Suncor inc.

ANNUAL REPORT 1983

Highlights *year ended December 31*	1983	1982
Revenues ($ millions)	$ 1,484.3	$ 1,550.6
Earnings ($ millions)	$ 108.4	$ 60.1
Earnings per common share	$ 2.06	$ 1.13
Dividends per common share	$ 0.80	$ 0.80

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Front Cover: This new 420 tonne telescopic headstation at the Fort McMurray oil sands plant drives the conveyor belt carrying oil sand from the mine to the plant at five metres per second. The headstation has its own hydraulic feet for walking.

In 1983, Suncor successfully pushed ahead with four major new projects which will shape the Company for years to come. In doing so, we confirmed our fundamental belief in Canada and our Company's future.

The success of these projects and of our ongoing operations depends in large measure upon the skills of the people who manage them. In this report, we highlight some of these people and their accomplishments during the past year.

Suncor's Corporate Committee: Dudley McGeer, Senior Vice-President, Administration and Chief Financial Officer (left), Bill Loar, President and Chief Executive Officer (centre) and Stan Cowtan, Executive Vice-President, Sunoco Group (right).

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 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 transportation fuels, 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.

About 75 per cent of Suncor's 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.

Board of Directors

From left to right: (lower level, front row) John Poole, Dudley McGeer; (lower level, back row) Peter Kingsmill, Guy Saint-Pierre, Jack Neafsey; (on stairway) Gerry Hobbs, Gordon Hillhouse, Michael Koerner, Bill Loar, Walt Huffman, Ted Jarmain, Malcolm Rowan, Max Clarkson, Pierre Genest.

Suncor is guided by a Board of Directors with extensive and varied business experience.

Of the 14 directors, 10 are Canadians including the Chairman, Michael Koerner, who has 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.

Summary of Results

Financial

($ millions except per share data)	1983	1982
Revenues	$ 1,484.3	$ 1,550.6
Earnings		
–for the year	$ 108.4	$ 60.1
–per common share	$ 2.06	$ 1.13
–as a percentage of capital employed	6.5%	4.4%
–as a percentage of shareholders' equity	9.7%	5.6%
Funds from operations		
–for the year	$ 202.6	$ 158.5
–per common share	$ 3.88	$ 3.03
Capital expenditures	$ 353.2	$ 271.8
Dividends		
–per preferred share	$ 1.92	$ 1.92
–per common share	$ 0.80	$ 0.80

Operating

	1983	1982
Oil sands		
Synthetic crude oil		
–production (a)	2 776	1 970
–proven reserves (b)	63.6	66.5
Exploration, production and resources development		
Crude oil and natural gas liquids–gross production (a)	821	807
Crude oil and natural gas liquids–gross proven reserves (b)	8.8	9.6
Natural gas–gross sales (b)	539	639
Natural gas–gross proven reserves (c)	12.9	12.9
Refining, petrochemicals and marketing		
Crude oil processed at Suncor refinery (a)	4 091	4 039
Sales of refined products (a)	4 036	4 247

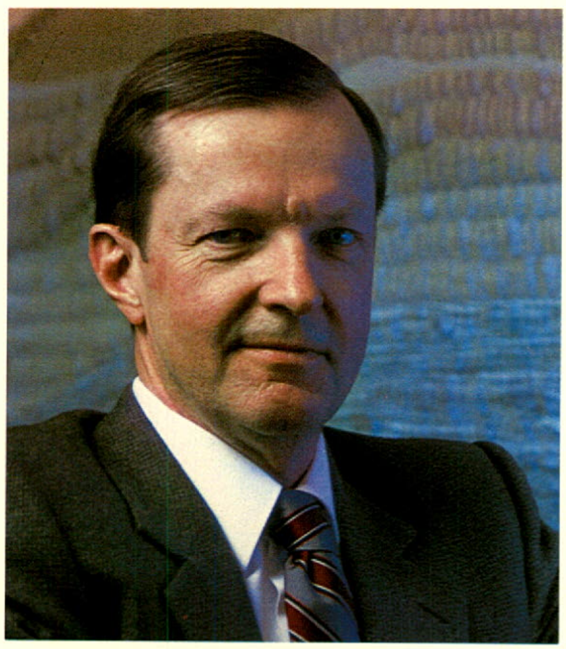
(a) thousands of cubic metres
(b) millions of cubic metres
(c) billions of cubic metres

PRESIDENT'S REPORT

Suncor's earnings rose 80 per cent in 1983. Gains from higher synthetic crude oil production, lower oil sands plant costs and higher conventional crude oil selling prices more than offset lower refined product margins. (For more analysis of earnings, see page 28.)

Major projects on course

The most significant achievement in 1983 was effective management of four major projects launched during the recession of 1982. One of these projects, the oil sands Plant Integrity Program, has already contributed favorably to our bottom line. This program played a major role in achieving higher production volumes and lower maintenance costs at the Fort McMurray plant in 1983.



William R. Loar, President and Chief Executive Officer

The large-pit project at the oil sands plant required substantial levels of overburden removal in 1983. This work is adding reserves which will generate revenues for Suncor after the year 2000 when the plant otherwise would have run out of mineable material.

Expansion of our in-situ heavy oil project at Fort Kent also increased Suncor's production and earnings in 1983. This project, now largely completed, should register further production increases in 1984 as the expanded facilities become fully operational.

The Sarnia refinery upgrading, the largest of the four projects, should begin to pay for itself late in 1984. The upgrading will substantially reduce the refinery's crude oil consumption and increase the proportion of higher value-added products in overall output.

All four projects are reviewed in greater detail in a special section beginning on page 6.

Capital investment remains high

Suncor's objective is to improve the profitability of each of three main operating units: exploration, production and resources development; oil sands; and refining, petrochemicals and marketing. This objective requires substantial capital investment.

Capital spending in 1984 should be about $310 million excluding capitalized interest. The allocation for exploration, production and resources development will rise to approximately $100 million. Another $65 million is earmarked for the oil sands operation and about $145 million for refining, petrochemicals and marketing. (For more information on Suncor's investment strategies, see the interview on page 14.)

Content policy benefits Canada

Suncor's spending is a significant benefit to Canada. For example, the refinery upgrading project operates under content guidelines requiring that, where economically feasible, 90 per cent of the project's content be Canadian-produced and this objective is being exceeded. Every effort is being made to locate competitively-priced Canadian products or services before a foreign source is considered.

In some cases, we have helped Canadian manufacturers bid on components never before produced in this country. This pro-active stance has contributed to the expertise and competitiveness of Canadian firms while also providing Suncor with local suppliers who can respond more effectively than foreign companies to our future requirements for maintenance and parts replacements.

Oil sands production increases

Production of fully processed and partially processed synthetic crude from our Fort McMurray oil sands plant averaged 7 606 m^3 per day (47,839 barrels) in 1983, up 41 per cent from 1982 when production was affected by a fire early in that year. Performance improved in every operating unit in response to a major effort by employees at all levels.

In 1983, we received an average of $250.68 per cubic metre ($39.85 per barrel) of partially and fully processed synthetic crude compared to $255.09 ($40.55 per barrel) in 1982. The decline resulted from a reduction in world oil prices during the year, offset to a large extent by the fact that a higher proportion of production was fully processed in 1983. Fully processed synthetic crude receives a higher price than partially processed crude which is produced when the plant is not completely operational.

Difficult year for refined products

Excess refinery capacity and intense competition for market share in a declining market led to severe gasoline price wars in eastern Canada in 1983. Profit margins were severely squeezed resulting in a loss for the Sunoco Group—our refining, petrochemicals and marketing operation. Industry-wide gasoline volumes fell for the third successive year.

Suncor's petrochemical volumes were down from 1982. Demand remained weak and prices declined in the early part of 1983, especially in European markets. Prices started to firm in the latter part of the year.

Suncor's home heating oil sales continued to fall as consumers converted to natural gas and electricity. Production of low-priced heavy fuel oil was reduced by using lighter crude oils as refinery feedstock.

Fiscal and regulatory environment continues to improve

In last year's annual report, I noted that the environment for our industry in Canada was beginning to improve. This trend continued in 1983 with a number of favorable decisions by governments.

The National Energy Board authorized exports of light crude oil to the United States for the first time in many years.

The 1983 federal budget introduced more liberalized provisions for utilizing investment tax credits and losses. It also suspended the incremental oil revenue tax on conventional crude oil production for another year and provided relief from the petroleum and gas revenue tax for eligible capital expenditures on enhanced recovery projects such as our Fort Kent heavy oil facility. These measures made a modest contribution to Suncor's 1983 cash flow. Other federal and provincial measures are mentioned throughout the report.

Nonetheless, serious problems remain for our industry. The high overall tax and royalty burden has combined with real price declines on the world market to reduce our industry's cash flow and limit its ability to work toward the federal government's objective of oil self-sufficiency. Too many government levies are based on revenues rather than earnings; for example, the incremental oil revenue tax which at this time applies only to Suncor and its oil sands production. A new tax and royalty structure is urgently needed to encourage increased investment in Canadian hydrocarbons, particularly heavy oil and oil sands production.

Outlook

In 1984, our main goals are successful completion and start-up of the new Sarnia refinery facilities; further improvement in the operating reliability of our oil sands plant; and expansion of our investment in the search for conventional crude oil in the western provinces.

Domestic crude oil prices should also remain relatively stable over the year. The result will be a price decline in real terms. Our ongoing cost management and productivity programs are responding to this challenge.

Suncor's production of hydrocarbons should increase in 1984, the result of greater operating reliability at our oil sands plant and increased output from our Fort Kent heavy oil project. Conventional crude oil production and natural gas sales will probably decline slightly.

We expect that refining and marketing operations will be profitable in 1984 following losses in 1983. Market demand will be flat but industry-wide refinery utilization rates should rise due to the refinery closings and rationalizations of 1983 and product margins should improve.

There is good reason to be optimistic about our prospects. We have a firm operating base and a solid financial position. We have sought out opportunities and we are investing in them. I am confident that we have the skills and resources to make these investments a success.

Submitted on behalf of the Board of Directors:

William R. Loar
President and Chief Executive Officer

February 6, 1984

SARNIA REFINERY UPGRADING

The refinery upgrading will make our Sarnia facility one of the most flexible and efficient in the country. It is also stimulating new management skills which will benefit the Sunoco Group for years to come.

Begun in 1982, the $335 million project includes installation of a hydrocracker, a vacuum unit, a sulphur plant, a hydrogen plant and various related facilities.

At year-end, engineering had been completed and all equipment had been delivered to the job site. The new facilities are expected to be fully operational by the end of 1984.

Wayne Wright, Vice-President, Refining (centre) reviews scale model of the upgrading project with Walter Petryschuk, Refinery Manager (left) and Maurice Stephenson, Project Director (right).

The upgrading is a major expenditure which has critical implications for the operating and financial performance of the Sunoco Group and it is therefore crucial that the project be managed as effectively as possible. To this end, a number of steps have been taken.

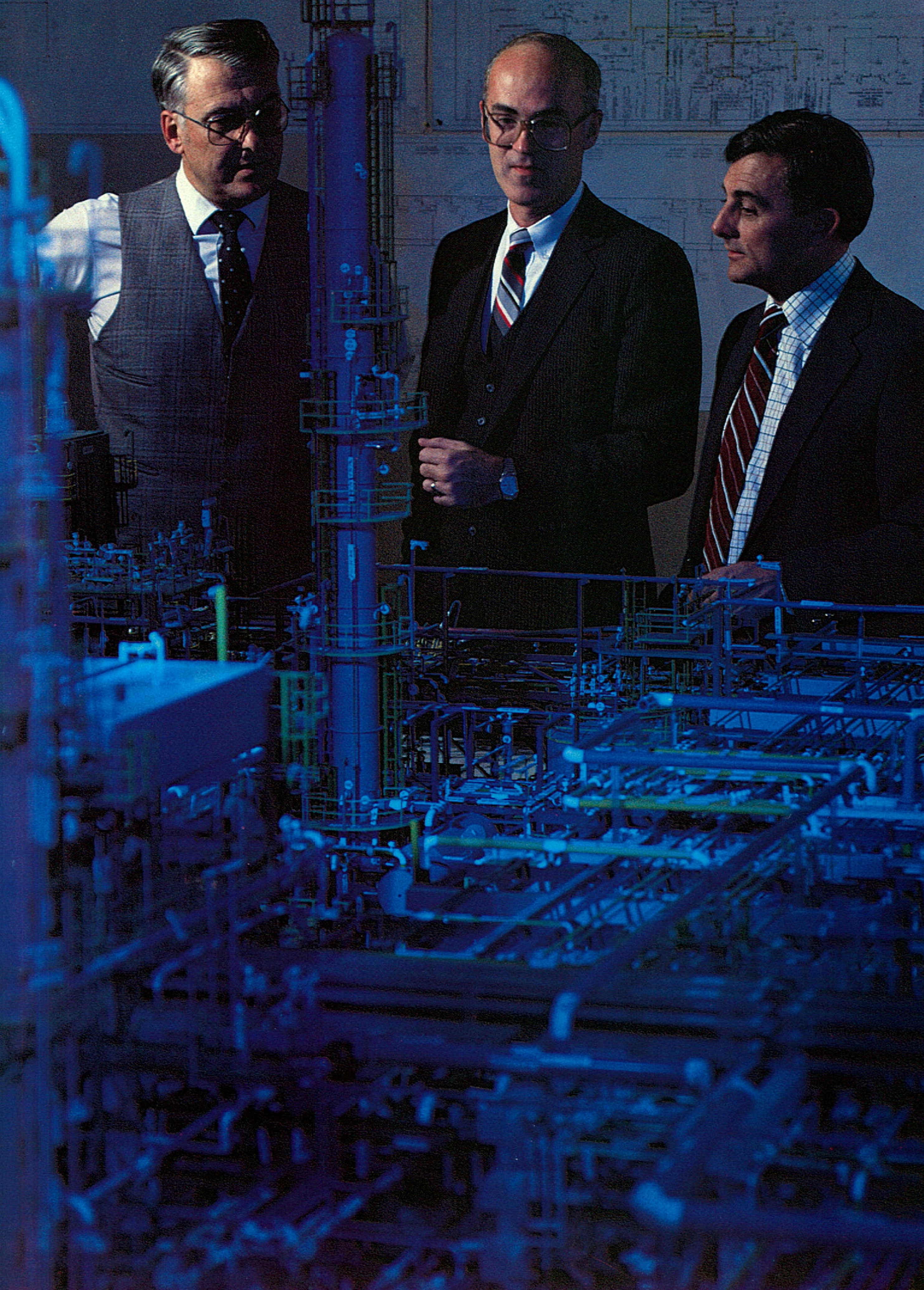
We introduced a successful new program called MAPLE—Maximum Achievement in Productivity with Labor Expertise. It's Canada's first construction productivity program to have the full co-operation of the building trades. Foremen, tradesmen and subcontractors are directly involved in planning, scheduling and productivity analysis.

We divided the job site into 64 separate areas to increase the opportunity for hands-on management. Key pieces of equipment were pre-assembled off-site which also saved time and money.

In another departure from tradition, there will be no single completion date when the plant is turned over to operating people for testing. A total of 175 separate systems will be completed successively, each of which will be tested and commissioned individually while construction is still proceeding on other units. This approach should save considerable time and use our operating people more effectively.

New ideas are also at work in our preparations for operating the new facilities. Operating people for the new units have been hired months in advance to check out design, inspect equipment and write operating manuals. They are training on a new, computer-driven Hydrocracker Simulator—a control board where operating situations can be recreated in life-like detail. By the time operations begin, our staff will know the plant and how to run it.

We are confident that we will achieve a trouble-free start-up of this project, on time and within budget.



Fort McMurray Large-Pit Project

This 2 000 tonne bucketwheel excavates overburden at the Fort McMurray plant. Jim Moore, Superintendent, Mining (left), Bill Romanchuk, Manager, Mobile Equipment Maintenance (centre) and Calvin Blanchard, Superintendent, Mine Maintenance (right) represent departments that were largely responsible for higher volumes of overburden removal and mining in 1983.

The large-pit project expands the area of our Fort McMurray oil sands lease which will actually be mined. This undertaking adds about 14 million m^3 (90 million barrels) to reserves and extends the life of the plant by almost five years.

The oil sands in the new area are under a thicker-than-normal layer of overburden which must be removed to enable mining. This overburden, which consists mainly of muskeg and glacial deposits, is expensive to move and the muskeg must be stored on site for eventual use in land reclamation. Thus, the decision to expand the area of the mine depended in large part upon cost-effective overburden removal at an accelerated pace. Careful management is needed.

Work on the large pit began in 1982. More than 17 million bank cubic metres of overburden weighing approximately 34 million tonnes were removed in 1983 primarily from the newly expanded area. This volume would cover a Canadian football field to a depth of nearly two miles. (A bank cubic metre is a measure of material in place.)

The cost of removal in 1983 was just over $50 million and the per unit cost was lower than expected. About 67 per cent was spent on in-house services and the remainder on outside contractors. In total, overburden removal costs for the expansion area may reach about $185 million through to 1987.

Mining of oil sands from the new area began in 1983. By the end of 1984, mining should total about 3.8 million tonnes while overburden removal will reach about 26 million bank cubic metres.

Overburden is used to build dikes for tailings ponds. One of these dikes is now one of the largest earth-built dams in the world, with an average base width of 550 metres, a height of 80 metres and a length of 3 000 metres. It contains almost half as much earth as was moved during the construction of the St. Lawrence Seaway.

Fort McMurray Plant Integrity Program

Suncor's profitability depends in large measure on the successful operation of the Fort McMurray oil sands plant. To improve production reliability, we initiated the Plant Integrity Program in 1982. Completion is now scheduled for 1985 at a total cost of $225 million.

In 1983, $30 million was spent under this program to upgrade instrumentation in the refinery area, rebuild one of the three major steam boilers and improve boiler feedwater systems.

In 1984, the second major boiler will be rebuilt, the process instrumentation upgrading project will be operational and further improvements will be made to boiler instrumentation and waste water control.

However, the most significant new measures relate to people rather than equipment. Reliable, safe production depends upon effective operating and maintenance procedures which require the participation of people at every level of the organization.

We began by identifying our operations priorities into a dozen Special Emphasis Areas ranging from environmental requirements to maintenance and housekeeping. A team leader was appointed for each area with a mandate to create opportunities for working outside the management hierarchy. Employees were directly involved in the design of operating procedures and training programs.

The Plant Integrity Program has helped increase production and reduce maintenance costs at the oil sands plant. Dennis MacKenzie, Manager, Utilities Integrity (left), Steve Yanciw, Manager, Refinery Integrity (centre) and Ernest Kalmanovitch, Manager, Plant Integrity Project (right) were the program leaders in 1983.

One of the key Special Emphasis Areas was human resources. Employees are participating in Employee Action Committees to develop plans to improve the human resources function following detailed examination of labor relations, communications, manpower utilization, recruiting, training and safety.

Another innovative technique to increase employee participation was a reorganization of the workplace along entrepreneurial lines. Suncor acts as a general contractor on a project team involving operations, maintenance, training and support services people. The result is more scope for commitment, initiative and teamwork than is found in the traditional pyramid structure used by most large companies. Substantial reductions in engineering and project support expenses have been realized from this approach as well as enhanced morale.

Overall, the Plant Integrity Program appears to be working well. The facilities are safer, productivity is higher and production reliability is measurably improved.


Suncor
Oil Sands
Division

FORT KENT EXPANSION

At Fort Kent, we have turned an experiment in non-conventional heavy oil into a small but successful producer. In doing so, we have developed valuable know-how for tapping Alberta's enormous heavy oil resources.

Suncor became Operator of the Fort Kent project in the Cold Lake area of northeastern Alberta in 1980. At that time, the project was producing 182 m^3 (1,145 barrels) per day. Steam and water were being forced underground to reduce the viscosity of oil trapped in the sand, inducing it to flow. The technique was working and we decided to expand the project to an economically-viable size in co-operation with our 50 per cent partner.

Expansion included new steam generating capacity and production facilities and drilling of additional wells at a cost originally estimated at $88 million. Work began in 1982 and was essentially completed in 1983 at a cost of $64 million of which our share was $35 million. Lower inflation, high labor productivity and a reduction in the number of wells accounted for the $24 million saving from the original cost estimate.

Del Vaughan, Manager, Heavy Oil (left) and Ed Pacholko, Vice-President, Resources Development assess installation of Cluster "K"—14 new slant pump jacks at Fort Kent.

Production in 1983 was virtually double the level of the previous year, averaging about 348 m^3 (2,200 barrels) per day. Output should reach 616 m^3 (3,875 barrels) per day in the fourth quarter of 1984.

Production rates will be lower than planned because drilling confirmed a more limited oil reservoir than expected and as a result, fewer wells were drilled. However, the percentage of the oil we actually recover should be considerably higher than originally estimated due to good performance of the steam mode of operation. Recovery factors could improve further through the application of enhanced techniques which are under current investigation and testing. These techniques include surfactant foams, steam additives and steam flood.

The Fort Kent expansion has added to our knowledge base in a number of areas. We have helped to pioneer slant drilling and production systems in Canada using new equipment especially designed for Suncor. The slant drilling technique means that sizeable shallow reserves can be accessed with wellheads clustered in a compact area to conserve agricultural land. We have developed new seismic techniques to help evaluate heavy oil deposits. And we have learned to make use of sewage effluent for steam generation. These successes, combined with a growing understanding of steam stimulation production, should open the way for Suncor to participate in further heavy oil projects.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Suncor
RESOURCES DEVELOPMENT DIVISION
Suncor
RESOURCES DEVELOPMENT DIVISION

LOOKING TEN YEARS AHEAD

Mr. Loar, what do you see as the prime objective for Suncor over the next several years?

It's to increase the level of our profitability. We have improved our bottom line in each of the past two years but we still have a way to go. The Company has ambitious plans for investment that will need higher earnings to generate the necessary funds. We also need to compete for the attention of the investing public. Our directors and shareholders want to attain majority Canadian ownership and control of Suncor and a wider distribution of our shares as soon as practicable.

Resources Group Management Committee in 1983 (left to right): Peter Bradbury, Vice-President, Controller; Ed Pacholko, Vice-President, Resources Development Division; Don Smith, Vice-President, Exploration Division; Bill Turner, Vice-President, Production Division; Mike Supple, Vice-President, Oil Sands Division; Peter Spelliscy, Director, Human Resources; David Galbraith, Director, Planning, Taxation and Risk Management; Joe Wolfe, Director, Special Projects. (Missing from photo, Bill Oliver, Vice-President, Administration.)

How do you intend to increase profit levels over the next few years, given the increasingly competitive nature of the industry?

Well, one key to higher profits is to achieve greater production reliability at the oil sands plant and we're certainly making headway. The plant had one of the best production years in its history in 1983 despite a fairly serious fire in early July. We have substantially upgraded equipment and control systems and we have introduced new training and employee participation programs. I'm excited by the prospects at Fort McMurray.

We also expect better returns from Sunoco once the hydrocracker project is completed in 1984. The refinery will be more cost-effective and we'll have more flexibility to produce a better mix of refined products to meet the needs of the marketplace.

In the longer term, we see a substantially higher profit contribution from conventional exploration and production.

More efficient use of resources in all areas of the Company will also help our earnings performance over the next several years.

What do you think Suncor will look like in 10 years' time?

I think we'll be a much larger, better balanced company. Based on current projections, we expect to invest nearly $7 billion in capital projects over the next decade and this spending will change the shape of the Company.

Basically, the largest proportion of the investment will be in exploration and production of conventional oil in western Canada where we believe there are some attractive opportunities for a company our size. Compared to other integrated oil companies, Suncor has a relatively small asset base in this end of the business. We plan to "grow" this segment to the point where it is capable of generating earnings more in balance with the other two main business segments—the oil sands plant and refining, petrochemicals and marketing.

We also plan to expand our involvement in non-conventional heavy oil with more projects like Fort Kent. Non-conventional heavy oil production is currently running at about 15 per cent of our conventional production and we expect to increase this ratio even as conventional volumes grow.

The second major area of capital expenditure will be at the oil sands plant in order to improve production reliability and achieve higher output.

A smaller proportion of our future spending will be in the downstream operations. The $335 million we are now spending to upgrade the Sarnia refinery should lay the foundation for more solid and profitable operations at the Sunoco Group which will help to support our thrust into exploration and production.

As a result of this capital program, what you will hopefully see in 10 years is a company obtaining substantial proportions of its income from three different segments: exploration, production and resources development; the oil sands plant; and refining, petrochemicals and marketing.

What do you see as the main challenge you face in reshaping the Company in this way?

Really there are two main challenges. One is to maintain tight control of our financial resources. We don't expect rapid increases in oil prices over the next 10 years, so we have to manage within narrow limits. We have set ourselves prudent ceilings on our borrowings and we intend to continue to run a very lean organization.

The other challenge is to keep and motivate our people, at all levels. I believe we have a really excellent group of experienced personnel. I see my task as maintaining the kind of organization where Suncor people can achieve the performance they are capable of.

Sunoco Group Management Committee (left to right): Mike O'Brien, Vice-President, Marketing; Mike Hayhow, Vice-President, Planning and Business Effectiveness; Ken Liddon, Director, Financial Administration; Stan Cowtan, Executive Vice-President; Bill Loar, President and Chief Executive Officer, Suncor Inc. (who is not a member of the Committee); George Brereton, Vice-President, Human Resources and Government Affairs; Wayne Wright, Vice-President, Refining; Nick Hathway, Director, Supply and Transportation. (Cliff Boland, formerly Vice-President, Human Resources and Corporate Affairs, Suncor Inc., has since replaced Mike O'Brien as Vice-President, Marketing. Mr. O'Brien is now Manager, Mining and Extraction at the oil sands plant.)

How do you go about encouraging the best from employees? Does Suncor have a particular management style?

I think we have developed our own flavor.

One thing that is clearly our style is decentralization. Each of our Groups has its own Management Committee and they make the day-to-day decisions affecting their business. The Groups have evolved their own operating styles consistent with the work they do and the environment in which they operate.

Our organizational structure is uncomplicated and fairly informal. We have a small corporate office for a company our size and managers on the spot usually make the decisions. The results of this approach are apparent in the fast and effective way our operating people have responded to emergencies such as the July fire at the oil sands plant and the catcracker shutdown at our refinery.

We are putting a great deal of emphasis on employee participation to improve our performance with innovations like the MAPLE program at the Sarnia refinery and the Employee Action Committees in the Oil Sands Division. (See pages 6 and 10.) We have also introduced performance-based training to upgrade skills. In our business, a wrong turn of the valve can cost millions of dollars. To minimize this kind of problem, we need everyone's involvement and support. That's part of our management style.

You can see the same approach at the Board level. We have an active Board. Six of our 14 directors are business people from across Canada who are independent of management and either of our major shareholders. This makes the Board an excellent forum for establishing the broad direction of the Company.

We know this will be a tough decade for the oil industry in Canada. Prices for oil and gas probably won't increase all that much, while margins for refined products will be narrow and markets will be competitive. People will determine which companies succeed. I think that's to our advantage at Suncor.

OVERVIEW

The Resources Group contributed $133.0 million to Suncor's earnings in 1983, more than twice the 1982 level. The Oil Sands Division accounted for most of the gain and generated most of the profit for the Group.

Revenues increased 21 per cent to $902.5 million in 1983, primarily due to higher volumes of synthetic crude and heavy oils, offset by declines in conventional crude oil and natural gas production.

Capital spending for the Group totalled $155.5 million for 1983. Most of the investment was directed to new initiatives at Fort McMurray and Fort Kent, as described on pages 8 through 12 of this report.

During 1983, Suncor participated in 52 completed exploratory wells and 107 development wells with success ratios of 38 and 87 per cent, respectively.

In 1984, capital outlays will demonstrate an increasing emphasis on conventional oil exploration and production in the western provinces. This emphasis reflects improved cash flow and a strategy of expanding this segment of our business. We believe there is considerable oil to be found in western Canada and the economic return on new oil is sufficiently attractive to warrant investment.

Resources Group capital expenditures

($ millions)	1983	1982
Oil sands		
Plant Integrity Program	$ **30.5**	$ 60.2
Mine and mobile equipment	**13.1**	25.0
Other plant	**34.9**	11.9
Housing	**3.0**	6.4
Total	**81.5**	103.5
Exploration, production and resources development		
Exploration*		
Land holdings	**16.0**	8.0
Drilling	**15.3**	27.9
Geology, geophysics and other	**7.7**	5.2
	39.0	41.1
Production		
Acquisitions and land holdings	**6.2**	0.8
Development drilling	**5.5**	6.0
Plants, related facilities and other	**6.3**	9.6
	18.0	16.4
Resources development		
Fort Kent	**14.7**	23.7
Other in-situ oil sands and minerals	**2.3**	4.0
	17.0	27.7
Total	**74.0**	85.2
Total Resources Group	$ **155.5**	$ 188.7

*Includes $1.4 million of frontier expenditures

Last year Suncor resumed exploration in Saskatchewan, due in large part to recent changes in provincial royalty regulations including one-year royalty-free production from new wells. Suncor conducted extensive seismic surveys during 1983 and made substantial purchases of new leases at Crown land sales, which will result in a substantial development program in the Dodsland area in 1984. About 15 per cent of Suncor's 1984 exploration budget for the western provinces has been allocated to Saskatchewan.

A superintendent inspects the conveyor belt carrying oil sands to the extraction unit.

Wells completed

	1983		1982	
	Gross	Net	Gross	Net
Exploratory wells				
Oil	**9**	**5**	6	6
Gas	**11**	**6**	11	7
Dry	**32**	**19**	24	17
Total	**52**	**30**	41	30
Success ratio	**38%**		41%	
Average depth drilled (metres)	**1 648**		1 416	
Development wells				
Oil	**87**	**25**	92	37
Gas	**6**	**3**	9	6
Dry	**14**	**6**	16	9
Total	**107**	**34**	117	52
Success ratio	**87%**		86%	
Average depth drilled (metres)	**1 333**		941	

Note: This table excludes wells completed under farmout agreements on Company properties as no cash expenditures were incurred by the Company. During 1983 there were 14 such wells (11 exploratory and 3 development); in 1982 there were 12 such exploratory wells.

As at December 31, 1983 there were 12 wells in progress (11 exploratory and 1 development).

Undeveloped land holdings

(thousands of hectares)	1983		1982	
	Gross	Net	Gross	Net
Oil and gas				
Western provinces				
British Columbia	**154**	**61**	208	64
Alberta	**392**	**261**	435	251
Saskatchewan	**10**	**7**	1	1
	556	**329**	644	316
Frontier*				
Northwest Territories and Yukon	**20**	**15**	20	15
Mackenzie Delta/ Beaufort Sea	**769**	**134**	462	173
Arctic Islands	**7 339**	**1 368**	7 332	1 370
Offshore Labrador	**9 010**	**900**	9 010	898
Offshore Nova Scotia	**341**	**49**	341	49
	17 479	**2 466**	17 165	2 505
Total oil and gas holdings	**18 035**	**2 795**	17 809	2 821
Minerals	**270**	**239**	555	405
Total	**18 305**	**3 034**	18 364	3 226

*Subject to future reductions as others earn interests in the lands by carrying out exploration activities pursuant to farmin agreements with Suncor and to reflect the Government of Canada's right to a 25 per cent interest in all Canada lands.

Demand declined in both domestic and export markets for natural gas during 1983, due to unseasonal winter weather and intense competition from other fuels. Gas industry revenues were down.

The National Energy Board approved a higher level of gas exports and introduced a volume related incentive pricing scheme to encourage increased sales to the United States. Ottawa also reduced its domestic natural gas tax and allowed more revenues for producers. Nonetheless, natural gas exploration and production will remain at depressed levels and few new projects will proceed given the fact that major

Bullet-like polyurethane "pigs" like this one clean internal corrosion to improve flow in underground water pipes at the oil sands plant.

transmission companies are operating well below contract volumes.

We believe that short-term growth potential exists in the domestic gas market and that the U.S. market continues to provide a major long-term opportunity. However, sizeable increases in demand will only occur if natural gas is allowed to compete freely with heavy fuel oil, electricity and, in the U.S. market, American natural gas. This would require a pricing system which responds to market forces. Current pricing for both domestic and export sales is not sufficiently responsive to the realities of the market.

Outlook

Production of synthetic crude and heavy oils should increase again in 1984 as we obtain a full year of benefits from the large investments we have made at our Fort McMurray and Fort Kent facilities. Conventional crude oil volumes will continue to decline at a modest rate due to reservoir depletion. Domestic natural gas sales should stabilize somewhat but we expect to see a further small decline due to continuing weakness in Canadian exports to the U.S.

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 units where it is thermally cracked into coke and distillates. The distillates are desulphurized and blended to form high-quality synthetic crude oil, almost all of which is shipped to Edmonton via pipeline for distribution.

Mario DeCrescentis (left) and Don Hindy, senior staff in the Mining Division at the oil sands plant, spot-check overburden removal by Demag shovel. Unit costs for this activity were lower than expected in 1983.

Production

A new plan was implemented in 1983 which identified special areas of emphasis for improving reliability. This initiative was a considerable success and production increased substantially. Output averaged 7 606 m^3 per day (47,839 barrels), up 41 per cent from 1982. Figures for both years include partially processed synthetic crude produced when the refinery was not fully operational.

Substantial overburden and mining volumes were recorded in 1983. A total of 17.1 million bank cubic metres of overburden were removed during the year, about 12 per cent above our budget. Meanwhile, unit costs actually declined 35 per cent from 1982 mainly due to reduced maintenance costs and improved productivity. Oil sands processed climbed to 35.9 million tonnes, slightly above the previous record set in 1972.

Improvements in operations included:

- *New instrumentation.* For example, in the extraction unit where bitumen is separated from sand and silt, new instrumentation was installed to measure density and weight, enabling better control of the extraction process.
- *Improved equipment.* Substantial investments were made to replace old equipment ranging from piping to trucks. For example, eight new 85 ton mechanical drive trucks were purchased early in 1983 at a cost of $4.7 million to haul overburden. Some of our existing 150 and 170 ton electrical drive units were retired. Significant savings were realized due to lower maintenance costs and improved availability of the new trucks.
- *Better housekeeping and safety.* Several new programs increased awareness of the importance of the work environment and safety procedures. For example, a volunteer committee was formed by personnel in the process area. They carefully analyzed and publicized each incident and the number of injuries began to decline steadily. Overall, lost time due to accidents at our oil sands plant dropped by almost half from 1982.
- *More effective maintenance.* More resources were committed to maintenance, including additional personnel, and the extra effort contributed to a sharp reduction in overall cost. There was a marked improvement in the availability of boilers and mobile equipment. For example, steam boiler #2 ran continuously for seven months without major problems despite the fact it is 15 years old and will be completely rebuilt in 1984.
- *More teamwork.* A number of programs were launched to encourage and facilitate a team approach. Traditional reporting relationships do not provide for the participation and sharing of ideas required to master the complex equipment and procedures at our oil sands plant. Several of our initiatives to increase teamwork are described in the section on the Plant Integrity Program on page 10.

When operating problems occurred, our personnel responded quickly and effectively. The most serious incident was a fire on July 2 which damaged the refinery area. No one was injured and production of partially processed synthetic crude resumed within hours. A bypass was completed around the damaged area in August, enabling fully processed output to reach 60 per cent of production. Damaged equipment was rebuilt by late October and production returned to normal. In the interim, partially processed output was exported to the United States under a temporary permit from Canada's National Energy Board.

Left: In performance-based training at the oil sands plant, trainees demonstrate proficiency on the job to an experienced operator. Cam Brinston observes Spencer Thibodeau reading outlet gas temperatures of the hydrogen reformer.

Right: Volunteer members of the Housekeeping and Safety Subcommittee discuss their ideas for improvements as part of the Employee Action Committee program.

Synthetic crude oil gross proven reserves

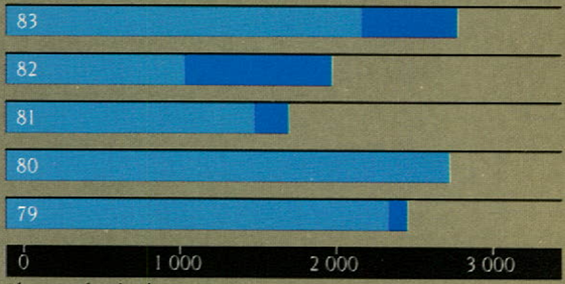
(millions of cubic metres)	
December 31, 1982	**66.5**
Production before in-plant usage	**(2.9)**
December 31, 1983	**63.6**

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.

Production of synthetic crude oil



(thousands of cubic metres)

Fully processed* Other

*Fully processed synthetic crude oil represents normal plant output

Environmental performance

The new water pollution control system installed at the plant in 1982 performed impressively in 1983. The system consists of three containment ponds in which plant effluent is treated. The water is then sampled and returned to the Athabasca River when clean.

The new system was designed, installed and commissioned with extraordinary speed to respond to water quality problems which occurred in early 1982 when a serious fire disrupted operating systems. Suncor was subsequently charged with 20 offences under federal fisheries legislation and two under provincial clean water legislation. Of the federal charges, seven went to trial in 1983, resulting in four acquittals and one conviction. Two others were still in progress at year-end. The Crown's appeal of the four acquittals was dismissed by the Court of Appeal. Suncor is appealing the one conviction. Of the two provincial cases, one was dismissed while the other resulted in conviction, which Suncor is appealing.

A faulty seal in a valve on Suncor's synthetic crude oil pipeline resulted in a 0.2 cubic metre per day (one barrel) oil leak about 91 metres (300 feet) north of where the pipeline crosses the Athabasca River near the city of Fort McMurray. Prompt action by specially-trained and equipped Suncor personnel located the small leak and repaired it within five days. The pipeline was shut down for 49 hours while repairs were made.

Suncor also responded to an air quality directive issued in May, 1983 by Alberta Environment. The directive requested Suncor to supply specific information on plant emissions, particularly sulphur. For information on the plant's air emissions program and other environmental initiatives, see page 26.

Exploration Division

This Division participated in 13 successful exploratory wells in the western provinces in 1983 of which six were oil wells eligible for the new oil reference price. In the Arctic Islands, one exploratory well found oil and gas while a delineation well confirmed a previous oil and gas discovery.

Western provinces

The Division contributed to the cost of 43 exploratory wells drilled in this region in 1983 and was Operator for 30 of them. In total, seven were gas wells, six were oil wells, 23 were dry, three were suspended and four were still in progress at year-end, yielding a success rate of 36 per cent. In total, 36 of these wells were spudded in 1983.

Exploratory drilling on Suncor interests in the Beaufort Sea.

There were a further 14 exploration wells drilled in 1983 on Suncor lands covered by farmout agreements requiring no cash expenditures by Suncor. Of these farmout wells, one was an oil well, one was both oil and gas, three were gas wells, six were dry, two were suspended and one was in progress at year-end.

Important drilling areas included:

- *Chigwell North Area.* Suncor discovered oil and gas at Chigwell North in 1983 and further evaluation is planned for 1984. Suncor holds 1 525 net hectares in this area of Alberta. Suncor discovered oil and gas a few kilometres to the south in 1982.
- *Phoenix area.* Gas was discovered in an exploratory test in this relatively undrilled area of western Alberta in 1983. A second well was being drilled at year-end. Suncor holds 6 029 net hectares in the immediate vicinity.
- *Drumheller area.* Three oil wells have been drilled on Suncor interests consisting of 283 net hectares in this area which is located one kilometre east of Drumheller. Development drilling will continue in 1984.

Arctic Islands

Three wells were drilled in the Arctic Islands offshore area during the 1983 season. Cisco K-58, a delineation well located five kilometres north of Cisco B-66 (a 1981 oil and gas discovery), found oil. Suncor has a 14.8 per cent working interest in the former permit on which the Cisco wells were drilled.

Cape MacMillan 2K-15, an offshore exploratory well 10 kilometres south of Ellef Ringnes Island found oil and gas. Suncor's 11.6 per cent working interest in the former permit for the MacMillan well was farmed out to Trillium Exploration Corporation. Suncor owns one-third of Trillium.

Grenadier A-26, also farmed out to Trillium, did not show any hydrocarbons.

Three offshore wells will be drilled in the 1984 program. Cisco M-22 and Skate C-59 are delineation wells to evaluate the oil and gas reserves of the Cisco and Skate fields discovered in 1981. Suncor has a 10.9 per cent interest in the Skate well. These wells will be funded directly by Suncor and are not included in the Trillium farmout agreement.

The third offshore well, Buckingham O-68, is an exploratory test in which Suncor had a 22.2 per cent interest before farmout to Trillium.

Offshore Labrador

Most of Suncor's interest in the Labrador Group is subject to a farmout agreement with Trillium Exploration Corporation. The drilling season opened with the spudding of a new exploratory well, Pining E-16, located 180 kilometres northeast of Cartwright, Labrador. The well was drilled to a depth of 573 metres and suspended.

Pothurst P-19, spudded in 1982, was re-entered in 1983 and abandoned at 3 992 metres due to mechanical problems. Rut H-11 was also re-entered and abandoned. A previously drilled and suspended well, North Bjarni F-06, was abandoned.

Corte Real P-85 was re-entered, drilled to 4 551 metres, cased to 3 921 metres and suspended.

Beaufort Sea

Suncor's interests in the Beaufort Sea are in four separate blocks: West; Centre; Northeast; and Herschel-West Beaufort Sea.

Suncor has farmed out its interests in the West and Centre blocks to Dome Petroleum. Dome spudded two wells in 1983, Natiak O-44 in the West block and Havik B-41 in the Centre block. Both wells were suspended at the end of the 1983 drilling season with re-entry planned for 1984. Suncor has a 27.5 per cent interest in the West block and a 50 per cent interest in the Centre block. Dome will earn half of these interests. Suncor retains a 19.055 per cent interest in the Northeast block.

Suncor's 5.6 per cent working interest in the Herschel-West Beaufort Sea block has been farmed out to Trillium Exploration Corporation. Gulf Canada is the Operator.

Mackenzie Delta

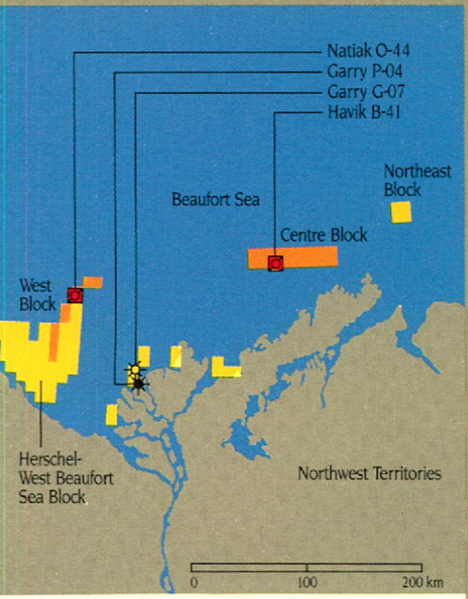
Suncor has a 45 per cent interest in 109 296 gross hectares in the Mackenzie Delta area. As Operator of these lands, Suncor completed negotiations with the Canada Oil and Gas Lands Administration and obtained approval of a five-year Exploration Agreement commencing March 4, 1983. Seismic work is planned in 1986.

Exploration Agreements

All of Suncor's frontier land holdings are covered by Exploration Agreements 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 before the last year 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.

Trillium Exploration Corporation

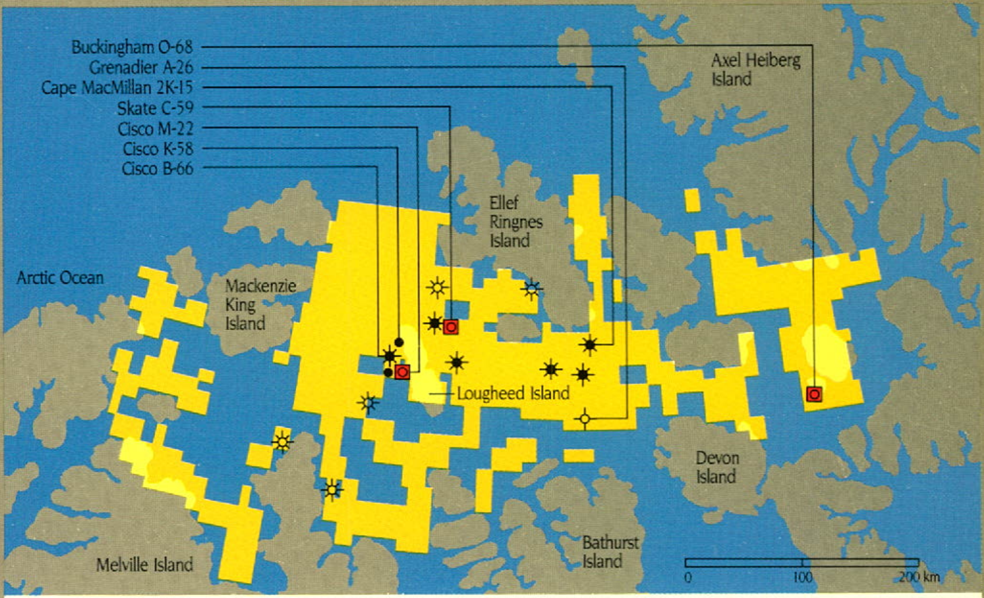
In addition to the exploration activity on Suncor acreage discussed above, Suncor participates through Trillium in other frontier lands. In the Beaufort Sea, Trillium has two farmins with Esso Resources involving three wells in 1983. Offshore Newfoundland, Trillium is participating in the drilling of one well immediately south of the major Hibernia oil field. Offshore Nova Scotia, Trillium is earning interests in acreage on which one well is being drilled.



Beaufort Sea/Mackenzie Delta

- Suspended (1984 re-entry)
- Oil and gas potential
- Gas potential
- Dry well
- Farmout to Dome Petroleum
- Suncor land holdings 0.79 million gross hectares 0.15 million net hectares

(The Herschel-West Beaufort Sea block lands have been farmed out to Trillium Exploration Corporation.)



Arctic Islands

- New locations
- Gas potential
- Oil and gas potential
- Oil potential
- Dry well
- Suncor land holdings 7.34 million gross hectares 1.37 million net hectares

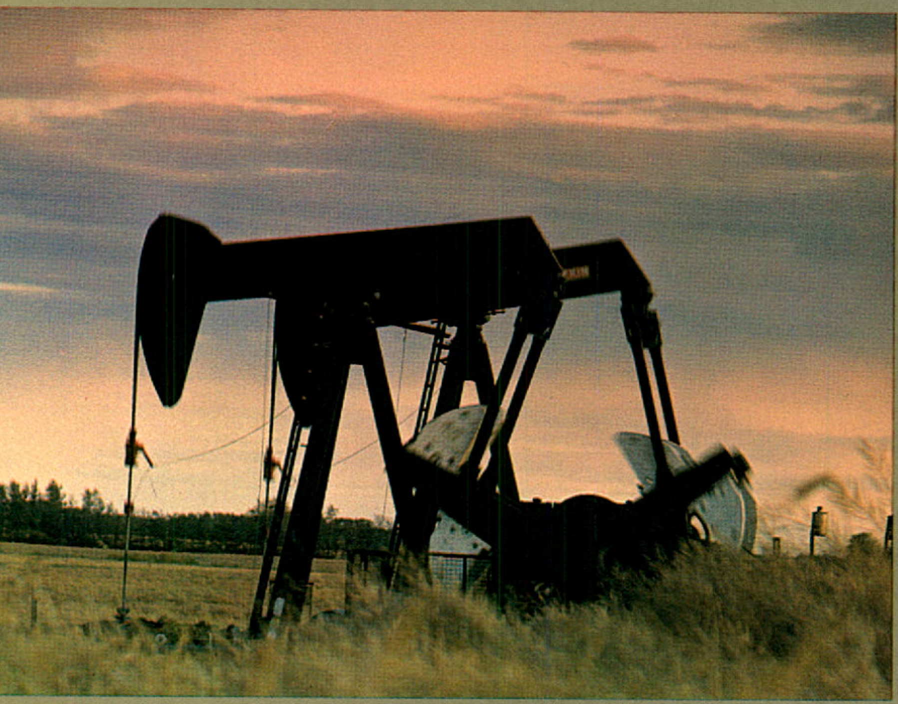
(All lands have been farmed out to Trillium Exploration Corporation except certain properties surrounding previous discoveries.)

Production Division

Suncor's conventional crude oil and natural gas production and proven reserves declined in 1983. Expenditures on production drilling and land acquisitions were increased to help offset the downward trend for crude oil.

Drilling

Suncor participated in drilling 74 conventional oil and gas wells in 1983, up from 50 in 1982. Results in 1983 included 60 oil wells, six gas wells and eight dry holes. In addition, four injection wells were also completed to stimulate production.



Two new Suncor oil wells in the Acheson area inside Edmonton city limits.

Spending on development drilling and equipment increased nine per cent to $9.0 million in 1983. Most of the expenditure related to oil rather than gas.

Production

Suncor's gross daily production of conventional crude oil and natural gas liquids fell about six per cent in 1983. The reduction for Suncor was the result of normal declines in older fields in Alberta, partially offset by an increase in Saskatchewan production.

Net production of crude oil and natural gas liquids, which is after royalty payments to governments and others, increased five per cent from 1982.

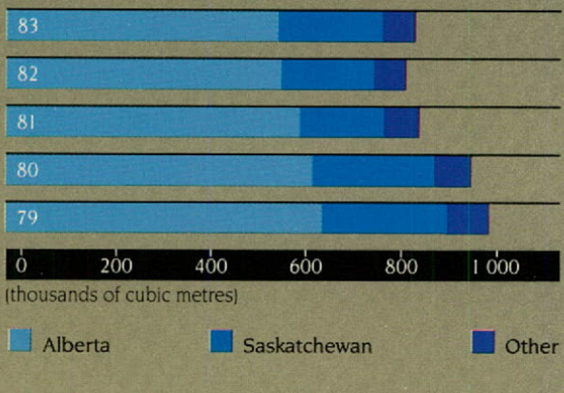
Suncor's gross sales of natural gas fell about 16 per cent in 1983, due to reductions in both exports and domestic demand. TransCanada PipeLines, our largest customer, purchased only 47 per cent of contracted volumes in 1983 compared to 58 per cent the year before. Similar reductions were made by other purchasers and industry-wide sales were down significantly. Suncor agreed to changes in the TopGas Agreement with TransCanada PipeLines which may reduce amounts payable to Suncor under the take-or-pay provisions of existing contracts in future years.

Net natural gas sales, which are after royalties, declined only eight per cent due to various reductions in government royalties.

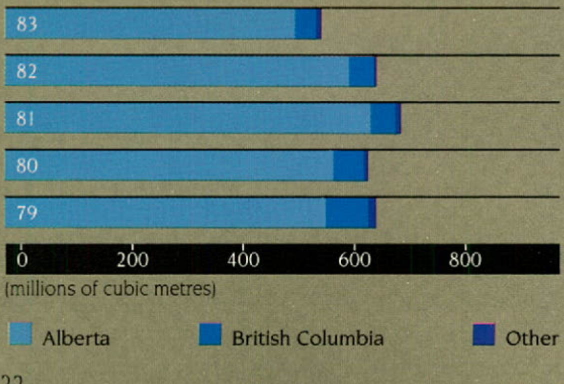
Spending on gas gathering and processing systems declined 83 per cent to $0.9 million in 1983. Two major investments were completed in 1982 and no comparable projects were undertaken in 1983.

Suncor's spending on production land purchases increased substantially in 1983, reaching $6.2 million. Several leases with undeveloped oil potential were obtained late in the year at a Crown land sale in Saskatchewan. The main property consists of 850 hectares in the Dodsland area near the Alberta border. Suncor has a 100 per cent interest in the property and will begin drilling in 1984 with 52 shallow wells planned. Production will be eligible for the new oil reference price and a special one year royalty-free period for new production.

Gross production of crude oil and natural gas liquids



Gross natural gas sales



Reserves

	Gross		Net	
	Conventional crude oil and natural gas liquids (millions of cubic metres)	Natural gas (billions of cubic metres)	Conventional crude oil and natural gas liquids (millions of cubic metres)	Natural gas (billions of cubic metres)
Proven				
December 31, 1982	**9.6**	**12.9**	**7.3**	**10.6**
Revisions	**(0.3)**	**0.1**	**(0.2)**	**0.3**
Additions	**0.3**	**0.4**	**0.3**	**0.3**
Production	**(0.8)**	**(0.5)**	**(0.6)**	**(0.4)**
December 31, 1983	**8.8**	**12.9**	**6.8**	**10.8**
Proven developed – December 31, 1983	**8.5**	**8.2**	**6.5**	**6.9**
Probable additional – December 31, 1983	**2.1**	**5.0**	**1.6**	**3.9**

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.

Proven developed reserves means those proven reserves that are actually on production or, if not producing, that could be recovered from existing wells or facilities.

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, 1983, using a discount factor of 10 per cent to be $624 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 crude oil (including Fort Kent) and natural gas liquids declined about 7.9 per cent in 1983 as production exceeded net additions. Significant new reserves were developed in the Acheson and Ricinus areas of Alberta. Reserves were also added in the Boundary Lake, Medicine River, Trochu/Twining North and Youngstown areas of Alberta.

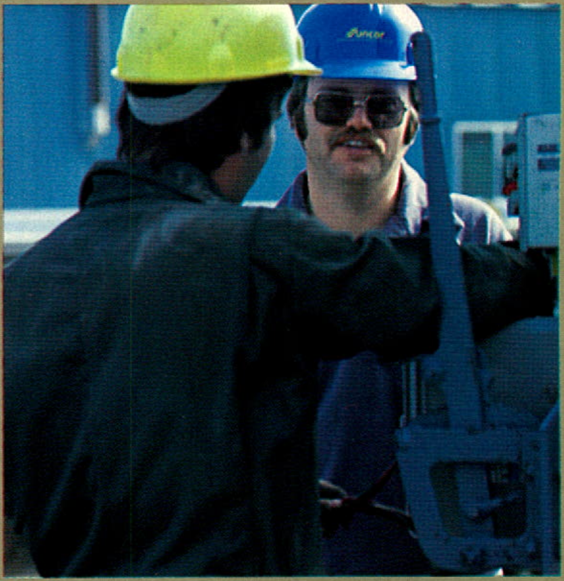
Gross proven reserves of natural gas declined 0.2 per cent in 1983. Additions and revisions to reserves in 1983 were the result of revaluation of reserves in several fields, especially in the Bougie area of northeast B.C., and also due to exploration work in the Phoenix area of Alberta.

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 hydrocarbon supplies are of commercial size and their recovery depends upon approval and construction of transportation systems to deliver them to market.

Resources Development Division

This Division is engaged in evaluating and investing in new energy resource opportunities with emphasis on in-situ heavy oil production. We are actively involved in developing this technology as Operator of the Fort Kent project which is described in detail on page 12.

New projections by the Alberta Energy Resources Conservation Board confirm the growing importance of non-conventional oil production to Canada's energy future. Our strategy is to assemble the necessary technology, skills and land holdings to be an important participant in this development.



Bruce Wilson (facing camera) and Bob Chalut inspect safety shutdown connections for Cluster "M" at Fort Kent.

In addition to drilling the Fort Kent development wells, this Division completed 10 exploratory wells, of which three found oil, four found gas and three were dry.

We hold a total of 61 204 net hectares in western Canada with potential for in-situ heavy oil production. Seismic work and drilling were conducted on two properties in Alberta in 1983 to assess the size and characteristics of their reservoirs. Further evaluations are planned in 1984.

Initial work is also being done on several coal prospects. Three drill holes were completed on a property acquired during 1983 in Pictou County, Nova Scotia and exploratory drilling is still in progress.

The Resources Development Division is also evaluating a number of properties for mineral and precious metals potential.

OVERVIEW

The Sunoco Group suffered a loss of $15.0 million in 1983. Sales volumes declined slightly due to lower demand and operating margins were depressed by competitive pressures.

Capital expenditures by the Sunoco Group totalled $197.7 million in 1983. Most of the spending related to the major refinery upgrading described on page 6 but a number of other significant projects also proceeded, including the following:

- *Liquid petroleum gas splitter.* This equipment will separate refinery-produced gases into isobutane and other butane components (used in manufacturing gasoline) and propane (some of which is sold through selected Sunoco outlets as a transportation fuel). The cost for the splitter is estimated at $10.9 million and completion is scheduled for late 1984.
- *New transformer station.* This $9 million project, completed in 1983, provides service directly from Ontario Hydro rather than through the local public utility commission. Ontario Hydro required the station because additional service is needed for the hydrocracker facilities which are being installed as part of the refinery upgrading project.
- *Flare upgrade.* This project, to be completed in 1984, will result in more efficient flaring of waste gas at a cost of $5 million.

One of Sunoco's marketing strengths is the Blender Centre which provides consumers with six grades of gasoline, twice that of most other competitors. Georges Kahale (above) is Manager, Retail Sales, Quebec.

Our relationships with governments once again required considerable attention in 1983. We appeared before the federal Restrictive Trade Practices Commission to assist the Commission in its enquiry into industry-wide marketing and refining issues. The Commission is expected to produce a report toward the end of 1984 assessing the competitiveness of the oil industry's downstream operations.

The Sunoco Group also made a presentation to a special federal task force on the petrochemical industry. Canadian producers are becoming uncompetitive in some of their export markets because of rapid increases in Canadian crude oil prices and taxes over the past several years. In our brief, we proposed that, in the short term, two taxes be eliminated on exported products and that current government policies should be reconsidered to ensure the long-term competitiveness of Canadian products. The Canadian petrochemical industry is an efficient world-scale producer which contributes considerable export earnings through the upgrading of Canadian resources.

Outlook

We look for a much improved year for the Sunoco Group in 1984 with operations returning to a profitable position. The Company's refinery will become substantially more cost-effective late in the year with the start-up of the new hydrocracker facilities. Meanwhile, we expect demand for gasolines to stabilize following three successive years of rapid decline. A dramatic upward shift in industry refinery utilization is projected for 1984 as a result of a significant number of refinery closings in eastern Canada over the past two years. Gasoline margins should improve considerably. Suncor's petrochemical sales will benefit from economic growth in North America and Europe but margins will likely remain below the levels of two years ago. Sales of home heating and heavy fuel oils will continue to decline due to conservation and competition from other fuels.

OPERATIONS

Refining

Average daily throughput of crude oil at the Sarnia refinery was about 11.2 thousand m^3 (70.5 thousand barrels), virtually unchanged from 1982. This volume was 78 per cent of rated capacity.

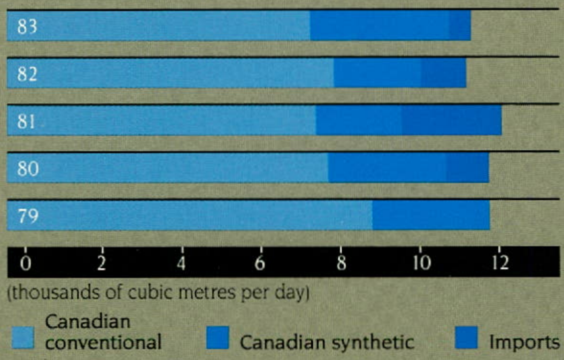
In 1984, throughput will decline with the start-up of the hydrocracker unit which will enable the refinery to produce current levels of transportation fuels and petrochemicals from considerably less crude oil.

The refinery's catalytic cracker was shut down on July 1 after an inspection revealed a bulge in the top of the unit. Repairs were completed in early August and offsetting measures were taken in the interim to ensure that the needs of our customers were met. A planned two-week maintenance shutdown of the petrochemical unit was successfully completed in April. Other minor shutdowns occurred during 1983, one of them the result of a fire which led to a fatality and serious burns to two other workers. The Ontario Ministry of Labour investigated the fire but has not yet released its findings.

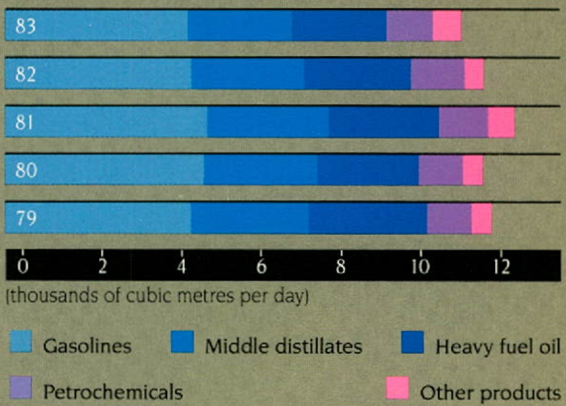
Petrochemicals

Suncor produces "aromatic" petrochemicals—benzene, toluene, xylene and orthoxylene—for the Canadian, U.S. and European markets. Sales volumes decreased about nine per cent in 1983 primarily due to reduced demand in export markets and changing feedstocks. Prices for our products were generally lower in 1983 due to the lingering effects of the world-wide economic recession and margins were squeezed by rising domestic crude oil prices.

Sources of crude oil refined for Suncor account



Sales of refined products



For details of refined products sales, see page 45.

Gasoline marketing

Suncor supplies gasoline to the Ontario and Quebec markets. At year-end, we had a total of 860 outlets, down 10 from the year before.

Demand in both major markets continued to fall in 1983, especially in Quebec, although the decline levelled out in the second half of the year. There was a surplus of gasolines, competition for sales was fierce, price wars were common and losses were incurred. Our strategy was to respond to our competitors' prices to protect our market share.

Home heating oil

Suncor's home heating oil sales fell about 18 per cent in 1983 reflecting unusually warm winter weather as well as continued intense competition from natural gas and electricity. Prices and margins were reasonably firm in Ontario but severe discounting occurred in the Quebec market. Industry rationalization of refineries should strengthen prices and margins in 1984 but overall sales of home heating oil will continue to decline.

MANAGING THE ENVIRONMENT

In its day-to-day business, Suncor is responsible for helping to manage Canada's natural environment in a manner which protects it for future generations of Canadians.

In 1983, Suncor invested a total of $55 million in environmental protection. In this section, we look at the results that are being obtained.

Clean air

Clean air is a number one priority in all our operations.

At the Fort McMurray oil sands plant, we installed electrostatic precipitators in 1979 at a cost of more than $20 million. This equipment removes fly-ash from the stack of the utility plant. Another $10 million may be spent on improvements to this system to enhance operating efficiency.

Marie Wright and Tim Shopik of Suncor's environmental staff inspect trees planted in 1975 which prevent erosion and provide habitats for wildlife near the oil sands plant.

In 1978, we constructed a second sulphur recovery unit at a cost of $7 million. Four years later, we upgraded it at a cost of $8 million. This plant is able to reduce sulphur dioxide emissions by more than 800 tonnes daily. Further engineering work is now in progress to make this plant more effective and reliable. Also in 1983, we completed installation of floating roofs on storage tanks to control hydrocarbon emissions.

Our Fort McMurray air management programs have effectively limited sulphur dioxide emissions to 60 per cent of permitted levels. Our annual assessment of local forests and lakes shows no environmental damage due to sulphur dioxide emissions and we presented these findings to the House of Commons Subcommittee on Acid Rain. Suncor is currently participating in a joint industry/government research study on acid rain deposition.

At the Sarnia refinery, air management programs have also focussed on minimizing sulphur and hydrocarbon emissions since the facility was first opened. Major new initiatives at a total cost of $28 million include installation of a sour water stripper and amine units to recover hydrogen sulphide and construction of two new sulphur units to convert this gas into molten sulphur. These improvements will lower sulphur levels in refined products resulting in approximately 30 tonnes per day less sulphur emitted to the atmosphere when these products are consumed.

At our Fort Kent heavy oil project, gases which are normally vented are being gathered as a source of fuel or flared to control hydrocarbon and hydrogen sulphide pollution.

Clean water

A second area of emphasis is the prevention of water pollution. At the Sarnia refinery, waste water is treated to remove such contaminants as oil and grease, suspended solids, phenols and other dissolved organics. The systems to deal with waste waters include sewers, API separators, air flotation units, a biological oxidation unit, clarifiers and settling ponds, in addition to the hydrogen sulphide stripper. Dikes around the storage tanks help to contain accidental spills of crude oil or petroleum products.

Service station storage tanks are checked and replaced to keep ground water contamination to an absolute minimum. A major multimillion dollar program to upgrade these tanks is scheduled to begin in 1985.

Water quality is also a priority at Fort McMurray. A new waste water treatment system, installed in 1982 at a cost of $12 million, operated very successfully in 1983, enabling us to meet government water quality standards on a consistent basis. A considerable investment is also being made in ditches, containment ponds and oil retention weirs to protect bodies of fresh water from drainage from the mine. Further improvements to this system are planned in 1984.

At Fort Kent, sewage effluent from the town of Bonnyville is treated and converted to steam. The same water is recycled after it is used to produce oil.

Throughout the organization we have attained a high state of preparedness to deal with oil spills. Programs include contingency planning, acquisition of the best available equipment and simulation training, all in partnership with industry co-operatives. Sunoco Group employees teach courses on oil spill containment and clean-up at Lambton Community College in Sarnia.

Land use

Suncor is investing in a number of new initiatives to preserve or rehabilitate land resources.

At Fort Kent, clustering wellheads has preserved agricultural land. The key to this approach was the development of new slant-drilling technology enabling us to reach into the corners of a field from near its centre.

During the early development of western Canadian oil fields, Suncor played a leading role in developing salt water disposal systems to minimize the impact of oil field brine on agricultural and natural habitats. Our personnel routinely advise and participate in oil field spill contingency exercises.

At the oil sands plant, the objective is to return our lease to a forested condition suitable for recreation and wildlife. Muskeg salvage, soil reconstruction, erosion control and revegetation techniques have been successfully used to reclaim 225 hectares to date. Suncor is participating in a joint industry/government study dealing with soil reconstruction and is conducting its own research into methods of reclaiming tailings ponds.

Arctic and offshore production

The northern environment is especially fragile and careful research is needed to determine how to protect it. Because of the high cost of operating in the Arctic, programs are conducted on a co-operative basis. Oil spill research is carried out by the Canadian Offshore Oil Spill Research Association. Engineering and site-specific environmental studies are managed by the Arctic Petroleum Operators Association and the Offshore Operators Division of the Canadian Petroleum Association. Suncor is active in all three.

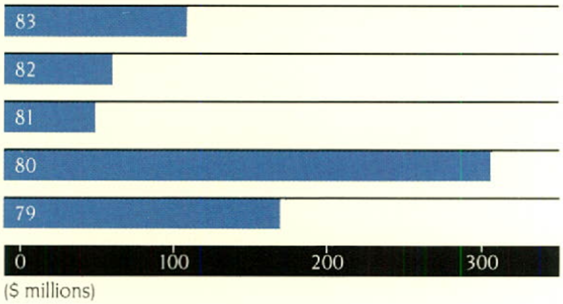
In addition, studies are being financed by the Environmental Studies Revolving Funds which were set up under the Canadian Oil and Gas Act. These funds finance environmental and social studies to assist government decision-making on oil and gas activity in the frontier areas.

FINANCIAL REVIEW

Consolidated statement of earnings

Earnings for the year were $108.4 million, up $48.3 million or 80 per cent over 1982. This increase was primarily due to higher synthetic crude oil sales volumes, lower maintenance expenses at the Company's oil sands plant and higher conventional crude oil selling prices, partially offset by lower refined product margins. These factors are discussed more fully in the following segmented analysis.

Earnings before extraordinary gains



Suncor's corporate office is responsible for financial controls and reporting. Shown clockwise, Tony Wright, Treasurer; Alan Watkins, Controller; Pamela Dixon, Manager, Insurance; and Jim Gilchrist, Director, Taxation, review data for Suncor's annual report.

Schedule of segmented data

Exploration, production and resources development

Earnings from this segment were $30.9 million, an increase of $6.2 million or 25 per cent over 1982.

Revenues rose by $9.8 million or five per cent. Higher crude oil selling prices and sales volumes increased revenues by $26 million. However, lower natural gas sales decreased revenues by $19 million mainly due to reduced market demand and the loss of certain export price adjustments related to royalty-free natural gas production.

Expenses (excluding both income and incremental oil revenue taxes) increased by $6.6 million or four per cent mainly as a result of inflation.

Income and incremental oil revenue taxes decreased by $3.0 million primarily reflecting the utilization of higher income tax allowances and the continued suspension of the incremental oil revenue tax on conventional oil. This tax was suspended in May of 1982.

Oil sands

Earnings from this segment were $102.1 million, substantially above the 1982 level of $41.5 million.

Revenues, excluding 1982 business interruption insurance proceeds, increased by $184 million or 36 per cent. Higher synthetic crude oil sales volumes increased revenues by approximately $198 million. In 1983, revenues also increased by $19 million due to improved crude quality. These increases were partially offset by lower average selling prices reflecting the decline in world crude oil prices.

Expenses (excluding both income and incremental oil revenue taxes) were up $29.7 million or seven per cent. Royalties and petroleum and gas revenue taxes (PGRT) increased by $47 million and $8 million respectively mainly as a result of higher sales volumes. Other expenses related to volume rose by $10 million, despite a reduction in overburden removal unit costs. Other expenses decreased by $35 million primarily reflecting lower maintenance expenses and a gain on the disposal of equipment.

Income and incremental oil revenue taxes increased by $54.1 million mainly as a result of improved operating results. However, the combined effective tax rate declined from 59 per cent to 53 per cent.

Refining, petrochemicals and marketing

This segment experienced a loss of $15.0 million in 1983 compared to earnings of $19.0 million in 1982.

Revenues decreased by $9.9 million or one per cent. This was primarily due to lower sales volumes (down five per cent) which were partially offset by higher refined product selling prices (up four per cent).

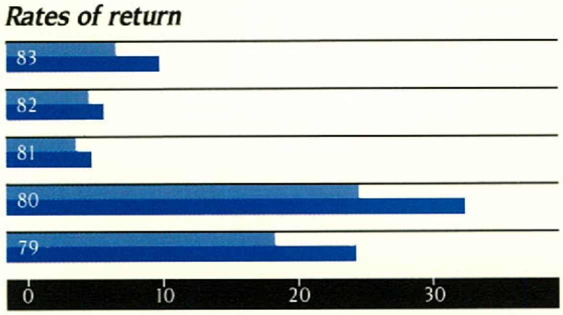
Expenses (excluding income taxes) were up $58.1 million or five per cent. Crude oil and raw feedstock costs rose approximately $51 million mainly as a result of higher purchase prices partially offset by lower volumes. Other expenses increased by $7 million or three per cent mainly as a result of inflation.

Income taxes changed from a charge of $4.3 million in 1982 to a recovery of $29.7 million in 1983 primarily as a result of impaired operating results and higher investment tax credits.

Interest and other unallocated items

Net interest income (income less expense) was $5.4 million in 1983 compared with an expense of $10.0 million in 1982. While increased interest costs were incurred on higher debt levels in 1983, the interest expense charged to earnings was lower due to a higher proportion of interest being capitalized in connection with major project expenditures and lower interest rates.

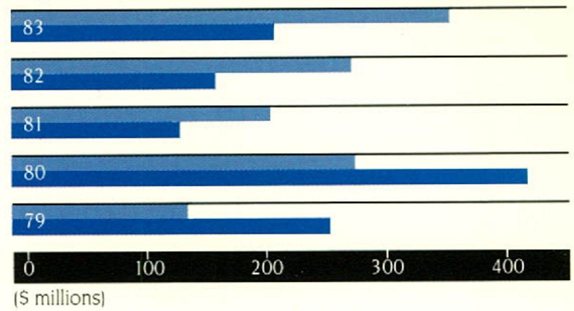
Rates of return



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.

Capital expenditures vs. funds from operations



For details of capital expenditures, see pages 16 and 44.

Consolidated statement of changes in financial position

Funds from operations increased by $44.1 million or 28 per cent in 1983 reflecting the effect of higher earnings discussed in the previous sections.

Disposals of properties, plant and equipment increased by $28.6 million primarily reflecting insurance proceeds related to property damage claims and the sale of a petrochemical tanker.

Operating working capital decreased by $48.1 million in 1983. The factors which reduced working capital included lower accounts receivable ($50 million) resulting primarily from decreased sales volumes and lower income taxes receivable ($28 million) arising from higher taxable earnings. Partially offsetting these decreases were increases in inventory carrying values ($13 million) caused by higher crude oil prices and lower liabilities for IORT and PGRT ($15 million) as a result of higher installments during 1983.

Capital expenditures of $353.2 million represented an increase of $81.4 million or 30 per cent over 1982. These expenditures included higher outlays of $112 million for the Sarnia refinery upgrading project.

In May, 1983 Suncor raised $100 million from the Canadian public debt markets through the issue of 12 per cent twenty-year debentures. The proceeds of the issue were used to reduce borrowings under revolving credit and term loan arrangements.

Later in the year, the introduction of a commercial paper borrowing program provided access to funds at advantageous rates and increased the flexibility in the Company's overall borrowing structure.

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 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, 1983 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, 1983 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 24, 1984

Suncor Inc.

SUMMARY OF ACCOUNTING POLICIES

December 31, 1983

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 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 pipelines, 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 nine 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 accrued liabilities" 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
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 capitalized expenditures as follows:

- approximately $224 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, service stations and related equipment over an average of 20 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 and experience gains and losses 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, depleted or amortized as part of the cost of the asset.

CONSOLIDATED STATEMENT OF EARNINGS

for the year ended December 31, 1983

($ millions except per share amounts)	1983	1982
Revenues		
Sales and other operating revenues	**$ 1,473.8**	$ 1,543.4
Interest income	**10.5**	7.2
	1,484.3	1,550.6
Expenses		
Costs and operating expenses	**582.2**	714.5
Selling, administrative and general	**169.3**	166.0
Royalties (note 1)	**175.5**	126.7
Taxes (note 2)	**328.6**	354.4
Depreciation, depletion and amortization	**115.2**	111.7
Interest (note 3)	**5.1**	17.2
	1,375.9	1,490.5
Earnings for the year	**$ 108.4**	$ 60.1
Earnings per common share	**$ 2.06**	$ 1.13

See accompanying summary of accounting policies and notes

CONSOLIDATED STATEMENT OF RETAINED EARNINGS

for the year ended December 31, 1983

($ millions)	1983	1982
Balance - beginning of year	**$ 610.7**	$ 593.4
Earnings for the year	**108.4**	60.1
	719.1	653.5
Dividends on preferred shares	**0.8**	1.0
Dividends on common shares	**41.8**	41.8
Balance - end of year	**$ 676.5**	$ 610.7

See accompanying summary of accounting policies and notes

Consolidated Statement of Financial Position

as at December 31, 1983

($ millions)	1983	1982
Assets		
Current assets		
Cash and short-term investments	$ 5.3	$ 18.6
Accounts receivable (note 4)	175.9	225.8
Income taxes receivable	–	28.4
Inventories (note 5)	249.4	235.7
	430.6	508.5
Properties, plant and equipment, net (note 6)	1,508.3	1,259.6
Deferred charges and other (note 7)	191.5	167.5
	$ 2,130.4	$ 1,935.6
Liabilities and shareholders' equity		
Current liabilities		
Short-term borrowings	$ 14.1	$ –
Accounts payable and accrued liabilities (note 4)	230.3	225.8
Taxes other than income taxes	85.7	106.7
Current portion of long-term borrowings (note 8)	2.6	3.5
	332.7	336.0
Long-term borrowings (notes 8 and 9)	243.4	161.4
Deferred revenues and accrued liabilities	97.9	67.8
Deferred income taxes	311.5	291.0
Contingent liabilities (note 10)		
Shareholders' equity		
Share capital (note 11)	468.4	468.7
Retained earnings	676.5	610.7
	1,144.9	1,079.4
	$ 2,130.4	$ 1,935.6

See accompanying summary of accounting policies and notes

Approved on behalf of the Board:

William Loar

W.R. Loar, Director

D.M. McGeer, Director

Consolidated Statement of Changes in Financial Position

for the year ended December 31, 1983

($ millions)	1983	1982
Internal funds generated		
Operations		
Earnings for the year	**$ 108.4**	$ 60.1
Depreciation, depletion and amortization	**115.2**	111.7
Deferred income taxes	**20.5**	21.5
Deferred overburden removal outlays (note 7)	**(50.0)**	(42.2)
Other non-cash items	**8.5**	7.4
Funds from operations	**202.6**	158.5
Disposals of properties, plant and equipment	**37.8**	9.2
Increase in deferred revenues	**8.5**	22.3
Decrease in operating working capital	**48.1**	50.3
Internal funds generated	**297.0**	240.3
Investment of funds		
Capital expenditures		
Exploration, production and resources development	**74.0**	85.2
Oil sands	**81.5**	103.5
Refining, petrochemicals and marketing	**197.7**	83.1
	353.2	271.8
Increase in deferred charges and other excluding overburden	**9.2**	10.4
Total investment of funds	**362.4**	282.2
Dividends	**42.6**	42.8
Net cash surplus (deficiency) before external financing	**(108.0)**	(84.7)
External financing		
Net increase in borrowings	**95.0**	108.5
Redemption of preferred shares	**(0.3)**	(7.3)
Total external financing	**94.7**	101.2
Increase (decrease) in cash and short-term investments	**$ (13.3)**	$ 16.5

See accompanying summary of accounting policies and notes

SCHEDULE OF SEGMENTED DATA*

($ millions)	Resources Group				Sunoco Group		Total	
	Exploration, production and resources development		Oil sands		Refining, petrochemicals and marketing			
	1983	1982	**1983**	1982	**1983**	1982	**1983**	1982
Revenues and earnings *for the year ended December 31*								
Sales and other operating revenues	**$ 116.9**	$ 111.5	**$ 175.0**	$ 240.1	**$ 1,181.9**	$ 1,191.8	**$ 1,473.8**	$ 1,543.4
Intersegment revenues	**89.0**	84.6	**521.6**	312.1	**1.7**	1.7	**612.3**	398.4
Segment revenues	**$ 205.9**	$ 196.1	**$ 696.6**	$ 552.2	**$ 1,183.6**	$ 1,193.5	**$ 2,086.1**	$ 1,941.8
Operating profits (losses) before taxes (note 12)	**$ 45.6**	$ 42.4	**$ 215.3**	$ 100.6	**$ (44.7)**	$ 23.3	**$ 216.2**	$ 166.3
Income and incremental oil revenue taxes	**(14.7)**	(17.7)	**(113.2)**	(59.1)	**29.7**	(4.3)	**(98.2)**	(81.1)
Segment earnings (loss)	**$ 30.9**	$ 24.7	**$ 102.1**	$ 41.5	**$ (15.0)**	$ 19.0	**118.0**	85.2
Change in intersegment profit elimination							**(4.2)**	(7.6)
Interest income							**10.5**	7.2
Corporate expense							**(11.2)**	(11.7)
Interest expense							**(5.1)**	(17.2)
Related income taxes							**0.4**	4.2
Earnings for the year							**$ 108.4**	$ 60.1
Depreciation, depletion and amortization *for the year ended December 31*								
Segments	**$ 33.4**	$ 33.1	**$ 68.5**	$ 62.5	**$ 12.9**	$ 14.8	**$ 114.8**	$ 110.4
Corporate							**0.4**	1.3
							$ 115.2	$ 111.7
Capital employed *as at December 31*								
Segment assets	**$ 587.5**	$ 556.1	**$ 825.0**	$ 799.3	**$ 780.2**	$ 626.9	**$ 2,192.7**	$ 1,982.3
Corporate assets and intersegment eliminations							**(62.3)**	(46.7)
Total assets							**2,130.4**	1,935.6
Segment current liabilities	**$ 45.4**	$ 61.2	**$ 130.1**	$ 133.6	**$ 196.1**	$ 199.2	**371.6**	394.0
Corporate current liabilities and intersegment eliminations							**(38.9)**	(58.0)
Capital employed							**$ 1,797.7**	$ 1,599.6

See accompanying summary of accounting policies and notes

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

Notes to the Consolidated Financial Statements

December 31, 1983

1. Royalties

The following is an analysis of the amounts expensed:

($ millions)	1983 Crown	1983 Other	1983 Total	1982 Total
Exploration, production and resources development	**$ 42.3**	**$ 10.6**	**$ 52.9**	$ 51.4
Oil sands	**79.3**	**43.3**	**122.6**	75.3
	$ 121.6	**$ 53.9**	**$ 175.5**	$ 126.7

2. Taxes

The following taxes and charges have been expensed:

($ millions)	1983	1982
Petroleum compensation charges	**$ 115.9**	$ 176.2
Petroleum and gas revenue tax	**40.3**	30.9
Federal sales and excise taxes	**60.9**	58.1
Production, property and other taxes	**13.7**	12.6
Incremental oil revenue tax*	**82.3**	80.4
Income taxes - current	**(5.0)**	(25.3)
- deferred	**20.5**	21.5
	$ 328.6	$ 354.4

*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 June 1, 1982 the tax on conventional crude excess revenue was suspended for a year and from June 1, 1983 for a further year. From 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)	1983	1982
Gasoline and diesel fuel taxes	**$ 153.9**	$ 131.6
Export taxes	**26.2**	34.4
	$ 180.1	$ 166.0

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 and the dollar effect are as follows:

($ millions)	1983	1982	1983	1982
	Percentage		Dollar effect	
Federal tax rate	**46.0%**	46.0%	**$ 57.0**	$ 25.9
Provincial abatement	**(10.0)**	(10.0)	**(12.4)**	(5.6)
Provincial tax rate	**10.4**	11.0	**12.9**	6.2
Statutory tax rate	**46.4**	47.0	**57.5**	26.5
Add (deduct) the tax effect of:				
Incremental oil revenue	**(71.9)**	(156.7)	**(89.1)**	(88.4)
Crown royalties	**46.3**	80.2	**57.4**	45.2
Incremental oil revenue tax	**31.5**	69.6	**39.0**	39.2
Resource allowance	**(25.9)**	(23.6)	**(32.1)**	(13.3)
Petroleum and gas revenue tax	**15.4**	26.8	**19.1**	15.1
Depletion allowance	**(15.3)**	(6.6)	**(19.0)**	(3.8)
Investment tax credits	**(9.6)**	(18.3)	**(11.9)**	(10.3)
Provincial royalty tax credits and rebates	**(5.8)**	(16.8)	**(7.2)**	(9.5)
Inventory allowance	**(2.5)**	(8.0)	**(3.1)**	(4.5)
Manufacturing and processing profits deduction	**1.5**	1.0	**1.9**	0.6
Federal surtax	**0.9**	1.8	**1.1**	1.0
Other	**1.5**	(3.0)	**1.9**	(1.6)
Effective income tax rate before incremental oil revenue tax	**12.5**	(6.6)	**15.5**	(3.8)
Incremental oil revenue tax - 50 per cent of taxable incremental oil revenue	**34.9**	62.7	**82.3**	80.4
Effective income and incremental oil revenue tax rate (note 12)	**47.4%**	56.1%	**$ 97.8**	$ 76.6

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

($ millions)	1983	1982
Excess of tax over (under) book expense:		
Depreciation	**$ (1.3)**	$ 6.3
Exploration and development costs	**14.6**	11.9
Overburden removal	**5.1**	1.1
Preproduction expense	**(0.7)**	(0.3)
Other	**2.8**	2.5
	$ 20.5	$ 21.5

3. Supplemental earnings statement information

($ millions)	1983	1982
Crude oil receipts in excess of conventional "old oil" prices	**$ 176.7**	$ 199.3
Export sales		
Unaffiliated customers -		
United States - heavy fuel oil	**$ 149.4**	$ 137.8
- petrochemicals	**60.8**	54.7
- other refined products	**10.3**	5.8
Europe - petrochemicals	**64.1**	100.2
	284.6	298.5
Affiliates -		
United States - refined products	**–**	7.5
	$ 284.6	$ 306.0
Research and development expense	**$ 2.5**	$ 5.8
Pension expense	**$ 11.3**	$ 10.0
Interest expense - short-term	**$ 0.2**	$ 9.8
- long-term	**23.9**	13.3
Less interest capitalized	**(19.0)**	(5.9)
	$ 5.1	$ 17.2

4. Related party transactions

In transactions with Sun Company, Inc. and its affiliates during 1983, the Company purchased crude oil and raw feedstocks for $58.6 million (1982—$34.6 million). In turn, the Company sold crude oil for $117.7 million (1982—nil) to Sun Company, Inc. and its affiliates. Since these crude oil revenues are netted against "costs and operating expenses" in the Consolidated Statement of Earnings in accordance with the Company's accounting policy, they are not shown as export sales.

Amounts due to Sun Company, Inc. and its affiliates at December 31, 1983 totalling $2.4 million (1982—$5.5 million) are included in accounts payable and accrued liabilities. Amounts due from Sun Company, Inc. and its affiliates totalling $3.1 million (1982—$0.1 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"). Trillium, one-third owned by the Company and two-thirds indirectly owned by Ontario Energy Corporation, was formed in 1982 to explore for oil and gas in the frontier areas of Canada. As at December 31, 1983 the Company had invested $8.4 million in Trillium.

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

5. Inventories

($ millions)	1983	1982
Crude oil - conventional	**$ 32.3**	$ 48.7
- synthetic	**46.1**	33.3
Refined products	**130.2**	111.7
Materials and supplies	**40.8**	42.0
	$ 249.4	$ 235.7

6. Properties, plant and equipment

($ millions)			1983	1982
	Cost	Accumulated provisions	Net	Net
Exploration, production and resources development				
Oil and gas properties	$ 581.6	$ 167.1	$ 414.5	$ 381.3
Equipment and other	157.0	54.0	103.0	96.6
	738.6	221.1	517.5	477.9
Oil sands				
Mine and mobile equipment	180.8	60.2	120.6	115.4
Plant	481.5	112.6	368.9	330.6
Housing	69.8	3.5	66.3	69.6
	732.1	176.3	555.8	515.6
Refining, petrochemicals and marketing				
Refinery including petrochemicals	432.5	66.8	365.7	178.9
Marketing and transportation	128.9	60.2	68.7	86.5
	561.4	127.0	434.4	265.4
Corporate	1.0	0.4	0.6	0.7
	$ 2,033.1	$ 524.8	$ 1,508.3	$ 1,259.6

7. Deferred charges and other

($ millions)	1983	1982
Oil sands deferred overburden removal costs (see below)	$ 109.9	$ 89.6
Oil sands preproduction costs	41.2	43.0
Prepaid gas purchases	21.3	21.7
Other	19.1	13.2
	$ 191.5	$ 167.5
Oil sands deferred overburden removal costs		
Balance - beginning of year	$ 89.6	$ 83.5
Outlays during year	50.0	42.2
Depreciation on equipment during year	2.9	1.7
	142.5	127.4
Amortization during year	(32.6)	(37.8)
Balance - end of year	$ 109.9	$ 89.6

8. Long-term borrowings

($ millions)	1983	1982
12% Debentures, Series A, maturing in 2003, repayable at the rate of $5.0 million annually commencing in 1989	$ 100.0	$ –
5 3/4% Notes, maturing in 1991, repayable at the rate of U.S. $2.0 million annually. U.S. $24.0 million (1982-U.S. $26.0 million)	29.8	32.1
Borrowings with interest at variable rates averaging 10.6 per cent in 1983 (14.0 per cent in 1982) under or with support of revolving credit and term loan agreements (note 9)	113.4	124.1
Mortgages on housing, bearing interest at rates between 6 1/4 and 9 1/2 per cent, repayable over the next 20 years	2.7	8.6
Capitalized lease obligations	0.1	0.1
	246.0	164.9
Less current portion of long-term borrowings	2.6	3.5
	$ 243.4	$ 161.4

($ millions)	
Long-term borrowings mature as follows:	
1984	$ 2.6
1985	2.8
1986	2.8
1987	14.0
1988	14.0
Subsequent years	209.8
	$ 246.0

9. Lines of credit

The Company has revolving credit and term loan agreements with financial institutions aggregating $450 million. Revolving credit is available until 1986 generally, when the borrowings may be converted into term credit with maturities from 1987 through 1991. Borrowings under these lines of credit at December 31, 1983 are $336.6 million less than the aggregate credit.

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 obligation in respect of this royalty not exceeding $10 million before taxes would be charged against earnings in the year of settlement.

(c) Under the Company's business interruption insurance coverage, any loss arising from a future insured incident at its Oil Sands Division would be shared among the Company and its insurers. The Company would bear any loss up to $30 million. For any loss in excess of $30 million the Company would bear a declining proportion up to a loss of $180 million. At this level of $180 million the Company would bear $99 million.

Effective November 1, 1983, the Company renegotiated its property damage insurance coverage so that in substance the Company would bear most of the first $10 million of cumulative losses in the policy year should insurable incidents of that magnitude occur.

(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 (excluding interest capitalization) is $783 million with outlays of $501 million made to the end of 1983.

(e) Minimum annual rental charges under leases for a vessel, service stations, office space and other property and equipment approximate $11 million.

(f) An independent actuarial valuation of the Company's pension plan as of January 1, 1983, indicated that the actuarial present value of accumulated plan benefits was $92.1 million and that the plan had no unfunded liability for past service.

While the result of any litigation cannot be predicted with certainty, 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, 1983 have reduced the authorized number of Preferred Shares Series A to 632,075. 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.

($ millions)

Issued:	Preferred Shares Series A		Common shares	
	Number	Amount	Number	Amount
Balance - beginning of year	**505,172**	**$ 12.1**	**52,245,101**	**$ 456.6**
Redeemed for cash	**12,943**	**0.3**	**–**	**–**
Balance - end of year	**492,229**	**$ 11.8**	**52,245,101**	**$ 456.6**

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

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 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

Strict compliance with the CICA Handbook would require determination of segment operating profits before income taxes but after incremental oil revenue tax ("IORT"). Since net revenue subject to IORT is not subject to income taxes and since the Company is the only company now paying IORT, it believes that strict compliance with the Handbook is inappropriate in its unique circumstances. Consequently, IORT has not been deducted in determining segment operating profits.

Quarterly Summary

(unaudited)

Financial Data ($ millions except per share amounts)

	For the quarter ended Mar 31 1983	June 30 1983	Sept 30 1983	Dec 31 1983	Total year 1983	For the quarter ended Mar 31 1982	June 30 1982	Sept 30 1982	Dec 31 1982	Total year 1982
Revenues	**$ 362.8**	**$ 355.8**	**$ 376.1**	**$ 389.6**	**$ 1,484.3**	$ 378.2	$ 342.6	$ 395.2	$ 434.6	$ 1,550.6
Segment earnings (loss)										
Exploration, production and resources development	**11.3**	**2.5**	**7.4**	**9.7**	**30.9**	3.8	2.7	6.7	11.5	24.7
Oil sands	**22.9**	**33.4**	**20.7**	**25.1**	**102.1**	(10.5)	9.1	13.8	29.1	41.5
Refining, petrochemicals and marketing	**(5.0)**	**(12.2)**	**0.8**	**1.4**	**(15.0)**	11.8	4.3	5.7	(2.8)	19.0
	$ 29.2	**$ 23.7**	**$ 28.9**	**$ 36.2**	**$ 118.0**	$ 5.1	$ 16.1	$ 26.2	$ 37.8	$ 85.2
Earnings for the period	**$ 22.7**	**$ 18.3**	**$ 27.7**	**$ 39.7**	**$ 108.4**	$ 1.1	$ 15.2	$ 19.2	$ 24.6	$ 60.1
Funds from operations	**$ 32.3**	**$ 25.7**	**$ 59.6**	**$ 85.0**	**$ 202.6**	$ 23.5	$ 5.0	$ 53.5	$ 76.5	$ 158.5
Earnings per common share	**$ 0.43**	**$ 0.35**	**$ 0.52**	**$ 0.76**	**$ 2.06**	$ 0.02	$ 0.28	$ 0.36	$ 0.47	$ 1.13

Operating Data

	For the quarter ended Mar 31 1983	June 30 1983	Sept 30 1983	Dec 31 1983	Total year 1983	For the quarter ended Mar 31 1982	June 30 1982	Sept 30 1982	Dec 31 1982	Total year 1982
Gross production conventional crude oil and natural gas liquids (a)	**2.2**	**2.2**	**2.3**	**2.3**	**2.2**	2.2	2.0	2.3	2.4	2.2
Synthetic crude oil - gross production less in-plant usage (a)	**6.8**	**7.9**	**8.1**	**7.7**	**7.6**	3.9	3.5	6.7	7.6	5.4
Gross natural gas sales (b)	**2.0**	**1.4**	**1.0**	**1.4**	**1.5**	2.0	1.7	1.3	1.9	1.8
Sales of refined products (a)	**11.0**	**10.9**	**10.9**	**11.4**	**11.1**	12.1	10.8	11.5	12.1	11.6

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

FIVE YEAR FINANCIAL SUMMARY

(unaudited)

($ millions except for ratios)	1983	1982	1981	1980	1979
Revenues	**$ 1,484.3**	$ 1,550.6	$ 1,320.7	$ 1,259.4	$ 865.1
Segment revenues					
Exploration, production and resources development	**205.9**	196.1	166.9	152.5	125.3
Oil sands	**696.6**	552.2	249.3	595.3	343.4
Refining, petrochemicals and marketing	**1,183.6**	1,193.5	1,145.2	831.4	684.4
	$ 2,086.1	$ 1,941.8	$ 1,561.4	$ 1,579.2	$ 1,153.1
Segment earnings (loss)					
Exploration, production and resources development	**30.9**	24.7	8.7	20.0	23.8
Oil sands	**102.1**	41.5	(19.3)	211.3	99.0
Refining, petrochemicals and marketing	**(15.0)**	19.0	53.3	62.0	48.5
	$ 118.0	$ 85.2	$ 42.7	$ 293.3	$ 171.3
Earnings before extraordinary gains	**108.4**	60.1	50.1	306.4	169.8
Extraordinary gains	–	–	–	–	3.1
Earnings for the year	**$ 108.4**	$ 60.1	$ 50.1	$ 306.4	$ 172.9
Funds from operations	**$ 202.6**	$ 158.5	$ 127.7	$ 418.0	$ 252.4
Oil and gas expenditures					
Property acquisition costs	**23.8**	10.6	12.4	44.4	16.5
Exploration costs	**35.8**	55.0	42.9	37.1	21.5
Development costs	**26.1**	38.3	23.6	27.4	20.8
Production costs	**108.4**	102.5	95.5	71.1	56.1
	$ 194.1	$ 206.4	$ 174.4	$ 180.0	$ 114.9
Capital expenditures					
Exploration, production and resources development	**74.0**	85.2	75.4	110.0	64.4
Oil sands	**81.5**	103.5	83.6	132.2	59.4
Refining, petrochemicals and marketing	**197.7**	83.1	42.1	29.0	8.9
Corporate	–	–	–	0.7	0.1
	$ 353.2	$ 271.8	$ 201.1	$ 271.9	$ 132.8
Capital employed					
Long-term borrowings	**243.4**	161.4	40.7	47.9	69.7
Deferred income taxes, deferred revenues and accrued liabilities	**409.4**	358.8	307.7	278.9	191.2
Shareholders' equity	**1,144.9**	1,079.4	1,069.4	1,102.3	797.6
	$ 1,797.7	$ 1,599.6	$ 1,417.8	$ 1,429.1	$ 1,058.5
Average number of common shares	**52,245,101**	52,245,098	52,245,085	52,245,085	52,191,626
Ratios					
Earnings before extraordinary gains per common share	**$2.06**	$1.13	$0.93	$5.83	$3.24
Earnings per common share	**$2.06**	$1.13	$0.93	$5.83	$3.30
Funds from operations per common share	**$3.88**	$3.03	$2.44	$8.00	$4.84
Earnings as a percentage of capital employed	**6.5%**	4.4%	3.5%	24.6%	18.2%
Earnings as a percentage of shareholders' equity	**9.7%**	5.6%	4.6%	32.3%	24.3%
Earnings as a percentage of revenues	**7.3%**	3.9%	3.8%	24.3%	20.0%
Long-term borrowings as a percentage of capital employed	**13.5%**	10.1%	2.9%	3.4%	6.6%
Interest coverage	**5.4X**	3.1X	12.5X	47.7X	23.2X

Five Year Operating Summary

(unaudited)

	1983	1982	1981	1980	1979
Resources Group					
Production (thousands of cubic metres per day)					
Conventional crude oil and natural gas liquids					
- gross	**2.2**	2.2	2.3	2.6	2.7
- net	**1.6**	1.5	1.5	1.7	1.8
Synthetic crude oil - gross production less in-plant usage	**7.6**	5.4	4.7	7.4	6.8
Natural gas sales (millions of cubic metres per day)					
- gross	**1.5**	1.8	1.9	1.7	1.8
- net	**1.2**	1.4	1.3	1.1	1.2
Average sales price					
Conventional crude oil (dollars per cubic metre)	**188**	158	117	96	81
Natural gas (dollars per thousand cubic metres)	**92**	88	88	82	56
Synthetic crude oil (dollars per cubic metre)					
- net customer price	**189**	156	122	102	85
- government compensation	**62**	99	8	115	52
	251	255	130	217	137
Gross proven reserves					
Conventional crude oil and natural gas liquids (millions of cubic metres)	**9**	10	10	10	12
Synthetic crude oil (millions of cubic metres)	**64**	67	54	56	65
Natural gas (billions of cubic metres)	**13**	13	13	13	14
Undeveloped land holdings (millions of hectares)					
- gross	**18.3**	18.4	18.2	19.2	19.4
- net	**3.0**	3.2	3.3	3.1	5.0
Net wells completed					
Exploratory - oil	**5**	6	5	2	–
- gas	**6**	7	14	9	4
- dry	**19**	17	12	14	12
Development - oil	**25**	37	5	12	39
- gas	**3**	6	9	25	23
- dry	**6**	9	8	7	7
	64	82	53	69	85
Other oil sands statistics					
Oil sands mined (millions of tonnes)	**35.9**	27.1	22.9	33.1	29.3
Average bitumen content of oil sands mined (% by weight)	**12.0**	12.4	12.3	12.9	12.1
Average crude yield of oil sands (cubic metres per tonne)	**.077**	.073	.074	.082	.084
Overburden removed (millions of cubic metres)	**17.1**	9.3	10.4	18.8	11.7
Sunoco Group					
Crude oil supply and refining					
Refined for Suncor account (thousands of cubic metres per day)	**11.3**	11.2	12.1	11.8	11.8
Gross crude oil production as a percentage of crude oil refined for Suncor account	**86%**	68%	56%	84%	79%
Processed at Suncor refinery (thousands of cubic metres per day)	**11.2**	11.1	12.1	12.4	12.2
Utilization of refining capacity	**78%**	77%	84%	86%	85%
Service stations (number at year-end)	**860**	870	870	920	950
Sales of refined products (thousands of cubic metres per day)					
Gasolines	**4.2**	4.3	4.7	4.6	4.3
Middle distillates	**2.6**	2.8	3.0	2.8	2.9
Heavy fuel oil	**2.4**	2.7	2.8	2.6	3.0
Petrochemicals	**1.2**	1.3	1.2	1.1	1.1
Other products	**0.7**	0.5	0.7	0.5	0.5
	11.1	11.6	12.4	11.6	11.8
Suncor employees (number at year-end)	**5,410**	5,190	4,930	4,620	4,310
Salaries, wages and employee benefits ($ millions)	**196.5**	172.1	144.0	112.8	87.4

SUPPLEMENTAL INFORMATION ON THE EFFECTS OF CHANGING PRICES

(unaudited)

Introduction

The problem

Traditional financial reporting is based on transactions recorded at historic cost. Prolonged periods of significant inflation have raised concerns that financial statements prepared on this basis may not allow users to assess properly the performance or prospects of the enterprise. Because of this concern the accounting bodies in Canada and other countries are searching for alternative methods of financial reporting which would reflect the impact of changing prices.

The response

The Canadian Institute of Chartered Accountants (CICA) has begun a five-year experiment requiring companies such as Suncor to disclose certain supplemental current cost information. The following current cost information is generally based on the CICA requirements. The costs of the Company's principal assets are restated at estimated current prices, and the effect is shown of measuring earnings after adjusting the historic cost of certain assets to estimated current cost. Thus, cost of sales is adjusted to reflect the cost to replace inventory at the time of sale rather than the historic cost, and depreciation is adjusted to reflect the higher cost of properties, plant and equipment (PP&E) at estimated current prices. In addition, information concerning the year-to-year change in the current cost of certain assets is compared with the change in cost attributable to general inflation, to determine if the enterprise is maintaining its purchasing power. Finally, the effect of holding monetary assets and liabilities while prices change is provided.

Limitations of the response

The Company is providing this information in support of the CICA's experiment. However, the Company wishes to identify certain limitations to the usefulness of this information.

At best, the results can be read as providing a broad indication of the effects of changing prices on the performance of the Company. At this stage of development of the current cost accounting experiment, meaningful comparisons between companies and industry groups will be difficult.

This information may not be useful for evaluating future prospects for several reasons. Although the current cost information has been prepared on a reasonable basis, these estimated current costs could differ significantly from actual current costs. This is particularly true for resource assets where, for the most part, historical expenditures to establish reserves have been restated to reflect the change in average industry costs. Since oil and gas reserves are finite in nature and unique, they cannot be replaced in exactly the way that they were established.

In regard to downstream assets, with the changing patterns of refined product demand, it is difficult to say what operating capability would be maintained by the Company if existing assets were replaced. By supplying current cost results, the Company is not implying that it intends to replace all its existing assets now or in the future.

Since current cost accounting is an evolving experiment for financial reporting, we intend to continue researching the usefulness of this information and will change our approach in future when and if more appropriate reporting is identified. Until a method of reflecting the effects of changing prices is found which overcomes the limitations of the CICA experiment and that method gains general acceptance, historic cost information will continue to be the most accepted, reliable and consistent measure for judging performance.

Methods of adjustment

Current cost

The Company's current cost amounts are determined primarily by applying appropriate indices to historic costs of homogeneous groups of assets. However, other methods such as direct pricing and land appraisals are used to obtain certain current costs. Where there is no suitable alternative, the current costs of some resource assets are determined by adjusting the historic costs to reflect the effects of general inflation as measured by the Consumer Price Index.

Income taxes

In keeping with the experimental spirit behind the required CICA disclosures, certain current cost adjustments are tax effected. Due to the complexity of the tax issue, the CICA recommends that taxes should not be adjusted. We believe an alternative presentation is appropriate. Current cost adjustments for cost of sales and depreciation, depletion and amortization can be viewed as advance recognition of costs yet to be incurred, limited to that amount recoverable out of future net revenues. As these cost adjustments will have a future tax impact, it seems appropriate to match the tax impact to the time current cost effects are recognized.

For simplicity a 50 per cent tax rate is assumed. Although rates of future tax can vary due to statutory changes, source of revenues or costs, investment tax credit assumptions and other factors, the disadvantage of any lack of precision is outweighed by the advantage of providing the tax adjustment.

Tax effects would also be associated with other information provided. Changes during the year in the current cost amounts of inventories and PP&E represent amounts that will be realized out of future net revenues, and therefore should be tax effected. However, the changes during the year in the current cost amounts of inventories and PP&E attributable to general inflation represent funds which need to be retained in the business

Effects of changing prices (1)

Adjusted earnings

($ millions)	1983	1982
Historic cost earnings	**$ 108**	$ 64
Adjustments for:		
Cost of sales	**(10)**	(39)
Depreciation, depletion and amortization (2)	**(98)**	(112)
Income taxes	**54**	75
Adjusted earnings	**$ 54**	$ (12)

Balance sheet items

($ millions)	1983 Historic Cost	1983 Current Cost	1982 Current Cost
Inventories	**$ 249**	**$ 264**	$ 255
Properties, plant and equipment (3)	**$ 1,659**	**$ 2,808**	$ 2,741
Net assets (common shareholders' equity)	**$ 1,133**	**$ 2,297**	$ 2,412

Other supplementary information

($ millions)	1983	1982
Gain in purchasing power from having net monetary liabilities	**$ 24**	$ 44
The amount of change during the year in the current cost amounts of inventories and properties, plant and equipment (4)	**$ 21**	$ 336
The amount of change during the year in the current cost amounts of inventories and properties, plant and equipment that is attributable to the effects of general inflation	**$ 123**	$ 255
Financing adjustments:		
(a) Based on the change in current cost of inventories and properties, plant and equipment	**$ 4**	$ 59
(b) Based on current cost adjustments for cost of sales and depreciation, depletion and amortization	**$ 22**	$ 26

(1) The 1982 comparative amounts have been restated to dollars of 1983 year-end purchasing power to reflect the increase in general price levels.

(2) Depreciation, depletion and amortization includes current cost adjustment for asset disposals.

(3) Properties, plant and equipment also includes deferred overburden removal costs and preproduction costs.

(4) This amount would be tax effected at a 50 per cent rate.

to maintain purchasing power. As Canadian tax law generally gives no relief for general inflation, this amount should not be tax effected. For the same reason, inflationary gains and losses arising from holding net monetary assets or liabilities should not be tax effected.

An additional departure from the CICA pronouncement is to treat deferred taxes as a monetary item because, in our opinion, this is more in keeping with its nature—that of a liability which will be paid.

Discussion of information provided

Adjusted earnings for 1983 were $54 million, a decrease from historic cost earnings of $108 million resulting from the effects of additional charges for depreciation based on higher current cost assets and increased cost of sales caused by a higher replacement cost of crude experienced during the year.

Adjusted earnings improved by $66 million when compared with 1982 results restated into dollars of 1983 year-end purchasing power. This improvement reflected the effect of better operating results, lower crude oil cost increases when compared with 1982 and the unfavorable effect in 1982 of adjusting asset disposals to current cost.

The gain on holding net monetary liabilities throughout the year reflected that obligations can be repaid in dollars of reduced purchasing power. The year-to-year change of $20 million was caused by lower general inflation in 1983 when compared with 1982 partially offset by the effect of debt taken on in 1983 to finance certain capital projects.

The current cost of inventories and PP&E increased $21 million in 1983. This increase was $102 million less than that which would be attributable to inflation and $315 million less than the 1982 increase. Costs did not increase to the same extent in 1983 as they did in 1982 largely reflecting the lower level of activity in upstream oil and gas activities. In particular, exploration and drilling, and overburden removal costs declined in 1983 whereas they had increased in 1982.

The CICA requires the disclosure of a financing adjustment, which is to reflect the benefits which accrue to common shareholders by financing assets with borrowings. While the information has been provided herein, we do not believe it is meaningful. It implies that an enterprise's debt-to-equity ratio remains constant, which has not been our experience.

Glossary of Terms

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

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.

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 heavy oil 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 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.

NORP oil: in general, oil discovered after 1973, oil from certain infill and suspended wells, additional oil obtained by certain enhanced recovery techniques and frontier production.

New oil reference price (NORP): the price applicable to NORP oil.

Old oil: any oil that is not NORP oil.

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): a 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

Corporate Directory

Offices

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Exploration, Production & Resources Development Divisions
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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

Fair Wind 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

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

Directors

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

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

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

William R. Loar, Toronto
President and Chief Executive Officer
Suncor Inc.

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.

Officers of Suncor Inc.
(as at December 31, 1983)

Michael M. Koerner
Chairman of the Board

William R. Loar
President and Chief Executive Officer

Stanley A. Cowtan
Executive Vice-President,
Sunoco Group

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

Howard B. Maxwell
Vice-President, Government Affairs

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

Edward J. Pacholko
Vice-President,
Resources Development Division,
Resources Group

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

Michael A. Supple
Vice-President, Oil Sands Division,
Resources Group

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

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

Alan J. Watkins
Controller

Georges Dubé
Director, Legal Affairs and Secretary

Anthony A.L. Wright
Treasurer and Assistant Secretary

Brian R.A. Gibbings
Assistant Treasurer

Officers of Sunoco Inc.
(as at December 31, 1983)

William R. Loar
President

Stanley A. Cowtan
Senior Vice-President

George H. Brereton
Vice-President, Human Resources and Government Affairs

Michael R. Hayhow
Vice-President, Planning and Business Effectiveness

Michael W. O'Brien
Vice-President, Marketing

Murray S. Smith
Vice-President, Sunchem

D. Wayne Wright
Vice-President, Refining

Georges Dubé
Secretary

Anthony A.L. Wright
Treasurer and Assistant Secretary

Kenneth V.E. Liddon
Assistant Secretary-Treasurer

(Clifford K. Boland has since replaced Michael W. O'Brien as Vice-President, Marketing and as an officer of Sunoco Inc.)

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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