss of $19.3 million.

Revenues decreased by $346.0 million or 58 per cent. Of this amount approximately $239 million was due to lower synthetic crude oil selling prices under the National Energy Program. Sales volumes decreased 38 per cent reducing revenues by a further $111 million (after estimated insurance recoveries). The reduction in sales volumes was due to a planned plant maintenance shutdown in the second quarter and operating problems in the last half of the year. Partly offsetting these factors was an increase of $4 million in revenues from sales of technology, coke and sulphur.

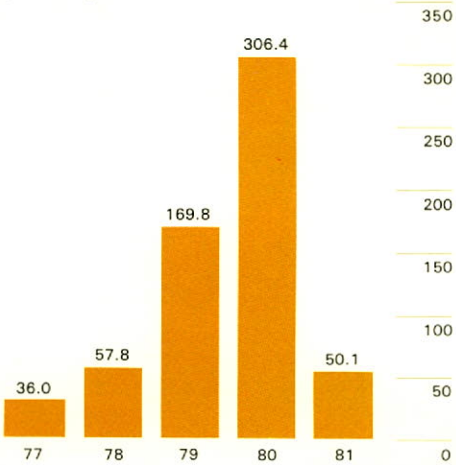
Expenses were down by $13.1 million or four per cent. Royalties decreased by $75 million as a result of the lower synthetic crude revenues and overburden removal amortization was reduced by $6 million reflecting lower production volumes. Partially offsetting these decreases were higher maintenance expenses related to the plant shutdown and second half operating problems ($22 million), increased power supply costs ($10 million) and other operating expense increases of $36 million or 29 per cent. These other operating expense increases were primarily due to the start-up and operating costs of the expanded plant, inflation, and inefficiencies caused by the second half production problems.

Refining, petrochemicals and marketing

Earnings from this segment declined by $8.7 million to $53.3 million.

Revenues rose by $313.8 million or 38 per cent. Selling prices for refined products increased 31 per cent primarily reflecting the pass-through of increases in the federal government's petroleum

Earnings before extraordinary gains
($ millions)



compensation charges and higher crude oil costs. The higher selling prices increased revenues by approximately $246 million. Refined product sales volumes rose six per cent increasing revenues by $68 million.

Expenses were up by $329.3 million or 46 per cent. Federal government charges on crude oil purchases increased by $162 million and federal sales and excise taxes rose $10 million. Crude oil and raw feedstock costs (excluding federal government charges) rose approximately $139 million as a result of higher purchase prices and volumes. Other expenses increased by $18 million or 12 per cent primarily reflecting the effect of higher sales volumes on distribution costs and the effect of inflation on refining, marketing and administrative expenses.

In summary, the decline in operating profits of $15.5 million was primarily due to lower refined product margins ($20 million) and higher marketing and administrative expenses ($11 million) partially offset by the effect of higher refined products sales volumes ($15 million). Non-cash gains arising from increases in federal government charges on crude oil purchases were more than offset by declining margins due mainly to crude quality problems. This is reflected above in the $20 million reduction in margins.

Income taxes

Total Company income taxes were down by $109.2 million to $54.1 million reflecting lower pre-tax earnings partially offset by an increase in the effective tax rate caused mainly by the National Energy Program and related tax changes.

Consolidated statement of changes in financial position

Funds from operations in 1981 decreased by $290.3 million or 69 per cent from 1980 reflecting the funds flow effect of the reduction in earnings partially offset by reduced outlays for overburden removal.

Capital expenditures decreased by $70.8 million or 26 per cent. As the oil sands plant expansion neared completion, capital expenditures on this project were $60 million lower than the previous year.

Dividends increased by $78.3 million as Suncor paid its first common share dividend of $1.50 cash per share to common shareholders of record on December 22, 1981.

Working capital decreased by $161.2 million in 1981. Comparing this change in current assets and current liabilities from December 31, 1980 to December 31, 1981: cash, time deposits and short-term investments net of short-term borrowings decreased by $273.9 million as funds generated by operations and other sources were insufficient to meet capital and other requirements. Accounts receivable rose by $54.2 million mainly as a result of estimated insurance claims and higher refined products selling prices. Inventories increased $126.8 million reflecting higher crude oil purchase prices and higher volumes due to the timing of purchases. Accounts payable and accrued liabilities increased $88.2 million mainly as a result of higher crude oil purchase liabilities. Taxes other than income taxes payable increased by $28.9 million primarily reflecting dividend withholding taxes and higher federal government petroleum compensation charges. Income taxes payable decreased by $50.1 million as a result of lower currently taxable earnings.

Rates of return

(percentages)

Return on capital employed is earnings as a percentage of average capital employed. Average capital employed is the average of total assets less current liabilities at the beginning and end of the year.

Return on shareholders' equity is earnings as a percentage of average shareholders' equity. Average shareholders' equity is the average of total shareholders' equity (including Preferred Shares Series A) at the beginning and end of the year.

Accounting for inflation

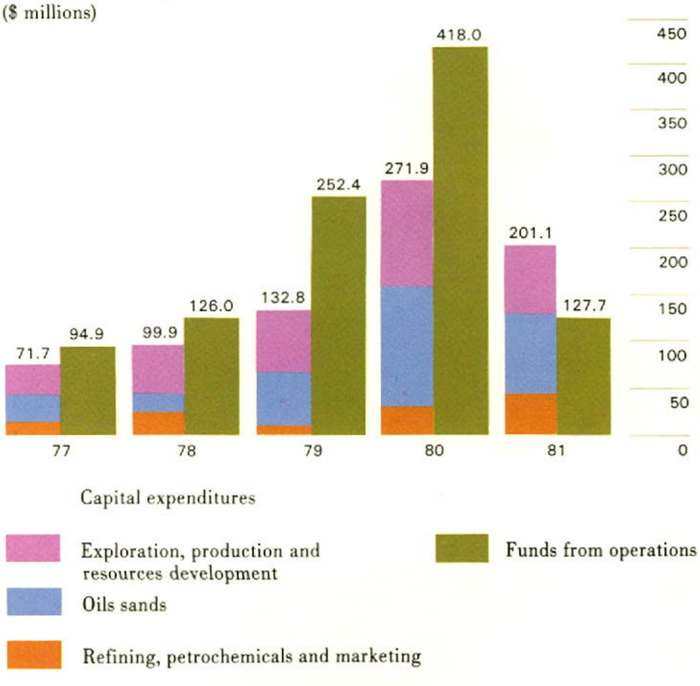
The Company's primary financial statements are based on historical costs. In prolonged periods of significant inflation, this method of accounting distorts reported earnings as certain costs, for example depreciation, are measured in older dollars, whereas other costs and revenues are measured in current, inflated dollars. Generally, adjusting for inflation tends to depress reported earnings but increase net worth.

There remains a general lack of consensus over the most appropriate method to apply in order to adjust for the effects of inflation. One method is to adjust for the general decline in the purchasing power of the dollar; another is to adjust for changes in costs of the Company's specific purchases. The Canadian Institute of Chartered Accountants has reviewed this matter at length and expects to provide definitive direction by the end of 1982. At present, however, no single method of accounting for inflation is widely accepted in Canada.

The Company has conducted extensive research and continues to monitor external developments while seeking a method that appropriately measures its financial performance.

Funds from operations vs. capital expenditures

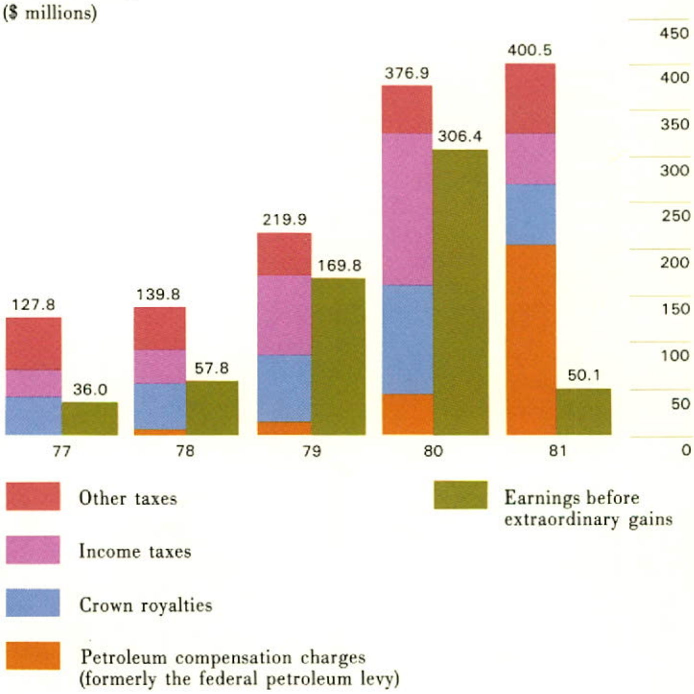
($ millions)



For details of capital expenditures, see pages 13 and 44.

Government royalties, levies and taxes vs. earnings

($ millions)



▼ Gaylord Schofer operates a compressor station constructed by Suncor to service the Medicine River natural gas field near Eckville, Alberta.

▼ Maintenance foreman, Rene Desnoyers, makes adjustments to one of the wells at our Fort Kent in-situ oil sands project which is slated for expansion in 1982.

Overview

A loss from the Oil Sands Division more than offset earnings from the Resources Group's Exploration, Production and Resources Development Divisions in 1981.

Production of synthetic and conventional crude oils fell well below 1980 levels, although natural gas sales increased. Combined oil and gas revenues dropped 48 per cent to $379 million in 1981, primarily due to lower prices and reduced production of synthetic crude oil.

Reduced cash flows resulted in capital spending cuts which especially affected Suncor's land acquisition and development drilling programs. These were sacrificed in the short term in order to maintain our exploration drilling which increased in 1981 although the industry-wide total declined.

A number of initiatives were placed on hold during the year including the large-pit project (described on page four) and initial work on a new, experimental in-situ oil sands project (see page 21).

Overall, capital spending for the Resources Group was $159 million in 1981 compared to $242 million the year before.

The most important event of 1981 was the signing of an agreement between the Alberta and federal governments which should result in improved cash flows from oil sands operations and a price for new oil sufficient to sustain exploration and production programs. Meanwhile, the oil sands plant produced its 200-millionth barrel of synthetic crude oil and expansion of the plant was completed. Three oil and gas discoveries were made in the Arctic Islands on lands in which we have an interest and encouraging results were obtained in the Offshore Labrador area following a disappointing drilling season in 1980.

Outlook

New initiatives highlighting 1982 will include the large-pit project (subject to favorable tax rulings) and expansion of our Fort Kent in-situ oil sands operation. We also will begin the process of reorienting our exploration and production efforts to respond to new incentives arising from the 1981 federal/provincial energy agreements.

The search for oil in the western provinces will become very competitive over the next several years. Few good farmins will be available and land purchases will be expensive as a result of the incentive created by the new oil reference price. We expect that our industry will locate a significant number of new fields although they will not be sufficient to offset a continuing decline in Canada's conventional crude oil production. Suncor will be putting growing emphasis on the search for new oil and extension of existing fields in the western provinces.

Sizable new discoveries will have to come from the frontiers. The federal government has skewed its petroleum incentive grants to encourage exploration in these areas and we expect to increase the level of activity on our frontier land holdings. Production from these interests will pose a major challenge, however.

Because of uncertainty about markets, Suncor will be increasingly selective about gas exploration in the coming months. Sales of Canadian gas in the U.S. have been disappointing, with a consequent negative impact on our industry's cash flow. Canadian gas exports to the U.S. have actually declined by 20 per cent since 1979 despite a 35 per cent increase in volumes authorized for export

Resources Group capital expenditures ($ millions)	**1981**	1980
Exploration, production and resources development		
Exploration		
Land holdings	**$ 10.8**	$ 36.4
Drilling	**31.3**	26.8
Geology, geophysics and other	**8.1**	7.6
	50.2	70.8
Production		
Acquisitions and land holdings	**0.5**	7.1
Development drilling	**8.5**	12.8
Plants, related facilities and other	**11.9**	17.6
	20.9	37.5
Resources development		
In-situ oil sands	**4.3**	1.7
Total	**75.4**	110.0
Oil sands		
Plant expansion	**38.5**	98.4
Mine and mobile equipment	**24.6**	5.9
Plant	**2.3**	15.9
Housing	**18.2**	12.0
Total	**83.6**	132.2
Total Resources Group	**$159.0**	$242.2

Wells completed

	Gross 1981	Net 1981	Gross 1980	Net 1980
Exploratory wells				
Oil	**5**	**5**	3	2
Gas	**22**	**14**	15	9
Dry	**22**	**12**	23	14
Total	**49**	**31**	41	25
Success ratio	**55%**		44%	
Average depth drilled (metres)	**1 771**		1 670	
Development wells				
Oil	**17**	**5**	55	12
Gas	**20**	**9**	46	25
Dry	**11**	**8**	12	7
Total	**48**	**22**	113	44
Success ratio	**77%**		89%	
Average depth drilled (metres)	**1 555**		1 479	

Note:
This table excludes wells completed under farmout agreements on Company properties as no cash expenditures were incurred by the Company. During 1981 there were 17 such wells (13 exploratory and 4 development); in 1980 there were 11 such wells (8 exploratory and 3 development).

Undeveloped land holdings

(thousands of hectares)

	Gross 1981	Net 1981	Gross 1980	Net 1980
Oil and gas				
Western provinces				
British Columbia	**346**	**68**	153	62
Alberta	**562**	**330**	517	303
Saskatchewan	**4**	**2**	5	2
	912	**400**	675	367
Frontier				
Northwest Territories and Yukon	**204**	**84**	204	84
Beaufort Sea/Mackenzie Delta	**567**	**223**	567	223
Arctic Islands	**7 958**	**1 284**	7 996	1 287
Offshore Labrador	**7 474**	**746**	9 018	902
Offshore Nova Scotia	**341**	**77**	341	68
	16 544	**2 414**	18 126	2 564
Total oil and gas holdings	**17 456**	**2 814**	18 801	2 931
Minerals	**769**	**515**	427	176
Total	**18 225**	**3 329**	19 228	3 107

by the National Energy Board. The price for exported gas, set by the federal government, is generally higher than the average price of U.S. production and Canadian gas is currently encountering stiff competition from alternate forms of energy, especially in the northwest U.S. We expect gas exports to the U.S. would increase in the near future provided that gas is priced competitively with alternate fuels and that it is made available to markets in the northeast U.S.

A strong demand for Canadian gas exists in the eastern U.S. and several Canadian pipeline companies have obtained contracts from their U.S. counterparts to supply this region. Export permits are needed and the NEB will begin holding hearings in March of 1982 to consider permit applications. We are hopeful that permits will be issued which could enable Suncor to bring a number of new gas fields on stream, perhaps late in 1983.

Domestic sales of gas will be slow in the near term but home-heating conversions to gas should accelerate over the next several years to reflect favorable pricing compared with oil. Also, new domestic markets will be opened up in 1983 with the completion of the Trans-Quebec and Maritimes Pipeline and the Victoria Island Pipeline. Steady growth in Canadian demand should be achieved for the rest of this decade.

In 1982, Suncor's synthetic crude production should increase substantially as there is no maintenance shutdown planned for the year and the plant has been expanded. However, operating problems at the plant were continuing in early 1982 as this report was being written.

Conventional crude oil production should increase over 1981, reflecting an end to the Alberta cutbacks. Natural gas sales should remain at about the same level as last year.

In the longer term, nonconventional oil supplies and coal will become increasingly significant energy sources. Suncor intends to pursue other projects like Fort Kent and participate to a greater extent in the coal business. Oil production will become progressively more expensive as conventional reserves dwindle and are replaced by nonconventional supplies. Coal may therefore prove to be the energy bridge between oil dependency and increased reliance on renewable resources early in the next century.

Exploration Division

Oil and gas discoveries on Suncor interests in the Arctic Islands highlighted 1981 drilling. In western Canada, five relatively small oil discoveries were made during the year, all qualifying for the new oil reference price.

Highlights

- 27 discoveries in the western provinces compared to 18 in 1980
- Three significant oil and gas discoveries in the Arctic Islands
- Small oil discovery and indicated gas well off the Labrador coast

Western provinces drilling

Suncor participated in 54 exploratory wells in this region in 1981 and was operator for 33 of them. In total, five were oil wells, 22 were gas wells, 17 wells were dry, five were suspended and five were still in progress at year-end, yielding a success ratio of 61 per cent.

Oil was discovered in the Lanaway area (described below), in the Drumheller area 170 kilometres northeast of Calgary, in the Heathdale area 200 kilometres east of Calgary and at Ferrier, 125 kilometres northwest of Calgary. The most significant gas discoveries were in the Bougie area (described below), the Chigwell area 100 kilometres south of Edmonton and the Wood River area about 90 kilometres south of Edmonton.

Important drilling areas included:

- Cosway area: All three wells drilled in 1981 were gas discoveries in this area 58 kilometres northeast of Calgary. The lease consists of 3 328 hectares wholly owned by Suncor. No further drilling is planned until markets for gas improve.
- Lanaway area: Two wells were drilled in 1981 in this area 106 kilometres northwest of Calgary. Both were oil discoveries in which Suncor has a working interest of 47 per cent. Further drilling is planned for 1982 pending negotiations for additional land. Suncor holds 512 gross hectares or 280 net hectares in this area.

▼ Three drillships contracted for the 1981 Offshore Labrador drilling season worked on a total of five wells. (Photo courtesy of Petro-Canada Ltd.)

- Bougie area: One gas well was completed in this area 250 kilometres northwest of Fort St. John in northeastern British Columbia during 1981. Suncor's interest is 100 per cent. Another well was spudded but was still in progress at year-end. Further drilling and land acquisitions are planned for 1982. Suncor's holdings in this area total 18 609 gross hectares or 8 166 net hectares with working interests ranging from 25 to 100 per cent.

Spending on land acquisitions for future exploration drilling dropped substantially in 1981 due to cash flow restraints and lower anticipated netbacks under the NEP (subsequently augmented by the new oil reference price). A total of 74 thousand gross hectares were acquired (46 thousand net) at a cost of $9.8 million compared to expenditures of $36.4 million spent in 1980. Key acquisitions were in the Normandville/Dixonville area of Alberta which has significant oil and gas potential. Other operators have already made discoveries in the area. A large seismic program is planned and as many as three wells may be drilled on the newly-acquired properties in 1982. Significant land purchases were also made in the Drumheller area where Suncor discovered oil in 1981.

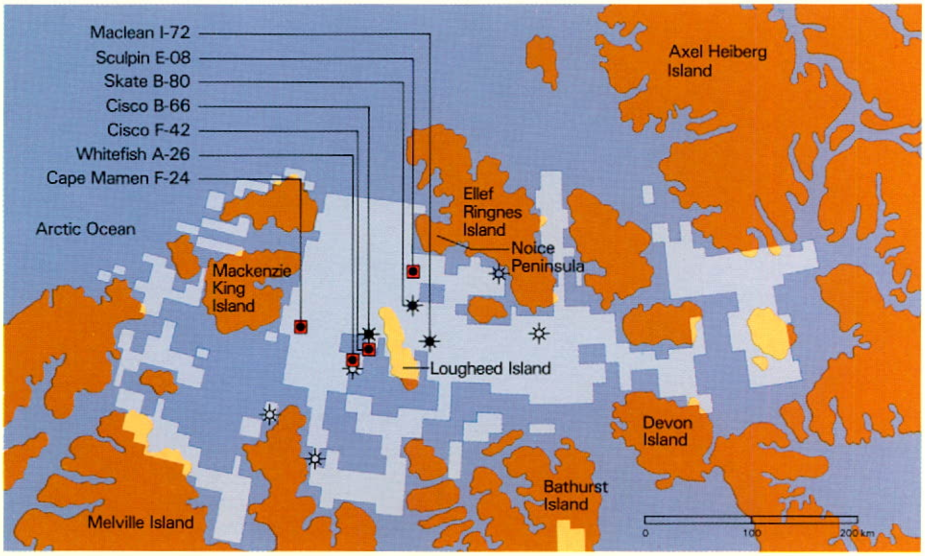
Arctic Islands drilling

The 1981 drilling season in the Arctic Islands was highly successful. Three wells were spudded in late January and all three were discoveries. Oil and gas were found at Skate B-80, 18 kilometres north-east of Lougheed Island; Cisco B-66, 16 kilometres west of the Island; and Maclean I-72, 27 kilometres east of the Island. Panarctic Oils Ltd. is the operator for a number of partners including Suncor.

Skate B-80 found natural gas in its first test of the interval from 872 to 877 metres. Mechanical problems restricted the flow rate to 23 thousand m^3 per day. A flow rate of 163 thousand m^3 per day of natural gas was tested over the interval from 876 to 909 metres with a recovery of small amounts of oil. Medium-gravity crude oil flowed to the surface at a rate of 150 m^3 per day, in a test over the interval from 898 to 903 metres. Testing of a lower 27 metre zone yielded gas at a rate of 208 thousand m^3 per day with a salt water spray. Suncor's interest in the permit on which the well was drilled is 14.8 per cent.

At Cisco B-66, the second test over the interval 2 096 to 2 100 metres flowed gas at the rate of 180 thousand m^3 per day with condensate. The third test over the interval 2 102 to 2 106 metres flowed light-gravity oil at the rate of 132 m^3 per day and gas at the rate of 247 thousand m^3 per day. The fourth test over the interval 2 104 to 2 108 metres flowed light-gravity oil at the rate of 269 m^3 per day and gas at the rate of 194 thousand m^3 per day. Over the interval 1 636 to 1 644 metres, the well flowed light-gravity oil to the surface at the rate of 233 m^3 per day and gas at the rate of nearly 31 thousand m^3 per day. Suncor's interest in the Cisco well permit is 14.8 per cent.

Arctic Islands



At Maclean I-72, gas flowed at 163 thousand m^3 per day over the interval 1 476 to 1 480 metres and at a rate of 276 thousand m^3 per day with some condensate from the interval 1 761 to 1 766 metres. Over the interval 1 768 to 1 773 metres, gas flowed at a maximum of 349 thousand m^3 per day with condensate while from the interval 1 779 to 1 783 metres, gas was measured at 11 thousand m^3 per day with a drill pipe recovery of 110 metres of light-gravity crude. The final test from the interval 1 792 to 1 796 metres produced a pipe recovery of 510 metres of light- to medium-gravity crude, small flows of gas and some salt water. Suncor's interest in the Maclean well permit is 11.6 per cent.

In total, Suncor has now participated in eight discoveries in the Arctic Islands.

More drilling and seismic remains to be done before the full potential of this area can be determined and it is too early to say if reserves will prove to be large enough to warrant the enormous cost of developing the facilities to produce and transport these hydrocarbons to southern markets. However, the results to date are very encouraging, particularly the recent oil discoveries. Nonetheless, Arctic Islands offshore discoveries are counted as dry holes in the table on page 14 because transportation facilities for their production are not yet available.

Four wells are planned for this area in 1982, two of them to explore new parts of the basin and two designed to delineate existing discoveries.

Cape Mamen F-24 is an exploratory well approximately 22 kilometres east of the southern corner of Mackenzie King Island which will be drilled to a total depth of 2 980 metres. Suncor's interest will be 8.4 per cent. Sculpin E-08 is the second exploratory well which will be drilled to a planned depth of 3 000 metres about 17 kilometres southwest of Noice Peninsula, Ellef Ringnes Island. Our interest in this well will also be 8.4 per cent.

Cisco F-42, a delineation well on the Cisco structure will be drilled to a projected total depth of 1 775 metres. It is located about nine kilometres south of the 1981 Cisco B-66 oil and gas discovery. Suncor's interest is 14.8 per cent. A third probe is also planned for the Whitefish structure with Whitefish A-26. The projected total depth is 3 000 metres. This well is located approximately eight kilometres northeast of the 1979 Whitefish H-63 gas discovery. Suncor's interest is 20 per cent.

Six ice-movement monitoring stations were positioned in the Norwegian Bay area during the 1981/1982 winter season to determine the stability of ice for future drilling. In addition, three seismic crews will operate in the Arctic Islands during the coming season. We hope to acquire about 2 500 kilometres of seismic data, largely on lands in which we have an interest.

The new Canada Oil and Gas Act allows the federal government to obtain a 25 per cent interest in all currently held permits in the Arctic Islands, which would reduce our holdings accordingly.

Offshore Labrador drilling

The 1981 drilling season in this area produced some encouraging results. The Labrador Group, in which Suncor has a 10 per cent interest, contracted three drillships for 100 days each. Drilling and testing operations were completed at two previously-drilled wells, one of which yielded a significant flow of gas and condensate while the other showed small amounts of oil. An indicated gas discovery was drilled and suspended pending further evaluation and drilling was also begun at two new wildcat wells which could not be completed before the end of the season.

Bjarni 0-82, drilled to a total depth of 2 650 metres in 1979, was re-entered in 1981. A total of 67 metres of net pay were indicated and drillstem tests were conducted over the intervals 2 314 to 2 342 metres and 2 291 to 2 296 metres. Gas flowed at a rate of 566 thousand m^3 per day with 123 m^3 per day of condensate. This well was plugged and abandoned following completion of the testing.

North Leif I-05 was drilled to a total depth of 3 513 metres. The well had been suspended at 423 metres in 1980. Drillstem testing over the interval 3 101 to 3 110 metres yielded 3.6 m^3 of oil over a four-hour period. This is the first oil recovered in the Offshore Labrador area. North Leif was subsequently plugged and abandoned.

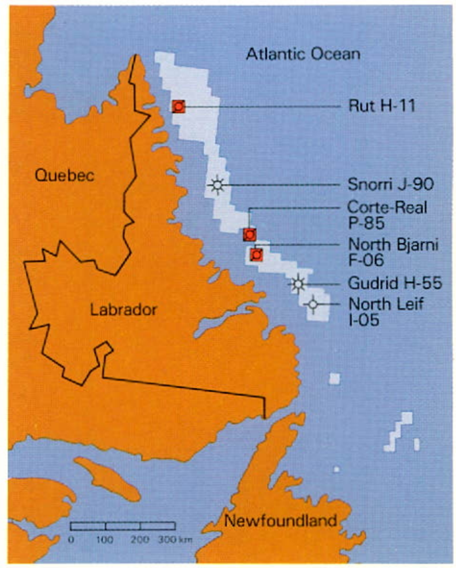
North Bjarni F-06, drilled to a depth of 423 metres in 1980 and suspended, was re-entered in 1981 and drilled to a total depth of 2 812 metres, yielding an indicated 177 metres of net pay. The Group expects to re-enter and fully evaluate this well in 1982.

Two new wildcat wells were also spudded during 1981. Rut H-11 was suspended at a total depth of 3 527 metres and will be drilled to its projected total depth of 5 262 metres in 1982. Corte-Real P-85 was drilled to a depth of 770 metres and suspended; it will be re-entered in 1982 and taken to its projected depth of 5 312 metres. One other exploratory well will likely be spudded in 1982. Three drillships are expected to be employed for the coming season.

In addition to its drilling program, the Labrador Group conducted a 3 200 kilometre seismic program and continued with its environmental studies in 1981.

Offshore Labrador

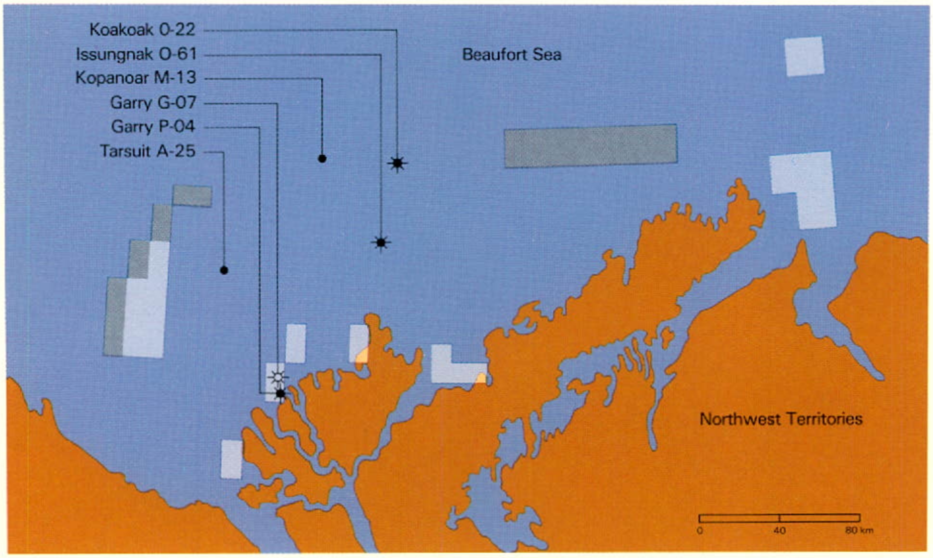
Gas potential
Suspended (1982 Re-entry)
Dry well
Suncor land holdings



Beaufort Sea/Mackenzie Delta

• Oil potential
✱ Oil and gas potential
☼ Gas potential
■ Farmout Agreement

Suncor land holdings
0.6 million gross hectares
0.2 million net hectares



Beaufort Sea/Mackenzie Delta

Suncor has 567 thousand gross hectares in this area of which about 245 gross hectares are located in the Beaufort Sea on either side of Dome Petroleum's oil discoveries at Kopanoar and Koakoak. Several blocks of this Beaufort acreage were farmed out to Dome in 1980 under an agreement requiring Dome to perform extensive seismic work on the properties in return for options to drill five wells. The seismic work has been completed and is now being interpreted. Several potentially drillable structures are indicated.

Under the agreement, two of Dome's drilling options are to be exercised by December 31, 1982 and at least one well is to commence during 1983. If Dome proceeds, it will earn an interest in proportion to its financial participation in the wells actually drilled.

No drilling is planned by Suncor in the Mackenzie Delta in 1982. We have an interest in 109 thousand gross hectares in this area containing one gas discovery and one oil and gas discovery made over the past decade. Further drilling depends upon development of a transportation system to convey the gas to market and on negotiations with the federal government concerning the work required to maintain holdings under the new Canada Oil and Gas Act.

Production Division

Our production development program brought several new gas fields on stream in 1981, contributing to a significant increase in sales over 1980. However, conventional crude oil production fell sharply. Proven reserves of conventional crude oil declined, while natural gas reserves remained the same as the year before.

Highlights

- Gross conventional crude oil production drops 11 per cent, in line with industry performance
- Gross natural gas sales rise nine per cent compared to an industry decline of three per cent
- Capital expenditures for development drilling fall 34 per cent to $8.5 million

Drilling

A total of 48 gross development wells were drilled in 1981, yielding 17 oil wells, 20 gas wells and 11 dry wells for a success ratio of 77 per cent. One well was in progress at year-end.

Spending on development drilling, well equipment and related items declined 33 per cent to $20.4 million in 1981. Fewer new projects were considered to be economic under the NEP and Suncor's expenditures were reduced wherever possible, reflecting a dramatic decline in our cash flow from operations.

Production

Gross daily conventional production of crude oil and natural gas liquids averaged 2.3 thousand m^3 in 1981 (14.4 thousand barrels), down about 11 per cent from 1980. The total includes both conventional and in-situ heavy oil production but excludes synthetic crude oil from the oil sands.

There were four main reasons for the decline. Alberta's production cutbacks were an important factor, although they ended on September 1, 1981 when a new price agreement was signed with the federal government. Secondly, industry production has been falling for more than a decade due to the maturing of reservoirs. Lower production of higher-quality Alberta crude meant reduced demand for Saskatchewan production which is normally blended with Alberta volumes, and Saskatchewan production therefore fell. In addition, production from Saskatchewan was adversely affected by low netbacks to producers, legislated by the provincial government, which made some fields uneconomic. Saskatchewan's production was returning to higher levels by year-end following the signing of a new price agreement with the federal government.

Gross daily natural gas sales were 1.9 million m^3 (67 million cubic feet), up about nine per cent from 1980. This increase, virtually all from Alberta, was due to new fields coming into production. Calling Lake South began producing in February, 1981, the Monitor field came on stream in March, and Malmo/New Norway production commenced in August while the Stolberg field produced for the full 12 months of 1981 compared to six months in 1980. These additions helped to offset reduced sales from fields already on stream; purchasers took less than contract minimums due to oversupply problems including weakness in the U.S. export market as well as sluggish domestic demand.

Overall, 70 per cent of our gross crude oil production, including natural gas liquids and heavy oils, came from Alberta in 1981 as did 92 per cent of gross natural gas sales.

In the Blueberry area of northeast British Columbia, Suncor has a working interest of 35 per cent in 34 736 hectares on which there are 15 oil wells and five producing gas wells. Substantial upgrading of the field's facilities was undertaken in late 1980 and early 1981 in order to increase field production. During 1981 Suncor reached an agreement with the B.C. Government by which lands currently leased would be retained by undertaking a multi-year drilling program. Two new indicated gas wells were drilled in late 1981 and at least four more wells are planned for 1982 which we believe will confirm additional reserves and production capability in the field.

Spending on gas gathering and processing systems to facilitate production totalled $4.2 million in 1981, down 50 per cent from the previous year. Most of the funds required to bring new fields into production in 1981 were actually spent in 1980. Almost all reserves that have sales contracts are now on stream. Further expenditures on new gas plants will be deferred until natural gas markets justify them.

Our 1981 spending for undeveloped production properties at Crown land sales fell 93 per cent from the previous year to $500 thousand, once again reflecting the impact of the NEP on producer netbacks and on reduced cash flow.

Reserves

Gross proven reserves of conventional crude oil and natural gas liquids declined by six per cent to 9.7 million m^3 (61 million barrels) in 1981. Additions to gross reserves during the year amounted to 217 thousand m^3 (1.4 million barrels). The most important additions were in the Medicine River area where enhanced recovery techniques augmented reserves and in the Drumheller area where Suncor recorded an oil discovery in 1981.

Gross proven reserves of natural gas were 13.3 billion m^3 (473 billion cubic feet), at the end of 1981, about the same as in 1980. Additions to gross reserves totalled 735 million m^3 (26 billion cubic feet). The largest additions resulted from development work in the Pine and Blueberry fields. The Pine property is located

Gross production of conventional crude oil and natural gas liquids

(thousands of cubic metres)	1981	1980
Alberta		
Bonnie Glen	**106**	96
Medicine River	**87**	89
Swan Hills	**64**	81
Fort Kent	**33**	31
Pembina	**32**	32
Mitsue	**25**	30
Other	**236**	250
	583	609
Saskatchewan		
Steelman	**41**	73
Oungre	**32**	47
Other	**104**	135
	177	255
British Columbia		
Boundary Lake	**22**	25
Other	**29**	27
	51	52
Manitoba	**22**	24
Total	**833**	940

Gross natural gas sales

(millions of cubic metres)	1981	1980
Alberta		
Calling Lake	**92**	35
Portage	**85**	90
Rosevear	**73**	105
Stolberg	**35**	20
Countess	**28**	25
Ghost Pine	**25**	25
Other	**296**	266
	634	566
British Columbia		
Inga	**13**	19
Other	**30**	36
	43	55
Saskatchewan	**9**	7
Total	**686**	628

Chuck Jang of our Production Division helped start up this new natural gas processing plant near Joffre, Alberta–one of two new gas plants we participated in during 1981.

240 kilometres northwest of Edmonton and the Blueberry field is about 80 kilometres northwest of Fort St. John in British Columbia.

All of Suncor's proven reserves are located in western Canada: approximately 63 per cent of gross conventional crude oil and natural gas liquids reserves are in Alberta, as are 79 per cent of gross natural gas reserves. Reserves in the frontier areas have not been included as there has been insufficient drilling to determine if they are of commercial size and their recovery depends upon approval and construction of adequate transportation systems to carry them to market.

In the accompanying table, reserves as of December 31, 1981 are based on prices and costs on that date without adjustment for the price and tax changes which became effective on January 1, 1982. Reserves as of January 1, 1982 are based on prices and costs in effect on that date. The increase over December 31, 1981 represents additional reserves at Fort Kent which became economic due to the implementation of the new oil reference price (subject to reductions for quality for this type of oil).

Reserves

	Gross conventional crude oil and natural gas liquids	Gross natural gas	Net conventional crude oil and natural gas liquids	Net natural gas
	(millions of cubic metres)	(billions of cubic metres)	(millions of cubic metres)	(billions of cubic metres)
Proven				
December 31, 1980	**10.3**	**13.3**	**7.3**	**10.1**
Additions	**0.2**	**0.7**	**0.2**	**0.6**
Production/sales	**(0.8)**	**(0.7)**	**(0.6)**	**(0.5)**
December 31, 1981	**9.7**	**13.3**	**6.9**	**10.2**
January 1, 1982	**10.1**	**13.3**	**7.3**	**10.2**
Probable additional				
December 31, 1981	**0.7**	**6.9**	**0.6**	**5.0**
January 1, 1982	**1.2**	**6.9**	**1.0**	**5.0**

The above reserve estimates have been prepared by independent petroleum consultants, Kloepfer Coles Nikiforuk Pennell Associates Ltd. ("Kloepfer").

Proven reserves are those which geological and engineering data demonstrate to be recoverable with a high degree of certainty, at commercial rates, from known oil and gas reservoirs under existing economic and operating conditions. Probable additional reserves are those which may be recovered from properties in the vicinity of proven reserves where there is some degree of geological, engineering or operational risk.

Royalty interests of governments and others are deducted from gross reserves to arrive at the net figure. Royalties can vary depending upon prices, production volumes, timing of initial production and changes in legislation. Net reserves displayed in the accompanying table are based on royalty rates in effect in late 1981.

Kloepfer has determined the present value of estimated future net revenues from reserves as of December 31, 1981, using a discount factor of 10 per cent, to be $568 million. These estimates have been calculated using constant prices and costs and represent gross revenues from the estimated future production, less royalties, petroleum and gas revenue tax and other taxes, operating costs and capital expenditures incurred in developing and producing the reserves. There has been no deduction for interest costs, or for income taxes or administrative costs. The provisions for higher prices for conventional and heavy oil, the increased petroleum and gas revenue tax and the new incremental oil revenue tax arising from the federal/provincial energy agreements that came into effect on January 1, 1982 have also not been reflected in this calculation. Hence, estimated future net revenues do not represent future net earnings or the present market value of the reserves. These estimates are particularly sensitive to government actions with respect to selling prices, royalties and similar levies, and production levels. For example, the effects of the federal/provincial energy agreements arising on January 1, 1982 decrease the estimated present value of future net revenues by 10% under the December 31, 1981 calculation.

Resources Development Division

This Division has the task of searching out and developing energy resources new to Suncor. The current emphasis is on in-situ production of heavy oil from Alberta's oil sands and establishing Suncor in the coal business.

In-situ projects involve separation of oil from the sand within the ore body itself rather than mining the sand and then extracting the oil.

Highlights

- Fort Kent expansion full speed ahead
- Coal leases show promise

In-situ oil sands development

The most important step in 1981 was the plan to proceed with expansion of our Fort Kent project. The expansion is described on page four.

At the Fort Kent project, we force steam and water underground to reduce the viscosity of heavy oil trapped in the sand, enabling it to flow. The oil is then pumped to the surface. This technology is used to tap oil-bearing sands buried too deep for application of the mining technology developed at our Fort McMurray oil sands plant.

A similar method will be used experimentally on our wholly-owned 20 232 hectare lease 27 (Cheecham), south of Fort McMurray. This is one of three Suncor leases considered suitable for in-situ recovery. Cash flow constraints have forced us to defer much of the work on this project. This year, we will drill a number of wells and undertake further laboratory research. Next year, we intend to drill out a pattern consisting of 10 wells and construct steam generating facilities. Steam injection could begin in late 1983.

In addition, nine holes were drilled in 1981 to evaluate our leases 84 and 85, north of Fort McMurray, to quantify the bitumen in place. Further work is expected on these properties in 1983.

Coal

Another 16 evaluation holes were drilled on our Chip Lake, Alberta property in 1981 bringing to 29 the total drilled to date. This property, about 100 kilometres west of Edmonton, consists of two coal leases totalling 6 799 hectares. On the basis of our drilling, an independent consultant has estimated total coal resources at 222 million metric tonnes. These resources are considered suitable for efficient, highly-mechanized underground mining.

Marketing efforts for Chip Lake were initiated in Japan during 1981. However, we concluded that we are unlikely to penetrate this market until late in the decade when Japan's utilities could be restructured to use coal with lower thermal values comparable to the coal on our property. Chip Lake has excellent access to rail, highway, water and power.

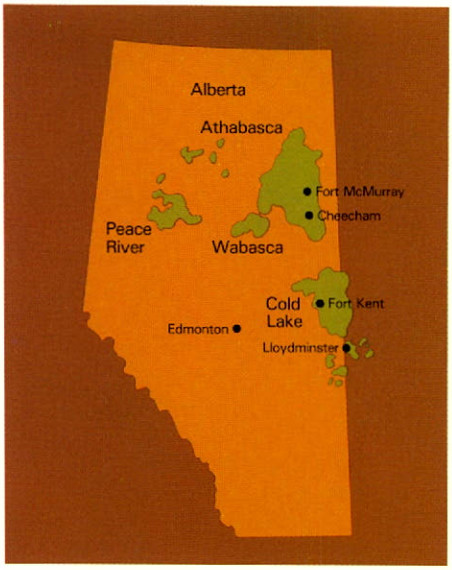
Also during 1981, Suncor entered into an agreement with Brinco Mining Ltd. for joint exploration and possible development of Brinco's 3 796 hectare lease in Pictou County, Nova Scotia, 240 kilometres northeast of Halifax. The lease is thought to have one seam of metallurgical coal (suitable for steel production) and just below it, another seam of thermal coal (suitable for electric power generation). Markets for both forms of coal are close by. One evaluation hole was completed on this property by year-end, encountering coal as expected. A further two holes were in progress. If sufficient reserves are established, the next step will be to develop a mine plan.

Two other coal properties were acquired in British Columbia during the year: Chisholm consists of 9 716 hectares 200 kilometres from Prince George while Sustut is comprised of 9 207 hectares 320 kilometres from Prince George. Both are in the very early stages of exploration.

Oil sands and heavy oil deposits

Oil sands and heavy oil deposits
Suncor developed and undeveloped land holdings (thousands of gross hectares)

Athabasca 68.9	Fort Kent 2.0
Cold Lake 1.7	Lloydminster 4.7



Other minerals

Our move into uranium and other minerals continued in 1981 on a modest scale. Total lease holdings were increased substantially. We are currently evaluating two mineral prospects in British Columbia, one involving copper and molybdenum and the other involving precious metal. Suncor is also participating in several uranium prospects in Manitoba, Saskatchewan and the Northwest Territories. These mineral prospects are all in the early stages of exploration.

Oil Sands Division

Suncor's Oil Sands Division operates the world's first plant to produce synthetic crude from bituminous sands on a commercial scale. The plant is located near Fort McMurray, Alberta, in the Athabasca oil sands region.

A four-step method is used to produce synthetic oil. First, overburden is removed to expose the oil-bearing sands. Second, the sand is mined and transported by conveyors to the extraction unit. Third, bitumen goes to the process area where it is thermally cracked into coke and distillates. The distillates are desulphurized and blended to form high-quality synthetic crude oil, most of which is shipped to Edmonton for distribution.

Highlights

- Production down 37 per cent from 1980
- Maintenance shutdown takes longer than expected
- Plant expansion completed on schedule and under budget
- Sale of oil sands technology

Production

Production of synthetic crude averaged 4.7 thousand m^3 per day (29.3 thousand barrels) in 1981. This includes unprocessed synthetic crude produced when the unifiners in the process area of the plant were not operating. Output was adversely affected by our biennial maintenance shutdown and by operating problems in the third and fourth quarters which combined to reduce synthetic crude production by 37 per cent from 1980.

The maintenance shutdown began on May 10 and was scheduled to end June 23. Over 90 per cent of the work, including repairs and tie-ins of expansion equipment, was completed as expected. However, major problems occurred in the process area. A large amount of work had to be done in locations difficult to access and this caused delays. In addition, some of the expansion tie-ins required major reworking because prefabricated components did not fit properly. The shutdown lasted 10 days longer than planned and total costs were about $31 million, $9 million more than expected.

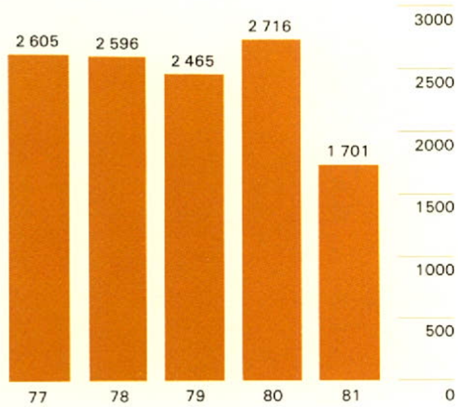
On the positive side, many aspects of the project were better handled than in previous years. Over 3,000 people were involved in safety, familiarization and job-training programs, resulting in an excellent safety record. A number of potential equipment failures were identified by rigorous inspection and corrected. Data now being analyzed will determine if the period between shutdowns can be extended. We will also examine the possibility of a series of partial stoppages to minimize difficulties arising from the high volume of work required during a major shutdown.

A series of problems, primarily in the process area, resulted in further shutdowns starting on July 4 when the hydrogen unit failed as the plant was returning to full production following the maintenance shutdown. Subsequent breakdowns affected the power generators, the sulphur plant and the unifiners. Unprocessed crude was shipped to a U.S. customer at various periods during the third and fourth quarters under a special federal export permit while repairs were made. The production revenues lost as a result of these operating problems have been partially offset by amounts recoverable from our insurance program.

Overburden removal reached 10.4 million m^3, six per cent above our volume target, at a per unit cost 18 per cent less than expected. Good weather, effective planning and equipment maintenance contributed to this performance.

Gross production of synthetic crude oil

(thousands of cubic metres)



Synthetic crude oil gross proven reserves

(millions of cubic metres)	
December 31, 1980	56.0
Revisions	(0.3)
Production	(1.7)
December 31, 1981	**54.0**

The above year-end reserve estimates have been prepared by independent petroleum consultants, Kloepfer Coles Nikiforuk Pennell Associates Ltd.

Proven reserves are those which are considered to a high degree of certainty to be mineable at commercial rates using current and planned future mining methods. All of these reserves are adjacent to the Fort McMurray oil sands plant.

Gross proven reserves do not reflect deductions in respect of Crown and applicable sublease royalties. Since the Crown royalty rate is dependent on the rate of synthetic crude oil production, calculations of net reserves would vary depending upon assumed production rates.

Bill Jahelka, a belt walker, checks conveyors at a transfer point where oil-bearing sand changes direction on the way to the extraction plant.

Expansion completed

Our $185 million expansion of the oil sands plant was completed in 1981 on schedule and slightly under budget. A fifth extraction line was commissioned for operation in January, a fourth coker started up in the process area in March and a new bucketwheel was added to the mining operation in November. The expansion should enable production of additional volumes in the order of 2 000 m^3 per day (13,000 barrels), an increase of about 25 per cent over the pre-expansion total.

Improving operations

We continue to search for ways to improve equipment and operating procedures. Our main objective is to find additional ways to avoid major interruptions in production. Steps taken in 1981 included:

- A program to strengthen the utilities management team with new people was undertaken and this program will be completed in 1982.
- In all areas, training and orientation programs are being stepped up and increased emphasis is being placed on hiring experienced operators.
- Maintenance programs on production equipment are being tightened, including recruitment of key personnel to ensure implementation.
- Control-room facilities in the process area are undergoing a major reworking which should be completed by the end of the first quarter of 1982.

A secondary bitumen extraction recovery system was installed during the year. It uses a froth flotation method to extract residual bitumen which would otherwise end up in the tailings ponds. Other improvements undertaken during the year included a major rebuilding of the number one sulphur plant to improve its performance; better instrumentation in the extraction area and improvements in office facilities.

Sale of technology

Suncor reached agreement with the Alsands consortium for sale of key parts of our oil sands technology. The agreement includes assistance from Suncor personnel, detailed operating data and the use of processes developed at our plant. An initial payment of $2 million was received in 1981 and the agreement calls for a further $11 million if the Alsands project goes ahead.

Prospects for 1982

As the year began, the plant was not operating at full capacity and on January 20 a fire in the compressor building completely disrupted operation of the unifiners. Since the fire, the plant has been producing about 40,000 barrels per day of unprocessed synthetic crude, approximately 70 per cent of planned production. Some of this output has been exported under an interim permit subject to renewal by the National Energy Board and some has been shipped to Syncrude for final upgrading. Suncor's production of fully processed synthetic crude oil is expected to resume by July, 1982 and we anticipate a substantial increase in output compared to 1981.

The cost of reconstructing the compressor building and restoring or replacing compressors and related equipment has been estimated at $21 million.

A fourth reactor was constructed at the Sarnia refinery in 1981 enabling increased production of unleaded gasolines and petrochemical feedstocks.

Overview

Revenues increased 38 per cent to $1.1 billion for the Sunoco Group in 1981, primarily the result of passing through higher government levies and crude oil costs. Operating margins were down somewhat and the Group's contribution to Suncor's earnings declined $8.7 million from 1980.

Capital expenditures by the Sunoco Group in 1981 totalled $42 million, up from $29 million in 1980. The main expenditure was for the addition of a fourth reactor to our refinery's number two reformer. It is now operating smoothly, enhancing our production of gasolines and petrochemical feedstocks.

The key strategic question facing the Sunoco Group–and all refiners–is how to deal best with changing markets. Industry-wide sales of gasoline, home heating oil and heavy fuel oil declined in 1981 and we expect this trend to continue.

Heavy fuel oil is the single largest problem. Suncor has a contract with a U.S. purchaser and an accompanying export permit covering much of our production of heavy fuel oil. However, the remainder had to be sold into a depressed domestic market again in 1981 and losses were incurred. The refinery upgrading project now under consideration is one possible solution (see page six).

Another response to declining demand is superior marketing. Our strategy is to be more responsive to consumer needs and this strategy is working. In 1981, we once again increased our share of gasoline and home heating oil markets in Ontario and Quebec.

A new and disturbing issue surfaced during the year. The federal government released its seven-volume report entitled "The State of Competition in the Canadian Petroleum Industry," prepared by the Director of Investigation and Research under the Combines Investigation Act. The report alleged that Canadian consumers had been overcharged by oil companies who had conspired to lessen competition. These concerns were considered seven years ago by an Ontario Royal Commission which concluded that industry practices were competitive and that the consumer was being well served. However, the federal government referred its report to the Restrictive Trade Practices Commission for public hearings.

Suncor submitted an opening brief to the Commission which clearly and forcefully refuted allegations of wrongdoing. This brief demonstrated that competition had been intense during the period covered by the original study and that Suncor had pursued a unique marketing stance designed to increase its sales volumes. Our brief also showed that independent gasoline retailers had tripled their market share in Ontario since 1960 and that Suncor had kept to its agreements to supply its independent customers with their product requirements.

Outlook

We expect that industry sales of gasoline will continue to decline in Ontario and Quebec in 1982. Petrochemical demand will be somewhat softer in the early part of the year due to the economic recession, with an upturn expected in the second half. Home heating oil sales will decline substantially again in 1982 and the heavy fuel oil market also will remain depressed.

There should be sufficient domestic crude oil to meet all our Ontario requirements and about one-third of our Quebec needs in 1982. Foreign supply should be available in ample quantities to satisfy the balance of our Quebec demand.

Operations

Refining

The average daily throughput of crude oil at our Sarnia refinery was 12.1 thousand m^3 (75.9 thousand barrels) in 1981. This volume was 84 per cent of rated capacity compared to the 86 per cent level of the previous year.

Alberta's phased cutback of light crude oil production caused a significant realignment of our crude supply in 1981. Alberta reduced its total output by 9 535 m^3 per day (60,000) barrels on March 1st and by an equal amount again on June 1st. As a result, we had to import substantially more foreign crude oil to meet our Quebec refining requirements. Imports reached an average of about 1 800 m^3 per day (11,300 barrels) compared to 1 100 m^3 (6,900 barrels) in 1980. The additional costs incurred because of the higher price of imported oil were covered by the federal government's import compensation program.

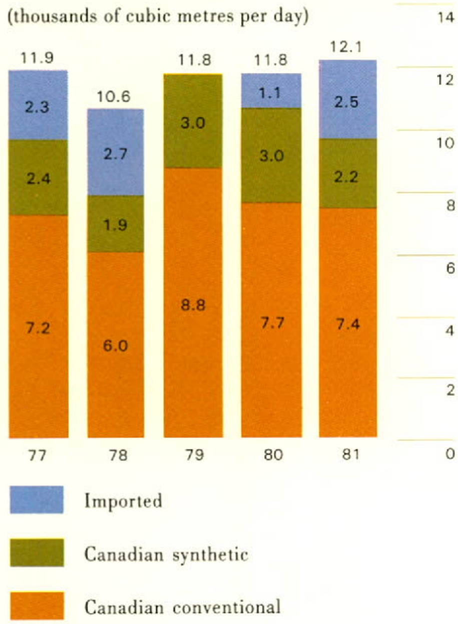
Our crude oil supplies for the Ontario market were also affected. Alberta cutbacks of high quality crude meant that the sulphur content in our refined products would have been too high to meet specifications if we had processed only available domestic crude supplies. Consequently, we imported 85.7 thousand m^3 (539 thousand barrels) of low sulphur Algerian crude for our Sarnia refinery which enabled us to maintain our refined product specifications. Foreign supplies were readily available at reasonable prices and the higher costs were mostly offset by federal import compensation.

Alberta's cutbacks were rescinded following the signing of the energy pricing agreement with the federal government on September 1, 1981 and high grade domestic crude was once again available in sufficient volumes to meet all of our Ontario requirements.

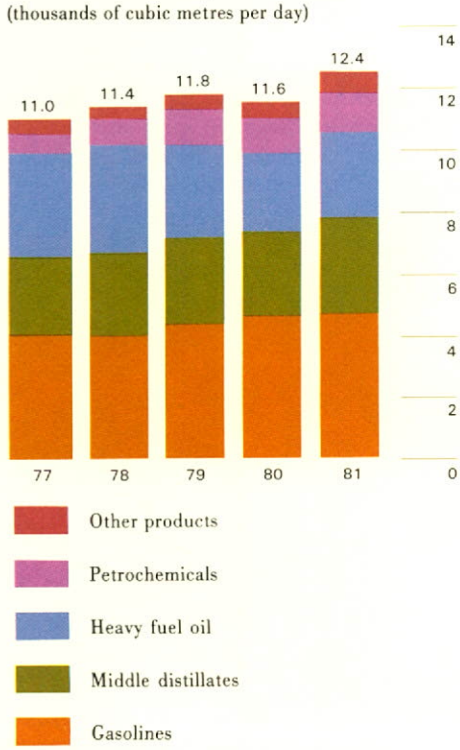
A major three-week, $3 million maintenance shutdown was successfully completed in October. The shutdown affected plant number two, one of the refinery's two main plants, as well as the BTX unit which produces petrochemicals. (BTX is short for benzene, toluene and xylene.) In addition to extensive maintenance work, the shutdown permitted completion of a $12 million expansion of the Powerformer unit. Included in this project were the installation of a fourth reactor and a new furnace to preheat feedstock, a larger electric motor for the compressor and larger heat exchangers. The result is greater production of unleaded gasolines and petrochemical feedstocks.

The only other major shutdown was for six days in May when plant number two was damaged by a power failure.

Sources of crude oil refined for Suncor account
(thousands of cubic metres per day)



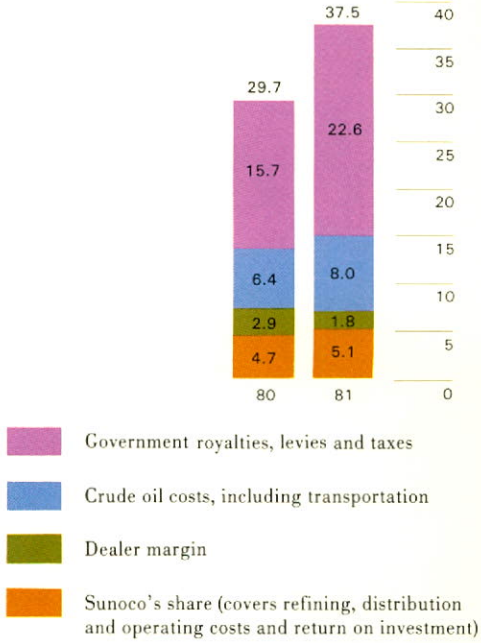
Sales of refined products
(thousands of cubic metres per day)



For details of refined products sales see page 45.

▼ Suncor's M.V. Chippewa at its moorings in Sarnia taking on a load of Sunchem products.

Components of gasoline pump price
(cents per litre*)



*Typical Sunoco gallon of regular leaded gasoline sold at full-service branded outlets in Toronto as at year-end.

Petrochemicals

Petrochemicals are produced and sold under the Sunchem name for use in the manufacturing of plastics, solvents, nylon, dynamite, pesticides, polyesters and paints. Production increased 10 per cent and sales rose 32 per cent in 1981 despite a maintenance shutdown affecting the main production unit. Output was in excess of rated capacity. Increased production was achieved by debottlenecking and optimizing operating procedures at the BTX unit.

Demand was somewhat sluggish, particularly later in the year as the recession deepened in North America and Europe. Prices reflected this trend but remained, on average, considerably above 1980 levels.

Exports were assisted during 1981 by the M.V. Suncor Chippewa, our new petrochemical tanker, which was delivered in April.

Gasoline marketing

Sunoco supplies gasolines to the Ontario and Quebec markets. Overall, demand declined by about five per cent for these markets in 1981. Consumers responded to sharply higher prices by conserving fuel. However, Sunoco's retail volumes increased from the previous year and revenues climbed 40 per cent, due largely to the pass-through of higher government levies and the impact of increased crude costs (see accompanying chart).

Blender Centres continued to boost sales at Sunoco service stations. Blender Centres enable motorists to choose between three blends each of leaded and unleaded gasoline–the widest choice available in Ontario and Quebec. Our highly effective Half and Half Unleaded advertising campaign, launched early in 1981, was reintroduced in the third quarter. It was followed by a successful promotion of our Premium Leaded Blend. These campaigns helped to increase awareness of the benefits of our Blender Centres.

At year-end, there were 870 service stations in the Sunoco Group system, down 50 from the year before. A number of small unproductive locations were dropped. About $6 million was spent on

Sunoco's responsiveness to motoring needs continues. A growing number of stations now sell diesel fuel to meet rising demand, and six car wash facilities are testing a new underbody rust-inhibiting process.

new outlets and improvements involving 35 locations. Upgrading of our stations will continue in 1982.

We continue to look for other ways to respond to consumer needs. For example, the number of locations offering diesel fuel doubled during 1981 to meet growing demand. One of the problems faced by diesel car owners was the availability of a suitable high-quality lubricant. We therefore introduced DIESELUBE, a new oil for diesel passenger cars and light trucks, available in two different grades. This product was well received. We also expect further development of fast oil change and car wash facilities.

Home heating oil marketing

Refiners are faced with adverse market conditions for home heating oil over the next several years. The conservation ethic, government off-oil programs and pricing that favors natural gas and electricity are just some of the negative factors curtailing demand.

In 1981, the home heating oil demand in Ontario and Quebec fell by about 10 per cent. Nonetheless, our volume increased three per cent, reflecting higher sales to our independent distributors and revenues rose 40 per cent.

Lubricants and specialty products

Our sales volumes declined 19 per cent in 1981. Sales were affected by the recession which has especially hit the automotive industry and related rubber, plastic and metalworking industries–all major customers for our lubricants.

Revenues increased nearly seven per cent due to the pass-through of higher costs for petroleum feedstock while average operating margins were about the same as in 1980. Diversification of our products and greater sales emphasis in the West helped to counterbalance the impact of the economic recession on our eastern Canadian customer base. A total of 23 new products were developed in 1981 including drawing compounds, metalworking, hydraulic, process and automotive engine oils.

Three new distributors were established in Atlantic Canada in 1981 and one in Alberta. Our CAM2 and SUNFLEET brands of automotive engine oil are now being distributed from coast to coast.

Suncor's Sarnia refinery manufactures a broad range of transportation fuels and petrochemicals.

Financial Statements

Management's Statement on Financial Reporting

The financial statements on pages 31 to 42, which consolidate the financial results of Suncor and its subsidiaries have been prepared in accordance with accounting principles generally accepted in Canada, consistently applied. The objectivity and integrity of data in these financial statements, including estimates and judgments relating to matters not concluded by year-end, are the responsibility of management as is all other information included in the annual report unless otherwise indicated.

In management's opinion the financial statements have been properly prepared within reasonable limits of materiality and within the framework of the accounting policies summarized on pages 31 and 32. In meeting its responsibilities for the reliability of the financial statements, management maintains a system of internal accounting controls and administers a program of proper business conduct compliance. Management also supports a program of internal audit.

Coopers & Lybrand, the Company's independent chartered accountants, have been engaged to render an independent professional opinion on the accompanying financial statements. In order to complete their report, which is shown below, they develop and maintain an understanding of the Company's systems and procedures and conduct an examination in accordance with generally accepted auditing standards.

The Audit Committee, a committee of the Board of Directors, is composed primarily of independent outside directors. It meets regularly with management, the internal auditors and the independent auditors to assure that they are all carrying out their responsibilities and to discuss auditing, internal control, accounting policy and financial reporting matters. The internal auditors and the independent auditors periodically meet alone with the Audit Committee and have unrestricted access to the Audit Committee and Board of Directors at any time. The financial statements were reviewed by the Audit Committee and were approved by the Board of Directors.

Auditors' Report

To the shareholders of Suncor Inc.

We have examined the consolidated statement of financial position of Suncor Inc. as at December 31, 1981 and the consolidated statements of earnings, retained earnings and changes in financial position for the year then ended. Our examination was made in accordance with generally accepted auditing standards, and accordingly included such tests and other procedures as we considered necessary in the circumstances.

In our opinion, these consolidated 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.

Coopers & Lybrand

Coopers & Lybrand
Chartered Accountants
Toronto, Ontario
January 27, 1982

Summary of Accounting Policies

December 31, 1981

Basis of presentation

(a) Principles of consolidation
The financial statements are prepared on a consolidated basis to include the accounts of all subsidiaries.

(b) Intersegment transfers
Transfers of crude oil, natural gas and refined products between segments are recorded at prevailing fair market prices in the Schedule of Segmented Data. Profit on such transfers is deferred on consolidation until realized by third party sales.

(c) Crude oil revenues
The Company is a net purchaser of crude oil and hence deems its own production, including synthetic crude oil production, to be consumed internally, with the exception of sales to the Alberta Petroleum Marketing Commission (APMC) as noted below. Consequently, on consolidation, revenues arising from the sale of crude oil at conventional crude oil prices are eliminated from "sales and other operating revenues" and "costs and operating expenses." As a result synthetic crude oil receipts in excess of conventional crude oil prices are deemed to be realized and included in "sales and other operating revenues."

Effective April 1, 1980, sales of conventional crude oil to the APMC have been included in "sales and other operating revenues" because the Company is no longer permitted to designate the ultimate purchaser of its crude oil.

(d) Oil import compensation
The Company periodically imports crude oil to meet a portion of its refining needs. The amounts received or claimed under the federal compensation program for oil imports are deducted from "costs and operating expenses."

(e) Joint ventures
A significant part of the Company's oil and gas activities is conducted jointly with others. The accounts reflect the Company's proportionate interest in these activities.

Policies of application to specific segments

The descriptions of the Company's classes of business or segments are detailed below together with their respective accounting policies.

(a) Exploration, production and resources development
This segment encompasses exploration for crude oil and natural gas in the western provinces and frontier areas and the production of oil and gas in the western provinces. In addition, it includes the operation of a natural gas pipeline, in-situ steam recovery projects, and limited activities in coal and uranium.

– Capitalization and write-off
The full cost method of accounting for crude oil and natural gas activities is followed. All costs incurred in searching for oil and gas reserves, including leasehold acquisition and retention costs, are capitalized. Proceeds received from disposals of properties are deducted from these costs. Capitalized costs are charged against operations through a provision for depletion, calculated on a unit of production basis using estimates of proven reserves.

Wellhead equipment, gas plants and handling facilities are also written off primarily over the life of proven reserves. Support and movable equipment is depreciated on a straight line basis over an average of ten years.

– Natural gas take or pay contracts
Payments received or made under natural gas "take or pay" contracts without delivery of the related gas are deferred, and shown as "deferred revenues and other" and "deferred charges and other," respectively. The amounts will be taken into revenues or expenses when the related gas is delivered. Under current conditions substantially all of the gas due under such contracts is not expected to be delivered within the next year.

(b) Oil sands
This segment encompasses production of synthetic crude oil from oil sands mined in the Athabasca region of northeastern Alberta.

– Capitalization and depreciation
Major mine development expenditures that significantly benefit operations of future years and all outlays on mobile equipment acquisitions, are capitalized. Other mine development expenditures and outlays for mining equipment are expensed.

Plant expenditures are expensed except those resulting in major additions and improvements to plant capacity, productivity or environmental protection, which are capitalized. The cost of housing is capitalized.

Mine and plant expenditures which were capitalized prior to January 1, 1976 are depreciated over the life of proven reserves. Mine and plant expenditures capitalized after January 1, 1976 are depreciated over the lesser of their useful lives or the life of proven reserves. Depreciation over useful lives is on a time or usage basis depending upon the nature of the asset. Depreciation over life of proven reserves is on a unit of production basis.

As a result of the above policy, most of the capitalized plant expenditures, and a significant portion of the capitalized mobile equipment expenditures–the bucketwheel excavators–are depreciated over the life of proven reserves. Other mobile equipment and mine development expenditures are depreciated on average over three years. Rental housing is depreciated on average over 30 years.

– Other deferred charges
Overburden removal costs, including depreciation on overburden removal equipment, are deferred. Annual amortization of these costs is based on the amount of oil sands mined in the year, the ratio of total overburden to be removed to total reserves of oil sands to

be mined, and the year's removal cost per unit of overburden.

Deferred preproduction costs are amortized over the life of proven reserves on a unit of production basis.

– Reclamation costs
Reclamation costs over the entire term of the project are estimated and charged against earnings over the life of proven reserves on the unit of production basis.

(c) Refining, petrochemicals and marketing
This segment encompasses the manufacture, transportation and marketing of petroleum and petrochemical products, primarily in Ontario and Quebec. Petrochemical products are also sold in the United States and Europe.

– Depreciation
Depreciation of properties, plant and equipment is on a straight line basis. The refinery and additions thereto are depreciated over an average of 23 years, the petrochemical tanker over 20 years, service stations and related equipment over an average of 15 years, and other facilities and equipment over four to 20 years.

Policies of general application

(a) Maintenance, repairs and shutdown expenses
Normal maintenance and repairs are charged to expense as incurred. The cost of major maintenance shutdowns is estimated and accrued over the period to the next shutdown.

(b) Disposals
Costs of assets sold, retired or abandoned and the related amounts of accumulated depreciation are eliminated from the accounts, and resultant gains or losses on disposals are included in earnings except for oil and gas assets accounted for under the full cost method.

(c) Pension expense
The Company has a non-contributory pension plan providing retirement benefits for its eligible employees. Pension expense includes the current pension costs, the amortization of initial past service costs over 25 years, and the amortization of plan improvements over 15 years. It is the Company's policy to fund the total pension expense and such additional amounts as deemed appropriate.

(d) Research and development expenditures
Research expenditures are written off as incurred except for capital outlays, which to date have been for in-situ oil sands and heavy oil pilot projects. Such costs are written off over the lesser of useful life or the remaining life of the project. Development expenditures are also expensed as incurred except when future benefits from the project become reasonably assured.

(e) Income taxes
Some costs and revenues may by law be deducted from or added to earnings in the calculation of taxable income in years earlier or later than actually recorded in the Consolidated Statement of Earnings. The income taxes in the earnings statement are based upon the revenues and expenses actually recorded, but differ from taxes actually paid or payable. These differences are shown in the Consolidated Statement of Financial Position as deferred income taxes.

Investment tax credits are reflected as a reduction of income tax expense in the year the eligible expenditures are incurred.

(f) Inventories
Inventories of crude oil and refined products are valued at cost using the first-in, first-out method, which does not exceed net realizable value.

Materials and supplies are valued mainly at the lower of average cost and net realizable value.

(g) Foreign currency translation
The Company applies the temporal method of accounting for the translation of foreign currency amounts into Canadian dollars.

Under this method current assets except inventories, current liabilities and long-term debt are translated at year-end rates. Other assets, other liabilities and revenues and expenses are translated at the rate prevailing when they were acquired or incurred.

Unrealized exchange gains and losses on translation of long-term debt are deferred, and amortized over the remaining repayment periods. Other exchange gains and losses are reflected in earnings.

Consolidated Statement of Earnings

for the year ended December 31, 1981

($ millions except per share amounts)	1981	1980
Revenues		
Sales and other operating revenues	**$1,287.5**	$1,228.8
Interest income	**33.2**	30.6
	1,320.7	1,259.4
Expenses (note 1)		
Costs and operating expenses	**656.3**	355.1
Selling, administrative and general	**107.9**	87.9
Royalties (note 2)	**87.6**	158.6
Taxes other than income taxes (note 3)	**280.6**	97.5
Depreciation, depletion and amortization	**79.9**	84.1
Interest (note 6)	**4.2**	6.5
	1,216.5	789.7
Earnings before income taxes	**104.2**	469.7
Income taxes (note 4)	**54.1**	163.3
Earnings for the year	**$ 50.1**	$ 306.4
Earnings per common share	**$ 0.93**	$ 5.83

See accompanying summary of accounting policies and notes

Consolidated Statement of Retained Earnings

for the year ended December 31, 1981

($ millions)	1981	1980
Balance–beginning of year	**$623.2**	$318.4
Earnings for the year	**50.1**	306.4
	673.3	624.8
Dividends on preferred shares	**1.6**	1.6
Dividends on common shares	**78.3**	—
Balance–end of year	**$593.4**	$623.2

See accompanying summary of accounting policies and notes

Consolidated Statement of Financial Position

as at December 31, 1981

($ millions)	1981	1980
Assets		
Current assets		
Cash, time deposits and short-term investments	**$ 2.1**	$ 301.6
Accounts receivable (note 5)	**190.9**	136.7
Inventories (note 7)	**347.5**	220.7
	540.5	659.0
Properties, plant and equipment, net (note 8)	**1,067.6**	935.8
Deferred charges and other (note 9)	**154.6**	136.5
	$1,762.7	$1,731.3
Liabilities and shareholders' equity		
Current liabilities		
Short-term borrowings	**$ 10.0**	$ 35.6
Accounts payable and accrued liabilities (note 5)	**279.0**	190.8
Taxes other than income taxes	**51.2**	22.3
Income taxes	**0.5**	50.6
Current portion of long-term debt	**4.2**	2.9
	344.9	302.2
Long-term debt (note 10)	**40.7**	47.9
Deferred revenues and other	**38.2**	27.3
Deferred income taxes	**269.5**	251.6
Contingent liabilities (note 11)		
Shareholders' equity		
Share capital (note 12)	**476.0**	479.1
Retained earnings	**593.4**	623.2
	1,069.4	1,102.3
	$1,762.7	$1,731.3

See accompanying summary of accounting policies and notes

Approved on behalf of the Board:

Ross A. Hennigar

R. A. Hennigar, Director

Douglas McGeer

D. M. McGeer, Director

Consolidated Statement of Changes in Financial Position

for the year ended December 31, 1981

($ millions)	1981	1980
Source of funds		
Operations		
Earnings for the year	**$ 50.1**	$306.4
Depreciation, depletion and amortization	**79.9**	84.1
Deferred income taxes	**17.9**	77.2
Deferred overburden removal outlays (note 9)	**(29.6)**	(49.4)
Other	**9.4**	(0.3)
Funds from operations	**127.7**	418.0
Disposals of properties, plant and equipment	**4.2**	5.9
Increase in deferred revenues and other	**5.4**	10.5
	137.3	434.4
Use of funds		
Capital expenditures		
Exploration, production and resources development	**75.4**	110.0
Oil sands	**83.6**	132.2
Refining, petrochemicals and marketing	**42.1**	29.0
Corporate	**—**	0.7
	201.1	271.9
Increase in deferred charges and other excluding overburden	**7.4**	8.4
Reduction of long-term debt	**7.0**	22.2
Dividends	**79.9**	1.6
Redemption of preferred shares (note 12)	**3.1**	0.1
	298.5	304.2
Increase (decrease) in working capital	**(161.2)**	130.2
Working capital–beginning of year	**356.8**	226.6
Working capital–end of year	**$ 195.6**	$356.8
Analysis of increase (decrease) in working capital		
Cash, time deposits and short-term investments	**$(299.5)**	$156.6
Accounts receivable	**54.2**	(19.0)
Inventories	**126.8**	97.7
Short-term borrowings	**25.6**	(9.1)
Accounts payable and accrued liabilities	**(88.2)**	(73.1)
Taxes other than income taxes	**(28.9)**	(6.8)
Income taxes	**50.1**	(17.0)
Current portion of long-term debt	**(1.3)**	0.9
	$(161.2)	$130.2

See accompanying summary of accounting policies and notes

Schedule of Segmented Data*

	Resources Group				Sunoco Group		Total	
	Exploration, production and resources development		Oil sands		Refining, petrochemicals and marketing			
Revenues and earnings for the year ended December 31	**1981** ($ millions)	1980	**1981**	1980	**1981**	1980	**1981**	1980
Sales and other operating revenues	**$101.7**	$ 81.5	**$ 41.8**	$317.1	**$1,144.0**	$830.2	**$1,287.5**	$1,228.8
Intersegment revenues	**65.2**	71.0	**207.5**	278.2	**1.2**	1.2	**273.9**	350.4
Segment revenues	**166.9**	152.5	**249.3**	595.3	**1,145.2**	831.4	**1,561.4**	1,579.2
Expenses	**143.2**	117.6	**285.8**	298.9	**1,045.2**	715.9	**1,474.2**	1,132.4
Segment operating profits (loss)	**23.7**	34.9	**(36.5)**	296.4	**100.0**	115.5	**87.2**	446.8
Income tax recovery (expense)	**(15.0)**	(14.9)	**17.2**	(85.1)	**(46.7)**	(53.5)	**(44.5)**	(153.5)
Segment earnings (loss)	**$ 8.7**	$ 20.0	**$ (19.3)**	$211.3	**$ 53.3**	$ 62.0	**42.7**	293.3
Change in intersegment profit elimination							**(1.0)**	8.9
Interest income							**33.2**	30.6
Corporate expense							**(11.0)**	(10.1)
Interest expense							**(4.2)**	(6.5)
Related income taxes							**(9.6)**	(9.8)
Earnings for the year							**$ 50.1**	$ 306.4
Depreciation, depletion and amortization for the year ended December 31								
Segments	**$ 28.7**	$ 28.2	**$ 38.6**	$ 43.1	**$ 12.4**	$ 12.2	**$ 79.7**	$ 83.5
Corporate							**0.2**	0.6
							$ 79.9	$ 84.1
Capital employed as at December 31								
Segment assets	**$506.2**	$442.9	**$673.3**	$554.4	**$609.9**	$459.0	**$1,789.4**	$1,456.3
Corporate assets and intersegment eliminations							**(26.7)**	275.0
Total assets							**1,762.7**	1,731.3
Segment current liabilities	**$ 44.3**	$ 48.6	**$ 78.6**	$ 94.1	**$249.1**	$162.9	**372.0**	305.6
Corporate current liabilities and intersegment eliminations							**(27.1)**	(3.4)
Capital employed							**$1,417.8**	$1,429.1

*The Company has no foreign geographic segments. See note 6 for information on export sales.

See accompanying summary of accounting policies and notes

Notes to the Consolidated Financial Statements

December 31, 1981

1 Presentation of expenses

In order to present more clearly the impact on the Company of taxes and levies, petroleum compensation charges (arising as a result of the National Energy Program, and as described in note 3) have been classified in "taxes other than income taxes" instead of "costs and operating expenses." The comparative figures for 1980 have been reclassified. This change increased "taxes other than income taxes" for the year ended December 31, 1981 by $204.8 million (1980–$43.0 million), and decreased "costs and operating expenses" by the same amounts, with no impact on total expenses or earnings.

2 Royalties

The following is an analysis of the amounts expensed:

($ millions)	Crown	Other	Total 1981	Total 1980
Exploration, production and resources development	**$43.7**	**$ 9.7**	**$53.4**	$ 49.6
Oil sands	**22.1**	**12.1**	**34.2**	109.0
	$65.8	**$21.8**	**$87.6**	$158.6

3 Taxes other than income taxes

The following taxes and charges have been expensed:

($ millions)	1981	1980
Petroleum compensation charges (see below)	**$204.8**	$43.0
Petroleum and gas revenue tax (see below)	**8.7**	—
Federal sales and excise taxes	**55.6**	45.2
Production, property and other taxes	**11.5**	9.3
	$280.6	$97.5

Petroleum compensation charges
The petroleum compensation charges (formerly the federal petroleum levy) are federal levies designed to fund payments for equalization of foreign and synthetic crude oil prices with domestic conventional crude oil prices, and also to finance the acquisition of petroleum industry assets by Petro-Canada Inc. The charges are levied primarily on crude oil volumes received at the refinery gate.

Petroleum and gas revenue tax
The petroleum and gas revenue tax, effective January 1, 1981 is a new eight per cent tax on net operating revenues related to the production of oil and gas. Deductions for crown royalties, exploration and development expenditures, capital cost allowances and interest costs are not allowed. Commencing January 1, 1982 this tax is to be increased to an effective rate of 12 per cent.

In addition, certain taxes are collected from customers on behalf of governments and are not shown in the Company's revenues and expenses. The most significant of such taxes are:

($ millions)	1981	1980
Gasoline and diesel fuel taxes	**$ 91.3**	$ 70.1
Export taxes	**41.9**	55.1
	$133.2	$125.2

4 Income taxes

The provision for income taxes reflects a statement tax rate which differs from the statutory tax rate. A reconciliation of the two rates is as follows:

	1981	1980
Federal tax rate	**46.0%**	46.0%
Federal surtax	**1.8**	1.8
Provincial abatement	**(10.0)**	(10.0)
Provincial tax rate	**13.7**	11.4
Statutory tax rate	**51.5**	49.2
Crown royalty disallowance	**33.4**	12.4
Petroleum and gas revenue tax disallowance	**4.3**	—
Resource allowance	**(11.6)**	(12.6)
Depletion allowance	**(4.2)**	(11.2)
Investment tax credits	**(6.2)**	(1.8)
Inventory allowance	**(2.5)**	(0.3)
Provincial royalty tax credits, incentives and rebates	**(6.3)**	(0.4)
Manufacturing and processing profits deduction	**(2.7)**	(0.9)
Other	**(3.8)**	0.4
Statement tax rate	**51.9%**	34.8%

Investment tax credits reduced the income tax provision for 1981 by $6.4 million (1980–$8.6 million).

Deferred income taxes result from timing differences. The sources and the tax effects of deferred income taxes charged to expense are as follows:

($ millions)	**1981**	1980
Excess of tax over (under) book expense		
Depreciation	**$ 4.4**	$47.3
Exploration and development costs	**11.4**	20.8
Overburden removal	**4.5**	9.1
Preproduction expense	**(0.5)**	(1.0)
Other	**(1.9)**	1.0
	$17.9	$77.2

5 Related party transactions

Purchases of crude oil and raw feedstocks from Sun Company, Inc. and its affiliates ("Sun") increased to $269.9 million in 1981 from $77.2 million in 1980. The major reason for this increase was the need to import crude oil as a result of Alberta's cutback of light crude production. In turn, the Company sold refined products to Sun for $3.0 million (1980–$0.7 million).

Amounts due to Sun at December 31, 1981 totalling $75.1 million (1980–$21.2 million) are included in accounts payable and accrued liabilities. Amounts due from Sun totalling $0.3 million (1980–$0.2 million) are included in accounts receivable.

The Company believes these transactions were carried out on fair and equitable terms.

6 Supplemental earnings statement information

($ millions)	**1981**	1980
Synthetic crude oil receipts in excess of conventional crude oil prices	**$ 12.7**	$314.5
Export sales		
Unaffiliated customers–		
United States–heavy fuel oil	**$121.7**	$ 96.8
–petrochemicals	**50.2**	36.8
–middle distillates	**15.7**	—
Europe –petrochemicals	**99.3**	83.8
	286.9	217.4
Affiliates–		
United States–refined products	**3.0**	0.7
	$289.9	$218.1
Research and development expense	**$ 7.1**	$ 6.3
Pension expense	**$ 9.8**	$ 6.3
Interest expense–short-term	**$ 1.0**	$ 0.6
–long-term	**3.2**	5.9
	$ 4.2	$ 6.5

7 Inventories

($ millions)	**1981**	1980
Crude oil–conventional	**$119.3**	$ 60.4
–synthetic	**36.8**	22.8
Refined products	**154.2**	106.1
Materials and supplies	**37.2**	31.4
	$347.5	$220.7

8 Properties, plant and equipment

	Cost	Accumulated provisions	Net	Net
	($ millions)		1981	1980
Exploration, production and resources development				
Oil and gas properties	$475.2	$122.3	$352.9	$316.5
Equipment and other	106.4	33.1	73.3	64.8
	581.6	155.4	426.2	381.3
Oil sands				
Mine and mobile equipment	115.7	42.8	72.9	52.9
Plant	392.2	86.5	305.7	283.3
Housing	69.4	2.3	67.1	51.6
	577.3	131.6	445.7	387.8
Refining, petrochemicals and marketing				
Refinery including petrochemicals	165.6	55.6	110.0	89.3
Marketing and transportation	135.9	51.0	84.9	76.6
	301.5	106.6	194.9	165.9
Corporate	1.0	0.2	0.8	0.8
	$1,461.4	$393.8	$1,067.6	$935.8

9 Deferred charges and other

($ millions)	1981	1980
Oil sands deferred overburden removal costs (see below)	$ 83.5	$ 69.3
Oil sands preproduction costs	44.4	45.8
Prepaid gas purchases	17.3	12.0
Long-term receivables	2.0	3.2
Foreign exchange loss	1.7	1.9
Other	5.7	4.3
	$154.6	$136.5

	1981	1980
Oil sands deferred overburden removal costs		
Balance, beginning of year	$ 69.3	$ 40.4
Outlays during year	29.6	49.4
Depreciation on equipment during year*	2.3	2.7
	101.2	92.5
Amortization during year	(17.7)	(23.2)
Balance, end of year	$ 83.5	$ 69.3

*Depreciation on overburden removal equipment is not included in depreciation, depletion and amortization expense of $79.9 million (1980–$84.1 million).

10 Long-term debt

($ millions)	1981	1980
5¾% Notes, maturing in 1991, repayable at the rate of U.S. $2.0 million annually. U.S. $28.0 million (1980–U.S. $30.0 million)	**$33.2**	$35.8
Mortgages on housing, bearing interest at rates between 6¼ and 11¾ per cent, repayable over the next 22 years	**11.6**	14.9
Capitalized lease obligations	**0.1**	0.1
	44.9	50.8
Less current portion of long-term debt	**4.2**	2.9
	$40.7	$47.9

($ millions)	
Long-term debt matures as follows	
1982	**$ 4.2**
1983	**3.3**
1984	**3.4**
1985	**3.5**
1986	**3.6**
Subsequent years	**26.9**
	$44.9

11 Commitments and contingencies

(a) In response to changing market conditions, the Company is actively seeking a means of curtailing or eliminating the production of heavy fuel oil from the Sarnia refinery. Several options are being considered, most of which involve substantial capital outlays over the next few years. If heavy fuel oil production were not substantially curtailed, the Government of Canada has indicated that changes in its established policy for the determination of export charges on heavy fuel oil produced by the Company could be implemented which would have an adverse effect on the Company.

(b) In March, 1979 a suit was filed against the Company and the vendor of certain oil and gas properties which were purchased by the Company in 1973. The plaintiff has alleged that the vendor failed to honour a right of first refusal on the properties before completing certain transactions leading to the sale of the properties to the Company. The claim is for specific performance of the right of first refusal or, in the alternative, $35 million damages. If the plaintiff's suit is successful, indemnity will be claimed against the vendor.

(c) In 1973, the Director of Investigation and Research, under the Combines Investigation Act (the "Director"), commenced formal inquiry to examine conditions and practices affecting competition at all levels of the petroleum industry in Canada. On February 27, 1981, the Director submitted to the Restrictive Trade Practices Commission (the "Commission"), a Statement of Evidence and Material collected in the inquiry so that the Commission could consider it together with such further evidence or material it considers advisable and report thereon to the Minister of Consumer and Corporate Affairs of the Government of Canada. Suncor, together with a number of other petroleum companies, is named in the Statement of Evidence and Material. The Company believes that it has properly interpreted and complied in all material respects with the provisions of the Combines Investigation Act.

(d) Minimum annual rental charges under leases for service stations, office space and other property and equipment approximate $4.5 million.

(e) An independent actuarial valuation of the Company's pension plan as of January 1, 1981, indicated no unfunded liability for past service costs.

While the result of any litigation necessarily contains an element of uncertainty, the Company's management presently believes that, with respect to the above and other known contingent liabilities, including lawsuits, claims and guarantees, the aggregate amount of any liability and costs which might result would not have a materially adverse effect on the Company's consolidated financial position or operating results.

12 Share Capital

Authorized:
- an unlimited number of preferred shares without nominal or par value, issuable in series, the first being Preferred Shares Series A originally 1,107,145 in number. Redemptions to December 31, 1981 have reduced the authorized number of Preferred Shares Series A to 948,293. Preferred Shares Series A have the following attributes:
  $24 stated capital, $1.92 cumulative annual dividend, redeemable at $24, voting, convertible if and when a public distribution of common shares is made.
- an unlimited number of common shares without nominal or par value.

Issued:	Preferred Shares Series A		Common shares	
	Number	Amount ($ millions)	Number	Amount ($ millions)
Balance as at January 1, 1981	**938,981**	**$22.5**	**52,245,085**	**$456.6**
Redeemed for cash	**130,534**	**3.1**	—	—
Balance as at December 31, 1981	**808,447**	**$19.4**	**52,245,085**	**$456.6**

If and when a public distribution of common shares is made, the Preferred Shares Series A would be convertible into common shares during a 95 day period following such distribution, on the basis that $24 bears to the per share price (excluding commissions and discounts) at which the common shares are sold or issued for public distribution.

From August 22, 1979 to October 13, 1979 the Preferred Shares Series A were convertible to common shares on the basis of one common share for two Preferred Shares Series A.

The Preferred Shares Series A are redeemable at the option of the holder for $24 per share plus accrued and unpaid dividends at any time. The shares are redeemable also at the option of the Company at the same price following the 95 day conversion period.

Persons who held, or claim to have held, approximately 90,000 common shares of Great Canadian Oil Sands Limited at the time of amalgamation with Sun Oil Company Limited to form Suncor Inc., have demanded payment of the fair value of their shares in respect of which they claim to have dissented pursuant to the provisions of Section 184 of the Canada Business Corporations Act. Suncor Inc. has applied to the court for a determination of the persons entitled to be paid and the amount to be paid in accordance with the Act.

13 Reclassification

Certain 1980 amounts have been reclassified to conform with the 1981 presentation. Also see note 1 to the consolidated financial statements.

14 Pricing for synthetic crude oil

A memorandum of agreement entered into September 1, 1981 between the governments of Canada and Alberta provides that, effective January 1, 1982, the Company shall receive for all its synthetic crude oil production the new oil reference price (NORP). NORP is the lower of the price set forth in the agreement or the international price. Effective January 1, 1982 NORP was set at the deemed international price of $44.17 per barrel compared with $45.92 per barrel in the agreement. The price set forth in the agreement is due to reach about $78 per barrel by mid-1986. Also an incremental oil revenue tax (IORT) is levied effective January 1, 1982 on 75% of the Company's synthetic crude oil production at a rate of 50% on incremental oil revenue after deducting related royalties. Incremental oil revenue is defined as the difference between NORP and the National Energy Program price for conventional crude oil. Revenue subject to IORT will not be subject to income tax.

15 Subsequent event

On January 20, 1982, a fire at the oil sands plant heavily damaged a compressor building, and stopped production of refined synthetic crude oil. However, some unprocessed synthetic crude is being produced, but it is still too early to assess whether or not there will be any significant financial loss.

Quarterly Summary

(unaudited)

Financial Data

($ millions except per share amounts)

	For the quarter ended March 31 1981	June 30 1981	Sept. 30 1981	Dec. 31 1981	Total year 1981	For the quarter ended March 31 1980	June 30 1980	Sept. 30 1980	Dec. 31 1980	Total year 1980
Revenues	**$324.8**	**$310.9**	**$350.8**	**$334.2**	**$1,320.7**	$291.3	$325.0	$333.9	$309.2	$1,259.4
Segment operating profits (losses)										
Exploration, production and resources development	**8.9**	**4.7**	**3.0**	**7.1**	**23.7**	11.7	5.4	8.5	9.3	34.9
Oil sands	**5.2**	**(29.8)**	**(5.5)**	**(6.4)**	**(36.5)**	80.4	92.6	91.2	32.2	296.4
Refining, petrochemicals and marketing	**35.5**	**32.1**	**24.9**	**7.5**	**100.0**	33.6	27.6	29.1	25.2	115.5
	$ 49.6	**$ 7.0**	**$ 22.4**	**$ 8.2**	**$ 87.2**	$125.7	$125.6	$128.8	$ 66.7	$ 446.8
Earnings (loss) for the period	**$ 27.7**	**$ 11.2**	**$ 11.7**	**$ (0.5)**	**$ 50.1**	$ 87.3	$ 87.4	$ 80.7	$ 51.0	$ 306.4
Funds from operations	**$ 57.5**	**$ 16.8**	**$ 26.5**	**$ 26.9**	**$ 127.7**	$120.5	$102.4	$ 95.8	$ 99.3	$ 418.0
Earnings (loss) per common share	**$ 0.52**	**$ 0.21**	**$ 0.22**	**$ (0.02)**	**$ 0.93**	$ 1.66	$ 1.67	$ 1.53	$ 0.97	$ 5.83

Operating Data

	For the quarter ended March 31 1981	June 30 1981	Sept. 30 1981	Dec. 31 1981	Total year 1981	For the quarter ended March 31 1980	June 30 1980	Sept. 30 1980	Dec. 31 1980	Total year 1980
Gross production										
Conventional crude oil and natural gas liquids (a)	**2.5**	**2.4**	**2.1**	**2.1**	**2.3**	2.7	2.6	2.7	2.3	2.6
Synthetic crude oil (a)	**6.3**	**3.3**	**3.7**	**5.3**	**4.7**	7.2	8.4	7.6	6.4	7.4
Gross natural gas sales (b)	**2.4**	**1.5**	**1.4**	**2.1**	**1.9**	2.4	1.3	1.6	1.5	1.7
Sales of refined products (a)	**13.6**	**11.7**	**12.5**	**11.7**	**12.4**	11.9	10.8	11.9	12.0	11.6

(a) thousands of cubic metres per day
(b) millions of cubic metres per day

Five Year Financial Summary

(unaudited)

($ millions except for ratios)	1981	1980	1979	1978	1977
Revenues	**$1,320.7**	$1,259.4	$ 865.1	$562.5	$475.8
Segment revenues					
Exploration, production and resources development	**166.9**	152.5	125.3	106.9	92.3
Oil sands	**249.3**	595.3	343.4	210.1	178.7
Refining, petrochemicals and marketing	**1,145.2**	831.4	684.4	517.5	438.5
	$1,561.4	$1,579.2	$1,153.1	$834.5	$709.5
Segment operating profits (loss)					
Exploration, production and resources development	**23.7**	34.9	35.1	36.8	31.5
Oil sands	**(36.5)**	296.4	138.5	37.9	26.8
Refining, petrochemicals and marketing	**100.0**	115.5	84.0	19.2	23.6
	$ 87.2	$ 446.8	$ 257.6	$ 93.9	$ 81.9
Earnings before extraordinary gains	**50.1**	306.4	169.8	57.8	36.0
Extraordinary gains	**—**	—	3.1	3.1	6.3
Earnings for the year	**$ 50.1**	$ 306.4	$ 172.9	$ 60.9	$ 42.3
Funds from operations	**$ 127.7**	$ 418.0	$ 252.4	$126.0	$ 94.9
Capital expenditures					
Exploration, production and resources development	**75.4**	110.0	64.4	61.3	34.9
Oil sands	**83.6**	132.2	59.4	18.5	25.4
Refining, petrochemicals and marketing	**42.1**	29.0	8.9	20.1	11.4
Corporate	**—**	0.7	0.1	—	—
	$ 201.1	$ 271.9	$ 132.8	$ 99.9	$ 71.7
Capital employed					
Long-term debt	**40.7**	47.9	69.7	77.6	91.2
Deferred income taxes, deferred revenues and other	**307.7**	278.9	191.2	138.8	107.8
Shareholders' equity	**1,069.4**	1,102.3	797.6	627.5	566.6
	$1,417.8	$1,429.1	$1,058.5	$843.9	$765.6
Average number of common shares	**52,245,085**	52,245,085	52,191,626	52,175,200	52,175,200
Ratios					
Earnings before extraordinary gains per common share	**$0.93**	$5.83	$3.24	$1.11	$0.69
Earnings per common share	**$0.93**	$5.83	$3.30	$1.17	$0.81
Funds from operations per common share	**$2.44**	$8.00	$4.84	$2.41	$1.82
Earnings as a percentage of capital employed	**3.5%**	24.6%	18.2%	7.6%	5.8%
Earnings as a percentage of shareholders' equity	**4.6%**	32.3%	24.3%	10.2%	7.8%
Earnings as a percentage of revenues	**3.8%**	24.3%	20.0%	10.8%	8.9%
Long-term debt as a percentage of capital employed	**2.9%**	3.4%	6.6%	9.2%	11.9%

Five Year Operating Summary (unaudited)

Resources Group	1981	1980	1979	1978	1977
Production (thousands of cubic metres per day)					
Conventional crude oil and natural gas liquids					
– gross	**2.3**	2.6	2.7	2.5	2.5
– net	**1.5**	1.7	1.8	1.6	1.5
Synthetic crude oil – gross	**4.7**	7.4	6.8	7.1	7.1
Natural gas sales (millions of cubic metres per day)					
– gross	**1.9**	1.7	1.8	1.8	1.9
– net	**1.3**	1.1	1.2	1.2	1.2
Average sales price					
Conventional crude oil (dollars per cubic metre)	**117**	96	81	76	63
Synthetic crude oil (dollars per cubic metre)	**130**	217	137	81	69
Natural gas (dollars per thousand cubic metres)	**88**	82	56	47	40
Gross proven reserves					
Conventional crude oil and natural gas liquids (millions of cubic metres)	**10**	10	12	12	15
Synthetic crude oil (millions of cubic metres)	**54**	56	65	67	69
Natural gas (billions of cubic metres)	**13**	13	14	13	16
Land holdings (millions of hectares)					
–gross	**18.6**	19.6	19.7	23.9	26.5
–net	**3.5**	3.3	5.1	6.2	6.6
Net wells completed					
Exploratory – oil	**5**	2	—	1	—
– gas	**14**	9	4	5	5
– dry	**12**	14	12	6	9
Development – oil	**5**	12	39	27	11
– gas	**9**	25	23	40	36
– dry	**8**	7	7	7	1
	53	69	85	86	62
Sunoco Group					
Crude oil supply and refining					
Refined for Suncor account (thousands of cubic metres per day)	**12.1**	11.8	11.8	10.6	11.9
Gross crude oil production as a percentage of crude oil refined for Suncor account	**56%**	84%	79%	89%	80%
Processed at Suncor refinery (thousands of cubic metres per day)	**12.1**	12.4	12.2	11.1	12.2
Utilization of refining capacity	**84%**	86%	85%	77%	85%
Service stations (number at year-end)	**870**	920	950	990	1,040
Sales of refined products (thousands of cubic metres per day)					
Gasolines	**4.7**	4.6	4.3	4.0	4.0
Middle distillates	**3.0**	2.8	2.9	2.6	2.5
Heavy fuel oil	**2.8**	2.6	3.0	3.4	3.4
Petrochemicals	**1.2**	1.1	1.1	0.8	0.6
Other products	**0.7**	0.5	0.5	0.6	0.5
	12.4	11.6	11.8	11.4	11.0
Suncor employees (number at year-end)	**4,930**	4,620	4,310	4,130	4,000

In December, 1981, about 25 per cent of Suncor's common shares were purchased by the Ontario Government. This was the first step toward the goal of transferring majority ownership and control of Suncor to Canadian shareholders. Suncor President Ross Hennigar was interviewed about the transaction and its implications for the Company.

What impact will this change in ownership have on Suncor?
In many ways, I believe it will be business as usual for Suncor. We are a national company with holdings in all the major frontier areas, most of our assets are in Alberta and the majority of our service stations are in Ontario. Like any company with this range of interests, we will continue to respond to both national and provincial concerns, just as we always have.

On the other hand, as the result of the Ontario purchase, Suncor will never be the same. We have been plunged into a fishbowl where our every action and statement are subject to scrutiny. Of course, some of the critics will be off base and less than helpful. But on the whole, the extra attention is positive. It's excellent training for our people. I think we are coming to the point in Canada where all large corporations will have to live with this scrutiny. More than ever before, we must evaluate our statements and actions against the interests and concerns of others. We have to be perceptive about the implications of everything we do.

Was there any significance to the timing of the Ontario transaction? You have been talking about Canadianizing Suncor for some time.
First, there had to be a resolution of the oil sands pricing issue which is so significant to our earnings (see page two). We were on the verge of a major public offering in 1980 but the National Energy Program's low price for our synthetic crude simply reduced our value too much to consider proceeding at that time. The new pricing agreement between Alberta and the federal government made Suncor's prospects much more positive and opened the way for the Ontario transaction. Actually, Sun

Company has for many years favored shifting ownership of some of Suncor's shares into the hands of Canadians. And that's why, in principle, we support Ottawa's Canadianization objectives as set out in the National Energy Program.

You have some reservations?
Yes. The methods and the timing do cause us some concern. The government's approach is to force companies to Canadianize by imposing significant penalties on foreign-owned companies such as, for example, tying incentive grants for the frontier areas to Canadian ownership starting in 1982. The ownership requirements are rather high and the traditional tax write-offs ended abruptly.

There is no question the policy has worked. In one year following the introduction of the NEP, Canadians bought back $8 billion worth of oil and gas assets from foreign owners. Canadians now own 50 per cent of the oil industry's total assets. These figures don't even include our own agreement with Ontario. It's a fast pace that has put a lot of strain on our balance of payments. It's also meant higher gasoline taxes and more inflation for all of us. It's a high price to pay and it's doubtful we had to move that quickly. But Canadianization is well under way and I think we can take some satisfaction in that.

Canadianizing the oil industry has included substantial investments by the government sector. Was this necessary? How do you feel about it?
It was probably inevitable. Of course, our industry is still largely privately owned but there are a number of reasons why government ownership has increased. Probably the most significant is the strategic importance of petroleum to our national interests. In fact, all over the world, governments are taking steps to increase their control of oil and gas resources. Equity participation in the industry is certainly one way of achieving this objective. And it's one way for governments and the public to learn that generating a profit in our industry isn't easy–it takes good strategic planning, a lot of hard work, enormous amounts of money invested for long periods of time–and a fair bit of luck.

A second reason is the enormous amount of new investment in petroleum resources which will be necessary for Canada to achieve self-sufficiency. Most projections indicate there isn't enough risk capital in Canada to meet the need which is estimated at about $230 billion if we are to achieve self-sufficiency by 1990. Remember, that's the federal government's objective. To move this quickly, governments will have to reduce their revenues by cutting back on oil industry taxes or they will have to put up more of the equity. One way or the other, they will have to share the costs if they expect to reap the rewards.

A third motivation is the fact that oil and gas investments look like a pretty good deal to make on behalf of our citizens. It's buying a piece of future prosperity. This seems to be the philosophy in Alberta and in Ontario.

Finally, and perhaps most persuasively, governments are responding to what our citizens want. Perhaps we could argue that it's irrational–that regulation would achieve the same ends and who cares about who really owns the industry? But surely it's more conducive to national pride that we Canadians own a majority of what is perhaps our most important industry. For many Canadians, it is just that–a question of pride–mixed perhaps with some misplaced mistrust of multinational companies.

Do you think government intervention in the oil industry with policies like Canadianization is an erosion of the free enterprise system?

It's an erosion of the system as we know it but Canadians are obviously prepared to see some dislocation as a trade-off for Canadianization and other values. Personally, I have reservations about government interference in our economic system which produced the wealth and freedom that we now enjoy. However, businessmen have to live within the social context and respond to it.

Let's consider what is happening. Our way of looking at the world is changing. We now recognize that we live within an ecological system and there are limits to raw materials and open spaces. We are more aware of our interdependence–that what I do affects you. To many, it's only natural that more people therefore want to make an impact on the decision-making of large companies.

I think all of us accept the fact that we can't allow a company to go ahead and use whatever chemicals it wants and dump them where it likes. The private sector tries to deal with issues like this but there is pressure for more public sector involvement.

The community as a whole is being forced to take greater responsibility for the actions of its parts. The idea is that only the community as a whole can define the public interest, harmonize competing values and move toward consensus or, at least, reasonable compromise. What we are witnessing seems to be a powerful movement toward what the *Harvard Business Review* has called communitarianism –a philosophy based on the fact that since we share planet earth, we should share the decisions about what we do with it. In simple terms, it means that our business is everyone's business, at least to some extent. The great "isms" of the late twentieth century–consumerism and environmentalism–are an outgrowth of this philosophy.

The public no longer accepts that enlightened self-interest will tend toward the public good and they may be right. Certainly no individual, no company or government can even be aware of the implications of all that it does even if it wishes to be so. Input is needed from a wider perspective. And in any case, there must be some way of resolving the conflicts that inevitably arise as our interdependence increases.

Businessmen can respond in a number of ways. We can rail against what we perceive to be an invasion of business freedoms. We can ignore the issue, let the government make its rules and try to manage within them. Or we can get involved in government. Realistically, present trends point to a larger role for government. To me, that suggests the need for a creative response. Specifically, I think we have to expand our concept of government and see it as the *process* by which we govern ourselves. It cannot be limited to experts and civil servants and votes in the House of Commons. As businessmen, I believe we have to redefine private enterprise to allow for more public input. And at the same time, I think we have to redefine our idea of government to allow more business input.

We also have to become alert to abuses of the communitarian ethic. Individual freedoms, including those of businesses, organizations and institutions, must be protected. We can't allow a concern for the collective good to become an excuse for curbing the rights we now enjoy.

What will these social trends do to the bottom line? Isn't this still the main criterion for measuring a business?

Yes. The bottom line measures how efficiently a business is making use of our economy's resources such as skills, raw materials, investment funds and so on. And it determines how successful the company will be in attracting more of those resources. I might add that having a government shareholder doesn't change this.

It points to a very important principle. There is, and must continue to be, a clear difference between owning and managing. It may be quite suitable for government to have ownership in a corporation. And it is certainly the role of government to shape the context in which all businesses operate. But it is quite another thing if it is to begin to interfere directly in day-to-day operations. Managing an enterprise is something else again. When you manage, you still manage for profit and that's something that private enterprise will always do better than government. Now that the economy is in a severe slump, we may see renewed recognition of the vital role profits have in maintaining jobs and paying for social benefits. It's evident that when earnings decline as they are now, everyone is poorer.

Governments must also be sensitive to the other shareholders in the companies they buy into–shareholders such as pension funds and individuals who may be counting on the growth of their investment in order to retire.

To return to Canadianization, given what you know now, what advice would you give to the president of a large company contemplating the idea of having a government shareholder?

I wouldn't presume to advise. Every situation is probably different. But there are four basic principles that should be considered.

First, for the sake of all the investors, defend the right of management to manage. Devise a very clear procedure for ensuring this principle. That's one thing we have emphasized in our own case.

Secondly, learn from your public sector investor. Involve its directors in the assessment of your responsiveness to public policy. And sensitize your managers to the input government people can provide.

Third, continue to act as a private company. When you disagree with government policy, say so. I certainly intend to. Public ownership of some of your stock should not turn the CEO into a cipher. As the President, I have a responsibility to all our shareholders and employees–and an obligation to my own conscience–to call it the way I see it.

And finally, if you can, maintain a mix of shareholders so that public ownership does not assume full control. That is our approach at Suncor, with the full agreement and support of the Ontario Government.

What does it mean for a corporation to be responsible? At Suncor, we define this responsibility in two ways: to do what an oil company usually does in the course of its business but with sensitivity to the impact on others; and, secondly, to identify, investigate and attempt to meet social needs which may be unrelated to company operations but reflect the responsibilities of corporate citizenship.

How we treat the natural environment is a measure of our responsibility. Exploration and production, especially in the frontier areas, require great sensitivity to environmental impact. Therefore, Suncor is participating in a number of environmental studies off the coast of Labrador, in the Arctic Islands and the Mackenzie Delta.

▲ A fire drill at the Sarnia refinery. When working with volatile materials, it is essential to be prepared.

The Labrador program, now in its fourth year, is assessing the impact of exploration and future production on Labrador's fish, birds, animals, land and people. In 1981, about $2 million was spent on this work, shared among a number of companies. Currently, marine life, mammals, seabirds and ice are being surveyed near the Davis Strait in the Northern Labrador Sea to establish migration patterns, feeding areas and the speed and direction of ice movement.

In the Arctic Islands, a four-year oil-spill study is in progress off the northern shore of Baffin Island. Three beaches have been prepared for testing in 1982. One will be kept free of oil for control purposes, one will receive a small oil spill which will be treated with dispersants and the third will have a small spill without treatment. The impact on marine life will be carefully monitored and compared.

At our Sarnia refinery, preventing and cleaning up oil spills are well-developed skills. Sunoco is a member of the Petroleum Industry Marine Environment Co-operative (PIMEC), an Ontario-wide group formed by a number of companies to prevent and prepare for oil spills on the Great Lakes system.

A division of PIMEC, Bluewater Clean, was formed by four refineries in the Sarnia area, including ours. Bluewater Clean has a budget in excess of $1 million for joint training, purchase and maintenance of equipment and planning to enable a co-ordinated response to oil spills in the Sarnia area.

One key to effective response is practice. In addition to classroom sessions and drills, our training program includes simulated oil spills. The practice paid off in November 15, 1981, just a few weeks after Suncor had conducted another simulation. One cubic metre of bunker oil was accidentally spilled into the St. Clair River while being loaded onto a barge at our refinery. The spill was cleaned up quickly by Suncor personnel, backed up by Bluewater Clean. Environmental authorities were pleased with our response.

Steam pressure is released prior to a maintenance shutdown at Suncor's Fort Kent in-situ oil sands project. Steam generation needed for expansion will use waste water from the town of Bonnyville to help conserve local water supplies.

At our oil sands plant, our concern for the environment meant planting 75,000 trees and putting topsoil on 16 hectares of our lease in 1981–part of our ongoing land restoration program. Meanwhile, research continues on other methods of land reclamation. Also in 1981, we undertook a successful new pilot project to detoxify our tailings and we overhauled our number one sulphur plant to reduce the chance of accidental emissions.

At our Fort Kent oil sands project, we will be drilling wells on a slant to enable us to cluster the wellheads into a smaller area, thus preserving agricultural land. The project will conserve water needed for wildlife and agriculture in this area by using waste water from the nearby town of Bonnyville to produce steam for injection underground.

Full and frank disclosure is an important responsibility for major companies like ours. In *Oilweek* magazine's annual report contest, our 1980 report was judged to be "near perfect" and the best in our category of the industry, primarily because of its disclosure about operations.

Suncor also ventured into areas not expected of an oil company. In 1981, the International Year for Disabled Persons, we financed a 50-minute documentary film, Segregation: the Disability Myth, which eloquently pleads for greater understanding of the problems faced by disabled persons. The film had premiere showings to critical acclaim in Toronto, Calgary and Fort McMurray.

For young Canadian scientists, we sponsored Synergy '81, a two-day Symposium in Toronto on renewable energy. Experts in solar, wind, biomass and other forms of energy met with 57 high school students who had won Suncor Energy Awards at regional science fairs across Canada. This year, Synergy '82 will bring another group of award-winning students together in Ottawa to learn about, and work on, the energy problems of developing countries.

A new policy has been developed at our corporate office to concentrate our contributions in four main areas: supporting applied research on the special problems of the elderly (especially geriatric medicine which currently lacks adequate support); helping to improve the lot of Canada's disabled; assisting the development of effective coaching for young athletes; and supporting cultural organizations. Each of our two operating groups also has a contributions policy. The corporate office funds national organizations while the groups support provincial and local programs.

But as an oil company, we believe our prime responsibility is to participate in Canada's search for answers to its energy problems. To this end, three main courses of action are being pursued:

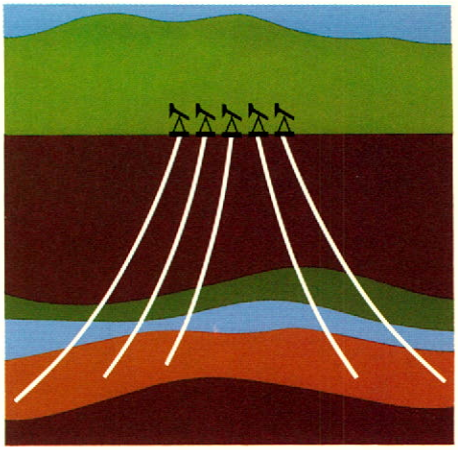
-To make a growing contribution to Canadian oil supplies

-To develop Canadian energy technology and expertise

-To transfer majority ownership and control of our Company to Canadians

Details on each of these commitments can be found elsewhere in this report.

Slant hole drilling at Fort Kent permits "clustering" of wellheads to reduce land area affected.



Board of Directors

Early in 1982, Suncor expanded its Board of Directors and created the new office of Chairman of the Board.

Three new directors nominated by Ontario Energy Resources Ltd., our new shareholder, joined our Board. All three are also on the Board of Ontario Energy Corporation, the parent of Ontario Energy Resources Ltd. Pierre Genest, Q.C. is a partner of Cassels, Brock, a law firm, and a director of Power Corporation of Canada and The de Havilland Aircraft of Canada Ltd. W. Edwin Jarmain, President of Jarmain Communications Inc., a television cable company, and Chairman of the Ontario Energy Corporation, has a background in electrical engineering and industrial management. Malcolm Rowan is President and Chief Executive Officer of the Ontario Energy Corporation and was from 1976 until 1981 the Deputy Minister of Energy for Ontario.

Suncor now has 14 directors; 11 are Canadians and eight directors have no other association with the Company or its controlling shareholder.

The Chairman of the Board acts as the Chief Officer of the Board responsible for its integrity, independence and efficiency of decision-making. His role is to ensure an atmosphere of free and open discussion in which Board members can work together for the long-term benefit of the Company. He also has the task of presiding at meetings of directors and of shareholders.

Our first Chairman is Michael M. Koerner, who assumed his responsibilities on January 29, 1982. Mr. Koerner has been a director of Suncor and one of its predecessor companies for five years. He heads his own corporation, Canada Overseas Investments Limited, which raises venture capital for new businesses, and is a director of a number of leading Canadian and U.S. corporations. Originally educated as a chemical engineer at the Massachusetts Institute of Technology, Mr. Koerner later obtained his Master of Business Administration from Harvard.

Suncor's President continues as the Chief Executive Officer with undiminished responsibility for managing the company.

The Board operates by a detailed, written job description. There are three standing committees of the Board: Audit, Board Policy and Nominating, and Human Resources and Compensation. Each of these committees is chaired by an outside director. The Audit Committee consists of John E. Poole, Chairman, Max B. E. Clarkson, Pierre Genest, Ardagh S. Kingsmill and John P. Neafsey. The Board Policy and Nominating Committee is headed by Michael M. Koerner, while the Human Resources and Compensation Committee is chaired by Max B. E. Clarkson.

Michael M. Koerner, Chairman of the Board

Pierre Genest, Q.C.

W. Edwin Jarmain

Malcolm Rowan

Directors
(as at December 31, 1981)

Max B. E. Clarkson, Toronto
Professor
Faculty of Management Studies
University of Toronto

Ross A. Hennigar, Toronto
President & Chief Executive Officer
Suncor Inc.

Gordon E. Hillhouse, Radnor, Pa.
Executive Vice-President
Sun Company, Inc.

Gerald H. D. Hobbs, Vancouver
Private Investor & Corporate Director

Ardagh S. Kingsmill, Q.C., Toronto
Partner, Tilley, Carson & Findlay

Michael M. Koerner, Toronto
President, Canada Overseas
Investments Limited

Robert McClements, Jr., Radnor, Pa.
President & Chief Operating Officer
Sun Company, Inc.

Dudley M. McGeer, Toronto
Senior Vice-President, Administration
& Chief Financial Officer, Suncor Inc.

John P. Neafsey, Radnor, Pa.
Senior Vice-President, Finance
Sun Company, Inc.

John E. Poole, Edmonton
Corporate Director

J. A. Guy Saint-Pierre, Montreal
President & Chief Executive Officer
Ogilvie Mills Ltd.

Glossary of Terms

Bitumen: extremely viscous (tar-like) form of oil (when extracted from oil sands and upgraded, it becomes a form of synthetic oil).

Coke: carbon and impurities in the form of a black powder which results from the heating of bitumen to 500° Celsius.

Conventional crude oil: oil produced through wells by ordinary oil field methods.

Downstream: this business segment manufactures, distributes and markets refined products from crude oil.

Drillstem test: a test performed during the drilling of a well to determine if hydrocarbon-bearing zones have been encountered.

Dry hole: an exploration or development well incapable of producing hydrocarbons economically.

Farmout: an agreement whereby the owner of a lease permits another operator to earn an interest in the lease by carrying out certain work. From the other operator's point of view, this same agreement is a farmin.

Gross production/reserves: Suncor's interest before deducting Crown royalties, freehold and overriding royalty interests.

Gross wells/land holdings: the total in which Suncor has an interest.

Heavy oil: crude oil which is more viscous, or thicker, than normal crudes and therefore does not flow as freely.

Hydrocarbons: organic chemical compounds of hydrogen and carbon atoms which form the basis of all petroleum products. May exist as gases, liquids or solids.

Hydrocracking: an efficient, relatively low-temperature refining process using hydrogen and a catalyst to convert home heating and industrial fuel oil to higher-value products.

In-situ oil sands production: separation of oil from the sand within the ore body itself and inducing the oil to flow so that it can be pumped to the surface.

Incremental oil revenue tax (IORT): a federal tax on the revenues obtained from old oil over and above NEP levels.

National Energy Program (NEP): the federal government's program announced in October, 1980.

Natural gas liquids: hydrocarbons found in natural gas which may be extracted or isolated as a liquid at standard temperatures and pressures.

Net pay: that part of an oil or gas-bearing zone which is capable of producing.

Net production/reserves: Suncor's working interest after deducting Crown royalties and freehold and overriding royalty interests.

Net well/land holdings: Suncor's interest after deducting interests of partners.

Netbacks: the amount of oil or gas revenue retained by the producer after Crown royalties, PGRT, IORT, other production taxes and operating costs.

New oil: oil discovered after December 31, 1980, additional oil obtained by certain enhanced recovery techniques and frontier production. (Defined in federal/provincial agreements signed in 1981.)

New oil reference price (NORP): the price applicable to new oil as defined in federal/ provincial agreements signed in 1981.

Old oil: oil discovered before January 1, 1981. (Defined in federal/provincial agreements signed in 1981.)

Overburden: material overlying oil sand which must be removed before sand can be mined; consists of muskeg (organic soil), glacial deposits and sand.

Petroleum and gas revenue tax (PGRT): a federal tax imposed on all oil and gas production, paid for by the producer.

Petroleum compensation charge (PCC): a tax levied on all crude oil used by refiners in Canada, whether imported or domestic.

Proven reserves: hydrocarbons yet to be economically produced whose quantity can be estimated with a high degree of certainty.

Reservoir: a body of porous rock containing an accumulation of water, crude oil or natural gas.

Seismic: a geophysical technique which helps to determine the oil and gas potential of an area.

Spud: to start drilling a well.

Synthetic crude: a blend of hydrocarbons resulting from the thermal cracking and purifying of bitumen.

Tailings: a sludge-like mixture of sand, water and clay remaining after bitumen has been removed from the ore; stored in a diked-in pond.

Thermal cracking: a refining process which uses heat and pressure to break the large hydrocarbon molecules found in bitumen into smaller hydrocarbon molecules and coke.

Upstream: this business segment explores for, develops and produces crude oil and natural gas; develops and produces synthetic crude and heavy oil from the oil sands; pursues coal, uranium and mineral activities.

Wells:
completed: a well having a definite status–gas, oil or dry.
delineation: a well drilled in close proximity to an oil or gas well to help determine the limits of the reservoir.
development: a well drilled with the expectation of producing from a known-productive oil or gas reservoir.
exploratory: a well drilled in unproven or semi-proven territory to find commercial deposits of crude oil or natural gas in a new reservoir.

Metric conversion guide

Crude oil, refined products, etc.
1 m^3 (cubic metre) = approx. 6.29 barrels

Natural gas
1 m^3 (cubic metre) = approx. 35.49 cubic feet

Land holdings
1 hectare = approx. 2.47 acres

Corporate Directory

Offices

Corporate Office
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Sunoco Group
56 Wellesley Street West
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Telephone (416) 924-4111

Resources Group
Exploration, Production & Resources Development Divisions
500-4th Avenue S.W.
P.O. Box 38
Calgary, Alberta T2P 2V5
Telephone (403) 269-8100

Oil Sands Division
P.O. Box 4001
Fort McMurray, Alberta T9H 3E3
Telephone (403) 743-6411

Subsidiary companies

(100% owned unless otherwise indicated)

Albersun Pipeline Ltd.
Calgary, Alberta
Natural gas pipeline operator

Athabasca Realty Company Limited
Fort McMurray, Alberta
Employee housing

Baron Petroleums Inc.
Toronto, Ontario
Retail gasoline distributor

Maywelle Properties Ltd.
Toronto, Ontario
Real estate developer

Ouimet-Gobeille Inc.
Montreal, Quebec
Heating oil and gasoline distributor

SMS Petroleums Ltd.
Toronto, Ontario
Retail gasoline distributor

Sun-Canadian Pipe Line Company Limited
Waterdown, Ontario
Petroleum products pipeline operator in southern Ontario (55% owned)

Suncor Supply Limited
Fort McMurray and Edmonton, Alberta
Provision of materials and supplies

Sun Explorations of Quebec Ltd.
Calgary, Alberta
Exploration in Quebec

Sunoco Home Comfort Inc.
Toronto, Ontario
Heating oil and gasoline distributor with various divisions in Ontario

Sunoco Inc.
(including Sunchem division)
Toronto, Ontario
Manufacturer/marketer of petroleum and petrochemical products

.Chemsun Inc.
Toronto, Ontario
Marketer of petrochemical products

Sunchem Shipping Inc.
Toronto, Ontario
Marine transportation

Principal officers

R. A. Hennigar, President and Chief Executive Officer

S. A. Cowtan, Executive Vice-President, Sunoco Group

W. R. Loar, Executive Vice-President, Resources Group

D. M. McGeer, Senior Vice-President, Administration and Chief Financial Officer

F. A. Bain, Vice-President, Technology

C. K. Boland, Vice-President, Human Resources and Corporate Affairs

P. M. Bradbury, Vice-President, Controller, Resources Group

G. H. Brereton, Vice-President, Refining, Sunoco Group

H. B. Maxwell, Vice-President, Government Affairs

W. L. Oliver, Vice-President, Administration, Resources Group

D. A. Smith, Vice-President, Exploration Division, Resources Group

W. N. Turner, Vice-President, Production Division, Resources Group

D. R. Galbraith, Controller

A. S. Kingsmill, Q.C., Secretary

A. A. L. Wright, Treasurer and Assistant Secretary

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G. H. Brereton is Vice-President,
Marketing, Sunoco Group.

Major shareholders
Sun Company, Inc.
Radnor, Pennsylvania
(owning 75% of common shares)
Ontario Energy Resources Ltd.
Toronto, Ontario
(owning 24.9% of common shares)

Stock exchange listings
The Suncor Preferred Shares Series A are listed on the Toronto and Alberta Stock Exchanges.

Transfer agent and registrar
The Canada Trust Company
110 Yonge St., Toronto,
Ontario M5C 1T4

800 Dorchester Blvd. W., Montreal,
Quebec H3B 3L3

10150-100th St., Edmonton,
Alberta T5J 0P6

505-3rd Ave. S.W., Calgary,
Alberta T2P 3E6

Investor information
Information to assist the investor in evaluating the Company's operations and results, including additional copies of this annual report, may be obtained from the Manager, Investor Relations, Suncor Inc. at 20 Eglinton Avenue West, Toronto, Ontario M4R 1K8.

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