Suncor Inc

Annual Report 1982

Highlights year ended December 31	1982	1981
Revenues ($ millions)	**$1,550.6**	$1,320.7
Earnings ($ millions)	**$ 60.1**	$ 50.1
Earnings per common share	**$ 1.13**	$ 0.93

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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. About 75 per cent of its common shares are held by Sun Company, Inc. of the United States and 25 per cent are owned by Ontario Energy Resources Ltd., a corporation indirectly owned by the Province of Ontario.

Cover photo:
As part of the upgrading project at our Sarnia refinery, construction crews erect the superstructure to house two new 725-tonne reactors. One reactor will remove nitrogen and sulphur from the feedstock while the other will crack hydrocarbon molecules in the presence of hydrogen.

The New Environment

In just two years, the environment for Canada's oil and gas industry has been transformed.

Demand for refined petroleum products has fallen abruptly and shifts have taken place in the relative level of consumption for different products.

During this period, the Canadian crude oil price has risen sharply toward world market levels, reflecting a change in federal government policy. New oil production currently receives the international price.

The Opportunities

Refiners able to meet changing market requirements efficiently will remain competitive and profitable.

Major opportunities exist in exploring for, and producing, new oil which qualifies for the new oil reference price.

Suncor's Response

To seize these opportunities, we are now:

- Upgrading our Sarnia refinery to make it one of Canada's most flexible and cost-effective;
- Adding oil sands reserves eligible for the new oil reference price and improving operational reliability of our oil sands plant; and
- Developing significant new sources of oil including an expansion of our in-situ heavy oil project and a concentrated search for conventional crude in Canada's western provinces.

William R. Loar

This report should have been signed by Ross Hennigar. The accomplishments of 1982 reflect so clearly his vision and leadership of the Company. He died on January 11, 1983, in a plane crash near Toronto.

One of Ross Hennigar's achievements was the development of an experienced management team. From these ranks, the Board of Directors has appointed a new president and chief executive officer, William R. Loar, 56, who has been with Suncor and its predecessor companies for 16 years in Calgary, most recently as Executive Vice-President, Resources Group.

Suncor's earnings increased in 1982. Higher prices for crude oil and natural gas and higher synthetic crude production more than offset lower returns from the sale of refined products and increased interest expense related to financing new capital projects.

The most important achievement of the year was an improvement in production levels at our Fort McMurray oil sands plant following a major fire in January and other operating problems which severely limited output during most of the year.

Strategic plan emphasizes new initiatives

Suncor has a strategic plan covering the period to the end of 1992. Our objective in this plan is to continue to be a highly competitive integrated oil company whose growth and stability are based on a number of distinct sources of income.

The strategy to meet this objective has three components: a viable refining and marketing business; a continuing emphasis on investment in our hydrocarbon resources base and production capability; and attaining production reliability at the oil sands plant with effective cost controls.

A number of the plan's key components have already been announced, including upgrading our Sarnia refinery, increasing oil sands reserves, improving the performance of our oil sands plant, and expanding our Fort Kent in-situ heavy oil project. These projects are described in greater detail on pages seven to nine.

To finance these projects, Suncor will use significant amounts of outside financing for the first time in its history. Tough spending restraints have therefore been implemented to keep borrowings within prudent limits.

Oil sands plant production improves

Our largest operation is the oil sands plant. Major operating problems kept production well below potential during 1982 although output was higher than the year before when an extended maintenance shutdown and operational difficulties resulted in lower volumes.

Production in 1982 averaged 5.5 thousand m^3 per day (34 thousand barrels) compared to 4.7 thousand m^3 (30 thousand barrels) in 1981. However, in the fourth quarter of 1982, the average daily volume reached 7.6 thousand m^3 (48 thousand barrels), indicating that we had made significant headway in overcoming operating problems.

Beginning January 1, 1982, our entire oil sands production received the new oil reference price under the terms of an agreement between the Alberta and federal governments signed September 1, 1981. Consequently, during 1982 we obtained an average price of $40.55 per barrel (including partially processed synthetic crude) compared to $20.67 per barrel the year before. However, the benefits of the increased price are offset somewhat by higher taxes.

The oil sands plant underwent a major expansion program which was completed in 1981 at a cost of $185 million. To help realize the potential of the plant on a consistent basis, significant improvements were made to equipment and operating procedures during 1982. These improvements are described on page nine.

Markets decline substantially

Demand for refined petroleum products fell for a second consecutive year in 1982. Canada's consumption of these products dropped about 10 per cent from 1981.

Most major product categories participated in the sales decline, from gasolines to middle distillates and heavy fuel oil. Suncor's 1982 sales performance generally exceeded that of the industry, particularly for petrochemicals and retail gasoline, but margins for these products were under substantial pressure. An excess of refinery capacity within the industry and softening demand led to very tough competition in our markets.

Natural gas sales were lower than expected. Both Canadian and U.S. demand were adversely affected by the recession. A soft world crude oil market gave residual fuel oils a price advantage to industrial users in the U.S., which reduced exports of higher-priced Canadian gas. U.S. production of gas also proved to be much more plentiful than anticipated.

We were able to sell all the synthetic crude produced by our oil sands plant, whether partially or fully processed. However, demand for our conventional crude oil declined marginally due to generally lower consumption.

Fiscal environment improves

Federal and provincial governments modified some elements of their tax and royalty policies in 1982 to provide the oil industry with additional cash flow. These changes were needed to compensate for the substantially larger share of oil and gas revenues allocated to governments by the federal/provincial agreements signed in 1981 and the fact that oil prices did not rise to meet the levels anticipated in these agreements.

At the federal level, the most important changes for Suncor included a two-year reduction in the petroleum and natural gas revenue tax on synthetic crude production and a one-year elimination of the incremental oil revenue tax on conventional production. In 1982, these revisions increased our after-tax cash flow by about $6.5 million. The benefits will rise to nearly $23 million in 1983 and about $15 million in 1984. These estimates depend upon the actual level of production we attain. Most of the overall gain accrues to the Oil Sands Division.

The Alberta Government increased its Royalty Tax Credit for 1982 and 1983. The Royalty Tax Credit rebates a portion of royalty payments due to the province. Additional grants were also provided for development drilling. These measures have enabled us to increase our drilling programs. Saskatchewan also initiated a royalty reduction program which has made exploration and production in that province considerably more attractive.

These fiscal changes, combined with the world price for new oil, provide a substantial incentive for new oil exploration and production.

Overall, however, our industry's share of the oil revenue dollar remains below what it was before the introduction of the National Energy Program. Unlike other industries, ours is increasingly taxed on revenues rather than earnings. Tax and royalty provisions are sometimes complex and overlapping. Furthermore, revenue-sharing between the different levels of government and the industry is based on oil price projections which are clearly unreliable in the short term. Further modifications in the fiscal environment are therefore needed.

New company to explore frontier areas

Trillium Exploration Corporation, controlled and two-thirds owned indirectly by the Ontario Energy Corporation and one-third owned by Suncor, has been formed to explore for oil and gas in the frontier areas of Canada.

Trillium is eligible to receive the maximum level of support from the federal government's Petroleum Incentive Program (PIP). PIP grants pay up to 80 per cent of exploration costs.

Trillium will enable Suncor to maintain a significant level of exploration activities on its frontier interests while preserving cash flow for increased emphasis on new oil exploration in the western Canadian provinces.

During 1982, Suncor farmed out to Trillium its interests in the eight-company Labrador Group which holds 9.0 million hectares off the Labrador coast and our participation in two exploratory wells now being drilled in the Arctic Islands. Early in 1983, Trillium farmed into Suncor's interests in 6.9 million hectares in the Arctic Islands.

Outlook

Suncor's long-term prospects are good. Our earnings have turned upward and a firm direction has been established to take advantage of the opportunities available to us.

The next two years will require a superb effort to ensure that the four new major capital projects now in progress are completed on schedule and within budget. We will also need to manage existing operations at optimum levels to maximize cash flow for these projects. I am confident we have the talent to do the job.

The most significant unanswered question is the outlook for the international price of crude oil which now applies to our Fort McMurray and Fort Kent production. World oil production is at its lowest level since 1975, surpluses exist in the world market and a number of exporting countries have reduced their official prices.

We believe the world oil market will remain soft in 1983 and 1984. However, prices should be sufficient to generate reasonable cash flow for Suncor. By 1985, world economic recovery is expected to absorb the crude oil surplus and moderate real price increases are then likely for the rest of the decade, assuming no major disruptions in supply. If instability in the major oil producing regions should increase, more rapid price gains would almost certainly ensue.

In any case, all available projections point to growing shortages and higher prices in the 1990s. This is no time for Canadians to become complacent about the national objective of petroleum self-sufficiency. Suncor will continue to do its utmost to ensure that this objective is realized.

William R. Loar
President and Chief Executive Officer

February 22, 1983

Ross A. Hennigar

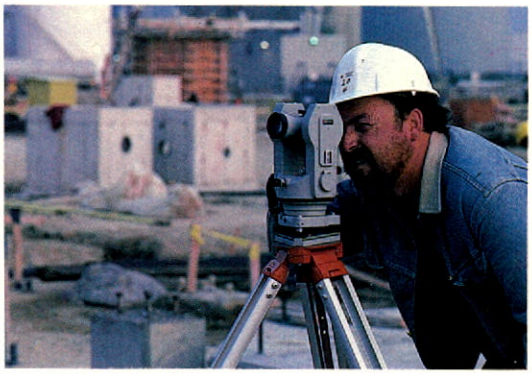
1929 · 1983

We wish to honor Ross A. Hennigar, the first President of Suncor, who died in a tragic air crash on January 11, 1983. We remember Ross for his leadership through an exciting period of the Company's short history as Suncor. He brought to the Presidency balanced judgment, warmth and humor. He was the most approachable of executives, interested in the personal development of those around him. He shared his skills and time generously with all in the Company and also with his industry and community. The Company gained much from his leadership and his legacy of character, style and humanity will continue to influence all who knew him.

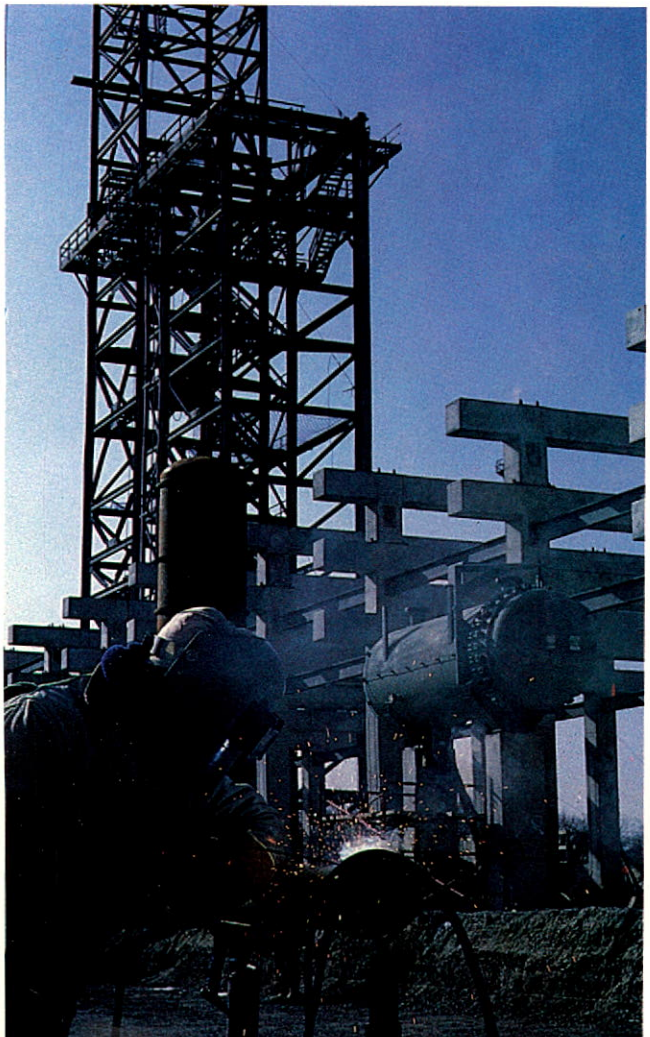
Resolution of the Board of Directors
of Suncor Inc.
January 27, 1983

Suncor launched a number of new capital projects in 1982. In this section, we tell you about the four largest.

These initiatives will increase Canadian oil reserves, enhance oil production, conserve millions of barrels of oil annually and create employment. About 1,300 urgently-needed jobs are being generated in Ontario, Quebec and Alberta as a direct result of these projects as well as additional work for manufacturers and suppliers across Canada.



Construction work on the upgrading of our Sarnia refinery is in full swing. Direct employment for more than 1,000 people will be generated by the $335-million project.



Saving 25 thousand barrels of oil every day: the Sarnia refinery upgrading

It's the largest capital project ever undertaken by Suncor.

The refinery upgrading will enable us to produce current levels of transportation fuels and more petrochemicals while using almost 4 000 m^3 per day (25 thousand barrels) less crude oil.

The benefits of conserving this oil are considerable. But the prime motivation is to be more responsive to the marketplace. At present, most Canadian refineries, including our own Sarnia facility, are designed to produce considerable amounts of home heating and heavy fuel oil but demand for these products is declining rapidly. The refinery upgrading, which will cost an estimated $335 million by the time it is completed in 1984, will enable us to be more selective about end products. We will be able to meet our customers' requirements for transportation fuels and petrochemicals without having to produce a large amount of heavy fuel oil. That's the main reason we save the 25 thousand barrels of crude.

The upgrading is equivalent to discovering an oil field in Canada producing more than 1.4 million m^3 (nine million barrels) of oil every year. A new oil sands project producing this amount would cost many times more.

The project includes a hydrocracker, a vacuum unit, a sulphur plant, a hydrogen plant and related facilities.

Here's how it works. The heavier fuel oils will flow to the new vacuum unit where they will be turned into feedstock for the hydrocracker and mixed with other lighter oils.

In the hydrocracker, hydrogen will be forced into the hydrocarbon molecules, converting them into more valuable products such as gasoline, aromatics, propane and butane.

The hydrogen unit will use plentiful and lower cost natural gas as feedstock—a key advantage of the process.

An additional bonus of the upgrading is the removal of sulphur from the final product. The sulphur plant which forms part of the project

will remove approximately 30 tonnes of sulphur per day, representing about 70 per cent of the sulphur content of our refined product.

But the main benefit is that we will be able to produce what our customers want. In fact, after the upgrading, our refinery will be one of the most flexible and efficient in Canada.

In addition to the upgrading, we are adding equipment to split liquefied petroleum gases. This will permit the separation of these gases into propane, isobutane and normal butane components. Isobutane and butane will be used by the refinery to manufacture gasoline while propane will be sold in increasing amounts as a transportation fuel. The splitter should be completed at the same time as the upgrading at an additional cost of approximately $8 million.

Between 85 and 90 per cent of the total cost for the refinery upgrading and the gas splitter will be spent in Canada. Employment on site will reach about 700 during the peak construction period in 1983.

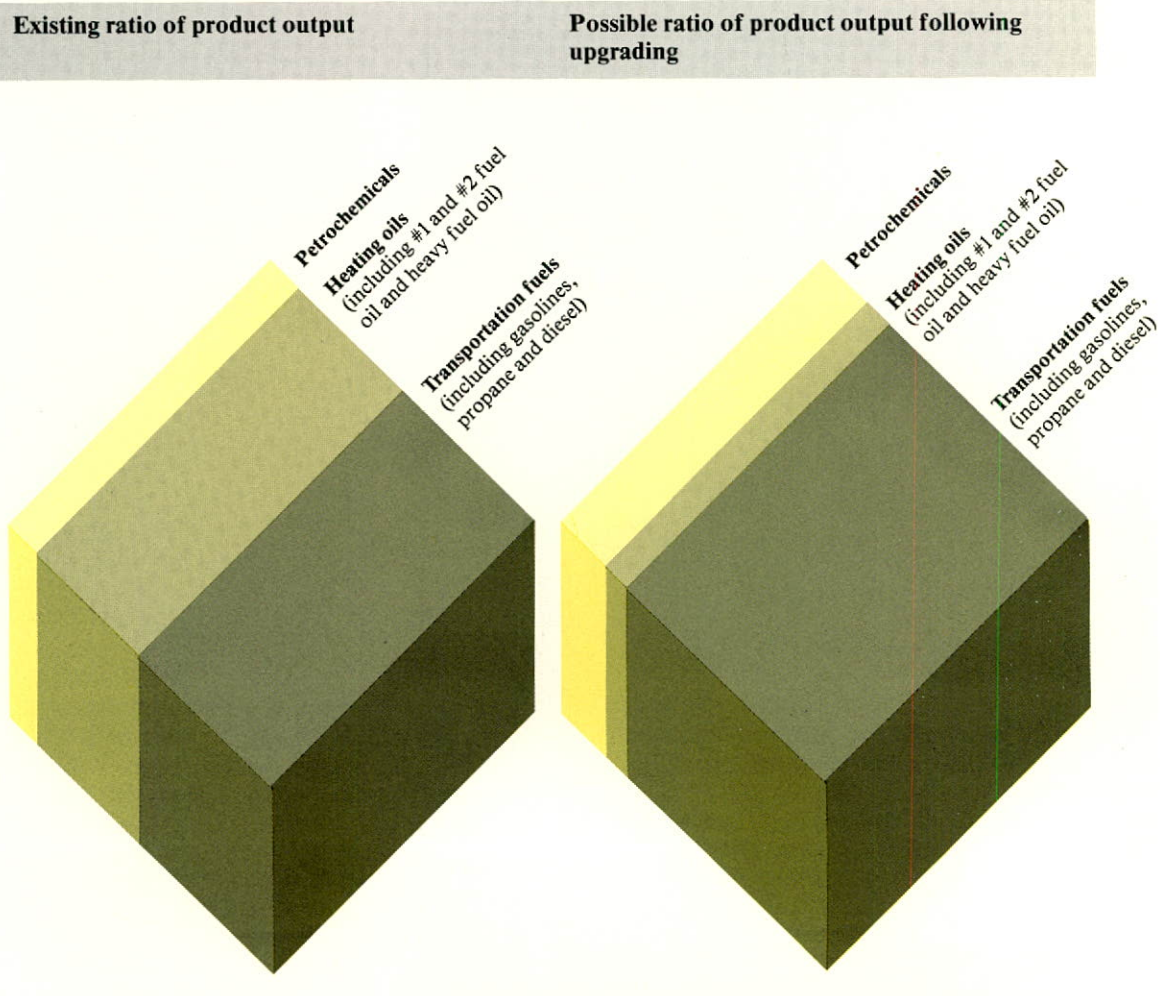
Adding 90 million barrels of oil to reserves: the large-pit project

At our Fort McMurray plant, bitumen is extracted from oil-bearing sand which is taken from a large open pit mine. But to get at the sand, we must first remove a covering layer of muskeg and glacial deposits called overburden.

Removing overburden and relocating it at the mine site is one of the main expenses of our oil sands operation. When the overburden is too thick, it becomes uneconomic to mine the oil-bearing sand lying beneath it. Thus, in determining the shape and size of the mine pit on our lease, the depth of overburden is a crucial factor.

In 1982, we started to remove thicker-than-normal overburden from an area of the lease which we had not originally intended to mine. Negotiations with the federal and Alberta governments produced a package of tax and royalty incentives enabling us to expand the mineable area by about 20 per cent. That's why we call it the large-pit project.

Refinery output pre- and post-hydrocracker



The large-pit project adds about 14 million m^3 (90 million barrels) to our synthetic crude reserves, bringing the total to about 66 million m^3 (418 million barrels). The extra reserves add nearly five years to the life of the oil sands project. But this additional oil is expensive. We will need to move additional volumes of overburden which will cost $185 million through to 1987.

Expanding the mine area will reduce the cost of Canada's oil imports by almost $4 billion based on current prices. The additional reserves will also provide significant production royalties and taxes to both the Alberta and federal treasuries. The large-pit project will employ approximately 100 people for the next five years.

Using new technology to recover heavy oil: the Fort Kent expansion

Canada's oil sands contain billions of barrels of oil. With the cancellation of several oil sands megaprojects in 1982, the question facing Canadians is how to tap this enormous resource.

Suncor may have part of the answer. For the past several years, we have been the operator and 50 per cent owner of an experimental in-situ heavy oil project at Fort Kent in the Cold Lake area of northeastern Alberta.

The project uses steam stimulation to produce heavy oil. Heat in the form of steam and water is forced underground to reduce the viscosity of the oil trapped in the sand, inducing it to flow. The oil is then pumped to the surface.

In 1982, Fort Kent production averaged 181 m^3 per day (1,140 barrels). But an expansion program now in progress should bring average daily output to around 795 m^3 per day (five thousand barrels) by the end of 1984.

The expansion involves drilling up to 112 wells and constructing additional steam and production facilities at an estimated total cost of $88 million. Suncor's share of the costs will be 55 per cent. By the end of 1982, 57 of these wells had been cased for production and about half of the work on the new steam and production facilities had been completed.

All of the expansion-related wells are being drilled on a slant, using new equipment specially developed for Suncor. The slant drilling technique means that sizeable reserves can be accessed with wellheads clustered in a compact area to preserve agricultural land. This new procedure has proved successful.

The additional steam facilities will use waste water from the nearby town of Bonnyville, thus conserving valuable surface water.

We are now actively evaluating opportunities for other projects like Fort Kent.

Improving the performance of our oil sands plant: the Plant Integrity Program

In the last days of 1981, we were looking forward to a good year from our oil sands operations. The expansion project and the maintenance shutdown had been completed and we were about to move under a new and far more equitable price schedule.

But during January and February of 1982, the plant was buffeted by a series of misfortunes including a major fire in the compressor house and unusually cold weather. As the thermometer dropped to minus 45° Celsius, equipment would not operate, lines split, safety valves stuck, instruments froze and emergency shutdowns were frequent. Preventive thawing and draining procedures were necessary to keep the plant from freezing up and these efforts aggravated the overload on people and systems.

It was a painful and disappointing year. But the problems helped us to identify possible areas of improvement to equipment and procedures which will help to make the plant more reliable. These improvements were brought together into one co-ordinated effort called the Plant Integrity Program which will cost about $170 million by the time it is completed in 1984. The Program includes:

- Redesigning and rebuilding the compressor house (now completed). Major modifications were made to the building and to the arrangement of the compressors to provide safeguards against further problems. The cost totalled almost $30 million.
- Improving waste water treatment facilities including new equipment and modifications totalling more than $12 million. This work is now largely completed.
- Rebuilding the three main steam boilers including installation of additional backup capacity. This project will be completed in 1984 at a cost of approximately $66 million.
- Upgrading the instrumentation system in the process area, including a new control room. Completion is scheduled for 1984 at a cost of about $24 million.
- Undertaking additional maintenance and upgrading work (now largely completed) enabling us to postpone by one year the maintenance shutdown originally scheduled for 1983.

We are confident that these major improvements, and many others of a less significant nature, will contribute to more effective operations and higher production volumes in 1983 and beyond.

Summary of Results

Financial ($ millions except per share data)	1982	1981
Revenues	**$1,550.6**	$1,320.7
Earnings		
-for the year	**$ 60.1**	$ 50.1
-per common share	**$ 1.13**	$ 0.93
-as a percentage of capital employed	**4.4%**	3.5%
-as a percentage of shareholders' equity	**5.6%**	4.6%
Funds from operations		
-for the year	**$ 158.5**	$ 127.7
-per common share	**$ 3.03**	$ 2.44
Capital expenditures	**$ 271.8**	$ 201.1
Dividends		
-per preferred share	**$ 1.92**	$ 1.92
-per common share	**$ 0.80**	$ 1.50

Operating	1982	1981
Exploration, production and resources development		
Conventional crude oil and natural gas liquids -gross production (a)	**807**	833
Natural gas-gross sales (b)	**639**	686
Conventional crude oil and natural gas liquids -gross proven reserves (b)	**9.6**	9.7
Natural gas-gross proven reserves (c)	**12.9**	13.3
Oil sands		
Synthetic crude oil -gross production (a)	**1 990**	1 701
-gross proven reserves (b)	**66.5**	54.0
Refining, petrochemicals and marketing		
Crude oil processed at Suncor refinery (a)	**4 039**	4 403
Sales of refined products (a)	**4 247**	4 521

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

A slant pump jack during assembly at our Fort Kent in-situ heavy oil project. This equipment has been specially developed to pump slant wells which have been clustered to conserve agricultural land.

Overview

The Resources Group contributed $66.2 million to Suncor's earnings in 1982 compared to a loss for the Group in 1981. Increased oil sands production (despite a major fire in January) and higher prices for both synthetic and conventional crude accounted for most of the improvement.

Production of conventional crude oil and natural gas declined in 1982 but the impact of these reductions on our earnings was more than offset by price increases for these commodities.

Total oil and gas revenues increased 86 per cent to $704 million in 1982.

Exploration and production development spending was cut back from 1981 levels reflecting the reduction in cash flow stemming from oil sands operating problems and the need to conserve financial resources for major new capital projects announced during the year. A number of other initiatives were placed on hold for budgetary reasons.

However, the Alberta Government extended its $250-million Well Servicing Program in August, 1982, both in duration and in scope.

Resources Group capital expenditures ($ millions)	1982	1981
Exploration, production and resources development		
Exploration		
Land holdings	**$ 8.0**	$ 10.8
Drilling	**27.9**	31.3
Geology, geophysics and other	**5.2**	8.1
	41.1	50.2
Production		
Acquisitions and land holdings	**0.8**	0.5
Development drilling	**7.3**	8.5
Plants, related facilities and other	**8.3**	11.9
	16.4	20.9
Resources development		
In-situ oil sands and minerals	**27.7**	4.3
Total	**85.2**	75.4
Oil sands		
Plant expansion	**2.8**	38.5
Mine and mobile equipment	**25.0**	24.6
Plant	**9.1**	2.3
Plant Integrity Program	**60.2**	–
Housing	**6.4**	18.2
Total	**103.5**	83.6
Total Resources Group	**$188.7**	$159.0

Under the new Development Drilling Incentive Supplement Program, virtually every conventional oil well drilled in the province during the period of the Program was eligible for cash grants covering approximately 25 per cent of drilling costs. Suncor participated in 14 wells eligible for these grants and received more than $1.6 million.

Overall, the Group's capital spending reached $188.7 million in 1982, up 19 per cent from the year before. Decisions to proceed with two large projects–the Fort McMurray Plant Integrity Program and the expansion of the Fort Kent in-situ heavy oil project–led to the increase. These initiatives, and a project to add to reserves at the oil sands plant, are described on pages seven to nine. Together, these three projects require expenditures by Suncor of more than $400 million over five years.

Outlook for 1983

During 1983, the Resources Group's main task will be to manage its three major capital projects effectively, to keep them within prescribed budgets and timetables.

We expect a substantial increase in synthetic crude production in 1983. Operations are improving and volumes late in 1982 were encouraging. However, the new oil reference price paid for synthetic crude production may not increase at the rate anticipated in federal/provincial pricing agreements. Reductions in the international price could result in reduced cash flow for the Oil Sands Division.

Softening world oil prices may also affect the price of old oil. Although a $4 per barrel increase in the old oil price was implemented on January 1, 1983, a similar increase scheduled for July 1, 1983 may not take place, as the old oil price is limited to 75 per cent of the world price. However, any increase in the price of old oil, combined with rising natural gas prices, will improve the Resources Group's cash flow, after allowance for royalties and taxes.

Spending on exploration and production of conventional crude oil will be increased to take advantage of the new oil reference price which on January 1, 1983, was $43.11 per barrel.

Spending on natural gas exploration and production will be cut back somewhat, reflecting reduced demand from our major customers. There is a considerable surplus of Canadian gas and until new markets develop, our efforts will focus on maintaining volumes under existing contracts. One favorable sign was the recently announced National Energy Board decision to allow an increase in gas exports which will enable the industry to seek new or expanded markets in the United States. Economic recovery should also spur demand from existing customers.

Long range prospects

The Resources Group faces significant challenges over the next several years, in three main areas: achieving reliable production at the oil sands plant; discovering new supplies of conventional oil; and increasing our participation in in-situ heavy oil projects.

The necessary steps are being taken to improve the reliability and efficiency of the oil sands plant. Our strategy is to manage this operation for cash which will be invested in other segments of the Company.

Exploration in western Canada is still at a relatively early stage, compared to some oil-producing areas in other parts of the world. Most of the easy-to-find fields have been discovered but more elusive, smaller and probably more numerous pools are still waiting to be drilled. Many of the deeper zones have yet to be explored adequately.

New technology for processing and modelling seismic recording has provided a valuable new tool in the search for hydrocarbons. Better measuring devices are now available for use in well bores to improve assessment of reservoir characteristics. Increased understanding of sediment patterns has given us a more accurate picture of subsurface characteristics which should lead to greater efficiency in our exploration efforts. Suncor is committed to using the latest technological developments in its exploratory programs.

The challenge in the future will be to weigh the cost of applying this new technology and the increased expense of drilling and development against the size of hydrocarbon pools that can be expected.

The near-term prospects for major new oil sands projects remain discouraging following the cancellation of two megaprojects in 1982. The capital, confidence and higher prices necessary for these gigantic undertakings are not now in place. However, smaller scale in-situ heavy oil projects like Fort Kent, with capital costs in the $50- to $100-million range, involve far less risk and substantially lower costs per barrel of output. We are seeking a number of such opportunities.

Wells completed

	Gross 1982	Net 1982	Gross 1981	Net 1981
Exploratory wells				
Oil	**6**	**6**	5	5
Gas	**11**	**7**	22	14
Dry	**24**	**17**	22	12
Total	**41**	**30**	49	31
Success ratio	**41%**		55%	
Average depth drilled (metres)	**1 416**		1 771	
Development wells				
Oil	**92**	**37**	17	5
Gas	**9**	**6**	20	9
Dry	**16**	**9**	11	8
Total	**117**	**52**	48	22
Success ratio	**86%**		77%	
Average depth drilled (metres)	**941**		1 555	

Note:
This table excludes wells completed under farmout agreements on Company properties as no cash expenditures were incurred by the Company. During 1982 there were 12 such exploratory wells; in 1981 there were 17 such wells (13 exploratory and 4 development).

The large increase in oil development wells and the significant decline in average depth drilled is related to the Fort Kent expansion program.

Undeveloped land holdings

(thousands of hectares)

	Gross 1982	Net 1982	Gross 1981	Net 1981
Oil and gas				
Western provinces				
British Columbia	**208**	**64**	346	68
Alberta	**435**	**251**	562	330
Saskatchewan	**1**	**1**	4	2
	644	**316**	912	400
Frontier*				
Northwest Territories and Yukon	**20**	**15**	204	84
Mackenzie Delta/Beaufort Sea	**462**	**173**	567	223
Arctic Islands	**7 332**	**1 370**	7 958	1 284
Offshore Labrador	**9 010**	**898**	7 474	746
Offshore Nova Scotia	**341**	**49**	341	77
	17 165	**2 505**	16 544	2 414
Total oil and gas holdings	**17 809**	**2 821**	17 456	2 814
Minerals	**555**	**405**	769	515
Total	**18 364**	**3 226**	18 225	3 329

*Subject to future reduction as Trillium Exploration Corporation earns an interest in the lands by carrying out exploration activities pursuant to farmin agreements with Suncor.

Exploration Division

Suncor participated in 15 successful exploratory wells in the western provinces in 1982, four of which were oil wells eligible for the new oil reference price. In the Arctic Islands, one exploratory well found gas and a delineation well confirmed a previous oil and gas discovery.

Western provinces drilling

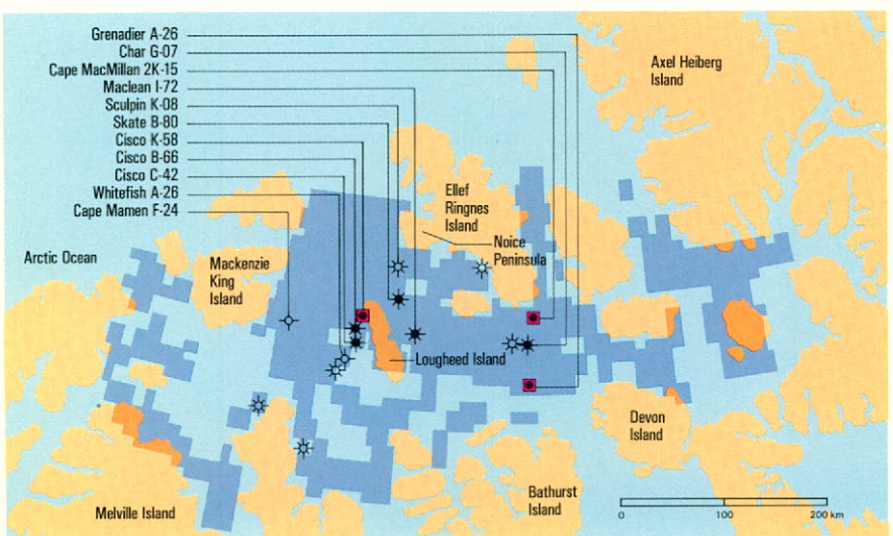
Suncor held interests in 40 exploratory wells drilled in this region in 1982 and was operator for 29 of them. In total, four were oil wells, 11 were gas wells, 18 were dry, one was suspended and six were still in progress at year-end, yielding a success ratio of 45 per cent.

Important drilling areas included:

- *Bougie Creek:* five exploratory wells have been drilled to date on this property of which four were gas wells and one was dry. Two of the gas wells were drilled in 1982. This area is located 105 kilometres south of Fort Nelson in British Columbia. Suncor has working interests ranging from 25 per cent to 100 per cent in 10 thousand hectares.
- *Chigwell area:* An oil well was drilled on this property in 1982. Two pay zones were encountered and the well is now producing from one of them. This area is located 100 kilometres south of Edmonton. Suncor has a 100 per cent working interest in 256 hectares including 64 hectares added in 1982.
- *Lochend area:* Suncor drilled a successful exploratory oil well on this property in 1982 following an initial oil discovery in the previous year. This area is located 40 kilometres northwest of Calgary and is considered to be an extension of the 1981 Cochrane play. Suncor has a 50 per cent interest in 7 680 hectares.
- *Wood River area:* Suncor farmed into this area in 1981 and drilled four wells. One of these wells discovered oil, the other three found gas. This area is located 85 kilometres south of Edmonton and offsets the Malmo field where we have an oil and gas operation. Suncor has a 50 per cent working interest in 1 280 hectares in the Wood River area.

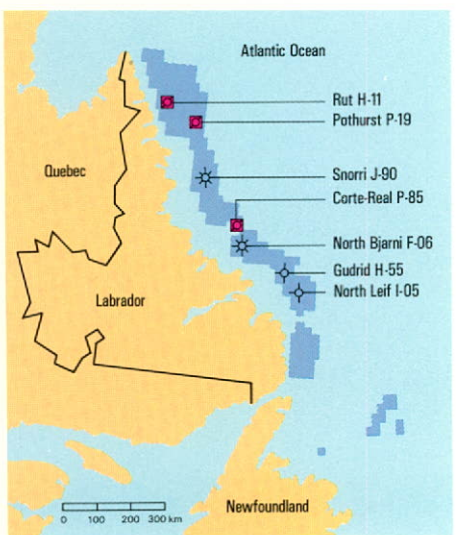
Overall, drilling expenditures declined 29 per cent to $16.5 million in 1982 because of budgetary constraints. Fewer wells were drilled and overall meterage was down. However, seismic spending increased 14 per cent, reflecting the decision to identify new oil prospects for future drilling. In general, oil reservoirs are smaller and harder to find than natural gas reserves, thereby requiring more seismic work.

Spending on land acquisitions for future exploration drilling decreased 19 per cent to $8.0 million in 1982. A total of 72 thousand gross hectares were acquired (41 thousand net). Key acquisitions were in the Daysland and Peace River Arch areas of Alberta and the Bougie Creek and Milligan areas of British Columbia.



Arctic Islands

- New locations
- Gas potential
- Oil and gas potential
- Dry well
- Suncor land holdings
  7.3 million gross hectares
  1.4 million net hectares



Offshore Labrador

- Gas potential
- Suspended (1983 Re-entry)
- Dry well
- Suncor land holdings
  (all lands have been farmed out to Trillium Exploration except certain properties surrounding previous discoveries)
  9.0 million gross hectares
  0.9 million net hectares

Arctic Islands

Four wells were drilled in the Arctic Islands offshore area during the 1982 season. Cisco C-42 was a step-out well approximately nine kilometres south of the 1981 Cisco B-66 oil and gas discovery. Cisco C-42 also found oil and gas. Suncor has a 14.8 per cent interest in the permit on which this well was drilled.

The Sculpin K-08 exploratory well located about 17 kilometres southwest of the Noice Peninsula, part of Ellef Ringnes Island, was a small gas discovery. Suncor's interest in this well is 8.4 per cent.

Two other wells were drilled in 1982, neither of which showed any significant hydrocarbons.

Three wells will be drilled in the 1983 program. Suncor's interests in two of these wells have been farmed out to Trillium Exploration Corporation which is one-third owned by Suncor. The 1983 program will also employ two seismic crews.

In early 1983, Suncor signed a 13-well, five-year farmout agreement with Trillium Exploration. Trillium may earn an average interest of five to six per cent (half of Suncor's interests) in the Exploration Agreements covering 6.9 million hectares in the Arctic Islands by assuming Suncor's share of exploration and drilling costs.

Suncor's total holdings in the Arctic Islands are 7.3 million gross hectares (1.4 million net). To date, 28 wells have been drilled on these lands, resulting in nine discoveries—five natural gas and four oil and gas. These discoveries are not included in the farmout agreement.

Offshore Labrador drilling

Suncor is a partner in the Labrador Group which commissioned three drillships for the 1982 exploration program. Three wells were drilled but because of bad weather, all were suspended before reaching their objectives. The plan for 1983 is to re-enter these wells and drill to the original projected depth. Suncor's interests in these wells were farmed out to Trillium Exploration Corporation in July, 1982.

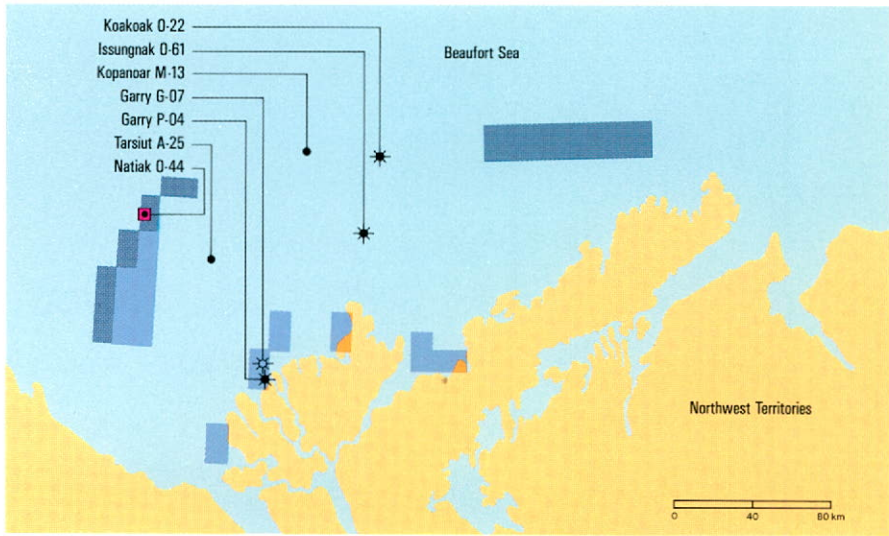
Beaufort Sea

Suncor has interests in 369 thousand gross hectares 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 Dome has elected to drill its first well, Natiak 0-44, in 1983. The projected total depth of this well is 4 875 metres. Suncor's current interest in the Natiak Block is 27.5 per cent.

Exploration Agreements

All of Suncor's frontier land holdings are covered by Exploration Agreements being negotiated with the Canada Oil and Gas Lands Administration.

In general, these agreements are for terms of three to five years and require seismic work, the drilling of at least one exploratory well, environmental work, relinquishing half of the acreage by the end of the term and maintaining an acceptable Canadian benefits package. This package specifies employment opportunities and other advantages to be generated for the benefit of Canadians.

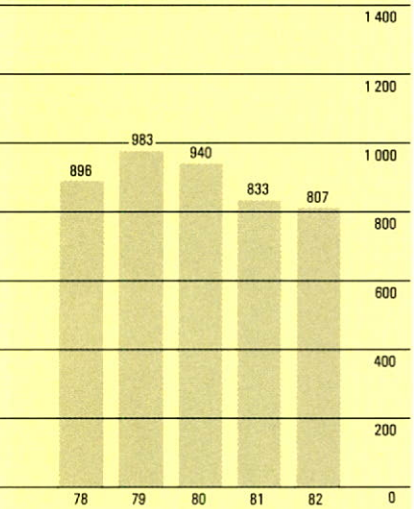


Beaufort Sea / Mackenzie Delta

- New location
- Oil potential
- Oil and gas potential
- Gas potential
- Farmout Agreement
- Suncor land holdings
  0.5 million gross hectares
  0.2 million net hectares

Gross production of conventional crude oil and natural gas liquids

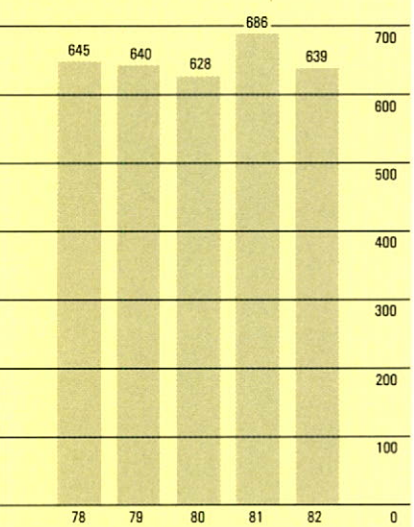
(thousands of cubic metres)



	1982	1981
Alberta	**544**	583
Saskatchewan	**195**	177
British Columbia	**49**	51
Manitoba	**19**	22
Total	**807**	833

Gross natural gas sales

(millions of cubic metres)



	1982	1981
Alberta	**593**	634
British Columbia	**41**	43
Saskatchewan	**5**	9
Total	**639**	686

Production Division

Suncor's conventional crude oil and natural gas production fell in 1982. Proven reserves of conventional crude oil, natural gas liquids and natural gas declined slightly as the year's production outpaced net additions.

Drilling

A total of 117 gross development wells were drilled in 1982, yielding 92 oil wells, nine gas wells and 16 dry holes for a success ratio of 86 per cent. One well was in progress at year-end. Included in these figures are 67 wells drilled as part of the expansion of the Fort Kent in-situ heavy oil project.

Spending on development drilling and related well equipment (excluding Fort Kent) declined 14 per cent to $7.3 million in 1982. Expenditures were reduced wherever possible, reflecting the decline in our cash flow from operations and the need to conserve cash for major capital projects.

Production

Gross daily production of crude oil and natural gas liquids averaged 2.2 thousand m^3 in 1982 (13.9 thousand barrels), down about three per cent from 1981. The total includes both conventional and in-situ heavy oil production but excludes synthetic crude from the oil sands plant.

Gradual depletion of the reservoir on our Bonnie Glen lease in Alberta was the main reason for the reduction. This lease is Suncor's largest producer. Production cutbacks resulting from lower demand for Alberta crude in 1982 were not a factor as these cutbacks were about equal to the production cuts mandated by the Alberta Government in 1981 during its dispute with the federal government.

Reductions in crown royalties in Alberta and Saskatchewan kept net production at nearly the same level as in 1981. Our net production was also assisted by a substantial increase in output from the Lindbergh area (150 kilometres east of Edmonton) in which Suncor has an overriding royalty.

Gross daily natural gas sales were 1.8 million m^3 (62 million cubic feet), down about seven per cent from 1981 mainly due to lower demand. TransCanada PipeLines, our largest customer, took 33 per cent less than its contract minimums in 1982 whereas in 1981, it took 25 per cent less than its contract minimums. TransCanada is a major supplier to U.S. customers in Michigan who were particularly hard hit by recession. Meanwhile, domestic markets were stagnant.

Net natural gas production rose slightly due to various reductions in Alberta crown royalties.

Overall, 67 per cent of our gross crude oil production, including natural gas liquids and heavy oil, came from Alberta in 1982 as did 93 per cent of our gross natural gas sales.

Spending on gas gathering and processing systems to facilitate production totalled $5.1 million in 1982, up 20 per cent from the previous year. Projects included new plant and field facilities in the Mountain Park, Portage and Calling Lake areas of Alberta. The Mountain Park field will begin producing in the first quarter of 1983 as part of the major Robb-Hanlon project in west central Alberta.

The most significant undeveloped production property acquired in 1982 is in the Ricinus field of Alberta. One well was spudded on the property and was completed in early 1983 as an oil well in the Cardium formation.

This 1 772-tonne bucketwheel scoops oil sand from the Fort McMurray mine site. Conveyors carry the oil sand to the extraction plant.

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, 1981	**9.7**	**13.3**	**6.9**	**10.2**
Additions	**0.7**	**0.2**	**0.9**	**0.9**
Production/sales	**(0.8)**	**(0.6)**	**(0.5)**	**(0.5)**
December 31, 1982	**9.6**	**12.9**	**7.3**	**10.6**
Probable additional				
December 31, 1982	**2.1**	**4.6**	**1.7**	**3.6**

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

1. 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.

2. Gross reserves are before deducting royalties. Net reserves are after deducting royalties. Royalties can vary depending upon prices, production volumes, timing of initial production and changes in legislation.

3. CNP has determined the present value of estimated future net revenues from reserves as of December 31, 1982, using a discount factor of 10 per cent to be $620 million.

These estimates have been calculated using constant prices and costs and represent gross revenues from estimated future production, less royalties, production taxes, operating costs and capital expenditures incurred in developing and producing the reserves. There has been no deduction for interest costs, income taxes or administrative costs.

Reserves

Gross proven reserves of conventional crude oil and natural gas liquids fell one per cent to 9.6 million m^3 (60 million barrels) in 1982. Net additions to gross reserves during the year amounted to 0.7 million m^3 (4.5 million barrels). The most important additions were in the Wood River area of Alberta, about 85 kilometres south of Edmonton, where Suncor recorded one oil and three gas discoveries. New oil was also discovered in the Swan Hills area of Alberta 255 kilometres northwest of Edmonton and in the Lochend area of Alberta 40 kilometres northwest of Calgary.

Gross proven reserves of natural gas were 12.9 billion m^3 (457 billion cubic feet) at the end of 1982, a drop of about three per cent from 1981. Net additions to gross reserves totalled 0.2 billion m^3 (six billion cubic feet). The largest additions resulted from exploratory drilling in the Wood River area noted above and the Bougie Creek area of British Columbia located 105 kilometres south of Fort Nelson.

All of Suncor's proven reserves are located in western Canada. Reserves in the frontier areas are not included in the calculations because there has not yet been sufficient drilling to determine whether or not they are of commercial size and their recovery depends upon approval and construction of transportation systems to deliver them to market.

Resources Development Division

The task of this Division is to search out and develop new energy resource opportunities. In the past several years, the emphasis has been on in-situ production of heavy oil from Alberta's oil sands. Some initial steps have also been taken toward evaluating the coal business.

In-situ production means that oil is separated from the sand within the ore body itself. A number of technologies exist but the most common one at this time is steam stimulation. Steam and water are forced 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.

Steam stimulation is the method now being used at our Fort Kent project. In 1982, Fort Kent production averaged 181 m^3 per day (1,140 barrels), of which Suncor's share was 50 per cent. This project is now undergoing substantial expansion as described on page nine.

In 1982, we farmed into a 6 912 hectare lease west of the Fort Kent property. Under the terms of the agreement, Suncor obtains a 50 per cent interest in this lease in exchange for conducting a drilling program. Four wells were drilled in 1982, two of which encountered natural gas and heavy oil. Evaluation of this property will continue in 1983.

We also conducted further work on our wholly-owned 20 232 hectare lease 27 known as Cheecham, located south of Fort McMurray. A water source suitable for steam generation was developed in 1982, two wells were drilled to probe the oil-bearing sand and engineering studies were conducted. Further work on this lease is being held in abeyance due to budget constraints.

Also in 1982, three core holes were completed on the Acadia lease located in Nova Scotia to quantify the coal in place. Geological and geophysics work was conducted on the property and engineering feasibility studies were also prepared. Additional drilling is planned for 1983. Suncor is the operator and 58.4 per cent owner of this 3 796 hectare lease.

Exploration continued on eight other coal and mineral properties during 1982. The majority of these prospects have matured to the point at which some drilling evaluation work will take place in 1983.

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 sand. Second, the sand is mined and transported by conveyors to the extraction unit. Third, hot water and steam are used to extract the bitumen from the sand. Fourth, the bitumen goes to the refinery 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.

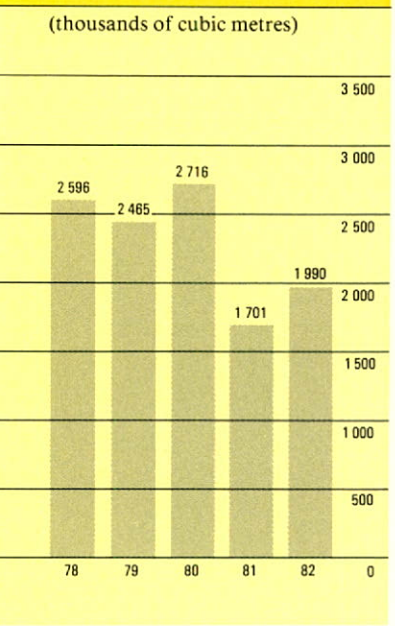
Production

Production of synthetic crude averaged 5.5 thousand m^3 per day (34 thousand barrels) in 1982. This amount includes unprocessed synthetic crude produced when the unifiners in the plant's refinery were not operating. Output was 15 per cent higher than in 1981, largely the result of improved operations in the last four months of the year.

Nonetheless, daily average output was much below potential capacity. Production was adversely affected by a compressor house fire and steam shortages from January through to August, 1982. The fire resulted in substantial damage to equipment, the compressor house building and hydrogen plant. Repairs took eight months to complete. Production in September and October was reduced by operating problems in the unifiners which remove impurities from the hydrocarbon to produce synthetic crude.

Operational problems made it difficult to maintain water control standards. Suncor was charged under fisheries and clean water legislation during 1982 and several of these charges went to trial. Suncor was acquitted on one charge and the judge noted that Suncor had faced unusual operating problems and that the Company had used all its resources to combat the pollution problem. Suncor was convicted on the charge of failing to report to Alberta's Director of Pollution Control within 24 hours of releasing a contaminant into the Athabasca River and the Company was fined $500. However, a notice of appeal has been filed. Other charges will be tried in 1983.

Gross production of synthetic crude oil



For details of gross production of synthetic crude oil see page 45.

Synthetic crude oil gross proven reserves

(millions of cubic metres)	
December 31, 1981	54.0
Revisions	0.4
Extension of mine boundaries	14.1
Production	(2.0)
December 31, 1982	**66.5**

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

Proven reserves are those which are considered with 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.

More than $11 million was spent in 1982 to improve the oil sands plant's environmental control systems. Work included a major upgrading of waste water handling facilities, land reclamation (including the planting of 76,000 trees) and a careful, independent study of the impact of the plant's air emissions on the surrounding forest. The study found no evidence of stress on the local flora.

Production reliability is being enhanced by a $170 million Plant Integrity Program to be completed over the next two years, as described on page nine. In addition, a number of major operating improvements were made to the plant during 1982 including nearly $19 million to install new conveyor systems which take oil sands from the mine face to the extraction plant. These new conveyors will permit expansion of the mining operation in 1983.

Sales of sulphur, coke and technology

Suncor's oil sands plant produces more than synthetic crude. Sulphur sales are continuing under a long-term contract. In 1982, 180 thousand tonnes (199 thousand tons) were shipped, which was less than originally expected because synthetic crude production levels were lower than anticipated. We also sold 19 thousand tonnes (21 thousand tons) of coke in 1982, also less than projected because of soft prices in the world market.

Suncor had expected to sell technology to the Alsands consortium in 1982 but the agreement was cancelled when the Alsands investors decided not to proceed with the project.

Human resources

The operating problems encountered in 1982 pushed employees to the limit. They responded with extraordinary efforts, often performing tasks outside their normal duties, safely and effectively, to get the plant back to normal production.

In March, 1982, a contract was negotiated with the McMurray Independent Oil Workers Union representing about 1,000 employees. The contract expires in May, 1984.

A number of factors point to improved morale. Grievances are down substantially and the safety record of the plant has improved significantly. Better training and communication programs are producing positive results.

Overview

Revenues rose four per cent to $1.2 billion for the Sunoco Group in 1982, the increase resulting from passing through higher crude oil costs and government taxes. Sales volumes declined due to lower demand and operating margins were adversely affected by increased competition. The Group's contribution to Suncor's earnings consequently fell to $19.0 million from $53.3 million in 1981.

Demand for refined products fell faster than anyone had expected. The economic recession, higher prices and government programs encouraging consumers to switch from oil to other fuels all contributed to the reduction in demand. Suncor's sales decline was not as steep as the industry average, but our volumes were down.

Canada's demand for refined products should stabilize when the economy recovers. However, higher prices have encouraged conservation and volumes of key products like gasoline may never again reach 1981 levels.

For 1982, capital expenditures by the Sunoco Group totalled $83 million compared to $42 million for the year before. Most of the spending related to the refinery upgrading project which is described on page seven.

At year-end, the upgrading was well under way. Engineering work was more than two-thirds finished, all major equipment was on order, the vacuum tower shell had been erected, shop fabrication of piping had commenced and all the underground work had been completed. More than 700 people were at work on the project.

One of the most important tasks facing the Sunoco Group is to complete the upgrading project on time and within budget. To help accomplish this task, we have introduced a new program called MAPLE. It stands for Maximum Achievement in Productivity with Labour Expertise and it is a construction productivity program having the full co-operation of the building trades unions.

Foremen, tradesmen and subcontractors involved in the upgrading project attend training sessions in such subjects as planning, scheduling and productivity analysis. Questionnaires and interviews are used to gather ideas from everyone involved in the project on how to improve equipment, tools or procedures to get the job done more effectively.

Propane is one of the transportation fuels of the future. Suncor has recently opened a new facility in Mississauga, Ontario to convert gasoline-powered vehicles to propane use. Four Sunoco service stations now offer propane in the Toronto area.

Suncor's joint shipping venture with Sun Company was highly successful in 1982. Two petrochemical tankers operated close to full capacity on voyages to Europe, and back haulage was much higher than for the shipping industry as a whole. To facilitate our petrochemical exports, we established a new subsidiary in London to act as our European sales agent.

The Canadian oil-based petrochemical industry has developed valuable export markets on the basis of federal policy specifying that Canadian oil prices would remain below world levels. This price advantage is now being eroded and export markets are in jeopardy. We have therefore joined with other chemical producers in urging the federal government to maintain a feedstock price advantage for the industry.

During 1982, Suncor became the first major integrated oil company to provide complete propane service under its own brand name. We opened a conversion centre and four service stations selling propane, all in the Toronto area. The conversion enables cars and trucks to burn propane. Both the federal and Ontario governments offer grants and tax incentives for this conversion.

Propane has a number of significant advantages. It costs about 40 per cent less than gasoline and its use substantially reduces vehicle maintenance costs. Propane consumption should increase rapidly in coming years.

Late in the year, three Suncor representatives appeared before the Restrictive Trade Practices Commission in Ottawa to testify on one section of the Bertrand Report. This report, entitled "The State of Competition in the Canadian Petroleum Industry" alleges that Canadian oil companies, including Suncor's predecessor Sun Oil Company Limited, conspired to lessen competition during the 1958 to 1973 period. In extensive questioning, Suncor's representatives clearly and forcefully denied the allegations of wrongdoing and offered substantive information to support the Company's position. The hearings continue.

Outlook for 1983

Our competitors announced the closing of a number of refineries in 1982, bringing Canada's supply and demand into somewhat better balance for transportation fuels. However, industry-wide sales of gasoline in Ontario and Quebec will probably decline by another two or three per cent in 1983 before stabilizing. Home heating oil sales will decline substantially again in 1983 and the heavy fuel oil market will remain depressed. Petrochemical and diesel sales should begin to rise somewhat in response to the tentative economic recovery expected in the second half of the year. Overall, it should be a year of tough competition and tight margins.

Operations

Refining

Average daily throughput of crude oil at our Sarnia refinery fell about eight per cent from 1981 to about 11.1 thousand m^3 (70 thousand barrels). This volume was 77 per cent of rated capacity.

Reduced demand for refined products and a scheduled maintenance shutdown of plant number one and the alkylation unit accounted for the decline in throughput.

Two minor fires occurred during 1982 but they had no impact on production.

Petrochemicals

Petrochemicals are produced and sold under the Sunchem name for use in the manufacturing of plastics, solvents, dynamite, pesticides, paints and synthetic fibres.

Our production rose more than five per cent in 1982. Sunchem fared much better than most Canadian petrochemical producers: oversupply was not as serious for our product lines as it was for other types of petrochemicals and most of our customers are committed to us under long-term contracts. New customers were also developed during the year.

World crude oil prices declined slightly in 1982 while crude oil prices in Canada continued to rise. Sunchem was therefore caught between rising costs in Canada and falling prices in foreign markets. As a result, our prices and margins dropped.

Gasoline marketing

Sunoco supplies gasoline to the Ontario and Quebec markets. Demand in these markets declined by about 10 per cent in 1982 due to increased prices, more fuel-efficient cars and reduced levels of economic activity. Resulting competition led to intermittent gasoline price wars in several Ontario markets. However, our volume reduction was somewhat less than industry average, largely the result of our unique Blender Centre concept and a successful promotion at Sunoco outlets.

Blender Centres enable motorists to choose between three blends each of leaded and unleaded gasoline—the widest choice available in Ontario and Quebec. This advantage was advertised early in the year.

In July, 1982, we launched a "Match and Win" promotion at our branded outlets in response to promotions from other retailers.

Home heating oil marketing

In 1982, demand for home heating oil in Ontario and Quebec declined by about 10 per cent. Our sales volumes fell by 16 per cent, primarily because reduced crude runs at our refinery and exchanges with other refiners resulted in less fuel oil available for sale. Sales by our branded distributors dropped by less than four per cent—an indication of our success in maintaining fuel oil markets.

We expect overall demand to continue downward in 1983, reflecting conservation efforts by consumers, government off-oil programs and government-controlled pricing that favors natural gas and electricity.

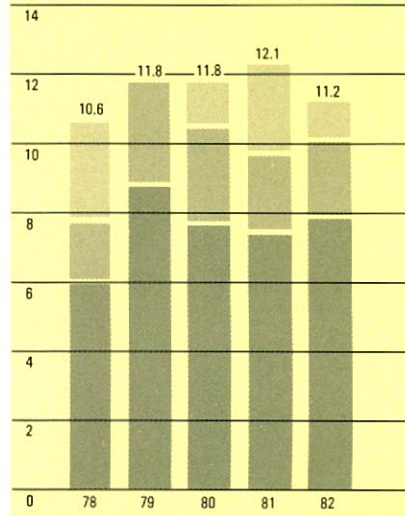
Lubricants and specialty products

The Sunoco Group blends and packages a wide range of lubricants, primarily for the industrial market. Sales volumes declined by 20 per cent in 1982, reflecting the impact of the recession on the industrial sector.

Thirty-two new products were developed and introduced in 1982 including industrial lubricants, hydraulic fluids, metalworking fluids and process oils to meet the specific needs of particular market segments and individual customers.

Sources of crude oil refined for Suncor account

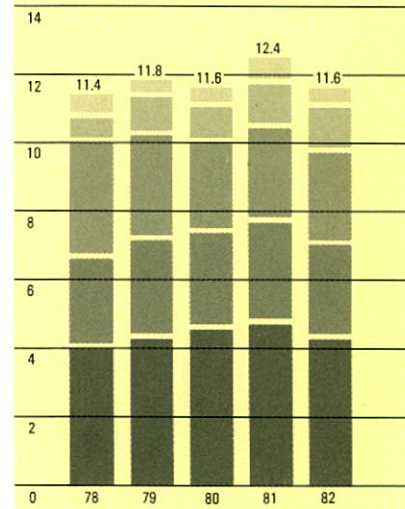
(thousands of cubic metres per day)



	1982	1981
Imported	**1.1**	2.5
Canadian synthetic	**2.2**	2.2
Canadian conventional	**7.9**	7.4
Total	**11.2**	12.1

Sales of refined products

(thousands of cubic metres per day)



Other products
Petrochemicals
Heavy fuel oil
Middle distillates
Gasolines

For details of refined products sales see page 45.

An Interview with Bill Loar

Bill Loar, Suncor's new President and Chief Executive Officer, first joined Sun Company in 1951 in Tulsa, Oklahoma. For the past 16 years, he has worked for Suncor and its predecessor companies in Calgary. He was President of Great Canadian Oil Sands Limited in 1979 when it was merged with Sun Oil Company Limited to form Suncor, at which time he became the Company's first Executive Vice-President, Resources Group, responsible for all upstream operations. Mr. Loar is a member of the Board of Governors of the Canadian Petroleum Association.

In this interview, Mr. Loar talks about the thinking behind Suncor's new capital spending initiatives and their implications for the Company.

Mr. Loar, Suncor unveiled four new projects in 1982 involving capital spending by the Company of around $738 million. Most companies are cutting their spending programs. Why is Suncor pursuing a different course?

There are several different reasons.

Each one of these projects is an opportunity in its own right. The upgrading of our Sarnia refinery will make it more efficient and responsive to the market. The extensive new maintenance program at the oil sands plant will make it more reliable operationally. Expanding the area we will mine at the oil sands plant adds to reserves. Expansion of our Fort Kent in-situ heavy oil project will also augment reserves and increase oil production. These projects are what business is all about. We are committing money to projects that we think will show a good return.

Their combined effect is significant. We want Suncor to be a more balanced company. By that we mean more income from operations other than the oil sands plant. Our capital spending program is designed to accomplish this objective, especially by strengthening the downstream operations.

But behind all this there is also something less tangible. When companies make sizeable investments like we have they are expressing their confidence in the future. What we are saying is that we believe in Canada and our future as a company.

The decision to spend $335 million on the refinery comes at a time when markets for refined products are taking a nose dive. Why do it?

So that we can meet the changing needs of our customers. Our refinery was originally designed to produce large amounts of home heating oil, gasoline and heavy fuel oil. In the '50s, '60s and '70s, these were the profitable products. Since then, crude oil has become much more expensive and consumption patterns have changed dramatically. The market for home heating and heavy fuel oils is diminishing. But our refinery is still producing roughly the same proportions of end product for each barrel it refines.

The upgrading changes all that. We will have much more flexibility in the mix of refined products that we produce. And we will also be much more efficient. In fact, we will be able to produce current levels of transportation fuels and more petrochemicals while using about 25,000 barrels per day less crude oil.

We aren't adding to our refinery's capacity because petroleum refining is no longer a growth business. But we are making the investments necessary for us to continue to be a powerful and effective competitor.

How is it possible to save such large amounts of crude oil?

Essentially, the new equipment we are installing will enable us to virtually eliminate the production of heavy fuel oil.

We have a major contract to supply heavy fuel oil to a U.S. customer. That contract is coming to an end in 1984. On the open market, heavy fuel oil sells for less than the crude oil it's made from. Our best strategy, therefore, was to overhaul the refinery process so that we won't have to produce it.

What we want is a product slate tilted toward certain petrochemicals and transportation fuels. The upgrading accomplishes this for us. In fact, it will enable us to choose from a range of end-product mixes.

Other companies have chosen to close refineries rather than modernize them. Will this mean shortages?

No, actually there has been a surplus of refining capacity. Shell, BP, Texaco and Gulf are cutting back because of lower demand.

What we are seeing is a period of consolidation. I think that it is fair to say there are going to be fewer players in the refining business. The sorting-out process may involve a little hardship. But the consumer will benefit, because refining operations will be much more cost-effective.

Do these closings suggest that we are facing a long-term decline in demand for refined products? Or is it just because of the recession?

It's both. Certainly the recession has cut into consumer spending on just about everything. For example, people are driving less and there are fewer trucks carrying fewer loads as a result of the economic downturn.

But we also have to look at the impact of higher prices. Consider gasoline. In today's environment, consumers normally pay just about twice as much per litre as they did three years ago. This increase reflects the federal government's decision to move Canadian prices closer to world levels. Gasoline sales have dropped sharply two years in a row, in line with U.S. trends where prices rose earlier. European demand is also lower.

Of course, in Canada, very little of the price increase goes to the refiner. In fact, in the past three years, less than 10 per cent of the total increase in Ontario's gasoline price went to our Sunoco Group. The lion's share went to governments.

Other government programs are also a factor. For example, Ottawa has been encouraging homeowners to reduce oil consumption by providing financial incentives to improve insulation

and switch to natural gas. These incentives have had a real impact on the market and the trend is bound to continue.

What's your outlook for demand in the future?
We expect Canadian consumption of refined petroleum products to drop by 15 to 20 per cent over the next 10 to 15 years. Gasoline, home heating oil and heavy fuel oil sales will decline, offset somewhat by more consumption of diesel fuel, propane and petrochemicals. When you consider that petroleum demand has risen for more than 40 years, this has to have a big impact on the industry.

How will the refinery upgrading be financed? Can it be done out of cash flow?
Not entirely. During 1982, we set up revolving credit and term loan arrangements with several financial institutions amounting to $550 million. These lines of credit have now been partly utilized.

The amount of money we actually borrow will depend upon our operations. If our oil sands plant meets its 1983 targets and if we have better price stability in our downstream markets, then operating cash flow should be able to finance the bulk of our capital program.

The oil sands plant did not run all that well in 1981 and 1982. Do you expect improvements in 1983?
I'm optimistic we're going to set production records for synthetic crude this year. However, there are some areas of risk, in particular the utilities plant. The three main boilers which generate steam used to extract bitumen from the oil sands are scheduled for major refurbishing in 1983 and 1984. Until this work is done, there is some risk of operating problems. However, in 1982 we completed considerable maintenance work on this equipment to reduce the risk and, in addition, we have installed and commissioned auxiliary boiler capacity.

But I think we also have to accept the fact that there will always be some problems mining oil sands. It's simply not like manufacturing widgets. The climate is very harsh on people and equipment. The quality of the ore is uneven—in some places the clay content is higher, which poses extraction problems. Furthermore, both overburden and the oil sands vary in thickness, requiring ongoing reviews of logistics and costs.

Last year it was announced that Suncor would be spending an extra $185 million over the next five years to increase the area of the lease which will be mined. Why was this necessary?
There is a section of the oil sands lease containing about 90 million barrels of oil which is buried under a thicker-than-normal layer of overburden. We have to remove this overburden to mine the oil sands. We're now at the point where we have to begin mining this area or bypass it altogether. So the strategic question we faced last year was whether or not to spend the extra money to mine this particular section which would extend the life of the lease by four to five years.

The economics were far from good. Under the National Energy Program, 75 per cent of the additional production was considered old oil and therefore subject to the federal incremental oil revenue tax. Also, there was a problem of timing. We don't really get the benefit of the extra oil until early in the next century when the lease would otherwise have run out. But the money to remove the overburden must be spent a lot sooner—most of it over the next five years. The federal government subsequently agreed to a reduction in the incremental oil revenue tax which Alberta is matching with a cut in production royalties. This made it worthwhile to proceed.

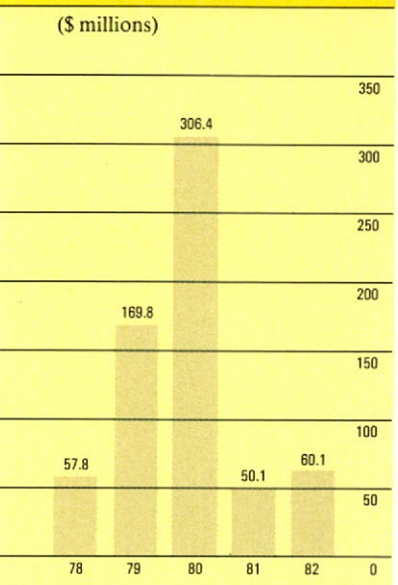
Ottawa is playing a major role in Canada's oil industry. Some of their policies have been damaging to your industry. Do you believe you can work with them in a productive way?
Our policy has always been to work with governments and I think our record is a good one.

Let's look at it from Ottawa's point of view. Our refinery upgrading will conserve Canadian oil and provide direct employment for more than 1,000 people. The extra 90 million barrels of oil from the oil sands will reduce the cost of Canadian imports by almost $4 billion at current prices and employ another 100 people or so on a contract basis over the next five years in overburden removal.

We are contributing to the national objective of self-sufficiency in oil. We have demonstrated our willingness to move toward Canadian ownership and control of our Company. We are creating new jobs for Canadians at a time when they are sorely needed. In other words, we're responding to national priorities and I believe Ottawa recognizes this.

That's not to say I accept the government's policy-making without complaint. I think there has been too much arbitrary intervention and too many rules, some of which have run counter to Ottawa's own objectives. Consultation and joint planning could make many of the regulations unnecessary. But on the whole, I think Ottawa is becoming more responsive to business and more understanding of the oil industry. If problems come up, I think we can work them out.

Earnings before extraordinary gains



Consolidated statement of earnings

Earnings for the year were $60.1 million, up $10.0 million or 20 per cent over 1981. The favorable earnings effects of higher synthetic and conventional crude oil and natural gas selling prices, and increased synthetic crude oil sales volumes, were substantially offset by higher operating and interest costs, and lower refined products sales volumes and profit margins. These factors are discussed more fully in the following segment analysis.

Schedule of segmented data

Exploration, production and resources development

Earnings from this segment were $24.7 million, an increase of $16.0 million over 1981.

Revenues rose by $29.2 million or 17 per cent. Higher crude oil and natural gas selling prices averaging 36 per cent and 10 per cent respectively, increased revenues by $37 million. This increase was partially offset by lower crude oil and natural gas sales volumes ($8 million) arising mainly from reduced market demand.

Expenses (excluding both income and incremental oil revenue taxes) increased by $10.5 million or seven per cent. The petroleum and gas revenue tax (PGRT) rose $5.2 million mainly as a result of higher revenues. The remaining increase of $5.3 million was primarily due to inflation partially offset by the impact of reduced crown royalty rates.

Income tax increased by $0.6 million as a result of higher earnings. The introduction of the new incremental oil revenue tax (IORT) in 1982 resulted in additional taxes of $2.1 million.

Oil sands

Earnings from this segment were $41.5 million compared to a loss of $19.3 million in 1981.

Revenues (excluding higher business interruption insurance proceeds of $15.7 million) increased by $287.2 million or 128 per cent. Of this amount approximately $213 million was due to higher synthetic crude oil selling prices arising from the September 1, 1981 agreement between the Alberta and federal governments. Higher synthetic crude oil sales volumes increased revenues by $74 million.

Expenses (excluding income and incremental oil revenue taxes) were up $165.8 million or 58 per cent. Royalties and PGRT increased by $41 million and $17 million respectively, mainly as a result of higher selling prices. Inflation and higher insurance premiums increased costs by approximately $46 million. Volume related expenses rose $18 million. The remaining increase of $44 million was primarily due to higher maintenance and other costs resulting from operating problems in the first nine months of 1982.

Income tax decreased by $2.0 million as a result of lower earnings subject to income tax. The introduction of IORT in 1982 resulted in additional taxes of $78.3 million. The effect of IORT was to increase the combined effective tax rate substantially.

Refining, petrochemicals and marketing

Earnings from this segment were $19.0 million, a decrease of $34.3 million or 64 per cent from 1981.

Revenues rose by $48.3 million or four per cent. Higher refined products selling prices averaging 11 per cent increased revenues by $112 million. This was partially offset by lower sales volumes (down six per cent) as a result of significantly reduced market demand.

Expenses (excluding income taxes) were up $125.0 million or 12 per cent. Crude oil and raw feedstock costs rose approximately $111 million mainly as a result of higher purchase prices partially offset by lower volumes. Other expenses increased by $14 million or nine per cent mainly as a result of inflation.

Income taxes were down $42.4 million as a result of the lower pre-tax earnings and higher investment tax credits and inventory allowances.

Interest and other unallocated items

Net interest expense (expense less income) rose $39.0 million reflecting increased borrowings and higher interest rates. Income taxes on unallocated items changed from an expense of $9.6 million in 1981 to a recovery of $4.2 million in 1982. This decrease resulted primarily from the change to net interest expense.

Consolidated statement of changes in financial position

Funds from operations in 1982 increased by $30.8 million or 24 per cent primarily reflecting the funds effect of higher earnings discussed in the previous sections.

Deferred revenues and other increased $22.3 million mainly as a result of higher receipts under take or pay contracts, for gas to be delivered later.

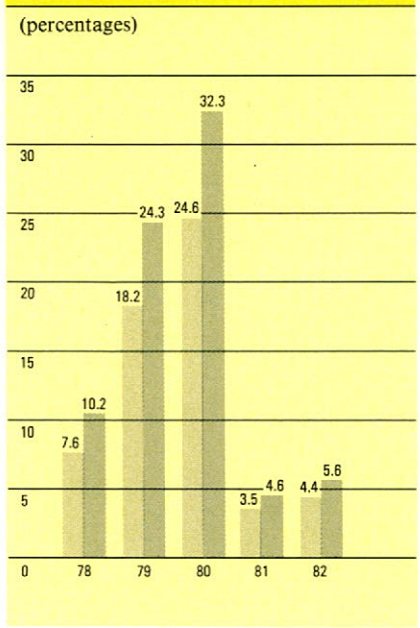
Operating working capital decreased by $50.3 million in 1982. The factors which reduced working capital included higher liabilities for taxes other than income taxes ($56 million—mainly IORT and PGRT), increased accruals for royalties and capital projects ($25 million), and lower inventory volumes ($53 million). The inventory volume decrease arose primarily from a major program to control working capital more tightly. The above factors were partially offset by higher accounts receivable ($44 million) due to increased revenues, income tax receivables ($28 million) arising from lower taxable earnings, and higher inventory carrying values ($20 million) due to increased crude oil prices. In addition to the above noted working capital changes, there were offsetting reductions in inventories and payables of $84 million, due to the timing of crude oil purchases in 1981.

Capital expenditures increased by $70.7 million or 35 per cent. They included outlays of $59.4 million ($49.0 million higher than 1981) for the Sarnia refinery upgrading project. Other major projects in 1982 included the Plant Integrity Program at the oil sands plant and the expansion of the Company's experimental in-situ heavy oil project at Fort Kent.

Following an initial common share dividend of $1.50 per share paid in 1981, the Company commenced paying regular quarterly dividends of $0.20 per share beginning with the first quarter of 1982.

The net increase in borrowings of $108.5 million in 1982 was necessary in order to finance capital and other expenditures in excess of internal funds generated. New borrowings consist of revolving credit and term loan agreements with Canadian financial institutions.

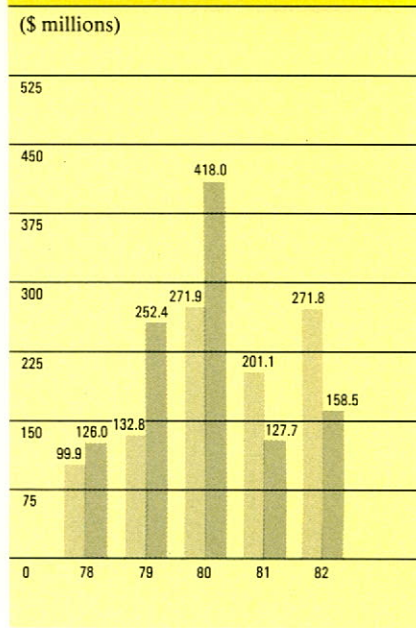
Rates of return



Return on capital employed is earnings before long-term interest expense 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.

Funds from operations vs. capital expenditures



Capital expenditures

Funds from operations

For details of capital expenditures, see pages 12 and 44.

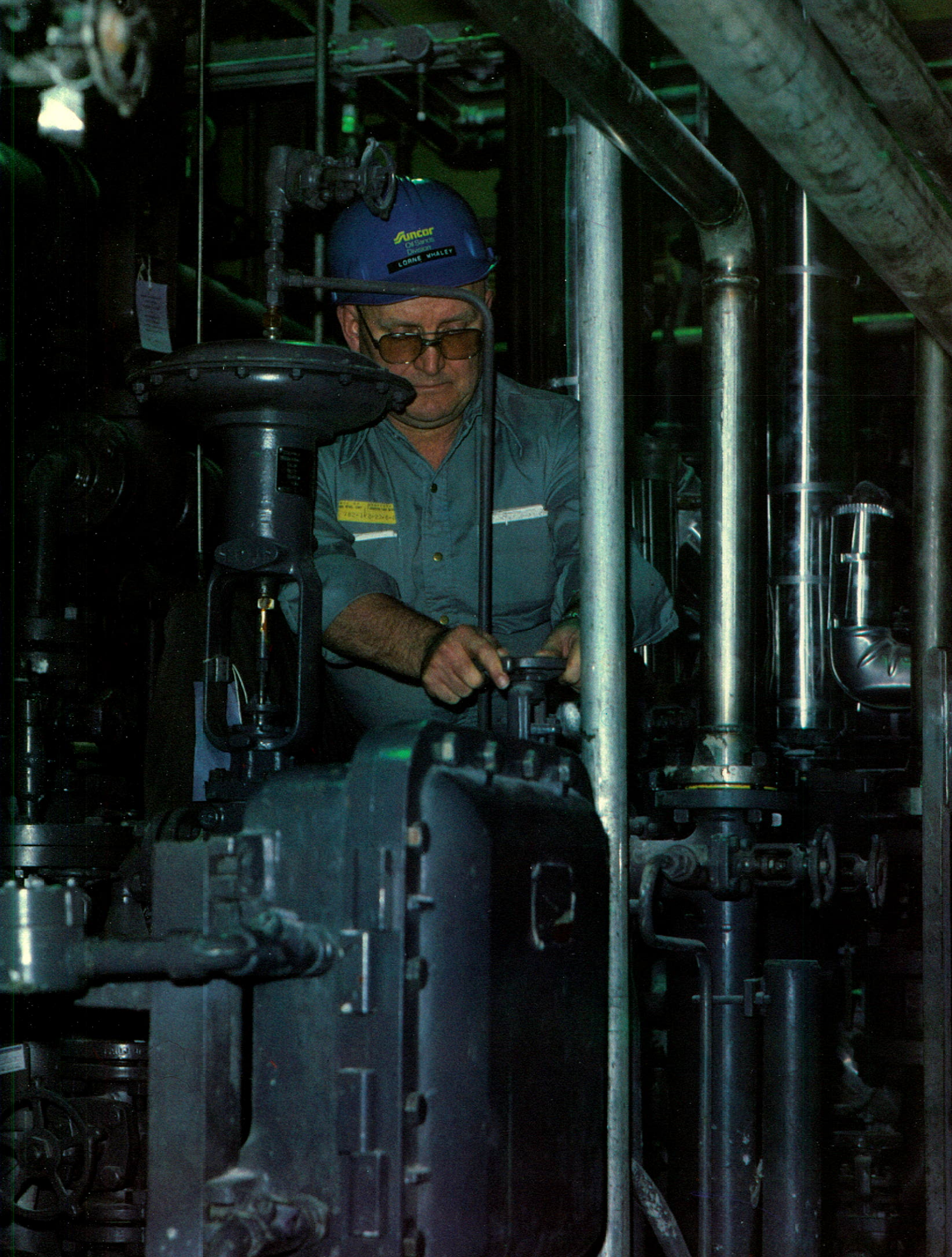
Reporting the effects of changing prices

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.

The Canadian Institute of Chartered Accountants spent over two years studying this issue, resulting in the release in December, 1982 of Section 4510. This section will be effective for the Company's 1983 fiscal year. Because the standard permits a number of options in the determination of current costs, in the selection of assets and liabilities to be adjusted to current costs and in the presentation of the information, the Company elected to study these options thoroughly during 1983 rather than hastily produce current cost information for 1982.

Taxes and other government revenues ($ millions)	**1982**	1981
From Suncor:		
Income taxes – current	**$ (25.3)**	$ 36.2
– deferred	**21.5**	17.9
	(3.8)	54.1
Incremental oil revenue tax	**80.4**	–
Petroleum and gas revenue tax	**30.9**	8.7
Petroleum compensation charge	**176.2**	204.8
Other taxes		
– federal sales and excise taxes	**58.1**	55.6
– production, property and other taxes	**12.6**	11.5
	354.4	334.7
Crown royalties, less incentive credits	**84.5**	61.3
Crude oil, natural gas and mineral lease acquisitions and rentals	**10.7**	13.7
	95.2	75.0
Collected on behalf of governments:		
Export taxes	**34.4**	41.9
Gasoline and diesel fuel taxes	**131.6**	91.3
	166.0	133.2
Total	**$615.6**	$542.9

Senior Technician Lorne Whaley applies seal oil to the compressors which were rebuilt in 1982 as part of the Plant Integrity Program to increase reliability of our oil sands plant. Lorne has worked at the plant for 16 years.


Suncor
Oil Sands
Division
LORNE WHALEY

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, 1982 and the consolidated statements of earnings, retained earnings and changes in financial position for the year then ended. Our examination was made in accordance with generally accepted auditing standards, and accordingly included such tests and other procedures as we considered necessary in the circumstances.

In our opinion, these consolidated statements present fairly the financial position of the Company as at December 31, 1982 and the results of its operations and the changes in its financial position for the year then ended in accordance with generally accepted accounting principles applied on a basis consistent with that of the preceding year.

Coopers & Lybrand

Coopers & Lybrand
Chartered Accountants
Toronto, Ontario
January 25, 1983

Summary of Accounting Policies

December 31, 1982

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 and other 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. On consolidation, revenues arising from the sale of crude oil at conventional "old oil" prices are eliminated from "sales and other operating revenues" and "costs and operating expenses." Crude oil receipts in excess of conventional "old oil" prices are deemed to be realized and included in "sales and other operating revenues." Sales to the Alberta Petroleum Marketing Commission, however, have been included in "sales and other operating revenues" because the Company is not permitted to designate the ultimate purchaser of such crude oil sales.

(d) Oil compensation
In those cases where the Company imports crude oil or purchases domestic oil at prices in excess of established conventional "old oil" prices, it applies for reimbursement of the excess under the federal government's compensation programs. Compensation claimed under such programs is 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, research into in-situ steam recovery projects and limited activities in coal and minerals.

–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 over the life of proven reserves. Support and movable equipment is depreciated on a straight line basis over an average of eight 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" or "deferred charges and other," respectively. The amounts will be taken into revenues or expenses when the related gas is delivered. Under current conditions, only a small portion of the gas due under such contracts is 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 (note 13)
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 which result in major additions and improvements to plant capacity, productivity or environmental protection are capitalized. Expenditures on major programs to improve plant reliability by rehabilitating, replacing or upgrading significant plant components are capitalized. Other plant expenditures are expensed.

Mine and plant expenditures are depreciated over the lesser of their useful lives or the life of proven reserves. Depreciation over useful lives is on a straight line basis for mobile equipment other than the bucketwheel excavators, which, together with all other assets, are depreciated on a unit of production basis.

The cost of housing is capitalized and depreciated on a straight line basis over its useful life.

As a result of the above policy, the Company is depreciating its capitalized expenditures as follows:
– approximately $214 million of certain older mine and plant expenditures over an average of 40 million cubic metres of production, and the balance of

mine and plant expenditures over total proven reserves;
- mobile equipment other than the bucketwheel excavators over three to five years; and
- housing units over an average of 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 a 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 over their useful lives. 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 ending in 1990 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. The cumulative effect of these differences is 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 the lower of cost using the first-in, first-out method and 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 borrowings 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 borrowings are deferred and amortized over the remaining repayment periods. Other exchange gains and losses are reflected in earnings.

(h) Interest capitalization
Interest cost incurred during the construction and pre-operating stages of major construction and development projects is capitalized and is then depreciated or depleted as part of the cost of the asset.

Consolidated Statement of Earnings

for the year ended December 31, 1982

($ millions except per share amounts)	1982	1981
Revenues		
Sales and other operating revenues	**$1,543.4**	$1,287.5
Interest income	**7.2**	33.2
	1,550.6	1,320.7
Expenses		
Costs and operating expenses	**728.6**	635.5
Selling, administrative and general	**151.9**	128.7
Royalties (note 1)	**126.7**	87.6
Taxes (note 2)	**354.4**	334.7
Depreciation, depletion and amortization	**111.7**	79.9
Interest (note 3)	**17.2**	4.2
	1,490.5	1,270.6
Earnings for the year	**$ 60.1**	$ 50.1
Earnings per common share	**$ 1.13**	$ 0.93

See accompanying summary of accounting policies and notes

Consolidated Statement of Retained Earnings

for the year ended December 31, 1982

($ millions)	1982	1981
Balance–beginning of year	**$593.4**	$623.2
Earnings for the year	**60.1**	50.1
	653.5	673.3
Dividends on preferred shares	**1.0**	1.6
Dividends on common shares	**41.8**	78.3
Balance–end of year	**$610.7**	$593.4

See accompanying summary of accounting policies and notes

Consolidated Statement of Financial Position

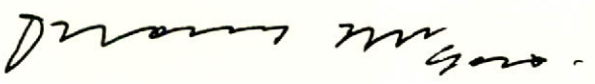
as at December 31, 1982

($ millions)	1982	1981
Assets		
Current assets		
Cash, time deposits and short-term investments	**$ 18.6**	$ 2.1
Accounts receivable (note 4)	**225.8**	190.9
Income taxes receivable	**28.4**	–
Inventories (note 5)	**235.7**	347.5
	508.5	540.5
Properties, plant and equipment, net (note 6)	**1,259.6**	1,067.6
Deferred charges and other (note 7)	**167.5**	154.6
	$1,935.6	$1,762.7
Liabilities and shareholders' equity		
Current liabilities		
Short-term borrowings	**$ –**	$ 10.0
Accounts payable and accrued liabilities (note 4)	**225.8**	279.0
Taxes other than income taxes	**106.7**	51.7
Current portion of long-term borrowings (note 8)	**3.5**	4.2
	336.0	344.9
Long-term borrowings (notes 8 and 9)	**161.4**	40.7
Deferred revenues and other	**67.8**	38.2
Deferred income taxes	**291.0**	269.5
Contingencies (note 10)		
Shareholders' equity		
Share capital (note 11)	**468.7**	476.0
Retained earnings	**610.7**	593.4
	1,079.4	1,069.4
	$1,935.6	$1,762.7

See accompanying summary of accounting policies and notes

Approved on behalf of the Board:

W. R. Loar, Director



D. M. McGeer, Director

Consolidated Statement of Changes in Financial Position

for the year ended December 31, 1982

($ millions)	1982	1981
Internal funds generated		
Operations		
Earnings for the year	**$ 60.1**	$ 50.1
Depreciation, depletion and amortization	**111.7**	79.9
Deferred income taxes	**21.5**	17.9
Deferred overburden removal outlays (note 7)	**(42.2)**	(29.6)
Other	**7.4**	9.4
Funds from operations	**158.5**	127.7
Disposals of properties, plant and equipment	**9.2**	4.2
Increase in deferred revenues and other	**22.3**	5.4
Decrease (increase) in operating working capital	**50.3**	(114.0)
Internal funds generated	**240.3**	23.3
Investment of funds		
Capital expenditures		
Exploration, production and resources development	**85.2**	75.4
Oil sands	**103.5**	83.6
Refining, petrochemicals and marketing	**83.1**	42.1
	271.8	201.1
Increase in deferred charges and other excluding overburden	**10.4**	7.4
Total investment of funds	**282.2**	208.5
Dividends	**42.8**	79.9
Net cash surplus (deficiency) before external financing	**(84.7)**	(265.1)
External financing		
Net increase (decrease) in borrowings	**108.5**	(31.3)
Redemption of preferred shares	**(7.3)**	(3.1)
Total external financing	**101.2**	(34.4)
Increase (decrease) in cash, time deposits and short-term investments	**$ 16.5**	$(299.5)
Working capital		
Increase (decrease) in operating working capital	**$ (50.3)**	$ 114.0
Decrease in short-term borrowings	**10.7**	24.3
Increase (decrease) in cash, time deposits and short-term investments	**16.5**	(299.5)
Increase (decrease) in working capital	**$ (23.1)**	$(161.2)

See accompanying summary of accounting policies and notes

Schedule of Segmented Data*
(note 12)

	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 ($ millions)	**1982**	1981	**1982**	1981	**1982**	1981	**1982**	1981
Sales and other operating revenues	**$111.5**	$101.7	**$240.1**	$ 41.8	**$1,191.8**	$1,144.0	**$1,543.4**	$1,287.5
Intersegment revenues	**84.6**	65.2	**312.1**	207.5	**1.7**	1.2	**398.4**	273.9
Segment revenues	**$196.1**	$166.9	**$552.2**	$249.3	**$1,193.5**	$1,145.2	**$1,941.8**	$1,561.4
Earnings before income and incremental oil revenue taxes	**$ 42.4**	$ 23.7	**$100.6**	$(36.5)	**$ 23.3**	$ 100.0	**$ 166.3**	$ 87.2
Income and incremental oil revenue taxes	**(17.7)**	(15.0)	**(59.1)**	17.2	**(4.3)**	(46.7)	**(81.1)**	(44.5)
Segment earnings (loss)	**$ 24.7**	$ 8.7	**$ 41.5**	$(19.3)	**$ 19.0**	$ 53.3	**85.2**	42.7
Change in intersegment profit elimination							**(7.6)**	(1.0)
Interest income							**7.2**	33.2
Corporate expense							**(11.7)**	(11.0)
Interest expense							**(17.2)**	(4.2)
Related income taxes							**4.2**	(9.6)
Earnings for the year							**$ 60.1**	$ 50.1
Depreciation, depletion and amortization for the year ended December 31								
Segments	**$ 33.1**	$ 28.7	**$ 62.5**	$ 38.6	**$ 14.8**	$ 12.4	**$ 110.4**	$ 79.7
Corporate							**1.3**	0.2
							$ 111.7	$ 79.9
Capital employed as at December 31								
Segment assets	**$556.1**	$506.2	**$799.3**	$673.3	**$ 626.9**	$ 609.9	**$1,982.3**	$1,789.4
Corporate assets and intersegment eliminations							**(46.7)**	(26.7)
Total assets							**1,935.6**	1,762.7
Segment current liabilities	**$ 61.2**	$ 44.3	**$133.6**	$ 78.6	**$ 199.2**	$ 249.1	**394.0**	372.0
Corporate current liabilities and intersegment eliminations							**(58.0)**	(27.1)
Capital employed							**$1,599.6**	$1,417.8

*The Company has no foreign geographic segments. See note 3 for information on export sales.

See accompanying summary of accounting policies and notes

Notes to the Consolidated Financial Statements

December 31, 1982

1. Royalties

The following is an analysis of the amounts expensed:

($ millions)	Crown	Other	Total 1982	Total 1981
Exploration, production and resources development	**$40.4**	**$11.0**	**$ 51.4**	$53.4
Oil sands	**51.1**	**24.2**	**75.3**	34.2
	$91.5	**$35.2**	**$126.7**	$87.6

2. Taxes

The following taxes and charges have been expensed:

($ millions)	1982	1981
Petroleum compensation charges	**$176.2**	$204.8
Petroleum and gas revenue tax	**30.9**	8.7
Federal sales and excise taxes	**58.1**	55.6
Production, property and other taxes	**12.6**	11.5
Incremental oil revenue tax*	**80.4**	–
Income taxes–current	**(25.3)**	36.2
–deferred	**21.5**	17.9
	$354.4	$334.7

*The federal government established a special 50 per cent tax on oil revenue (net of royalties) received in excess of what would have been received under the National Energy Program ("excess revenue"). Excess revenue subject to this tax is not subject to income tax. Effective January 1, 1982, this tax applied to 100 per cent of excess revenue from conventional crude and to 75 per cent of excess revenue from synthetic crude. On July 1, 1982 the tax on conventional crude excess revenue was suspended for one year and on August 1, 1982, the application of the tax on synthetic crude excess revenue was reduced from 75 to 65 per cent.

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)	1982	1981
Gasoline and diesel fuel taxes	**$131.6**	$ 91.3
Export taxes	**34.4**	41.9
	$166.0	$133.2

Income and incremental oil revenue 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:

	1982	1981
Federal tax rate	**46.0** %	46.0%
Federal surtax	**1.8**	1.8
Provincial abatement	**(10.0)**	(10.0)
Provincial tax rate	**11.0**	13.7
Statutory tax rate	**48.8**	51.5
Add (deduct) the tax effect of:		
Crown royalties	**80.2**	33.4
Petroleum and gas revenue tax	**26.8**	4.3
Incremental oil revenue tax	**69.6**	–
Incremental oil revenues	**(156.7)**	–
Resource allowance	**(23.6)**	(11.6)
Depletion allowance	**(6.6)**	(4.2)
Investment tax credits	**(18.3)**	(6.2)
Inventory allowance	**(8.0)**	(2.5)
Provincial royalty tax credits, incentives and rebates	**(16.8)**	(6.3)
Manufacturing and processing profits deduction	**1.0**	(2.7)
Other	**(3.0)**	(3.8)
Effective income tax rate before incremental oil revenue tax	**(6.6)**%	51.9%
Incremental oil revenue tax–50 per cent of incremental oil revenues	**62.7**	–
Effective income and incremental oil revenue tax rate (note 12)	**56.1** %	51.9%

Investment tax credits reduced the income tax provision for 1982 by $10.3 million (1981–$6.4 million).

Deferred income taxes result from timing differences and are primarily attributable to:

($ millions)	1982	1981
Excess of tax over (under) book expense		
Depreciation	**$ 6.3**	$ 4.4
Exploration and development costs	**11.9**	11.4
Overburden removal	**1.1**	4.5
Preproduction expense	**(0.3)**	(0.5)
Other	**2.5**	(1.9)
	$21.5	$17.9

3. Supplemental earnings statement information

($ millions)	1982	1981
Crude oil receipts in excess of conventional "old oil" prices	**$199.3**	$ 12.7
Export sales		
Unaffiliated customers–		
United States–heavy fuel oil	**$137.8**	$121.7
–petrochemicals	**54.7**	50.2
–middle distillates	**5.8**	15.7
Europe –petrochemicals	**100.2**	99.3
	298.5	286.9
Affiliates–		
United States–refined products	**7.5**	3.0
	$306.0	$289.9
Research and development expense	**$ 5.8**	$ 7.1
Pension expense	**$ 10.0**	$ 9.8
Interest expense–short-term	**$ 9.8**	$ 1.0
–long-term	**13.3**	3.2
Less interest capitalized	**(5.9)**	–
	$ 17.2	$ 4.2

4. Related party transactions

In transactions with Sun Company, Inc. and its affiliates during 1982, the Company purchased crude oil and raw feedstocks for $34.6 million (1981–$269.9 million). In turn, the Company sold refined products for $7.5 million (1981–$3.0 million) to Sun Company, Inc. and its affiliates.

Amounts due to Sun Company, Inc. and its affiliates at December 31, 1982 totalling $5.5 million (1981–$75.1 million) are included in accounts payable and accrued liabilities. Amounts due from Sun Company, Inc. and its affiliates totalling $0.1 million (1981–$0.3 million) are included in accounts receivable.

The Company has had no significant transactions with the Ontario Government other than those relating to Trillium Exploration Corporation ("Trillium"). During 1982, Trillium, one-third owned by the Company and two-thirds indirectly owned by the Ontario Energy Corporation, was formed to explore for oil and gas in the frontier areas of Canada. As at December 31, 1982 the Company had invested $2.3 million in Trillium.

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

5. Inventories

($ millions)	1982	1981
Crude oil–conventional	**$ 48.7**	$119.3
–synthetic	**33.3**	36.8
Refined products	**111.7**	154.2
Materials and supplies	**42.0**	37.2
	$235.7	$347.5

6. Properties, plant and equipment

($ millions)	Cost	Accumulated provisions	Net 1982	Net 1981
Exploration, production and resources development				
Oil and gas properties	$ 549.4	$ 148.2	$ 401.2	$ 352.9
Equipment and other	116.7	40.0	76.7	73.3
	666.1	188.2	477.9	426.2
Oil sands				
Mine and mobile equipment	175.8	60.4	115.4	111.4
Plant	415.1	84.5	330.6	267.2
Housing	72.6	3.0	69.6	67.1
	663.5	147.9	515.6	445.7
Refining, petrochemicals and marketing				
Refinery including petrochemicals	240.3	61.4	178.9	110.0
Marketing and transportation	142.7	56.2	86.5	84.9
	383.0	117.6	265.4	194.9
Corporate	1.0	0.3	0.7	0.8
	$1,713.6	$ 454.0	$1,259.6	$1,067.6

7. Deferred charges and other

($ millions)	1982	1981
Oil sands deferred overburden removal costs (see below)	$ 89.6	$ 83.5
Oil sands preproduction costs	43.0	44.4
Prepaid gas purchases	21.7	17.3
Long-term receivables	6.1	2.0
Foreign exchange loss	2.0	1.7
Other	5.1	5.7
	$167.5	$154.6
Oil sands deferred overburden removal costs		
Balance–beginning of year	$ 83.5	$ 69.3
Outlays during year	42.2	29.6
Depreciation on equipment during year*	1.7	2.3
	127.4	101.2
Amortization during year	(37.8)	(17.7)
Balance–end of year	$ 89.6	$ 83.5

*Depreciation on overburden removal equipment is not included in depreciation, depletion and amortization expense of $111.7 million (1981–$79.9 million).

8. Long-term borrowings

	1982 ($ millions)	1981
Borrowings under revolving credit and term loan agreements, with interest at variable rates averaging 14 per cent in 1982 (note 9)	**$124.1**	$ –
5¾% Notes, maturing in 1991, repayable at the rate of U.S. $2.0 million annually. U.S. $26.0 million (1981–U.S. $28.0 million)	**32.1**	33.2
Mortgages on housing, bearing interest at rates between 6¼ and 10¼ per cent, repayable over the next 20 years	**8.6**	11.6
Capitalized lease obligations	**0.1**	0.1
	164.9	44.9
Less current portion of long-term borrowings	**(3.5)**	(4.2)
	$161.4	$40.7

($ millions)

Long-term borrowings mature as follows:

1983	$ 3.5
1984	2.9
1985	3.1
1986	3.0
1987	15.5
Subsequent years	136.9
	$164.9

9. Lines of credit

The Company has revolving credit and term loan agreements with financial institutions aggregating $550 million. Revolving credit is available until 1986 generally, when the borrowings are convertible into term credit with maturities from 1987 through 1991. Undrawn lines of credit amounted to $426 million at December 31, 1982.

10. Commitments and contingencies

(a) 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 federal government. The Company, 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.

(b) On September 15, 1982, the Company commenced proceedings for a declaratory judgment in the Court of Queen's Bench of Alberta with respect to its royalty obligation to Norcen Energy Resources Limited under an oil sands sublease agreement. It is the Company's contention that the revenue upon which the royalty is calculated should not include compensation payments paid under the federal Energy Administration Act. Should the Company's position not be accepted by the Court, a further royalty obligation before taxes in the amount of $6.1 million for the year ended December 31, 1982 would be charged against earnings in the year of settlement.

(c) As a result of renegotiation of business interruption insurance coverage in June of 1982, the Company would bear a greater share of any loss arising from a future insured incident for its Oil Sands Division. Any such loss would, under the current coverage, be shared among the Company and its insurers, with the Company bearing 100 per cent up to $30 million and a declining proportion up to $180 million, of which amount 55 per cent would be borne by the Company.

(d) The Company has undertaken major projects to expand the oil sands mine and the Fort Kent in-situ oil sands project, and to upgrade the oil sands plant and Sarnia refinery. The estimated cost of these projects is $738 million with outlays of $188.5 million made to the end of 1982.

(e) Minimum annual rental charges under leases for service stations, office space and other property and equipment approximate $6.5 million.

(f) An independent actuarial valuation of the Company's pension plan as of January 1, 1982 indicated that the actuarial present value of accumulated plan benefits and the estimated unfunded liability were $79.9 million and $0.4 million respectively.

While the result of any litigation necessarily contains an element of uncertainty, the Company's management believes that, with respect to the above and other known contingencies, 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.

11. 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, 1982 have reduced the authorized number of Preferred Shares Series A to 645,018. These shares 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–beginning of year	**808,447**	**$19.4**	**52,245,085**	**$456.6**
Scrip certificates*	–	–	**16**	–
Redeemed for cash	**(303,275)**	**(7.3)**	–	–
Balance–end of year	**505,172**	**$12.1**	**52,245,101**	**$456.6**

*The scrip certificates were issued in 1979 and represent fractional shares exchanged for common shares.

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 retractable 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., demanded payment in 1979 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.

12. Segmented data disclosure

The CICA Handbook generally requires disclosure of segment operating profits which are measured before income taxes. The Company believes it is inappropriate to measure its segment performance on this basis because of the 1982 incremental oil revenue tax (IORT). Since IORT is levied on net revenues, under the CICA definition, it must be deducted to determine segment operating profits. However, the net revenue subject to this tax is exempt from income taxes. Consequently, segment operating profits from upstream operations are not comparable to downstream, nor are they comparable to other oil companies which generally pay a lower level of IORT. In these circumstances, the Company believes the only meaningful measure of its performance is after the deduction of all taxes.

13. Oil Sands capitalization and depreciation

During 1982, two events occurred which had significant effects on the application of the Company's accounting policy with respect to oil sands capitalization and depreciation:

(a) The Company decided to mine a larger area of its leases thereby adding significantly to proven reserves and bringing total proven reserves to approximately 66.5 million cubic metres as at December 31, 1982. Resulting from this decision, the Company commissioned engineering studies to determine if the useful life of its plant and equipment could be extended to process the additional reserves. As a result of such studies, the average useful life of certain older plant and equipment was estimated to enable the processing of a further 40 million cubic metres, while the remainder, including the plant expansion, was estimated to enable the processing of total proven reserves.

As a result of extending the life of certain assets and reducing the life of others, the depreciation expense for the year was not significantly changed.

(b) The Company commenced a major program to improve plant reliability by rehabilitating, replacing or upgrading major plant components. By December 31, 1982, $60.2 million had been capitalized.

Quarterly Summary

(unaudited)

Financial Data

($ millions except per share amounts)

	For the quarter ended				Total year	For the quarter ended				Total year
	Mar 31 1982	June 30 1982	Sept 30 1982	Dec 31 1982	**1982**	Mar 31 1981	June 30 1981	Sept 30 1981	Dec 31 1981	1981
Revenues	**$378.2**	**$342.6**	**$395.2**	**$434.6**	**$1,550.6**	$324.8	$310.9	$350.8	$334.2	$1,320.7
Segment earnings (loss)										
Exploration, production and resources development	**3.8**	**2.7**	**6.7**	**11.5**	**24.7**	2.8	1.5	1.1	3.3	8.7
Oil sands	**(10.5)**	**9.1**	**13.8**	**29.1**	**41.5**	2.7	(13.4)	(5.2)	(3.4)	(19.3)
Refining, petrochemicals and marketing	**11.8**	**4.3**	**5.7**	**(2.8)**	**19.0**	19.1	18.9	14.0	1.3	53.3
	$ 5.1	**$ 16.1**	**$ 26.2**	**$ 37.8**	**$ 85.2**	$ 24.6	$ 7.0	$ 9.9	$ 1.2	$ 42.7
Earnings (loss) for the period	**$ 1.1**	**$ 15.2**	**$ 19.2**	**$ 24.6**	**$ 60.1**	$ 27.7	$ 11.2	$ 11.7	$ (0.5)	$ 50.1
Funds from operations	**$ 23.5**	**$ 5.0**	**$ 53.5**	**$ 76.5**	**$ 158.5**	$ 57.5	$ 16.8	$ 26.5	$ 26.9	$ 127.7
Earnings (loss) per common share	**$ 0.02**	**$ 0.28**	**$ 0.36**	**$ 0.47**	**$ 1.13**	$ 0.52	$ 0.21	$ 0.22	$ (0.02)	$ 0.93

Operating Data

	For the quarter ended				Total year	For the quarter ended				Total year
	Mar 31 1982	June 30 1982	Sept 30 1982	Dec 31 1982	**1982**	Mar 31 1981	June 30 1981	Sept 30 1981	Dec 31 1981	1981
Gross production										
Conventional crude oil and natural gas liquids (a)	**2.2**	**2.0**	**2.3**	**2.4**	**2.2**	2.5	2.4	2.1	2.1	2.3
Synthetic crude oil (a)	**3.9**	**3.5**	**6.7**	**7.6**	**5.5**	6.3	3.3	3.7	5.3	4.7
Gross natural gas sales (b)	**2.0**	**1.7**	**1.3**	**1.9**	**1.8**	2.4	1.5	1.4	2.1	1.9
Sales of refined products (a)	**12.1**	**10.8**	**11.5**	**12.1**	**11.6**	13.6	11.7	12.5	11.7	12.4

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

Five Year Financial Summary

(unaudited)

	1982	1981	1980	1979	1978
	($ millions except for ratios)				
Revenues	**$1,550.6**	$1,320.7	$1,259.4	$ 865.1	$ 562.5
Segment revenues					
Exploration, production and resources development	**196.1**	166.9	152.5	125.3	106.9
Oil sands	**552.2**	249.3	595.3	343.4	210.1
Refining, petrochemicals and marketing	**1,193.5**	1,145.2	831.4	684.4	517.5
	$1,941.8	$1,561.4	$1,579.2	$1,153.1	$ 834.5
Segment earnings (loss)					
Exploration, production and resources development	**24.7**	8.7	20.0	23.8	23.4
Oil sands	**41.5**	(19.3)	211.3	99.0	22.1
Refining, petrochemicals and marketing	**19.0**	53.3	62.0	48.5	13.2
	$ 85.2	$ 42.7	$ 293.3	$ 171.3	$ 58.7
Earnings before extraordinary gains	**60.1**	50.1	306.4	169.8	57.8
Extraordinary gains	**–**	–	–	3.1	3.1
Earnings for the year	**$ 60.1**	$ 50.1	$ 306.4	$ 172.9	$ 60.9
Funds from operations	**$ 158.5**	$ 127.7	$ 418.0	$ 252.4	$ 126.0
Capital expenditures					
Exploration, production and resources development	**85.2**	75.4	110.0	64.4	61.3
Oil sands	**103.5**	83.6	132.2	59.4	18.5
Refining, petrochemicals and marketing	**83.1**	42.1	29.0	8.9	20.1
Corporate	**–**	–	0.7	0.1	–
	$ 271.8	$ 201.1	$ 271.9	$ 132.8	$ 99.9
Capital employed					
Long-term borrowings	**161.4**	40.7	47.9	69.7	77.6
Deferred income taxes, deferred revenues and other	**358.8**	307.7	278.9	191.2	138.8
Shareholders' equity	**1,079.4**	1,069.4	1,102.3	797.6	627.5
	$1,599.6	$1,417.8	$1,429.1	$1,058.5	$ 843.9
Average number of common shares	**52,245,098**	52,245,085	52,245,085	52,191,626	52,175,200
Ratios					
Earnings before extraordinary gains per common share	**$1.13**	$0.93	$5.83	$3.24	$1.11
Earnings per common share	**$1.13**	$0.93	$5.83	$3.30	$1.17
Funds from operations per common share	**$3.03**	$2.44	$8.00	$4.84	$2.41
Earnings as a percentage of capital employed	**4.4%**	3.5%	24.6%	18.2%	7.6%
Earnings as a percentage of shareholders' equity	**5.6%**	4.6%	32.3%	24.3%	10.2%
Earnings as a percentage of revenues	**3.9%**	3.8%	24.3%	20.0%	10.8%
Long-term borrowings as a percentage of capital employed	**10.1%**	2.9%	3.4%	6.6%	9.2%

Five Year Operating Summary

(unaudited)

Resources Group	1982	1981	1980	1979	1978
Production (thousands of cubic metres per day)					
Conventional crude oil and natural gas liquids					
-gross	**2.2**	2.3	2.6	2.7	2.5
-net	**1.5**	1.5	1.7	1.8	1.6
Synthetic crude oil-gross	**5.5**	4.7	7.4	6.8	7.1
Natural gas sales (millions of cubic metres per day)					
-gross	**1.8**	1.9	1.7	1.8	1.8
-net	**1.4**	1.3	1.1	1.2	1.2
Average sales price					
Conventional crude oil (dollars per cubic metre)	**158**	117	96	81	76
Synthetic crude oil (dollars per cubic metre)	**255**	130	217	137	81
Natural gas (dollars per thousand cubic metres)	**98**	88	82	56	47
Gross proven reserves					
Conventional crude oil and natural gas liquids (millions of cubic metres)	**10**	10	10	12	12
Synthetic crude oil (millions of cubic metres)	**67**	54	56	65	67
Natural gas (billions of cubic metres)	**13**	13	13	14	13
Land holdings (millions of hectares)					
-gross	**19.0**	18.6	19.6	19.7	23.9
-net	**3.5**	3.5	3.3	5.1	6.2
Net wells completed					
Exploratory -oil	**6**	5	2	–	1
-gas	**7**	14	9	4	5
-dry	**17**	12	14	12	6
Development-oil	**37**	5	12	39	27
-gas	**6**	9	25	23	40
-dry	**9**	8	7	7	7
	82	53	69	85	86
Sunoco Group					
Crude oil supply and refining					
Refined for Suncor account (thousands of cubic metres per day)	**11.2**	12.1	11.8	11.8	10.6
Gross crude oil production as a percentage of crude oil refined for Suncor account	**68%**	56%	84%	79%	89%
Processed at Suncor refinery (thousands of cubic metres per day)	**11.1**	12.1	12.4	12.2	11.1
Utilization of refining capacity	**77%**	84%	86%	85%	77%
Service stations (number at year-end)	**870**	870	920	950	990
Sales of refined products (thousands of cubic metres per day)					
Gasolines	**4.3**	4.7	4.6	4.3	4.0
Middle distillates	**2.8**	3.0	2.8	2.9	2.6
Heavy fuel oil	**2.7**	2.8	2.6	3.0	3.4
Petrochemicals	**1.3**	1.2	1.1	1.1	0.8
Other products	**0.5**	0.7	0.5	0.5	0.6
	11.6	12.4	11.6	11.8	11.4
Suncor employees (number at year-end)	**5,190**	4,930	4,620	4,310	4,130
Salaries, wages and employee benefits ($ millions)	**172.1**	144.0	112.8	87.4	81.8

What does it mean for a corporation to be responsible? At Suncor, we define this responsibility in two ways: to conduct our Company's business with sensitivity to its impact on others; and to identify, investigate and help to meet social needs which may be unrelated to Company operations.

In this report, we describe some of the institutions and organizations to which we provide financial support under our Corporate Contributions Program.

Health

As the proportion of elderly people in our society increases, we need to find alternate models of medical care which reduce the incidence of institutionalization. For this reason, we have helped to establish the Suncor Geriatric Unit at Parkwood Hospital in London, Ontario. This specially designed unit provides an environment in which the principles of modern geriatric care can be practiced. The facilities enable patients to become as independent as possible, which for many means returning to their own homes.

In 1982, we expanded our involvement in geriatric care by setting up a fellowship program at the University of Western Ontario's School of Medicine. The objective is to provide advanced training in geriatric medicine to Canadian physicians who will then be equipped to take up teaching duties at a Canadian faculty of medicine. At present, too few physicians are qualified to teach in this rapidly evolving field. The first fellowship was awarded during the year.

Other health projects in 1982 included assistance to the Ontario Crippled Children's Centre to enable them to make greater use of computer technology and the Canadian Cystic Fibrosis Foundation for purchase of research equipment.

The Edmonton Youth Symphony Orchestra, performing under the direction of Suncor International Guest Conductor Nicholas Braithwaite who frequently directs the London Philharmonic and other internationally-known orchestras.

Education

To stimulate the development of Canadian science, Suncor sponsors the Synergy program in co-operation with the Youth Science Foundation. Synergy '82 brought 60 top high school science students from across the country to Ottawa to learn about the energy problems of developing countries. Students were grouped in teams to create energy plans for three specific nations. Simulation exercises sensitized the students to the realities of living in a different culture. The students' draft energy plans were presented to government representatives of the countries involved. The Synergy '82 program has been put together in kit form and distributed to Canadian teachers, receiving wide acclaim.

Suncor also awarded six scholarships to doctoral students of business at various Canadian universities.

Arts

Suncor supports a wide range of arts and cultural groups.

In 1982, we funded the Suncor International Guest Conductors program enabling Canadian youth orchestras to play under the direction of internationally-renowned conductors. Three such conductors took part in the program organized by the Canadian Association of Youth Orchestras at Banff, Alberta in April, 1982.

Also in 1982, Suncor assisted the National Ballet and the Canadian Opera Company, the Toronto Symphony Orchestra, the Calgary Centre for the Performing Arts, Roy Thomson Hall and a number of other worthy organizations which contribute to the cultural wealth of Canada.

Community support

The current economic climate has put added stress on families and individuals. Many social agencies have been unable to respond effectively because of budget restraints. Therefore, toward the end of 1982, a large portion of the remaining contributions budget was directed to this area. Suncor's contributions policy now includes a special emphasis on support to organizations providing assistance to people in crisis—the unemployed, the homeless and families experiencing breakdown. Priority is being given to communities where the economic conditions are most pressing.

More information on our Corporate Contributions Program can be obtained by writing to the Company.

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

Canadian Ownership Rate (COR): the amount of beneficial Canadian ownership relevant in determining the level of payments to which a corporation is entitled under the Petroleum Incentive Program.

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

Compressor house: a building which houses compressors for the unifiners and for the hydrogen plant which supplies hydrogen necessary for the removal of sulphur from the crude oil produced in the unifiners.

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.

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 fuel oil: the residue of crude oil refining processes which remains after the lighter products such as gasolines, aromatics and home heating oil have been extracted from the crude oil.

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: a refining process using hydrogen and a catalyst to convert home heating and industrial fuel oil to higher-value products.

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

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.

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.

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.

Petroleum Incentive Program (PIP): federal program which provides incentive payments to corporations refunding a percentage of their exploration costs on the frontier lands. The amount of the incentive payments depends on the Canadian Ownership Rate (COR).

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.

Slant-hole drilling: a drilling technique utilizing a drilling rig which is angled at the surface. This allows access to hydrocarbon reserves not located vertically below the drilling location.

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 (or step-out): 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

One of the main objectives of Suncor and its shareholders is majority ownership and control of the Company by Canadians. This objective is reflected in the composition and processes of the Board of Directors.

Suncor has 14 directors. Ten are Canadians, including eight independent directors having no other association with the Company or its majority shareholder. The Chairman, Michael Koerner, is an outside director with primary responsibility for ensuring the integrity and independence of the Board's decision-making.

The Board has three standing committees, each headed by an independent director. The Audit Committee, chaired by John Poole, consists of Max Clarkson, Pierre Genest, Peter Kingsmill and Jack Neafsey.

The Board Policy and Strategic Planning Committee, chaired by Michael Koerner, includes Gordon Hillhouse, Gerry Hobbs, Bill Loar, Dudley McGeer and Malcolm Rowan.

The Human Resources and Compensation Committee, chaired by Max Clarkson, includes Gordon Hillhouse, Ted Jarmain, Bill Loar and Guy Saint-Pierre.

Robert McClements did not stand for re-election to the Board in 1982 in order to devote more time to his responsibilities as President and Chief Operating Officer of Sun Company in the U.S. He was the first manager of our oil sands plant in 1965 and contributed substantially to the evolution of Canada's oil sands technology.

A new director, Walter Huffman, was elected to the Board during the year to take Mr. McClements' place. Mr. Huffman recently retired as a vice-president of Sun Company in the U.S. During his career, he managed the Fort McMurray oil sands plant for three years.

Directors
(as at December 31, 1982)

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

Pierre Genest, Q.C., Toronto
Partner, Cassels, Brock

Ross A. Hennigar, Toronto
President and Chief Executive Officer
Suncor Inc.
(deceased January 11, 1983)

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

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

Walter C. Huffman, Moylan, Pa.
Retired Executive

W. Edwin C. Jarmain, Toronto
President, Jarmain Communications Inc.

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

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

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

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

John E. Poole, Edmonton
Corporate Director

Malcolm Rowan, Toronto
President and Chief Executive Officer
Ontario Energy Corporation

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

On January 27, 1983,
William R. Loar, Toronto,
became President and Chief
Executive Officer of Suncor Inc.
and was elected to the Board.

Offices

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20 Eglinton Avenue West
Toronto, Ontario M4R 1K8
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Sunoco Group
56 Wellesley Street West
Toronto, Ontario M5S 2S4
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)

Sunoco Group
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

Sunchem (U.K.) Limited
London, England
European petrochemical sales agency

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

Baron Petroleums Inc.
SMS Petroleums Ltd.
Sunoco Home Comfort Inc.
Toronto, Ontario
Retail personnel services

Ouimet-Gobeille Inc.
Montreal, Quebec
Retail personnel services

Maywelle Properties Ltd.
Toronto, Ontario
Real estate developer

Resources Group
Albersun Pipeline Ltd.
Calgary, Alberta
Natural gas pipeline operator

Athabasca Realty Company Limited
Fort McMurray, Alberta
Employee housing

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

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

Principal officers

(as at December 31, 1982)

M. M. Koerner,
Chairman of the Board

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,
Human Resources and
Government Affairs,
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

A. J. Watkins,
Controller

G. Dubé,
Secretary and
Director, Legal Affairs

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

Major shareholders

Sun Company, Inc.
Radnor, Pennsylvania
(owning 74.9% of common shares)

Ontario Energy Resources Ltd.
Toronto, Ontario
(owning 25% 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

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