C

Suncor inc.

ANNUAL INFORMATION FORM

March 16, 1995

Suncor inc.

ANNUAL INFORMATION FORM

DOCUMENTS INCORPORATED BY REFERENCE

INCORPORATED BY REFERENCE IN THIS ANNUAL INFORMATION FORM AND FORMING A PART HEREOF ARE CERTAIN SECTIONS OF THE ANNUAL REPORT ON FORM 10-K OF SUNCOR INC. ("SUNCOR") FOR THE YEAR ENDED DECEMBER 31, 1994 ("FORM 10-K"), SUNCOR'S MANAGEMENT PROXY CIRCULAR DATED MARCH 1, 1995 FOR ITS 1995 ANNUAL AND SPECIAL MEETING OF SHAREHOLDERS ("PROXY CIRCULAR") AND SUNCOR'S ANNUAL REPORT TO SHAREHOLDERS FOR THE YEAR ENDED DECEMBER 31, 1994 ("ANNUAL REPORT"). THE PROXY CIRCULAR AND THE ANNUAL REPORT ARE BEING FILED WITH CANADIAN SECURITIES REGULATORY AUTHORITIES IN EACH OF THE PROVINCES OF CANADA CONTEMPORANEOUSLY WITH THE FILING OF THIS ANNUAL INFORMATION FORM. THE FORM 10-K HAS BEEN FILED WITH THE SECURITIES AND EXCHANGE COMMISSION IN THE UNITED STATES PURSUANT TO THE SECURITIES EXCHANGE ACT OF 1934 AND IS ATTACHED HERETO AS SCHEDULE NO. 1. ONLY THOSE SECTIONS OF THE FORM 10-K, PROXY CIRCULAR AND ANNUAL REPORT SPECIFICALLY INCORPORATED HEREIN BY REFERENCE FORM A PART OF THIS ANNUAL INFORMATION FORM.

1. INCORPORATION

The information required by this item is set forth under the caption "Business and Properties" on page 4 of the Form 10-K and such information is hereby incorporated herein by reference.

2. GENERAL DEVELOPMENT OF THE BUSINESS

The information required by this item is set forth under the caption "General Development of the Business" on pages 4 to 6 of the Form 10-K and such information is hereby incorporated herein by reference.

3. NARRATIVE DESCRIPTION OF THE BUSINESS

The following table sets forth Suncor's determination of its estimated probable reserves based on constant year-end prices and costs with no escalation into the future as of the dates indicated. The accuracy of any reserve estimate is a function of the quality and quantity of available data and of engineering interpretation and judgement. While the reserve and production estimates presented in this Annual Information Form are considered reasonable, the estimate should be accepted with the understanding that the reservoir performance subsequent to the date of the estimate may justify revision, either upward or downward. The additional information required by this item is set forth under the captions "Narrative Description of the Business by Principal Operating Group" on pages 6 to 26 of the Form 10-K and "Suncor Employees" on page 26 of the Form 10-K and such information is hereby incorporated herein by reference.

Estimated Probable Reserves

	Gross		Net	
	Crude oil and natural gas liquids (millions of barrels)	Natural gas (billions of cubic feet)	Crude oil and natural gas liquids (millions of barrels)	Natural gas (billions of cubic feet)
December 31, 1990	17	227	14	185
December 31, 1991	16	240	13	198
December 31, 1992	18	366	15	285
December 31, 1993	20	332	16	255
December 31, 1994	23	368	18	305

Notes:

1. Probable reserves are those reserves which analysis of drilling, geological, geophysical and engineering data does not demonstrate to be proved under current technology and existing economic conditions, but where such analysis suggests the likelihood of their existence and future recovery. Probable reserves to be obtained by the application of enhanced recovery processes will be the increased recovery over and above that estimated in the proved category which can be realistically estimated for the pool on the basis of enhanced recovery processes which can be reasonably expected to be instituted in the future.

2. Gross reserves represent the aggregate of Suncor's working interest in reserves including the royalty interest of governments and others in such reserves and Suncor's royalty interest in reserves of others. Net reserves are gross reserves less the royalty interest share of others including governments. Royalties can vary depending upon selling prices, production volumes, timing of initial production and changes in legislation. Net reserves have been calculated, following generally accepted guidelines, on the basis of prices and the royalty structure in effect at year end and anticipated production rates. Such estimates by their very nature are inexact and subject to constant revisions.

4. SELECTED CONSOLIDATED FINANCIAL INFORMATION

The information required by this item is set forth under the captions "Share Trading Information" on page 55 of the Annual Report, "Quarterly Summary — Financial Data" on page 48 of the Annual Report and "Five Year Financial Summary" on page 49 of the Annual Report and such information is hereby incorporated herein by reference.

5. MANAGEMENT'S DISCUSSION AND ANALYSIS

The information required by this item is set forth under the caption "Management's Discussion and Analysis" on pages 12 to 29 of the Annual Report and such information is hereby incorporated herein by reference.

6. MARKET FOR THE SECURITIES OF THE ISSUER

The information required by this item is set forth under the caption "Share Trading Information" on page 55 of the Annual Report and such information is hereby incorporated herein by reference.

7. DIRECTORS AND OFFICERS

Certain information required by this item regarding Suncor directors and executive officers is set forth under the captions "Election of Directors" on pages 3 to 7 of the Proxy Circular, "Information Regarding the Board of Directors and its Committees" on pages 7 to 8 of the Proxy Circular, "Ownership of Common Shares by Directors and Executive Officers" on page 9 of the Proxy Circular and "Executive Officers" on pages 16 to 17 of the Proxy Circular and such information is hereby incorporated herein by reference. The only officer of Suncor not named in the Proxy Circular is Anthony A.L. Wright. Mr. Wright is the Treasurer and Assistant Secretary of Suncor, a position he has held for the past five years.

The municipal address of each Suncor director is as follows: Robert M. Aiken, Jr. — Berwyn, Pennsylvania; Harry Booth — Calgary, Alberta; Robert H. Campbell — Villanova, Pennsylvania; Bryan P. Davies — Etobicoke, Ontario; Deborah M. Fretz — Malvern, Pennsylvania; Richard L. George — Oakville, Ontario; Allan E. Gotlieb —Toronto, Ontario; Ardagh S. Kingsmill — Toronto, Ontario; David E. Knoll — Chester Springs, Pennsylvania; Bill N. Rutherford — Berwyn, Pennsylvania; W. Robert Wyman — Vancouver, British Columbia. The municipal address of each Suncor officer other than Mr. George is as follows: Michael W. O'Brien — Toronto, Ontario; Edythe A. Parkinson — Fort McMurray, Alberta; Barry D. Stewart — Calgary, Alberta; Timothy R. Hughes — Markham, Ontario; Peter T. Spelliscy — Etobicoke, Ontario; Donald R. Brown, Q.C. — Toronto, Ontario; Anthony A.L. Wright — Toronto, Ontario.

8. ADDITIONAL INFORMATION

Copies of the documents set out below may be obtained without charge by any person upon request, to the Secretary, Suncor Inc., 36 York Mills Road, North York, Ontario, M2P 2C5:

(i) The current Suncor annual information form together with one copy of any pertinent information incorporated by reference;

(ii) The current Suncor annual report containing financial statements for the most recently completed financial year and the report of the auditors relating thereto together with any subsequent interim financial statements;

(iii) Suncor's most recent management proxy circular; and

(iv) Any other documents incorporated by reference into the most recent preliminary short form prospectus or the short form prospectus if securities are in the course of distribution pursuant to such documents.

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SCHEDULE NO. 1

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

Form 10-K

ANNUAL REPORT PURSUANT TO
SECTION 13 OR 15(d) OF THE
SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 1994 Commission File Number 1-12384

Suncor Inc.

(Exact name of Registrant as specified in its Charter)

Canada	**Not Applicable**
(State or Other Jurisdiction of Incorporation or Organization)	*(I.R.S. Employer Identification No.)*

36 York Mills Road, North York, Ontario, Canada M2P 2C5
(Address, including zip code, of Principal Executive Offices)

(416) 733-7300
(Registrant's Telephone Number, Including Area Code)

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Shares	American Stock Exchange The Toronto Stock Exchange The Montreal Exchange The Alberta Stock Exchange Vancouver Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days.

Yes X No____

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Aggregate market value of the voting stock held by non-affiliates of the registrant at January 31, 1995, was approximately Cdn. $821 million.

As of January 31, 1995, there were 54,539,649 Common Shares, no par value, outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

(1) Suncor Inc. 1994 Annual Report to Shareholders — Incorporated in part in Form 10-K, Parts II and IV

(2) Suncor Inc. Management Proxy Circular for its 1995 Annual and Special Meeting of Shareholders — Incorporated in part in Form 10-K, Part III

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GLOSSARY OF TERMS

A Glossary of Terms is found in Suncor's 1994 Annual Report to Shareholders.

CONVERSION TABLE*

1 cubic metre (m3)	= 6.29 barrels	1 tonne	= 0.984 tons (long)
1 cubic metre (natural gas)	= 35.49 cubic feet	1 tonne	= 1.102 tons (short)
1 cubic metre (overburden)	= 1.31 cubic yards	1 kilometre	= 0.62 miles
1 hectare	= 2.5 acres		

* Conversion using the above factors on rounded numbers appearing in this report may produce small differences from reported amounts.

Some information in this report is set forth in metric units and some in imperial units.

FINANCIAL INFORMATION AND REPORTING CURRENCY

Financial information is presented in accordance with accounting principles generally accepted in Canada. Differences between accounting principles generally accepted in Canada and in the United States, as applicable to Suncor, are explained in note 19 to the consolidated financial statements of Suncor incorporated herein by reference from Suncor's 1994 Annual Report to Shareholders (the "1994 Annual Report").

Suncor publishes its consolidated financial statements in Canadian dollars. In this report, unless otherwise indicated, dollar amounts are expressed in Canadian dollars, references to "Cdn.$" or "$" are to Canadian dollars and references to "U.S.$" are to United States dollars. The following table sets forth certain exchange rates based on the noon buying rate in New York City for cable transfers as certified for customs purposes by the Federal Reserve Bank of New York (the "noon buying rate"). Such rates are set forth as U.S. dollars per $1.00 and are the inverse of rates quoted by the Federal Reserve Bank of New York for Canadian dollars per U.S.$1.00. On March 9, 1995, the inverse of the noon buying rate was $1.00 equals U.S.$0.7076.

	Year ended December 31				
	1990	1991	1992	1993	1994
	($1 Canadian = U.S. $)				
Low	0.8286	0.8587	0.7761	0.7439	0.7103
High	0.8837	0.8929	0.8757	0.8046	0.7632
Rate at end of period	0.8617	0.8652	0.7865	0.7544	0.7128
Average rate during period*	0.8564	0.8727	0.8235	0.7729	0.7300

* The average of the exchange rates on the last day of each month during the applicable period.

PART I

ITEMS 1. & 2. BUSINESS AND PROPERTIES

Suncor Inc. was originally formed by the amalgamation under the Canada Business Corporations Act on August 22, 1979 of Sun Oil Company Limited, incorporated in 1923, and Great Canadian Oil Sands Limited, incorporated in 1953. On January 1, 1989, Suncor amalgamated with a wholly owned subsidiary under the Canada Business Corporations Act. Its registered and principal office is located at 36 York Mills Road, North York, Ontario, M2P 2C5. Suncor has announced that it will be moving its principal office and, subject to shareholder approval, its registered office to Calgary, Alberta by the end of 1995. Suncor, a Canadian integrated oil and gas company, is engaged in the exploration for and acquisition, production and marketing of crude oil and natural gas and in the refining of crude oil and the marketing of petroleum and petrochemical products. In this report, references to "Suncor" include Suncor Inc. and its subsidiaries unless the context otherwise requires.

Suncor's only principal subsidiary is Sunoco Inc. Sunoco Inc., which is wholly owned by Suncor, is incorporated under the laws of Ontario. Sunoco refines and markets petroleum products and petrochemicals directly and indirectly through subsidiaries and joint ventures.

General Development of the Business

Suncor has three principal operating groups: Oil Sands Group, based near Fort McMurray, Alberta, which produces and markets high quality light sweet crude oil, diesel and custom blends; Resources Group, based in Calgary, Alberta, which explores for and acquires, produces and markets natural gas and crude oil; and Sunoco Group, headquartered in Toronto, Ontario, which refines and markets crude oil and markets a broad range of petroleum and petrochemical products.

In 1994, Suncor produced approximately 82,000 barrels per day of crude oil (approximately four percent of Canada's crude oil production) and 155 million cubic feet per day of natural gas. In 1993, Suncor was the sixth largest crude oil producer and the twenty-third largest natural gas producer in Canada. In 1994, Suncor sold approximately 85,100 barrels (13,500 m^3) per day of refined products, mainly in its core regional markets of Ontario and Quebec with some exports to the United States and Europe. In 1994, Suncor's refined product sales represented approximately 15 percent of Ontario's total refined product sales and approximately four percent of Quebec's total sales.

Suncor has a unique asset base, with a large interest in the oil sands industry, a competitive and growing conventional exploration and production business and a downstream business comprised of a top-quartile Canadian refinery and niche marketing businesses. Suncor intends to continue to improve this asset base through aggressive cost control, proactive loss management practices, innovative use of applied technology and increasing volumes of high-value products.

Suncor believes that it has strategic advantages resulting from the synergies in its operations and that these synergies will enhance its ability to compete in difficult and unpredictable market conditions. A critical success factor in the upstream oil business is the ability to economically find and develop new reserves. In contrast, the oil sands operation has a resource base that is well-defined and well-understood. In comparative terms, the oil sands operations are not faced with the finding costs that conventional petroleum requires. Suncor believes that its oil sands operations, accounting for 85 percent of Suncor's crude oil production, has a unique advantage in this respect. In the fall of 1994 the Alberta Chamber of Resources estimated that there are about 307 billion barrels of recoverable bitumen in the Athabasca, Cold Lake and Peace River oil sands regions. Suncor pioneered production of synthetic crude oil from the oil sands, with initial plant production beginning in 1967. There is only one other commercial oil sands mining operation in North America — Syncrude Canada Limited — and it is located near Suncor's operations. While there are a number of other operations that have the ability to upgrade bitumen, Suncor's primary competition comes from other crude oil suppliers.

The upstream industry environment in which Suncor operates is characterized by volatile crude oil prices, fluctuating price differentials between heavy and light grades of crude oil and oversupply of natural gas causing depressed prices. Over the last two years the supply and demand for natural gas strengthened and prices improved. However, in 1994 natural gas prices declined as growing supplies and weather factors offset demand. In the last five years, the downstream business has experienced over-capacity, volatile margins and flat demand for refined petroleum products. Some of these conditions were exacerbated by the recession in Canada in the early part of this decade.

In 1992, Suncor completed a heavy oil review in its upstream operations and as a result recorded an after tax charge against earnings of $238 million. The third quarter charge resulted in the writedown of certain oil sands assets, the writeoff of its Burnt Lake heavy oil investment and the provision for losses on the sale or abandonment of certain oil and gas properties. (For further details refer to note 2 to the consolidated financial statements.)

Suncor's upstream oil production is primarily light, low sulphur crude oil as a result of the characteristics of the synthetic crude oil produced at its oil sands plant and the quality of the conventional crude oil produced by Resources Group which is lighter than the Canadian average. As part of its strategy to improve the value of its oil sands operations, Suncor markets three groups of products — light sweet crude oil which has no heavy ends; light sour crude oil and high grade low sulphur diesel fuel.

In the light sweet crude market, demand is rising with supply currently somewhat tight. The decline in crude oil production in North America is expected to support and possibly, expand Suncor's demand base. Both Suncor and Syncrude have announced plans to increase their production. Suncor has a small but growing customer base as it broadens its marketing of synthetic crude oil and introduces custom blends to meet specific customer demands. The competition for Suncor's custom blended product is heavy, sour crude oil such as Canadian heavy crudes and Mexican crudes. In the western Canadian diesel market there is a tight supply situation which, coupled with strong diesel demand, is supporting high margins. Suncor's principal competitors in the diesel market are four Alberta refineries, though Syncrude also recently indicated that it is reviewing this market.

Suncor's gross crude oil production exceeded Sunoco Group's demand for crude oil by 24 percent in 1994 and 11 percent in both 1993 and 1992. Suncor believes this balance reduces the volatility of its earnings and cash flow due to world supply disruptions and other factors that cause crude oil and product price changes. In addition, Suncor uses some of its natural gas both at its Sarnia refinery and at its oil sands plant as a feedstock and fuel. When gas prices are depressed, the lower cost of internal consumption partially offsets the loss of revenue in Resources Group, which lessens the impact on Suncor's earnings.

The configuration of Suncor's refinery in Sarnia, Ontario permits the processing of a high percentage of synthetic crude oil. The refinery can process either light sweet or light sour synthetic crude oils in addition to conventional light and sour crudes. The competitive advantage of processing synthetic crude oil is that it is low in sulphur and heavy ends, yielding a more valuable product. Depending upon market place demands for different products, Suncor's earnings can be maximized by changing the crude composition and/or supply source of crude used at the refinery. This results in Suncor having a more highly valued product mix when compared to yields from average Canadian conventional crude oil and when compared to most other Canadian refineries.

In 1993 Suncor undertook a strategic study to assess whether Sunoco Group could compete successfully within the North American downstream industry. The scope of the study also encompassed a review of the linkages between Suncor's heavy oil upgrader in Fort McMurray, Alberta, and its refinery in Sarnia, Ontario and its retail marketing business.

As a result of the study, management began implementing a non-capital-intensive strategy that is intended to position Sunoco Group as a low-cost competitor and improve its earnings and cash flow regardless of any improvements in market product demand or margins. The strategy also allows Sunoco to benefit from any demand and margin improvements. Also as a result of this study an after tax charge of $16 million was recorded in the third quarter of 1993 (for further details refer to note 2 to the consolidated financial statements).

Narrative Description of the Business by Principal Operating Group

Oil Sands Group

	Year ended December 31		
	1994	1993	1992
		($ millions)	
Revenues			
Sales and other operating revenues	147	132	134
Intersegment	424	355	357
Total	571	487	491
Earnings (loss)	90	59	(74)*
Cash provided from operating activities	195	112	103
Total assets	857	779	721
Capital expenditures	103	116	65

* Includes a third quarter after tax charge of $85 million as explained in note 2 to the consolidated financial statements.

Suncor produces light sweet crude oil and other oil products by mining the Athabasca oil sands in Northeastern Alberta and upgrading the bitumen extracted at its plant site located near Fort McMurray, Alberta. The oil sands operation represents a significant portion of Suncor's asset base, cash flow and earnings. Suncor made substantial investments over the last three years to improve the reliability and flexibility of the oil sands operation, and these investments contributed to making 1994 the best year for production in the plant's 27 year history. In total, 25.8 million barrels, or an average of 70,700 barrels per day, were produced. In addition to record production, the plant's utilization rate rose to 97 per cent, meaning that Oil Sands Group met or exceeded its production plans for 354 days of the year.

At current levels of production, Suncor has about eight more years of mining under leases it is currently mining. About 50 years of additional mining production is estimated to exist on leases Suncor acquired in 1992 and 1994 (See "Leasehold Interest and Royalties"). New mine plans are being developed and subject to regulatory and board of director approval, Suncor intends to open its new mine at the turn of the century.

Oil Sands Group intends to continue to implement operational improvements which are expected to result in higher revenues through increased production and an expanded product mix for its customers, improved reliability, lower costs and improved safety and environmental performance.

Operations

Oil sands consist of a mixture of sand and bitumen. Suncor's integrated oil sands business involves three operating business units: bitumen production which involves mining the oil sands and extraction of the bitumen; a heavy oil upgrading process; and a utilities plant which provides the site with steam and electric power.

The first phase of the process in Oil Sands Group's open pit mining operation is the removal of overburden with trucks and shovels. The oil sands ore is extracted by 58-cubic yard shovels (80-ton buckets), and then transported to one of two sizing plants by a fleet of 240-ton trucks. After the ore is dumped into the sizers and crushed, it is transported to the extraction plant by a conveyor system which stretches approximately three miles. Bitumen is extracted from the oil sands by a hot water process which uses a settling separation method followed by dilution with naphtha (diluent) and the removal of water and fine sand in centrifuges.

The truck, shovel and sizer mining method, which Oil Sands Group introduced in late 1993 completely replaced the bucketwheel excavation method in February 1994. The transition to the truck and shovel method of mining occurred successfully and oil sands mining production increased by 21 per cent, while operational reliability improved significantly. In 1995, Oil Sands Group plans to spend approximately $10 million to purchase additional mining equipment (see "Capital Expenditures" for more information).

In the upgrading process, the bitumen from the extraction plant is first separated from the diluent and then is upgraded by coking, distillation and hydrogen treatment to remove sulphur and nitrogen. The upgraded distillate, referred to as light sour crude oil, is either sold directly to customers or blended into synthetic crude oil (a light sweet crude oil) according to customer specifications. The crude oil is then shipped approximately 270 miles in Suncor's pipeline to Edmonton, Alberta for sale and distribution to Suncor's Sarnia refinery and other customers.

In 1994, the value of the upgrader's products were improved and reliability of supply to customers was increased. New markets were opened for higher-value products and on-going sales of sour products. A new product blending system has allowed further customization of products to meet specific customer requirements. During the year, Oil Sands Group increased sales of diesel fuel, a premium value product. Oil Sands Group is also integrating production, marketing and transportation planning with Sunoco Group to enhance the value of both operations. Reliability of supply to customers also improved in 1994 through maintenance and modifications to Suncor's pipeline between Fort McMurray and Edmonton.

In 1994, integrity task force initiatives contributed to improved reliability in the upgrader by eliminating redundant piping, identifying and addressing process hazards, specifying new design/procurement standards and updating documentation.

The oil sands operation is largely self sufficient in terms of energy. To produce steam and electric power, Suncor operates its own utility plant using coke extracted from the bitumen as fuel. Additional power is purchased from an Alberta public utility. The operation also consumes natural gas which is carried to the plant through a pipeline owned by Suncor which runs to the site from north of Edmonton. The natural gas used includes volumes produced by Suncor, as well as gas purchased from others under long-term supply contracts. In addition to its use as a source of energy, natural gas is used as a feedstock in the upgrading process. Under current provincial regulations, the gas produced by Suncor and used in the oil sands plant is generally royalty free.

The oil sands plant is susceptible to loss of production due to the interdependence of its component systems. Under Suncor's business interruption insurance coverage, Suncor bears the first $100 million of any business interruption loss arising from an insured incident at its oil sands operation. Severe climatic conditions, such as extreme cold, can cause reduced production and in some situations result in higher costs. Over the past several years, back-up components and systems have been introduced in critical areas to reduce vulnerability. Major efforts and investments have been made over the same period to increase production, improve reliability and reduce cash operating costs. The oil sands plant experienced two production interruptions in 1993 during which the value of preparedness was demonstrated and the production interruption was minimized.

In addition to ongoing preventive and predictive maintenance programs, full plant maintenance shutdowns are completed periodically. Reliability improvements, along with ongoing maintenance programs have resulted in the next complete shutdown being scheduled for 1997, an interval of four years since the last complete shutdown. Formerly this interval had been three years. In addition to complete shutdowns, work in a portion of the upgrading operations can be done while the rest of the plant continues production. This reduces both the cost and scope of major shutdowns and permits continued production of light sour crude oil. Partial shutdown work was carried out in 1994 at a cost of $13 million. Despite this work, 1994 was a record production year. No partial work is scheduled for 1995 when production is estimated to average approximately 70,000 barrels per day.

A production committee is responsible for optimizing the plant output after the respective operating areas have developed their work plans and maintenance schedules to encompass all the work necessary in any given year. The production committee provides senior management with a forum to discuss plant activities.

The following table shows daily average production and cash costs of Oil Sands Group for the calendar years indicated.

	Year ended December 31		
	1994	1993	1992
Daily production (thousands of barrels)	70.7	60.5	58.5
Selling price ($ per barrel)	22.31	22.49	22.99
Cash cost ($ per barrel) (1)	14.00	16.00	19.50
Cash margin ($ per barrel) (2)	8.31	6.49	3.49

(1) Total cash costs include cash operating costs, the amortization of maintenance shutdown expenditures, sustaining capital and reclamation cash costs but excludes royalties and strategic capital expenditures.

(2) Defined as average selling price less cash cost per barrel. Excludes per barrel royalties of: 1994 — $1.55; 1993 — $1.44; 1992 — $1.91.

Given the high fixed cost nature of the operation combined with the volatility and unpredictable nature of commodity prices, lowering costs, improving the sales mix and increasing production are viewed as critical to improving the Oil Sands Group's cash margin.

A key component in the determination of the cash margin is the cash cost. Cash costs were reduced to $14.00 per barrel in 1994 from $16.00 per barrel in 1993 and $19.50 per barrel in 1992 through a combination of higher production and lower spending, partially related to low maintenance cost in the first year of operation of the new mining equipment. The improvement in cash costs over the 1992 level is due to the benefits associated with the change in mining technology, a workforce reduction of over 350 people, improved reliability and higher production. In 1992 cash costs of $1.25 per barrel were attributable to production interruptions. Refer to page 14 of the 1994 Annual Report for a more detailed discussion, and such information is hereby incorporated herein by reference pursuant to General Instruction G(2) of Form 10-K. While the cash costs were reduced to $14 per barrel in 1994, management believes that at current production levels the cash cost will fluctuate between $14 to $15 per barrel as spending to maintain production reliability and integrity fluctuates from year to year. The 1995 cash cost is expected to be approximately $14.75 per barrel. The increase reflects both higher sustaining capital expenditures with respect to bitumen production and upgrading reliability projects and higher maintenance costs for the truck and shovel equipment. These factors are expected to be partially offset by lower natural gas prices in 1995. With production planned to increase to over 80,000 barrels per day in 1998, it is expected that the cash cost per barrel will decline to $12 per barrel in 1998 as fixed costs are spread over a higher production base.

Leasehold Interests and Royalties

Suncor's current oil sands mining operations are conducted on a site of approximately 6,100 acres leased under two oil sands leases granted by the Government of Alberta known as Lease 86 and Lease 17. Lease 86 and Lease 17 are adjacent and located on the west bank of the Athabasca River, about 20 miles north of Fort McMurray. Lease 86 expires in the year 2008, Lease 17 expires in 2000 and each is renewable as long as the plant or other works are in operation. Suncor owns the surface area of the land on which most of its plant facility is located.

Lease 86 covers 4,500 acres. At December 31, 1994, approximately 56 percent of Suncor's proved reserves of synthetic crude oil were located on the property covered by Lease 86. Lease 17 covers 1,600 acres adjacent to Lease 86. At December 31, 1994, Lease 17 contained approximately 44 percent of Suncor's proved reserves of synthetic crude oil. In 1994, Lease 86 accounted for 99 percent of Suncor's production. Suncor expects that mining operations on the current leases will be completed in approximately eight years.

The Government of Alberta is entitled to royalties under the leases at rates which the Province establishes from time to time. Under the Alberta Suncor (OSG) Crown Agreement, the royalty is set at a rate of 30 percent of revenues less allowed operating and capital costs ("R-C") with a minimum payment of five percent of gross revenues. Amounts paid under the minimum test are considered prepayments and may be applied to reduce future obligations under the R-C formula. Such amounts, however, are not refundable. The royalty is payable in the form of synthetic crude oil, but the Crown may request that Suncor dispose of the Crown's share of synthetic crude oil on its behalf and pay the proceeds to the Crown. The Crown currently chooses the latter option.

In 1992 the Government of Alberta agreed to provide Suncor with an adjustment to the Crown Royalty payment mechanism, in conjunction with approved capital environmental spending for odour and sulphur dioxide emission reductions commencing January 1, 1992 and ending December 31, 1997. The relief, which will depend on a combination of crude oil pricing, timing and the actual amount of spending, provides reduction of payments in these years. The current minimum payment of five percent of gross revenues will be reduced by 50 percent of spending on the approved capital programs to a maximum reduction of four percent of gross revenues. The royalty reduction earned in 1994 was $6 million, with an expected additional reduction of $15 million in 1995, subject to the factors noted above. The Government of Alberta will effectively have recovered this benefit when the 30 percent royalty rate becomes payable.

Norcen International Ltd. has a gross overriding royalty pursuant to an agreement dated March 1, 1989 (the "Norcen Royalty"). The Norcen Royalty is based on a graduated scale dependent on synthetic crude oil price expressed as a percentage of gross revenue from production of the lease. As of December 31, 1994, under the Norcen Royalty no payment is required if synthetic crude prices are below $18.38 per barrel. Payment of one and one half percent of gross revenue is required if the synthetic crude price ranges from $18.39 to $19.38 per barrel. For every $1.00 per barrel increase in the price of synthetic crude in the range of $19.39 to $24.38 per barrel, the percentage rate of the royalty increases by one half percent. For every $1.00 per barrel increase in the price of synthetic crude in the range of $24.39 to $35.38 per barrel, the percentage rate of the royalty increases by a further one quarter percent until a maximum royalty of seven percent is reached. All synthetic crude prices are calculated on a monthly average basis and the crude price break points are adjusted annually on March 1 of each year by a contractually determined inflation component.

Royalties were as follows for the years indicated.

	Year ended December 31		
	1994	1993	1992
		($ millions)	
Crown royalty(1)	22	17	23
Norcen royalty(2)	18	14	18

(1) Payable with respect to Lease 86 and Lease 17

(2) Payable with respect to Lease 86

Synthetic Crude Oil Gross Proved Reserves

Suncor currently produces from Leases 17 and 86. At the end of 1994, gross proved reserves on these two leases were approximately 205 million barrels. Gross proved reserves do not reflect deductions in respect of Crown and applicable sublease royalties. Under the Crown Royalty Agreement the Crown royalty is dependent on deemed net revenues (R-C); therefore, the calculation of net reserves would vary depending upon assumed production rates, prices and operating and capital costs.

Production

Refer to page 50 of the 1994 Annual Report for information on production, and such information is hereby incorporated herein by reference pursuant to General Instruction G(2) of Form 10-K.

In 1994, Suncor received license approval from the Alberta government to increase its annual production from 23.7 million to 26.3 million barrels (or about 72,000 barrels a day).

Revenues from Synthetic Crude Oil

Under an agreement made in 1965 at the outset of the oil sands project, which has been amended from time to time, Shell Canada Products Limited ("Shell") is entitled to purchase approximately 25 percent plus

2,950 barrels daily of Suncor's synthetic crude oil production attributable to Lease 86. The agreement was renewed in December 1992 and is renewable, at Shell's option, for further five-year periods. In 1994, 6.8 million barrels were sold to Shell. The price at which synthetic crude oil is sold to Shell is based on the average price of three Alberta reference crude oils and approximates the price received from other customers.

Sales to Shell in 1994 of both Suncor synthetic crude oil and refined petroleum products represented approximately ten percent of Suncor's consolidated revenues. Shell is the only customer whose purchases account for ten percent or more of the consolidated revenues of Suncor.

Oil Sands Group's production is used in connection with Suncor's Sarnia refining operations. During 1994, the refinery processed approximately 37 percent of Oil Sands Group's crude oil production. The balance, after sales to Shell and the Sarnia refinery, is sold to others under contracts terminable by short notice or on a spot basis.

The following table provides information as to Suncor's sales volumes and related prices and costs for the years indicated.

	Year ended December 31		
	1994	1993	1992
Sales volumes (thousands of barrels per day)			
Light sweet crude oil	60.7	56.5	56.2
Light sour crude oil	9.8	3.3	2.2
Average sales price ($ per barrel)			
Light sweet crude oil	22.50	22.77	23.23
Light sour crude oil	21.18	17.65	17.05
Average cost of production sold ($ per barrel)*	16.95	18.53	20.86

* Includes all operating (including non-cash) costs and royalties; excludes corporate office overhead and interest.

Although revenues after royalties per barrel are higher for synthetic crude oil, operating costs to produce synthetic crude oil are currently substantially higher than lifting and administrative costs to produce conventional crude oil due to the nature of the operations required to produce synthetic crude oil. While there is no finding cost associated with synthetic crude oil, mine development and expansion of production can entail significant outlays. The costs associated with synthetic crude are largely fixed for the same reason and, as a result, operating costs per unit are largely dependent on levels of production. Cost reduction efforts, including the change in the equipment used in the mining operation, and higher production levels have combined to reduce unit costs. Plans to increase production to over 80,000 barrels per day by 1998 are expected to further reduce unit production costs. (See "Outlook").

In addition to increasing production, efforts have also been directed at enhancing revenue through the expansion of Oil Sands Group's product mix. For example, diesel, which sells at a premium to light sweet crude oil, had an 85 percent increase in volumes in 1994 over 1993 levels. Diesel volumes represented about 12 percent of sales volumes in 1994 compared to seven percent in 1993. During planned maintenance work in 1994, marketing initiatives to sell light sour crude oil resulted in the plant being able to maintain production during this 27 day period.

Employees

Oil Sands Group employs directly 1,379 people, of whom approximately 850 are unionized. During the first quarter of 1994, Oil Sands Group successfully reached a collective agreement with Local 707 of the Communications, Energy and Paperworkers Union. For the first time ever, a three-year agreement was signed. The new agreement provides the framework for continuously improving the joint problem solving initiatives underway with the union and is expected to encourage a climate of open and honest communications.

Suncor also uses the services of various outside contractors to provide contract maintenance support in certain areas of the plant. These contractors employ approximately 400 workers, most of which are trade union members. The collective agreement for the unionized workers of the largest of these contractors expires in late 1995.

Outlook

During 1994 a number of significant announcements were made. After a review of a number of options, Suncor's board of directors approved a capital investment of approximately $175 million (excluding capitalized interest), starting in 1994, to improve its oil sands operations' environmental performance. The completion of this project in 1996 will allow Suncor to meet its 1996 air licence requirements. The expenditure covers the installation of limestone flue gas scrubbing technology to reduce sulphur dioxide emissions from the utilities plant.

This project, along with $15 million of new sulphur recovery equipment installed in the upgrading area in 1994, is expected to reduce the plant's total sulphur dioxide emissions by at least 75 percent when all work is completed in 1996. To ensure the reliability of the generating facilities, Suncor expects to spend another $35 million over the next 10 years to refurbish the existing boilers. Oil Sands Group is also studying cost reduction opportunities through improved energy performance.

The significant increase in plant production and reliability combined with reductions in the largely fixed cost nature of the operations has paved the way for even further growth in production levels and profitability. This should serve to further reduce cash costs per barrel and increase the cash margin. During 1994, Suncor announced plans to expand the oil sands production from 68,000 per day to over 80,000 barrels per day, at an estimated cost of $250 million. This expansion will take place over the next three years and will position the plant for possible further expansion. The major part of the increase should occur in 1997 after scheduled maintenance work. Suncor's plans are subject to regulatory approval, stakeholder consultation and board of director approval.

As noted previously, Suncor's current operation occurs on two leases which are expected to be fully mined early in the next century. Over the last three years Suncor has acquired nine additional leases and lots near its present operation. In late 1994, Suncor announced plans to open its next oil sands mine on one of these leases on the east side of the Athabasca River, across the river from its current operations. The site was selected because of its close proximity to the processing plants. Geological and engineering assessments confirmed the quality of the mineable bitumen resources on this lease.

Feasibility studies during 1995 will define mine and facility design, infrastructure requirements and cost estimates. Approval from Suncor's board of directors and the Alberta government regulatory agencies are required before work can commence. An environmental impact assessment will be completed with public participation sought throughout the process.

Suncor estimates that it will spend up to $200 million over the next five years in preparing the new mine for production, with most of the spending occurring in 1997 and 1998. Together with leases purchased in 1992, the new mine site is expected to provide Suncor with an additional 50 years of production.

Capital Expenditures

Continued operation of the oil sands plant requires ongoing capital expenditures. As in 1994, the focus of Oil Sands Group's spending in 1995 will be on meeting the group's environmental commitments. Approximately $100 million of the remaining $150 million on the sulphur dioxide reduction project will be spent in 1995. Spending on production improvements throughout the site will total about $45 million, primarily consisting of work on the production expansion and adding another shovel for the mining operation.

Main feed conveyor systems were extended at a total cost of $48 million over the three year period ended in 1992. These extensions were required as mining activities have moved further away from the processing facilities, but are now sufficient to mine the rest of leases 86 and 17. Equipment, including mobile equipment, must be replaced as it wears out. It is expected that, as a result of strategic decisions made in 1992, Oil Sands Group's cash costs, including sustaining capital expenditures, will be reduced in the future. These actions are expected to reduce sustaining capital expenditures from the $50-$60 million range to an estimated range of

$45 to $50 million per year by 1996. These expenditures are made on an on-going basis primarily to refurbish or enhance the plant facilities.

Refer to page 29 of the 1994 Annual Report for additional information on the capital expenditures, and such information is hereby incorporated herein by reference pursuant to General Instruction G(2) of Form 10-K.

Environmental Compliance

Oil Sands Group's operating licences, including a development and reclamation approval, expire on April 25, 1995. As a result of the new Alberta Environment Protection and Enhancement Act, these licenses will become one overall operating licence at the next license renewal. Oil Sands Group anticipates that the operating licence will be renewed.

Oil Sands Group's reclamation plan, which has received regulatory approval, includes tailings pond reclamation and all surface reclamation at the site. The major component of the plan relates to the tailings ponds. The existing plan includes moving the fine tailings and water in the four active ponds to a fifth pond designed for this purpose. Suncor is aggressively researching technologies which reduce the volume of fine tailings and increase dry landscape reclamation areas.

Suncor is currently evaluating the economic viability and technical feasibility of these technologies on a demonstration scale. Some of the principal feasibility considerations include the availability of tailings sands from other leases, the cost of chemical treatment, and the handling of release water. Suncor expects to have fully tested and evaluated this technology within the next three years. The proposed reclamation plan is expected to be an integral component of the new mine development application. Further research and testing could result in cost revisions, including higher costs for alternative techniques if this technology does not prove successful.

Site reclamation costs, including the above noted pond reclamation work, have been estimated to be $180 million, and are being recorded over the expected remaining life of the reserves by charges against earnings on a unit of production basis. This primarily reflects the cost of the reclamation plan submitted to the Government of Alberta. This estimate is primarily based on the current development and reclamation approval which will expire in 1995.

Suncor's 1994 earnings reflect a before tax charge of $7 million for future reclamation costs. As of December 31, 1994, the accrued liability (net of payments for reclamation work already carried out) was $107 million.

In 1994, Oil Sands Group commissioned additional sulphur recovery equipment in its upgrader. As a result of this $15 million project, sulphur recoveries from the upgrader are now approximately 98 per cent — a 50 per cent improvement.

As discussed in the Outlook section above, the board of directors has approved the expenditure of $175 million (excluding interest capitalization) for the installation of limestone flue gas scrubbing technology to reduce sulphur dioxide emissions from the utilities plant.

In 1991, Oil Sands Group received an emission control order from the Government of Alberta in response to odour emanating from the tailings ponds. Approximately $20 million has been expended to date to reduce odorous emission from the site. The program includes improved site monitoring equipment, a vent collection and treatment system for vapours as well as improvements to the sour water and slop tank system. The completion of work in early 1995 is expected to address all the concerns raised with respect to odour emissions. Although all odours are not expected to be eliminated, the potential for odour emissions should be significantly reduced as a result of this work.

Refer to page 29 of the 1994 Annual Report for further information on environmental regulation, and such information is hereby incorporated herein by reference pursuant to General Instruction G(2) of Form 10-K.

Resources Group

	Year ended December 31		
	1994	1993	1992
		($ millions)	
Revenues			
Sales and other operating revenues	104	91	83
Intersegment	91	89	84
Total	195	180	167
Earnings (Loss)	21	28*	(141)*
Cash provided from operating activities	96	98	80
Total assets	496	402	386
Capital and exploration expenditures	169	100	120

* Includes a third quarter after tax charge of $153 million in 1992 and a favourable adjustment of $10 million in 1993 as explained in note 2 to the consolidated financial statements.

Suncor is active in the exploration, development and production of crude oil and natural gas in Canada, supplemented by opportunistic acquisitions, and the marketing of natural gas and crude oil in North America through its Resources Group. Suncor's strategy is to significantly increase the reserve and production base, moving production from approximately 29,300 gross BOEs (22,700 net BOEs) per day in 1994 to 40,000 BOEs (31,000 net BOEs) per day by 1998 with performance targeted in the top quartile of the industry. (Refer to the Glossary of Terms in the 1994 Annual Report for an explanation of net production/reserves.) During this period, Suncor is targeting for the addition of at least 1.5 times annual production in proved reserves each year. Suncor concentrates on conventional crude oil and natural gas activities in western Canada, with increasing emphasis on natural gas. Additionally, in situ recovery methods are evaluated and, when economically viable, will be used to initiate production from major heavy oil reserve holdings.

Improved results have been achieved due to higher volumes, lower costs and reserve replacement. During 1994 and 1993, Resources Group's exploration, development and acquisition activities have added proved reserves equalling more than 200% of the respective year's production on a BOE basis. The ability to consistently and economically add at least 1.5 times production to proved reserves is viewed by management as the critical factor to improved earnings, cash flow and Suncor's share value for this sector of the business. Given the nature of the exploration business, management believes that exploration results should be looked at on a rolling three year average. For the three years ended 1994, the average finding and development cost per BOE (an industry benchmark) was $5.30 and $6.42 per BOE for the three years ended 1993. Management believes that a finding and development cost of under $7 per BOE creates shareholder value. Resources Group has a target average finding and development cost of $6 per BOE for first quartile performance.

An in-house natural gas direct marketing operation exists to exploit opportunities as a result of the deregulation of natural gas marketing in 1985. The gas marketing group sells natural gas acquired from other producers in addition to Suncor's natural gas production.

While Resources Group views finding and development costs as one of the most critical success factors, if not the most critical success factor, another important factor that influences profitability and cash flow is lifting and administrative costs. These costs have decreased from $5.94 per BOE in 1990 to $5 in 1994. Due to the sour gas nature of new production and the natural decline rate in mature fields, management expects a modest increase in unit lifting costs for 1995.

Exploration, Development and Acquisitions

Over the last three years, Resources Group spent over $380 million on exploration, development and acquisition programs directed towards increasing natural gas and crude oil reserves and production levels. Exploration has been focused geographically. In this way, the productivity of the exploration teams and the ability to develop a competitive advantage in a given region are enhanced. In 1994, the exploration and development program added gross proved reserves of approximately 28.6 million BOE (22.9 million BOE on a net basis).

Natural gas exploration is concentrated on medium and deep targets in Northeast British Columbia, Northwest Alberta and Central Alberta. Oil exploration is concentrated in the same geographical regions.

In 1994, Suncor participated in the drilling of 29 gross exploration status wells (21 net). Oil and gas was found in 13 gross wells (nine net) for a gross success rate of 45 percent. In addition, Resources Group farmed out 24 prospects on which 20 oil and gas discoveries were made by others. Suncor retains varying interests in these discoveries.

In 1994, investment in exploration activities increased by 50% over 1993. The Grande Prairie area of west-central Alberta, where Suncor discovered 8.1 million BOE's of proved reserves in 1993, (5.7 million BOEs on a net basis) dominated exploration efforts in 1994. A high degree of focus was maintained in this region to test conceptual opportunities in which Suncor has established strategic expertise. Substantial funds were allocated to develop opportunities on established focus areas.

In 1994, major Suncor development projects were located at Grande Prairie, Glacier, Boundary Lake South, Simonette and Medicine River in Alberta and Blueberry in British Columbia. The result was a further increase in year end proved producing reserves to Suncor, 65 billion cubic feet ("BCF") of natural gas and 8.6 million barrels of oil and natural gas liquids (50 BCF and 6.6 million barrels on a net basis).

Acquisition opportunities continue to be pursued on an cost effective basis where they provide continued focus and upside potential to our existing properties. In 1994, acquisitions totalling $13 million added approximately 2 million BOEs of gross proved reserves (1.6 million BOE on a net basis). In 1993, investments totalled $7 million, adding approximately 1.6 million BOE of proved reserves (1.5 million BOEs on a net basis).

No wells were drilled on Resources Group's frontier lands in 1994. Suncor continues to hold interests in frontier properties, including 27 long term "significant discovery licences", which have currently uneconomic resources of 1.5 trillion cubic feet of natural gas and 50 million barrels of oil. Suncor has no plans to develop these resources in the foreseeable future with the exception of acquiring seismic data.

Conventional Oil

The following table shows estimates of Suncor's proved crude oil reserves and average daily production of crude oil in Alberta, British Columbia and Saskatchewan, represented by the major conventional oil fields identified in the tables.

	Proved Reserves Before Royalties at December 31, 1994(1)		1994 Average Daily Production Before Royalties(1)	
	(millions barrels)	%	(barrels of oil per day)	%
Fields				
Medicine River	5.63	15.4	1,925	17.0
Simonette	5.00	13.7	1,905	16.8
Oungre	4.67	12.8	768	6.8
Grande Prairie area	2.70	7.4	337	3.0
Pembina area	1.71	4.7	379	3.4
Youngstown	1.69	4.6	1,159	10.2
Blueberry	1.54	4.2	496	4.4
Steelman area	1.49	4.1	380	3.4
Gleneath	1.32	3.6	133	1.2
Nothingham/Alda	0.93	2.6	313	2.8
Boundary Lake	0.88	2.4	222	2.0
Mitsue	0.50	1.4	236	2.1
Other(2)	8.41	23.1	3,059	26.9
Total — gross	36.47	100	11,312	100
Total — net	30.93		8,900	

(1) The reserves and production in this table do not include natural gas liquids.

(2) Includes fields in which Suncor holds overriding royalty interests.

Most of the large conventional oil fields in the western provinces have been in production for a number of years and the rate of production in these fields is subject to natural decline. In some cases, additional amounts of crude oil can be recovered by using various methods of enhanced oil recovery, infill drilling and production optimization techniques.

The most commonly used enhanced oil recovery mechanism is waterflooding, where water is injected into the reservoir to pressurize the formation. Waterflood programs are used in 16 of Suncor's top 20 oil producing fields. At Mitsue and Swan Hills, Alberta sophisticated miscible flooding is employed involving high pressure, natural gas and solvent injection into the reservoir. At the end of 1994, approximately 80 percent of Suncor's proved conventional oil reserves were under enhanced oil recovery programs.

Some reserves are capable of production using primary methods which utilize the reservoir's natural pressure. Primary recovery methods are used at four of Suncor's top 20 producing fields. Suncor has employed horizontal and directional drilling techniques in order to increase oil recovery, reduce development costs and minimize environmental disturbance. Horizontal drilling techniques have been applied at the Oungre field in Saskatchewan. Suncor plans to continue to apply this technology where technically and economically feasible.

Natural Gas

Since natural gas deregulation in 1985, Suncor has focused exploration, development and acquisition programs on increasing natural gas production. In 1994, drilling and facilities projects were focused at such properties as Grande Prairie, Boundary Lake South, Simonette, Pine Creek and Glacier in Alberta, and Blueberry in British Columbia. In total, these projects added 23 million cubic feet per day (18 million cubic feet per day on a net basis) to Suncor's gas production by the end of 1994.

The following table shows estimates of Suncor's proved natural gas reserves and average daily production in Alberta and British Columbia, represented by the major natural gas fields identified in the table.

	Proved Reserves Before Royalties at December 31, 1994		1994 Average Daily Production Before Royalties	
	(billions of cubic feet)	%	(millions of cubic feet per day)	%
Fields				
Stolberg	98.2	13.1	9.2	5.9
Grande Prairie area	97.9	13.1	0	0
Glacier	80.0	10.7	9.0	5.8
Rosevear	68.8	9.2	29.4	19.0
Blueberry	61.4	8.2	9.5	6.1
Knopcik	59.6	8.0	0	0
Simonette	45.6	6.1	11.5	7.4
Pine Creek	40.0	5.3	12.2	7.9
Bonanza	25.2	3.4	11.2	7.2
Blackstone/Brown Cr	23.2	3.1	0	0
Medicine River	17.8	2.4	10.0	6.5
East Mel	14.5	1.9	4.6	3.0
Pembina	13.0	1.7	1.2	0.8
Other*	102.8	13.8	47.2	30.4
Total — gross	748	100	155	100
Total — net	593		119	

* Includes fields in which Suncor holds overriding royalty interests.

Suncor operates major gas processing plants at South and North Rosevear, Pine Creek, Boundary Lake South and Simonette with a total design capacity of approximately 180 million gross cubic feet per day (140 million net cubic feet per day). Suncor also has varying working interests in natural gas processing plants operated by other companies and is participating in a joint venture to construct a gas plant in the Grande Prairie area which is expected to be on-stream in the fall of 1995. This approach provides Suncor with access to strategically located plant capacity and opportunities to generate significant processing revenues and volume related reductions in unit operating costs. Increasing environmental concerns and regulations constraining new plant construction are likely to make these plant assets increasingly valuable.

Non-Conventional Heavy Oil

In 1992, the $143 million carrying value of the Burnt Lake heavy oil project was written-off as explained in note 2 of the consolidated financial statements. Resources Group, in cooperation with partners, will continue testing technology to identify a methodology with potential for future economic development of the property.

Resources Group has various interests in heavy oil leases in the Cold Lake and Athabasca regions of Alberta. These properties are carried at little book value. Suncor has no current plans to develop any of these leases. Current crude oil prices and technology results in unattractive economics for major heavy oil development projects.

Land Holdings

The following table sets forth the undeveloped and developed lands in which Resources Group held petroleum and natural gas interests at the end of 1994, 1993 and 1992, except as indicated in notes (3) and (4) below. Undeveloped lands are lands on which no producing well or well capable of production has been drilled or completed to a point that would permit production of commercial quantities of oil and natural gas regardless of whether or not such land contains proved reserves; developed lands are lands on which such a well has been drilled.

	Licences, Reservations, Permits and Exploration Agreements(1)						Leases(1)					
	Gross Acres(2)			Net Acres(2)			Gross Acres(2)			Net Acres(2)		
	1994	1993	1992	1994	1993	1992	1994	1993	1992	1994	1993	1992
	(thousands)						(thousands)					
Undeveloped Lands												
Western Provinces(3)												
British Columbia	129	103	137	85	69	89	174	136	163	119	92	114
Alberta(4)	252	315	341	179	187	174	474	396	419	281	211	218
Saskatchewan	—	55	55	—	55	55	2	2	15	2	2	7
United States of America												
Montana	—	—	—	—	—	—	3	3	—	2	2	—
Total	381	473	533	265	311	318	653	537	597	404	307	339
Frontier (Canada Lands)												
Mackenzie Delta	—	—	—	—	—	—	7	7	7	3	3	3
Beaufort Sea	—	—	30	—	—	1	59	59	34	4	4	4
Arctic Islands	—	—	—	—	—	—	406	406	392	56	56	56
Offshore Labrador	—	—	—	—	—	—	63	63	62	6	6	6
Total	—	—	30	—	—	1	535	535	495	69	69	69
Developed Lands												
Western Provinces(3)												
British Columbia	4	2	3	3	1	2	105	101	124	33	31	44
Alberta(4)	7	8	24	6	7	13	419	428	727	258	263	339
Saskatchewan	—	—	—	—	—	—	23	23	24	20	19	19
Total	11	10	27	9	8	15	547	552	875	311	313	402
Frontier (Canada Lands)												
Northwest Territories	—	—	—	—	—	—	14	14	14	14	14	14
Mackenzie Delta	—	—	—	—	—	—	7	7	7	3	3	3
Total	—	—	—	—	—	—	21	21	21	17	17	17

(1) No deduction has been made from Crown licences, reservations, permits or exploration agreements to reflect that only a portion of these areas may be converted to a lease or production licence. Crown licences, reservations and permits are acquired from the provincial governments through competitive bidding and exploration agreements are acquired from the federal government by undertaking work commitments. These confer upon the holder exploration rights and the right to lease or apply for a production licence for the crude oil and natural gas rights under portions of the lands covered. The extent of such rights differs in each jurisdiction and between various areas in a single jurisdiction. The holder is generally required to make cash payments or undertake specified work in order to retain such rights. Leases in general confer upon the lessee the right to explore for and remove crude oil and natural gas from the property with the lessee paying all the development and operating costs and being entitled to the production, subject to rental, tax and royalty.

(2) "Gross acres" means all acres in which Suncor has an interest. "Net acres" means gross acres after deducting interests of others.

(3) Includes 170,000 gross developed acres and 25,000 gross undeveloped acres (1993 — 170,000 and 5,000; 1992 — 202,000 and 14,000) in western Canada in which Suncor held overriding royalty interests at the end of the years indicated and from which it received revenues of $2 million in 1994, $2 million in 1993 and $3 million in 1992.

(4) Does not include the oil sands (including non-conventional heavy oil) leases comprising approximately 157,000 gross (116,000 net) undeveloped acres and 69,000 gross (8,000 net) developed acres at the end 1994, 1993 and 1992.

Certain of Suncor's interests in undeveloped lands are subject to reduction under farm-out agreements whereby others may earn interests by undertaking exploration or development work. Conversely, Suncor is a party to farm-in agreements whereby it may earn interests in land held by others by undertaking such work.

Drilling

The following table sets forth the gross and net exploratory and development wells which were completed, capped or abandoned in which Suncor participated during the years indicated, all in western Canada.

	Year ended December 31					
	1994		1993		1992	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells						
Oil	2	1	2	2	1	0
Gas	11	8	10	8	9	6
Dry	16	12	13	9	11	7
Total	29	21	25	19	21	13
Development Wells						
Oil	135	30	52	18	49	15
Gas	19	13	17	10	6	2
Dry	14	9	11	7	11	13
Total	168	52	80	35	66	30
Total	197	73	105	54	87	43

Not included are wells completed under farm-out agreements on Suncor properties, since Suncor did not incur cash expenditures in connection with such wells. In addition to the above wells, Suncor had interests in 15 gross (13 net) exploratory wells in progress at the end of 1994.

Reserves

Refer to page 52 of the 1994 Annual Report for information on crude oil and natural gas liquids reserves and natural gas reserves of the Resources Group, and such information is hereby incorporated herein by reference pursuant to General Instruction G(2) of Form 10-K. Suncor's estimated recoverable reserves are based on constant year end prices and costs with no escalation into the future as of the dates indicated. The accuracy of any reserve estimate is a function of the quality and quantity of available data and of engineering interpretation and judgment. While reserve and production estimates presented are considered reasonable, the estimates should be accepted with the understanding that reservoir performance subsequent to the date of the estimate may justify revision, either upward or downward.

Production

The following table sets out Suncor's gross and net production during the years indicated. Gross production is that attributable to Suncor's share of production before deduction of applicable royalties and interests owned by others. Net production is gross production less such royalties and other interests.

	Year ended December 31					
	1994		1993		1992	
	Gross	Net	Gross	Net	Gross	Net
Crude Oil (thousands of barrels)						
Alberta	3,063	2,452	2,717	2,202	2,864	2,235
British Columbia	355	270	403	309	414	312
Saskatchewan	711	527	671	478	671	479
Manitoba	0	0	0	0	48	39
Total	4,129	3,249	3,791	2,989	3,997	3,065
Natural Gas Liquids (thousands of barrels)						
Alberta	854	645	897	646	911	632
British Columbia	39	30	61	49	18	16
Saskatchewan	1	1	1	1	1	1
Total	894	676	959	696	930	649
Total Liquids	5,023	3,925	4,750	3,685	4,927	3,714
Natural Gas (millions of cubic feet)						
Alberta	49,871	37,888	46,461	36,072	45,128	34,661
British Columbia	6,469	5,505	7,332	6,031	8,259	7,357
Saskatchewan	205	184	129	112	341	303
Total	56,545	43,577	53,922	42,215	53,728	42,321

As of December 31, 1994, Suncor had interests in 3,016 gross (421 net) producing oil wells in 49 oil fields. Of the gross wells, 1,637 gross (222 net) were in Alberta, 1,083 gross (180 net) were in Saskatchewan, and 296 gross (19 net) were in British Columbia. Suncor had interests in 290 gross (86 net) natural gas wells in 57 gas fields. Of the gross wells, 267 gross (77 net) were in Alberta and 23 gross (9 net) were in British Columbia at the end of 1994. At the end of the year, 544 gross oil wells and 149 gross gas wells were shut-in.

Sales and Sales Revenues

The following table shows the breakdown of the source of revenues for Resources Group.

	1994	1993	1992
		($ millions)	
Gross Revenues*			
Crude oil and natural gas liquids	87	85	89
Natural gas	98	82	65
Pipeline	9	9	9
Other	1	4	4
Total	195	180	167

* Includes intersegment revenues.

The following table shows sales prices and production (lifting) costs in connection with Suncor's crude oil and natural gas operations for the years indicated.

	1994	1993	1992
Average sales price — gross			
Crude oil ($ per barrel)	20.17	20.28	20.71
Natural gas liquids ($ per barrel)	13.77	16.47	16.40
Natural gas ($ per thousand cubic feet)	1.85	1.67	1.22
Average production (lifting) cost of oil and gas*			
$ per BOE of gross production	3.23	3.14	3.42
$ per BOE of net production	4.16	4.03	4.45

* Production (lifting) costs include all expenses related to the operation and maintenance of producing or producible wells, gas plants and gathering systems.

Marketing, Pipeline and Other Operations

Suncor's crude oil production is used in its refining operations, exchanged for other crude oil with Canadian or U.S. refiners or sold to Canadian and U.S. purchasers, including certain subsidiaries of Sun Company, Inc. ("Sun"). Sales are generally made under spot contracts or under contracts which are terminable by relatively short notice.

Prior to deregulation of the Canadian natural gas industry, western Canadian natural gas production was sold primarily to large supply aggregators for resale into eastern Canadian and U.S. markets ("system sales"). With deregulation, it became feasible for producers to make sales arrangements directly with the end user ("direct sales").

Resources Group's natural gas production developed prior to 1986 is generally sold under long-term system sales contracts. Proceeds received by producers under these sales arrangements are determined on a net-back basis, whereby each producer receives revenue equal to its proportionate share of sales less regulated transportation charges and a marketing fee. Most of Resources Group's system sales volumes are contracted to Western Gas Marketing Limited and Pan-Alberta Gas Ltd. These companies resell this natural gas primarily to eastern Canadian and midwest and eastern U.S. markets. To ensure maximum sales, Suncor has been moving volumes not purchased by these companies to direct markets.

In 1993, Suncor's contracts relating to the long-term sale of natural gas to Alberta and Southern Gas Company Ltd. ("A&S") were terminated as part of a restructuring of gas supply from Alberta producers to Pacific Gas and Electric Company, a California utility. In 1993, Suncor sold 24 million cubic feet of its proprietary gas, or 16% of total production, to A&S. The gas supply released from the A&S contracts is now being sold on a direct basis.

Resources Group's natural gas production developed after 1985 is generally marketed under direct sales arrangements to customers in eastern Canada and the U.S. midwest and westcoast. Contracts for these direct sales arrangements are of varied terms with a majority having terms of one year or less and incorporate pricing which is either fixed over the term of the contract or determined on a monthly basis in relation to a specified market reference price. The pricing reference for direct sales to eastern Canadian customers is usually the Alberta border at Empress, Alberta, with the customer being responsible for the transportation of the purchased volume from the point of sale to its facility. The price reference for sales to midwest U.S. customers is usually Ventura and Harper, Iowa, a delivery point on the Northern Border Pipeline system. Resources Group is responsible for transportation arrangements to this point of sale. Sales to the U.S. westcoast are made under a variety or arrangements with differing transportation and pricing terms.

To ensure ongoing direct sales access to U.S. markets, Resources Group has entered into long term pipeline transportation contracts. Suncor has 53 million cubic feet per day of capacity on the Northern Border Pipeline to the U.S. midwest. This contract extends through to the year 2003. Resources Group also has firm capacity of 40 million cubic feet per day contracted on the Pacific Gas Transmission pipeline to the California border extending to the year 2023.

Suncor consumes a significant volume of natural gas in its oil sands plant at Fort McMurray and in its Sarnia refinery. Resources Group contracts for the supply of natural gas to each facility. Natural gas consumption at the oil sands plant in 1994 was 25 million cubic feet per day. Natural gas consumption at the Sarnia refinery in 1994 was 20 million cubic feet per day.

The Albersun pipeline, owned and operated by Suncor, was originally constructed in 1968 to transport natural gas to the oil sands plant. It extends approximately 180 miles south of the plant and connects with NOVA Corporation's intraprovincial pipeline system. The Albersun pipeline has the capacity to move in excess of 100 million cubic feet per day of natural gas. Suncor contracts and controls most of the gas on the system under delivery based contracts. The pipeline moves gas both north and south for Suncor and other shippers. In 1994, throughput on Albersun was 106 million cubic feet per day and transportation and compression revenues were approximately $9 million.

The following table summarizes the volumes of gas marketed directly or indirectly by Resources Group for the last three years.

	Year ended December 31		
	1994	1993	1992
	(millions of cubic feet per day)		
Sales for Suncor's Own Account (Proprietary):			
System	61	73	69
Direct	94	75	78
Total*	155	148	147
Sales on Behalf of Others (Brokered):			
Direct	121	101	77
Total Proprietary and Brokered	276	249	224
Direct Sales (included in the above):			
Oil sands	25	22	21
Sarnia refinery	20	19	18
Other domestic	51	63	62
U.S. sales	99	72	54
Total Direct Sales	195	176	155

* Net sales (million cubic feet per day): 1994 — 119; 1993 — 116; 1992 — 116.

Resources Group arranges for the marketing of its own sulphur production as well as sulphur production from Suncor's Oil Sands Group. In 1994, sales from the two groups totalled 188,000 long tons (1993 — 133,000; 1992 — 204,000) and generated gross revenues of $2.3 million (1993 — $2.3 million; 1992 — $5.3 million). Suncor's sulphur is sold in Canada and offshore. Offshore sales are arranged through Prism Sulphur Corporation, a producer owned consortium of which Suncor was a founding member. World sulphur prices declined steadily from 1985 when spot FOB Vancouver prices were approximately U.S.$130 per tonne to 1993 when prices were under U.S.$30 per tonne. Strong international market demand and reduced supply resulted in improving spot prices to the U.S.$60 per tonne level in 1994.

Capital and Exploration Expenditures

Refer to pages 28 and 29 of the 1994 Annual Report for information on capital and exploration expenditures, and such information is hereby incorporated herein by reference pursuant to General Instruction G(2) of Form 10-K.

Environmental Compliance

Resources Group has all licences required to operate, including clean water licences and clean air licences. Resources Group anticipates that all necessary licences will either be renewed or extended upon expiry. Resources Group accrues the estimated cost associated with the reclamation of the properties it has an interest in. In 1994, $1 million was spent on the reclamation of properties that are no longer producing. These expenditures are charged against the amount that has been accrued over the years. At the end of 1994 the total estimated reclamation liability for producing properties was $20 million, of which $6 million had been accrued at the end of 1994.

Refer to page 29 of the 1994 Annual Report for further information on environmental regulation, and such information is hereby incorporated herein by reference pursuant to General Instruction G(2) of Form 10-K.

Additional information concerning Suncor's Resources Group business is set forth on pages 51 through 54 in the 1994 Annual Report, and such information is hereby incorporated herein by reference pursuant to General Instruction G(2) of Form 10-K.

Sunoco Group

	Year ended December 31		
	1994	1993	1992
		($ millions)	
Revenues			
Sales and other operating revenues	1,384	1,318	1,342
Intersegment	—	—	—
Total	1,384	1,318	1,342
Earnings	31	6*	9
Cash flow from operating activities	119	78	67
Total assets	867	860	879
Capital expenditures	31	30	29

* Includes a third quarter after tax charge of $16 million as explained in note 2 to the consolidated financial statements.

Suncor conducts its refining and marketing of petroleum products and petrochemicals through its principal subsidiary, Sunoco Inc., and its subsidiaries and joint ventures (referred to as "Sunoco Group"). Sunoco Inc. is incorporated under the laws of Ontario and is wholly owned by Suncor.

Sunoco Group's operations are carried out by two business units: the refining (including wholesale) unit and the retail marketing business.

Located in Sarnia, Ontario, the Sunoco Group refinery has a capacity of 70,000 barrels of crude oil per day. The complex refinery has the flexibility to produce premium transportation fuels and high value petrochemicals.

Production from the refinery is marketed through three distinct branded retail marketing channels:

- 260 high-volume, branded Sunoco stations in core urban areas and 125 sites located primarily in secondary markets;
- A 50 percent joint venture company with Pioneer Petroleums (a leading low-cost independent retailer), that owns and operates 105 Pioneer service stations, and manages 115 Sunoco sites located primarily in secondary markets; and

- UCO Petroleum Inc., 50 percent joint venture company with GROWMARK, Inc. (a U.S. agricultural supply and grain marketing co-operative), that operates retail sites in rural Ontario and sells to commercial and farm customers under the Co-Op brand.

Approximately 79 percent of the Sarnia refinery's gasoline production is sold through these secured distribution channels. Refinery production is also marketed through wholesale, commercial and industrial channels.

Over the past four years, the Sarnia refinery achieved more than 90 percent utilization of crude refining capacity. In its primary markets of Ontario and Quebec, Sunoco Group's share of total refined product sales is approximately 15 percent and four percent, respectively.

As a regional refiner and retail marketer, Sunoco Group's financial performance is strongly influenced by petroleum product supply and demand fundamentals in its primary markets of Ontario and Quebec. In the past five years, the downstream business has experienced overcapacity, volatile margins and flat demand for refined petroleum products. Some of these conditions were exacerbated by the recession in the early part of this decade. Based upon this situation, Suncor undertook a strategic study in 1993 to assess whether Sunoco Group could compete successfully within the North American downstream industry. The scope of the study also encompassed a review of the linkages between Suncor's heavy oil upgrader in Fort McMurray, Alberta, its refinery in Sarnia, Ontario, and its retail marketing business.

As a result of the study, management began implementing a non-capital-intensive strategy that is intended to position Sunoco Group as a low-cost competitor and improve its earnings and cash flow regardless of any improvements in market product demand or margins. The strategy also allows Sunoco Group to benefit from any demand and margin improvements.

Refining

Located in Sarnia, Ontario, the refinery has a complex and efficient configuration. Economic refining capacity is approximately 70,000 barrels of crude oil per day. The refinery has cracking capacity of 40,200 barrels per day arising from a catalytic cracker and a hydrocracker. The hydrocracker, which is capable of processing approximately 24,000 barrels per day, adds flexibility by producing premium distillate and naphthas. An alkylation unit, capable of processing 5,500 barrels per day, complements a petrochemical plant for flexibility in gasoline, octane and petrochemical production. The addition of a new jet tower in 1993 further added to the refinery's ability and flexibility in producing premium valued transportation fuels. In addition, the refinery manufactures high value petrochemicals. As a result of this configuration, the refinery has considerably greater flexibility to vary the gasoline/distillate ratio than other Ontario and Quebec refineries.

The performance of the refinery has been enhanced over the years through the addition of computer process controls (66 percent of the plant controls have been updated).

Average daily crude input was 66,000 barrels per day in 1994, 65,000 barrels per day in 1993 and 64,000 barrels per day in 1992. The average utilization rate of the refinery, based upon crude unit processing capacity and input to crude units was 94 percent in 1994, 93 percent in 1993 and 91 percent in 1992. The refinery utilization rate for cracking was 95 percent in 1994 and 90 percent in each of 1993 and 1992.

Approximately 40 percent of the cracking capacity at the refinery is attributable to the houdry catalytic cracker, which was built in the early 1950s and uses an older cracking technology. A comprehensive risk assessment on the houdry catalytic cracker was completed in January 1995. No major expenditures, other than regular maintenance, were identified as a result of this assessment.

The houdry cracker continues to run reliably and it is envisioned that the unit can continue to run well beyond the year 2000. A range of alternatives for enhancing the cracker operation continue to be evaluated, including re-instrumentation or advanced controls.

Sunoco Group's refining operation uses both synthetic and conventional crude oil. In 1994, 68 percent of the crude oil refined at the Sarnia refinery was synthetic crude oil, compared with 69 percent in 1993 and 64 percent in 1992, the remainder being conventional crude oil. The value of synthetic crude oil to Sunoco

Group has been further enhanced by the installation in 1993 of a jet fuel tower thereby increasing production of jet fuel and minimizing lower value products. Of the synthetic crude, approximately 58 percent in 1994 was from Suncor's oil sands plant production compared to 55 percent in 1993 and 54 percent in 1992, with the balance purchased from others under month-to-month contracts. In the event of a significant disruption in the supply of synthetic crude oil from either the Oil Sands Group or the three other suppliers of synthetic crude oil, additional sweet or sour conventional crude oil would be processed. Conventional crude oil refined by Sunoco Group comes mainly from the production of Suncor and others in western Canada, supplemented from time to time with crude oil from the United States which is purchased or obtained in exchange for Canadian crude. Crude oil from other countries can also be delivered to Sarnia via pipeline from the United States Gulf Coast providing additional flexibility and security of supply. The market for crude oil generally is conducted on a spot basis or under contracts terminable by short notice.

In order to ensure access to competitively-priced offshore crude oil, a number of Ontario refiners want the Interprovincial Pipeline from Sarnia to Montreal ("Line 9"), which was formerly used to deliver Western Canadian crude to Montreal but closed in 1991, reopened and reversed.

Timing of the probable reversal of Line 9 is contentious. Suncor has advocated "timely" reversal driven by the supply/demand balance of Western Canadian crudes. Suncor believes that timely reversal will minimize any negative price impact on upstream producers by ensuring that supply and demand remain in balance.

The refinery produces transportation fuels, heating oils, heavy fuel oils, petrochemicals and liquified petroleum gases. Production of transportation fuels is optimized through buy/sell agreements with a neighbouring petrochemical refinery in which feedstocks more suitable for gasoline blending are taken by Sunoco Group in exchange for feedstocks more suitable for petrochemical cracking. Sunoco Group's petrochemical facilities, with a design capacity of 10,000 barrels per day, produce benzene, toluene and mixed xylenes and recover orthoxylene from mixed xylenes.

Reciprocal product buy/sell agreements are also used with other refiners to minimize transportation costs, balance product availability in particular locations, and optimize refinery utilization. The largest agreement is with another regional refinery which receives products in Ontario from Sunoco Group and which supplies a similar volume of products to Sunoco Group in Quebec. On occasion, Sunoco Group purchases refined products to supplement its own refinery production.

A variety of transportation modes are used to deliver products, including by pipeline, water, rail and road. Sunoco Group owns and operates petroleum transportation, terminal and dock facilities in support of its refining and marketing activities. Such assets include storage facilities and bulk distribution plants in Ontario and Quebec and a 55 percent interest in a refined products pipeline between Sarnia and Toronto.

The major mode of transportation for gasolines, diesel, jet fuel and heating oils from the Sarnia refinery to its core markets in Ontario is the pipeline owned and operated by Sun-Canadian Pipe Line Company Limited. The pipeline serves terminals in London, Hamilton and Toronto, and has a capacity of 116,000 (18,500 m3) barrels per day of which 89 percent was utilized in 1994 (87 percent in 1993 and 80 percent in 1992). The line was originally built in 1953 and expanded in 1974. Ownership of the pipeline company is divided between Suncor with a 55 percent interest, and another refiner with a 45 percent interest. The pipeline operates as a private facility for its owners and provides a low cost method of distribution.

Sunoco Group also has direct pipeline access to petroleum markets in the Great Lakes region of the United States by way of connection to a Sun subsidiary's pipeline system at Sarnia. This link to the United States allows Sunoco Group to quickly capitalize on purchase and sales opportunities in the Michigan and Ohio markets.

Efforts to upgrade and automate Sunoco Group's key distribution facilities and to close and decommission less economically attractive facilities have resulted in an improvement in the average throughput and unit costs of its facilities. These efforts continue with the decision in late 1994 to close and decommission its terminal facilities in Ottawa in 1995. Sunoco Group has secured long-term access to facilities of another terminal operator to serve its market base in this area. In 1990, average throughput at

Sunoco Group's terminals was 479,000 cubic metres per year which increased to 837,000 cubic metres per year in 1994. Sunoco Group believes that its own facilities and those on long-term contractual arrangements with other parties will provide a sufficient level of storage for its current and foreseeable needs.

Sunoco Group markets transportation fuels (including gasoline, diesel, propane and jet fuel) heating oils, liquified petroleum gases, residual fuel oil and asphalt feedstock to its retail marketing business and industrial, commercial and wholesale customers and refiners, primarily in Ontario and Quebec. In addition, Sunoco Group also markets toluene, mixed xylenes, benzene and orthoxylene in Canada, the United States and Europe through a petrochemical marketing and distribution arrangement with Sun. This arrangement, established in 1992, covers petrochemicals produced at Sunoco Group's Sarnia and Sun's Toledo refineries. These petrochemicals are used in manufacturing plastics, rubber, synthetic fibres, industrial solvents, agricultural products and as gasoline octane enhancers. All Sunoco Group's benzene production is sold directly by pipeline to other petrochemical manufacturers in Sarnia. Sunoco Group also sells liquified petroleum gases to various industrial users and to resellers.

The addition of more jet fuel production capacity in 1993 has seen the volume of jet fuel sales increase by 71 percent since 1992. In addition, Sunoco Group's transportation fuels volumes, which generally has higher margins than other refined products, has increased from 69 percent of its total refined product sales volumes in 1990 to 79 percent in 1994. This increase in emphasis on transportation fuels has contributed to Sunoco Group's earnings and competitive position over the period.

Retail Marketing

In positioning Sunoco Group to be competitive in its markets in the long-term, the retail marketing business unit was restructured in 1993 into three distinct branded distribution channels as discussed above.

Approximately 79 percent of the Sarnia refinery's gasoline production is sold through these three secured distribution channels. Volumes to the Pioneer and GROWMARK joint ventures are supplied under exclusive supply agreements.

While retail marketing will be selling its product through fewer sites, management believes that the total gasoline volumes will remain at approximately current levels as a result of higher overall retail network throughput. Since 1990 retail site throughput has increased from 1.9 million litres per site to 3.4 million litres per site in 1994.

Sales of gasolines and other transportation fuels represented 70 percent of Suncor's consolidated sales and other operating revenues in 1994 compared to 71 and 68 percent in 1993 and 1992, respectively.

Capital Expenditures

Refer to pages 28 and 29 of the 1994 Annual Report for information on capital expenditures, and such information is hereby incorporated herein by reference pursuant to General Instruction G(2) of Form 10-K.

Environmental Compliance

Sunoco Group has all licences required to operate its refinery and other business assets, including land, water and air licences. Sunoco Group expects that all necessary licences will be renewed or extended. While environmental standards are quickly evolving, Sunoco Group's refinery is currently in compliance in all material respects with existing regulations as a result of investments and management's actions. At service stations in Ontario, environmental risks have been reduced through the implementation of a voluntary tank replacement program that exceeds current legislative and regulatory requirements.

Sunoco Group currently has provisions to cover the cost of remediating sites that are already closed or are to be closed. The cost is based on expenditure estimates less the estimated proceeds from the sale of the properties. Changes in any of these estimates will affect future earnings. The timing of the removal of service station sites from the retail market network will be determined by marketplace conditions in order to minimize any negative impact on Sunoco Group's marketing activities or presence. At the end of 1994, Sunoco Group had accrued liabilities of $14 million related to site remediation costs.

As Sunoco Group pursues its plan to improve the efficiency of its marketing and distribution network, it is anticipated that other terminals and retail sites may be closed. It is possible that further remediation will be required in connection with such closures but the cost and timing of such remediation cannot be estimated reasonably until environmental assessments have been completed and the means of remediation determined. Remediation costs, which will be incurred over an extended period of time, may be substantial.

In addition to the considerations discussed above there is continuing discussion around such topics as fuel quality standards for gasoline and diesel fuel, reformulated gasoline that will lower toxic emissions, the removal of additives from gasolines, carbon dioxide emission stabilization and new standards for remediation of sites, to name a few. Changes which may be required, as a result of some or all of these initiatives being implemented, have the potential to impact product demand and quality, methods of production and distribution, as well as the nature of products themselves (for example, cleaner-burning gasoline); with possible additional costs which may or may not be recoverable in the marketplace.

The complexity and breadth of these issues make it extremely difficult to predict their resolution. While it is possible that Sunoco will be required to make expenditures in the future to comply with new environmental regulations that may have an unfavourable impact on its financial results, management is not aware of any proposed changes to fuels qualities or environmental standards that would disadvantage Suncor in comparison to its competitors.

Refer to page 29 of the 1994 Annual Report for further information on environmental regulation, and such information is hereby incorporated herein by reference pursuant to General Instruction G(2) of Form 10-K.

Additional information concerning Suncor's Sunoco Group business is set forth on page 54 in the 1994 Annual Report, and such information is hereby incorporated herein by reference pursuant to General Instruction G(2) of Form 10-K.

Suncor Employees

As at December 31, 1994, Suncor had 2,326 full-time employees and 458 part-time and other employees which are counted on a full-time equivalent basis. The following table shows the distribution among the operating groups for the past three years.

	Year ended December 31		
	1994	**1993**	**1992**
Oil Sands Group	1,379	1,448	1,779
Resources Group	258	257	257
Sunoco Group	640	693	709
Corporate	49	53	53
Total	2,326	2,451	2,798
Sunoco Group retail marketing service stations*	458	495	494

* Excludes joint venture service stations employees

In addition to the Suncor employees, independent contractors supply a range of services to the operating, maintenance and support functions.

Approximately 850 Oil Sands Group employees are represented by a labour union. Approximately 180 employees at Suncor's Sarnia refinery and approximately 70 employees in Resources Group's field operations are represented by employee associations. Relations with these associations have been constructive for many years.

ITEM 3. LEGAL PROCEEDINGS

There are no material pending legal proceedings to which Suncor or any of its subsidiaries is a party, or of which any of their properties is the subject.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

There were no matters submitted to a vote of security holders during the fourth quarter of the fiscal year ended December 31, 1994.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

Information relating to the principal markets in which Suncor's common shares (the "Common Shares") are traded in the United States and Canada, the high and low sales prices per share in each such market for each full quarterly period within the two most recent fiscal years, the approximate number of holders of record of Common Shares and the frequency and amount of any cash dividends declared for the two most recent fiscal years is set forth under the caption "Share Trading Information" on page 55 of the 1994 Annual Report and such information is hereby incorporated herein by reference pursuant to General Instruction G(2) of Form 10-K.

ITEM 6. SELECTED FINANCIAL DATA

Selected financial data for Suncor and its subsidiaries for each of the last five fiscal years is set forth below:

	1994	1993	1992	1991	1990
	(Millions of dollars except per share amounts)				
For the years ended December 31:					
Sales and other operating revenues	1,635	1,546	1,559	1,564	1,654
Net earnings (loss) — Cdn. GAAP	121	75	(228)	77	124
— U.S. GAAP	110	141	(209)	80	127
Net earnings (loss) per common share — Cdn. GAAP	2.22	1.38	(4.19)	1.42	2.27
— U.S. GAAP	2.01	2.59	(3.84)	1.47	2.33
Cash dividends per common share	1.06	1.04	1.04	1.05	0.40
Cash dividends per Preferred Share, Series A	—	—	1.44	1.92	1.92
At December 31:					
Total assets	2,201	2,023	1,973	2,264	2,285
Preferred Shares, Series A	—	—	—	6	6
Common shareholders' equity	1,035	970	952	1,236	1,216
Long-term Borrowings*	195	196	180	141	222

* Includes current portion

ITEM 7. MANAGEMENT'S DISCUSSION & ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Management's Discussion & Analysis of Financial Condition and Results of Operations is set forth under the caption "Management's Discussion & Analysis" on pages 12 to 29 of the 1994 Annual Report. Such information is hereby incorporated herein by reference pursuant to General Instruction G(2) of Form 10-K and should be read in conjunction with the consolidated financial statements and the notes thereto contained on pages 31 to 47 of the 1994 Annual Report.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The following information in the 1994 Annual Report is incorporated herein by reference pursuant to General Instruction G(2) of Form 10-K: the auditors' report on page 30; the consolidated financial statements on pages 33-37; the notes to the consolidated financial statements on pages 38-47; applicable quarterly information in the Quarterly Summary of Financial Data on page 48; and Supplemental Financial and Operating Information on page 50 and pages 52-54 (excluding the section entitled "Sunoco Group").

Within the past 12 months, Suncor has not filed oil and gas reserve estimates with any authority or agency in the United States.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

Information relating to Directors of Suncor is set forth under the caption "Election of Directors" on pages 3 to 7 of Suncor's Management Proxy Circular for its 1995 Annual and Special Meeting of Shareholders and such information is hereby incorporated herein by reference pursuant to General Instruction G(3) of Form 10-K.

ITEM 11. EXECUTIVE COMPENSATION

Information relating to director and executive compensation is set forth under the captions "Information Regarding the Board of Directors and its Committees" on pages 7 to 8, "Remuneration of Executive Officers" on pages 9 to 10, and "Report on Executive Compensation" on pages 13 to 15 of Suncor's Management Proxy Circular for its 1995 Annual and Special Meeting of Shareholders and such information is hereby incorporated herein by reference pursuant to General Instruction G(3) of Form 10-K.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Information relating to security ownership of management and certain beneficial owners is set forth under the caption "Voting Shares and Principal Holders Thereof" on page 3, and "Ownership of Common Shares By Directors and Executive Officers" on page 9 of Suncor's Management Proxy Circular for its 1995 Annual and Special Meeting of Shareholders and such information is hereby incorporated herein by reference pursuant to General Instruction G(3) of Form 10-K.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Information regarding certain relationships and related transactions is set forth under the caption "Transactions with Principal Shareholders, Directors and Officers" on page 17 of Suncor's Management Proxy Circular for its 1995 Annual and Special Meeting of Shareholders and such information is hereby incorporated herein by reference pursuant to General Instruction G(3) of Form 10-K.

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K

(a) The following documents are filed as part of this report:

1. *Consolidated Financial Statements:*

   The information appearing in the 1994 Annual Report as described in Item 8 is incorporated herein by reference.

2. *Financial Statement Schedules:*

3. *Exhibits*

The following exhibits are filed as part of this Annual Report on Form 10-K:

3.1*	Certificate of Amalgamation of Suncor
3.2*	By-Laws of Suncor, as amended to date
4.1*	Certificate of Amalgamation of Suncor (see Exhibit 3.1)
4.2*	Form of Certificate of Common Shares, no par value, of Suncor
10.1*	Executive Stock Plan, as amended and restated January 26, 1995
10.2*	Management Incentive Plan
10.3*	Supplemental Executive Retirement Plan
10.4*	Termination Agreements
10.5*	Supplemental Executive Retirement Plan Trust Agreements
10.6*	Collective Agreement
10.7*	Oil Sands Lease No. 7279120092
10.8*	Oil Sands Lease No. 738706T04
10.9*	$400,000,000 Revolving Term Credit Facility Agreement dated as of October 1, 1993 among Suncor, Sunoco Inc. and the Banks named therein
11*	Statement Re: Computation of Earnings Per Share
12*	Statement Re: Computation of Ratios
13*	Suncor's 1994 Annual Report (furnished for the information of the Securities and Exchange Commission and not deemed "filed" as part of this Form 10-K, except for those portions that are expressly incorporated by reference herein)
21*	Subsidiaries of Suncor
24*	Powers of Attorney

* Filed herewith

(b) **Reports on Form 8-K**

There were no reports on Form 8-K filed during the fourth quarter of 1994.

(c) **Exhibits Required by Item 601 of Regulation S-K**

The exhibits listed on the Exhibit Index at page 29 are filed as part of this report.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on this 16th day of March, 1995.

SUNCOR INC.

By ______________*______________
Name: Timothy R. Hughes
Title: Senior Vice President, Finance

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities indicated on the dates indicated.

Signature	Title	Date
* Richard L. George	President, Chief Executive Officer and Director (principal executive officer)	March 16, 1995
* Timothy R. Hughes	Senior Vice President, Finance (principal financial officer)	March 16, 1995
* Robert M. Aiken, Jr.	Director	March 16, 1995
* Harry Booth	Director	March 16, 1995
* Robert H. Campbell	Director	March 16, 1995
* Bryan P. Davies	Director	March 16, 1995
* Deborah M. Fretz	Director	March 16, 1995
* Allan E. Gotlieb	Director	March 16, 1995
* Ardagh S. Kingsmill, Q.C.	Director	March 16, 1995
* David E. Knoll	Director	March 16, 1995

Signature	Title	Date
* Bill N. Rutherford	Director	March 16, 1995
* W. Robert Wyman	Director	March 16, 1995

*Pursuant to powers-of-attorney executed by the officers or directors named above, Jennifer A. C. Parkin, as attorney-in-fact, does hereby sign this report on behalf of each of such officers or directors, in each case in the capacity of such officer or director, on the date indicated.

By /s/ JENNIFER A. C. PARKIN Jennifer A. C. Parkin	Attorney-in-fact	March 16, 1995

SUNCOR INC.

Index to Financial Statements
and Financial Statement Schedule

Items (14)(a)(1) and (14)(a)(2)

REPORT OF THE INDEPENDENT ACCOUNTANTS

To the Shareholders and Board of Directors, Suncor Inc.:

Our report on the consolidated financial statements of Suncor Inc. and its subsidiaries has been incorporated by reference in this Form 10-K from page 30 of the Suncor Inc. Annual Report to Shareholders. In connection with our audits of such financial statements, we have also audited the related financial statement schedule listed in the index on page F-1 of this Form 10-K.

In our opinion, the financial statement schedule referred to above, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information required to be included therein.

Coopers & Lybrand

Toronto, Ontario
Canada
January 20, 1995

SUNCOR INC.

SCHEDULE VIII — VALUATION ACCOUNTS

For the years ended December 31, 1994, 1993 and 1992
(millions of dollars)

	Balance at beginning of period	Additions charged to costs and expenses	Deductions	Balance at end of period
For the year ended December 31, 1994:				
Deducted from asset in balance sheet — allowance for doubtful accounts receivable	7	3	1	9
For the year ended December 31, 1993:				
Deducted from asset in balance sheet — allowance for doubtful accounts receivable	7	2	2	7
For the year ended December 31, 1992:				
Deducted from asset in balance sheet — allowance for doubtful accounts receivable	4	7	4	7

Suncor Inc.

PRIMED *for* GROWTH

1994 Annual Report

About the Company

Suncor Inc. is a growing Canadian integrated oil and gas company with assets of $2.2 billion, including a large stake in the country's oil sands industry. The company has three operating groups and employs about 2,800 people. Shares of Suncor (SU) are traded on the Montreal, Toronto, Alberta, Vancouver and the American stock exchanges.

OIL SANDS GROUP

Produces light sweet crude and other oil products from the oil sands near Fort McMurray, Alberta. Average 1994 production: 70,700 barrels/day.

SEE PAGE 6

RESOURCES GROUP

Explores for, acquires and produces crude oil and natural gas in Western Canada. Average 1994 production: 29,300 barrels of oil equivalent/day.

SEE PAGE 8

S U N

SUNOCO GROUP

Refines and markets petroleum products in Ontario and Quebec. Refinery capacity: 70,000 barrels/day. Retail sites: 500.

SEE PAGE 10

Financial Highlights

($ millions except per share amounts) Year ended December 31	**1994**	1993	1992
OPERATING RESULTS AND FINANCIAL POSITION			
Revenues	**1 637**	1 549	1 562
Net earnings (loss)	**121**	75	(228
Cash flow from operations	**331**	225	193
Long-term debt	**190**	191	171
DATA PER COMMON SHARE			
Net earnings (loss)	**2.22**	1.38	(4.19)
Cash dividends	**1.06**	1.04	1.04
Cash flow from operations	**6.07**	4.13	3.55
KEY RATIOS – %			
Return on capital employed	**7.5**	5.0	(12.3
Return on shareholders' equity	**12.1**	7.8	(20.8)
Long-term borrowings to capital employed	**10.7**	11.3	10.6
Net debt/cash flow from operations	**57**	98	102

Milestones for Growth The successful rollout of Suncor's strategic plan has provided the company with financial capacity to grow its business. We are committed to investing this capital to deliver near-term growth for shareholders.

RECORD PRODUCTION OF 100,000 BARRELS OF OIL EQUIVALENT/DAY IN 1994

Plan to raise production to 120,000 BOEs/day in 1998 through major investments in both upstream operations.

CASH FLOW INCREASED 47% IN 1994

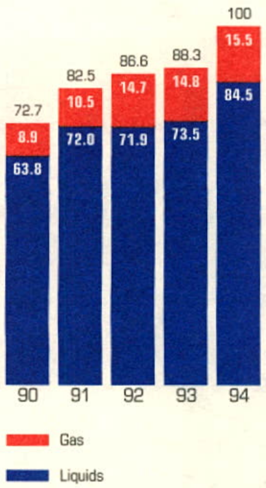
Goal to increase cash flow by 10% per year on average over the next three years through higher production and lower costs.

CAPITAL INVESTMENT ROSE 23% IN 1994 TO $303 MILLION

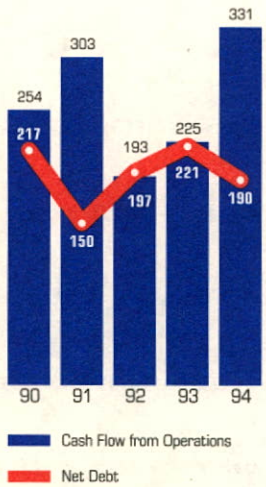
Plan to invest $1.4 billion by 1998 with a goal of double-digit return on capital employed.

C O R I N C.

BOE Production
(thousands of barrels of oil equivalent per day)



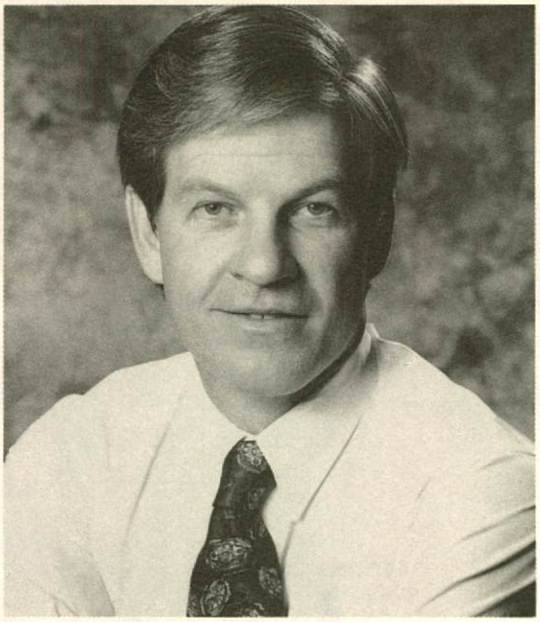
Cash Flow from Operations/ Net Debt Levels
($ millions)



Earnings
($ millions)

Note: 1992 includes $238 million restructuring charge. 1993 includes $6 million restructuring charge

I am pleased to report that Suncor achieved excellent results again this year. With nine consecutive quarters of rising profits year over year, we are primed for growth. Cash flow from operations rose 47% to $331 million, while our earnings climbed 61% to $121 million. Higher levels of cash flow and profitability paved the way for a 4% increase in our annualized dividend to shareholders. Our position was further strengthened when our credit rating was upgraded. Suncor's financial performance is steadily improving without the benefit of higher crude oil prices. The company's consistent results reflect the successful implementation of our business plans to increase production, improve reliability, reduce costs, and mitigate price and exchange rate risks. Production of crude oil, natural gas and natural gas liquids reached a record 100,000 barrels of oil equivalent (BOEs) per day in 1994 — the highest ever — while per unit costs were reduced in each of our three operating divisions. We are not resting on our laurels. Each of the businesses has set aggressive, quantifiable targets into 1998 and can meet them by managing the factors within our control.



Rick George
PRESIDENT AND CHIEF EXECUTIVE OFFICER

"The success of our strategic plan over the past few years has provided a strong foundation for growth even as we 'raise the bar' on our operational objectives."

OIL SANDS GROUP

Oil Sands Group cash flow from operations increased 75% in 1994 as the Group continued to deliver on its promises.

Reliability improvements and conversion to a more flexible mining technology contributed to higher levels of productivity. This year we mined more oil sand than ever before and averaged record production of 70,700 barrels per day. We also reduced unit cash costs to $14 per barrel, down more than 25% from $19 in 1992 when Oil Sands Group began implementing its strategic plan. We expect to reach the $12 mark by 1998.

Oil Sands Group is also enhancing shareholder value by diversifying its products and customer base. By custom blending crude according to customer requirements – everything from light sour crudes to high-value, low-sulphur diesel – we leverage our production, achieve higher margins and enhance market flexibility. In 1994, higher margin products represented 20% of our total sales compared with 11% in 1993.

RESOURCES GROUP

Resources Group, our conventional oil and natural gas division, has built an exceptional track record of cost-effectively replacing production with new proved reserves.

The addition of more than 28 million BOEs of proved reserves in 1994 was our highest on record and represents a reserve replacement rate of over 260%. Over the past three years, the Group added more than 58 million BOEs of reserves through exploration and development, and replaced an average 190% of production on a proved reserve basis at a cost of $5.30 per BOE.

This rate and cost of replacement places Suncor in the top tier of comparable Canadian exploration and production companies. The Group increased production to 29,300 BOEs per day in 1994 despite a sizable divestment of non-core properties in 1992 and 1993. Cash flow from operations rose 16% over 1993.

SUNOCO GROUP

Sunoco Group has completed the first year of a three-year strategic plan to improve the cost-competitiveness of refining and retail marketing operations, including a substantial reduction in overhead costs. As part of this strategy, we restructured our operations and eliminated unnecessary work. At our refinery in Sarnia, Ontario, we reduced operating costs by negotiating a reduction in energy costs with Ontario Hydro.

To reposition our branded retail business with high-volume, low-cost urban sites, we reduced our entire network by 18% in 1994. This smaller, more focused network managed to increase total retail gasoline sales by 8%, while throughput per site increased by 30%.

In total, initiatives undertaken by Sunoco in 1994 increased earnings by $9 million, and cash flow from operations by about $15 million.

GROWING THE COMPANY – AN INVESTMENT IN OUR FUTURE

Our financial and operational achievements in the face of sustained commodity price challenges confirm our strategies are on track. We are generating higher levels of earnings and cash flow, our assets are strong and reliable, and we have the financial capacity to grow.

From 1995 to 1997, we plan to reinvest in our upstream businesses, where we see the greatest potential for profitable growth in the near term. Our goal is to increase cash flow by an average 10% per year over the next three years through a combination of higher production and lower costs. We expect to increase total oil and natural gas production to 105,000 BOEs per day in 1995, rising to 120,000 BOEs per day by 1998.

OIL SANDS GROUP – NEXT STEPS

As part of our growth strategy, Oil Sands Group plans to spend $250 million over the next three years to increase production to more than 80,000 barrels per day in 1998. At the same time, this investment is expected to lower unit costs and create the infrastructure for subsequent growth. Production increases will be staged to ensure the operation remains safe, reliable and environmentally sound. These plans are subject to board of director and regulatory approval.

To reduce sulphur dioxide emissions, we invested $15 million in the upgrader in 1994 and about $24 million of an anticipated $175 million in the utilities plant. Together these initiatives will achieve a cumulative 75% plant-wide reduction in sulphur dioxide emissions.

The oil sands give Suncor a competitive advantage that is unique in the world. We have just begun to unlock the total potential of this vast resource. We have proven that mining for oil is an economic alternative to conventional exploration and development, and we have the reserves, people and technology to expand the business. From this secure position, Suncor has taken steps to extend the life of its oil sands operations for the next 50 years.

Over the next five years, we plan to spend up to $200 million to develop a new mine site on a recently acquired lease. We will conduct an environmental impact assessment and consult with community stakeholders so that their concerns and ideas can be incorporated into our plans. Site work will proceed when we have obtained final approval from our board of directors and regulatory agencies.

RESOURCES GROUP – NEXT STEPS

Resources Group plans to spend $300 million over the next two years to increase reserves through focused exploration and development. The Group is able to capitalize on an investment of this magnitude and grow cost-effectively as a result of strategies it initiated in the early 1990s. We have a high-quality property portfolio in three core areas of Alberta and British Columbia. Our exploration expertise in those areas is proven and we have an excellent track record in adding new reserves.

We anticipate that Resources Group production will increase from 29,300 BOEs per day in 1994 to 40,000 BOEs per day in 1998 as new discoveries come on-stream. During this period, we are targeting to cost-effectively replace at least 150% of production in proved reserves. If high-quality acquisition opportunities arise at an acceptable price, we are prepared to step into the market and further increase reserves and production levels.

SUNOCO GROUP – NEXT STEPS

Implementation of Sunoco Group's strategic plan should be complete in 1996. The plan calls for the Sarnia refinery to enter the top quartile of North American refiners and the retailing businesses to be in the top decile of their chosen markets.

Sunoco has devised strategies that should improve pretax cash flow by $30 million per year by the end of 1996, independent of margin improvements. To date, we have realized about $15 million of our target. Sunoco plays an important role as a generator of cash flow for Suncor.

"We plan to invest in our upstream businesses, where we see the greatest potential for profitable growth in the near term."

HEALTH AND SAFETY

We are saddened to report that a fatal accident occurred at our oil sands plant in 1994. In February Patrick Dyck, a long-time employee in our mine operations, was killed on the job. We immediately launched an investigation along with the Alberta Ministry of Labour that included a comprehensive review of our management processes.

We continue to strive for improvement in our safe work practices and to provide a safe and healthy workplace for our employees and contractors. As Chief Executive Officer, I am committed to achieving safety standards that will serve as a model for the industry.

ENVIRONMENTAL REPORT IN 1995

Suncor has demonstrated commitment to its "We Care" policy through its actions in 1994. Over the next two years, we expect to spend nearly $200 million on addressing environmental issues. In 1995, we plan to produce our first stand-alone environmental report which will provide a full discussion of our environmental issues and action plans.

If you are not currently on the mailing list for Suncor annual reports and would like to receive a copy of our environmental report, please contact us at 1-800-558-9071.

TRANSFORMING OUR WORKPLACE

As part of our drive to add shareholder value, we will continue to upgrade our technology and implement best practices from around the world. To measure our progress in reaching top-quartile levels of performance, we will benchmark our businesses on an ongoing basis.

However, the real key to Suncor's future lies with our highly skilled, motivated and efficient workforce. Our people have accepted profound change, yet the organization has not missed a beat. Our senior management team has shown strong leadership throughout, displaying an uncommon ability to generate and implement new ideas.

A year ago, we began a process intended to reshape Suncor's culture and build on our strengths. We recognize that we cannot reach our goal overnight, but we have a clear vision of the kind of company we want to become. In our ideal workplace, all employees have the opportunity to make full use of their talents. It is a challenging, stimulating and fair place; an environment where commitment is freely given and the desire to outperform competitors is strong.

At Suncor, we are determined to create and maintain this ideal. In so doing, we will enhance our ability to continuously create value for our shareholders beyond today's level. I have a vision of Suncor achieving market capitalization of $3 billion within four years, and I have challenged our organization to help us get there.

Suncor closes 1994 primed for growth — and with a full agenda ahead of us.

Richard L. George

Richard L. George
PRESIDENT AND CHIEF EXECUTIVE OFFICER
JANUARY 26, 1995

"To create our future, we have changed fundamentally the way we mine for oil. In the process, we did what we set out to do – increased production, improved reliability and reduced costs."

OIL SA

Dee A. Parkinson
EXECUTIVE VICE PRESIDENT, OIL SANDS GROUP

Milestones for Growth

AN OUTSTANDING YEAR IN 1994

- Achieved all-time high productivity, as measured by tonnes of oil sand mined; production volumes; cash costs per barrel; and product sales
- Set record production of 70,700 barrels per day
- Reduced sulphur dioxide emissions in upgrading by 50%
- Selected location for new mine with dual advantages of high-quality reserves and close proximity to plant's processing facilities

A FIRM FOUNDATION FOR THE FUTURE

- Invest $150 million — the balance of a $175 million commitment — to reduce plant-wide sulphur dioxide emissions by 75% in 1996
- Invest approximately $250 million to raise production to more than 80,000 barrels/day in 1998
- Reduce cash costs to $12/barrel by 1998
- Invest up to $200 million to bring new mine into production by 2001

NDS GROUP

Production
(thousands of barrels per day)

NEW MINING TECHNOLOGY AND MODIFICATIONS TO THE UPGRADER WERE KEY FACTORS IN 1994'S RECORD PRODUCTION.

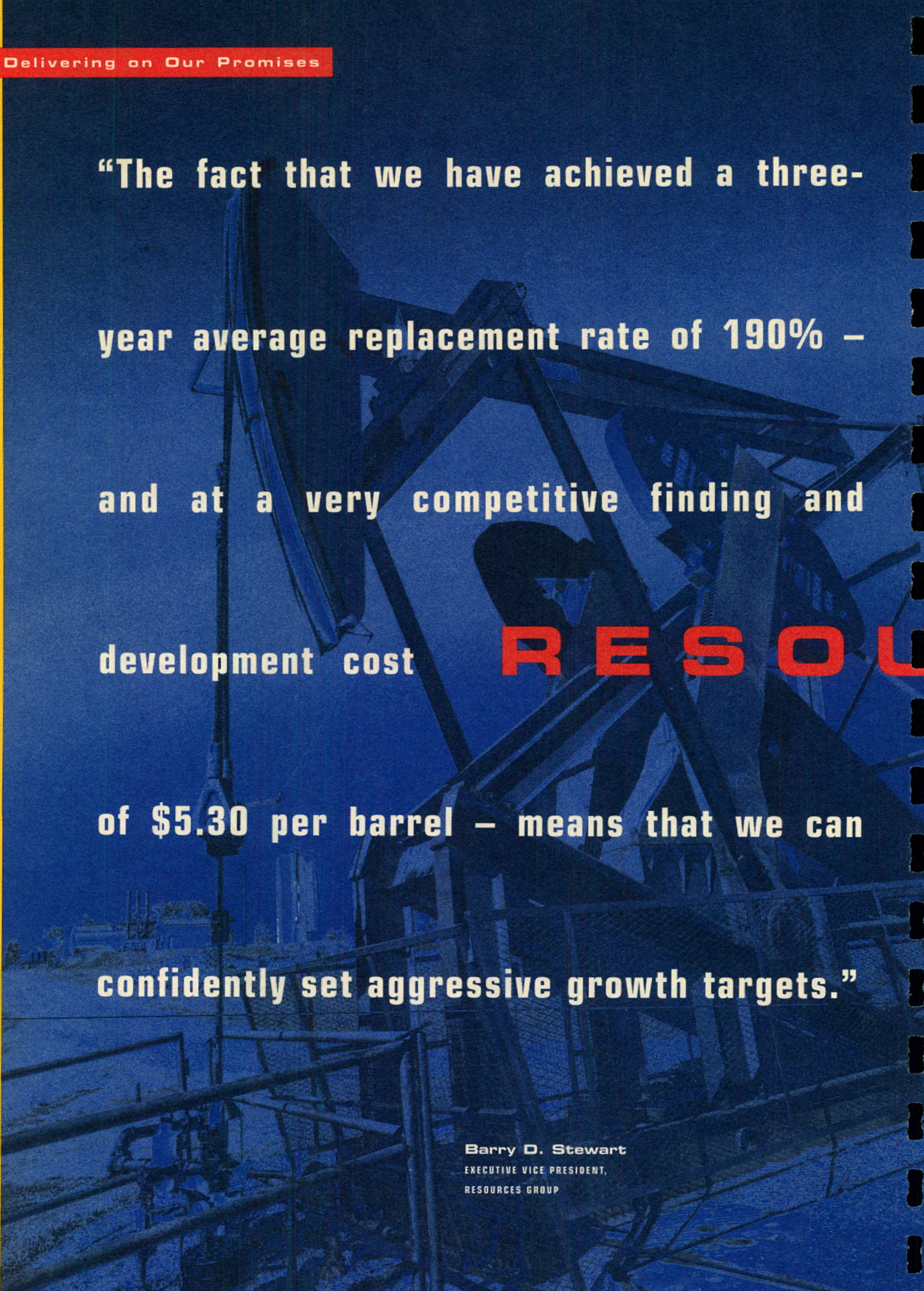
Utilization
(%)

Excluding 1993 maintenance shutdown period

PLANT INTEGRITY PROGRAMS PAID OFF IN 1994.

Cash Costs
($ per barrel)

LOWER CASH COSTS MEAN PROFITABILITY IS SUSTAINABLE WHEN OIL PRICES ARE LOW.



"The fact that we have achieved a three-year average replacement rate of 190% – and at a very competitive finding and development cost of $5.30 per barrel – means that we can confidently set aggressive growth targets."

RESOU

Barry D. Stewart
EXECUTIVE VICE PRESIDENT,
RESOURCES GROUP

Milestones for Growth

ON TRACK IN 1994

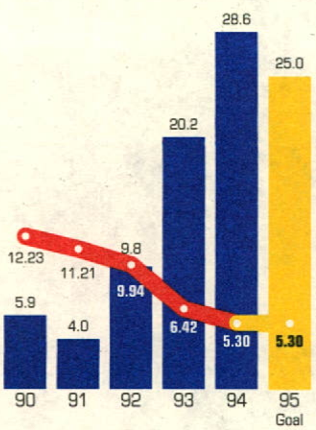
- Achieved record production of 29,300 BOEs/day
- Reduced finding and development costs to top-tier levels
- Replaced an average 235% of production with proved reserves over the last two years
- Surpassed one trillion cubic feet of proved and probable natural gas reserves

GAINING MOMENTUM

- Invest $300 million over next two years to increase reserves and production
- Raise production to 40,000 BOEs/day in 1998
- Replace 150%+ of production each year with new proved reserves through finding and development (F&D)
- Maintain top-quartile finding and development cost of $6/barrel or less

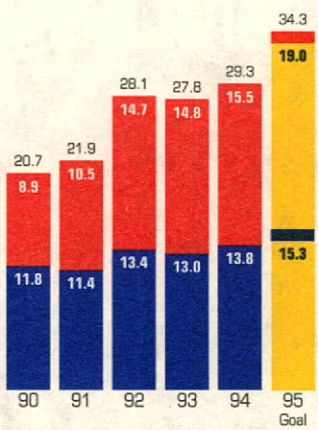
RCES GROUP

Finding and Development Costs/Proved F&D Additions
(millions of barrels of oil equivalent)



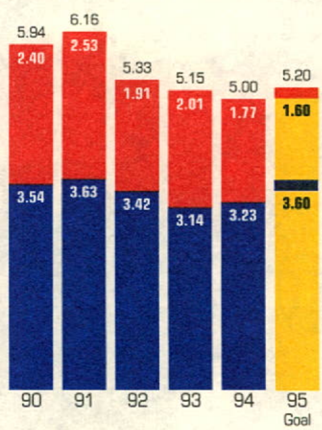
THE #1 WAY TO CREATE VALUE IN THE UPSTREAM IS TO COST-EFFECTIVELY ADD NEW PROVED RESERVES.

Production

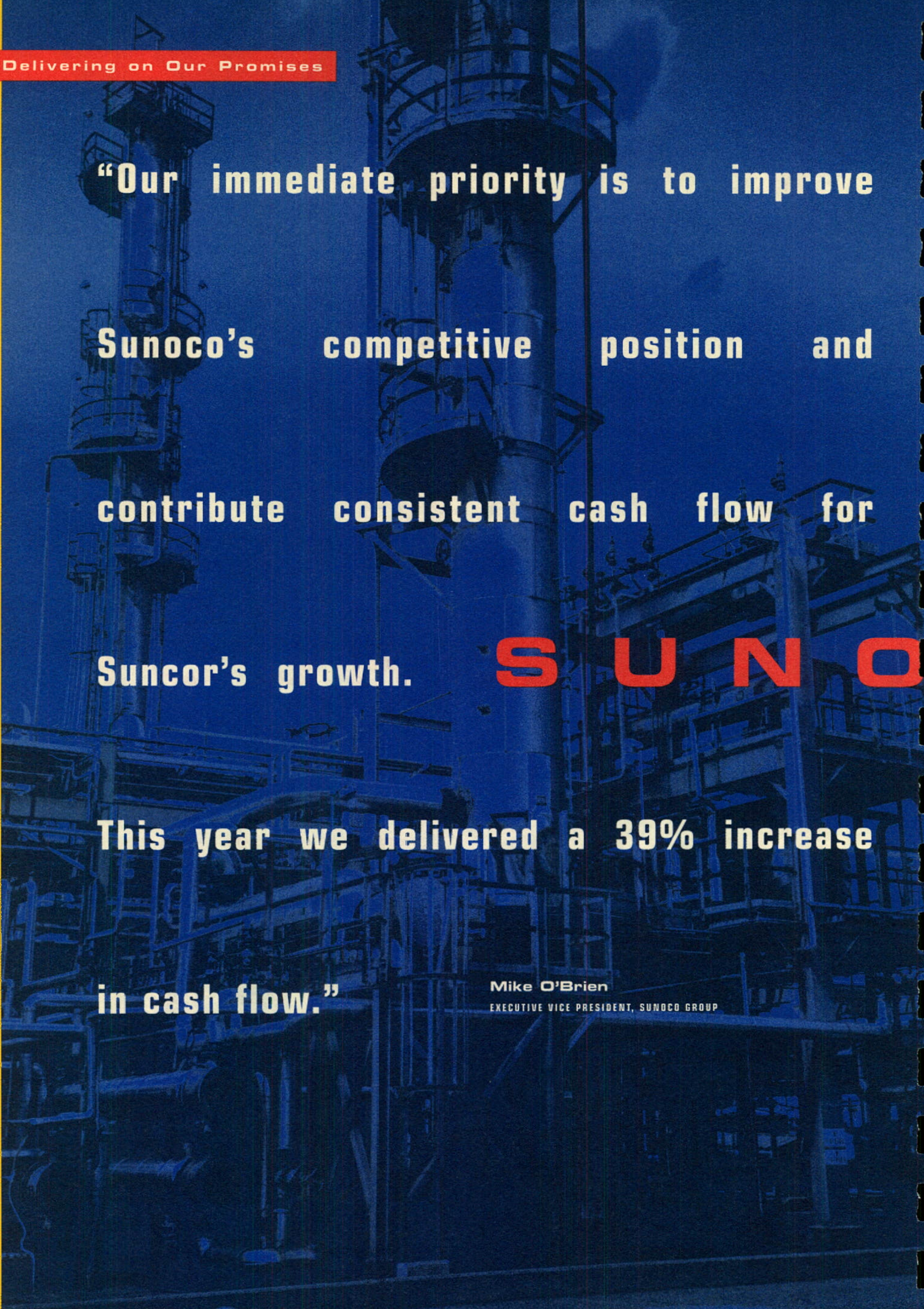


RECORD PRODUCTION IN 1994 DESPITE SIZABLE DIVESTMENT OF NON-CORE PROPERTIES THE PREVIOUS YEAR.

Lifting and Administration Costs
($ per barrel of oil equivalent)



LIFTING & ADMINISTRATION COSTS DECLINED APPROXIMATELY $1/BOE OVER 4 YEARS.



"Our immediate priority is to improve Sunoco's competitive position and contribute consistent cash flow for Suncor's growth. This year we delivered a 39% increase in cash flow."

SUNO

Mike O'Brien
EXECUTIVE VICE PRESIDENT, SUNOCO GROUP

Milestones for Growth

PROGRESS IN 1994

- Cash flow climbed to $93 million compared with $67 million in 1993
- Completed divestment of less profitable retail sites one year ahead of schedule
- Reduced size of retail network by 18%
- Increased retail gasoline sales by 8% and throughput per site by 30%

SETTING THE PACE FOR THE FUTURE

- Strategic initiatives are expected to increase cash flow and earnings $30 million/year and $20 million/year respectively by mid 1996
- Sarnia refinery in top 25% of refiners in North America by 1996
- Retail businesses in top 10% of retailers in Ontario and Quebec markets by 1996
- A customer service record second-to-none

CO GROUP

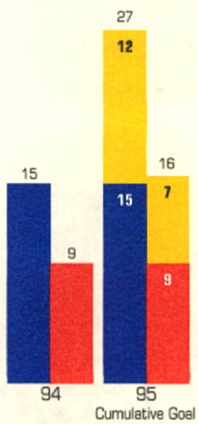
Crude Utilization/
High Value Components
(%)

THE SARNIA REFINERY ACHIEVED ALL-TIME HIGH 94% CRUDE UTILIZATION IN 1994.

Retail Network Efficiency
(millions of litres per site)

HIGHER SALES VOLUMES AND A SITE DIVESTMENT PROGRAM INCREASED THROUGHPUT PER SITE BY 30%.

Strategy Cost
Reduction Targets
($ millions)



INITIATIVES UNDERTAKEN BY SUNOCO IN 1994 INCREASED CASH FLOW FROM OPERATIONS BY ABOUT $15 MILLION.

INDUSTRY INDICATORS

(average for the year unless noted otherwise)	**1994**	1993	1992
West Texas Intermediate (WTI) U.S.$/barrel @ Cushing	**17.20**	18.50	20.50
Canadian par crude Cdn$/barrel @ Edmonton	**22.28**	21.92	23.56
Natural Gas U.S.$/thousand cubic feet @ Gulf Coast	**1.82**	2.06	1.72
Natural Gas (Alberta spot) Cdn$/thousand cubic feet @ Empress	**2.12**	2.39	1.22
Natural gas exports to the U.S. trillions of cubic feet	**2.5 est.**	2.2	1.9
Refined product demand (Ontario/Quebec) % change over prior year	**4.5 est.**	2.0	1.6
Exchange Rate: Cdn$: U.S.$	**0.73**	0.77	0.83

CONSOLIDATED FINANCIAL RESULTS

($ millions)	**1994**	1993	1992
Earnings (loss) (1)	**121**	75	(228)
Cash provided from operating activities	**379**	237	210
Investing activities	**292**	204	195
Dividends	**58**	57	57
Long-term borrowings	**190**	191	171

(1) 1993 and 1992 include restructuring charges of $6 million and $238 million, respectively, which are more fully described in note 2 to the consolidated financial statements.

OVERVIEW

Suncor's financial results are reported in three operating segments and a corporate segment for unallocated costs and for consolidation adjustments.

The segments discuss group operations, investment activities, outlook and factors critical to group success. Taken together, these segment analyses explain the changes in Suncor's overall financial performance.

* The tables and charts in this document form an integral part of Management's Discussion and Analysis and should be referred to when reading the narrative. References to Suncor include Suncor Inc. and its subsidiaries unless otherwise stated. A blue bar in the chart reflects a positive variance, while a yellow bar reflects a negative variance.

($ millions unless otherwise stated)	**1994**	1993	1992
Revenue	**571**	487	491
Production (thousands of barrels per day)	**70.7**	60.5	58.5
Average sales price ($ per barrel)	**22.31**	22.49	22.99
Earnings (Loss)	**90**	59	(74)
Cash provided from operating activities	**195**	112	103
Total assets	**857**	779	721
Capital expenditures	**103**	116	65

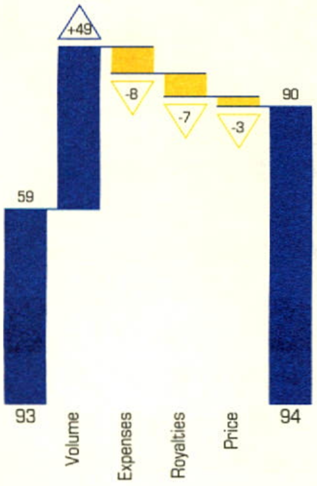
RESULTS OF OPERATIONS AND INVESTING ACTIVITIES

1994 vs 1993

Earnings from Oil Sands Group rose to $90 million in 1994 from $59 million in 1993.

In 1992 Oil Sands Group commenced a process of significant change to reliably increase production. This required a small investment to increase upgrader capacity to an average of 68,000 barrels per day and conversion to a truck and shovel mining system. In 1994 Oil Sands Group delivered record-setting production which averaged 70,700 barrels per day (25.8 million barrels for the year). In 1993 production averaged 60,500 barrels per day (22.1 million barrels for the year), when operations were shut down for nearly a month for planned maintenance work. The resulting 18% increase in sales volumes, less additional variable operating costs, improved earnings by $49 million over 1993.

Earnings Analysis
($ millions)



ALL-TIME HIGH PRODUCTIVITY FUELS 52% INCREASE IN EARNINGS FROM 1993.

During 1994 Oil Sands Group continued to improve the reliability of its upgrader through the efforts of an Integrity Task Force team. The costs associated with the work of the task force, as well as higher natural gas costs which more than doubled in the year, increased expenses. These increases were partially offset by a further reduction in the workforce and other efficiency initiatives. Overall, there was a net increase in expenses of $8 million.

Along with production levels, price is also instrumental in revenue determination. In addition to the achievements in improving production reliability, efforts have also been directed at enhancing revenue through the expansion of the Oil Sands Group's product mix. For example, diesel fuel, which sells at a premium to light sweet crude oil, had an 85% increase in volumes in 1994 over 1993 levels. During planned maintenance work in 1994, marketing initiatives to sell light sour crude resulted in the plant being able to maintain production during this 27 day period.

The product mix improvement, along with a weaker Canadian dollar relative to the U.S. dollar, were more than offset by lower WTI prices and a lower favourable impact from hedging activities (1994 – $3 million; 1993 – $13 million), resulting in an average price in the year of $22.31 per barrel compared to $22.49 in 1993. Combined, these factors reduced earnings by $3 million.

Royalty expenses in 1994 increased $7 million primarily due to higher volumes. The Crown royalty component is normally determined as the greater of 5% of revenues or 30% of the sum of revenues minus allowed operating and capital costs. Suncor's royalties are currently at the 5% rate. Suncor does not expect to pay the 30%

rate until the end of the decade, although this depends on future oil prices, production, operating costs and capital expenditures. In 1992 the Government of Alberta agreed to provide Suncor with an adjustment to the Crown royalty payment mechanism between January 1, 1992 and December 31, 1997 in conjunction with approved environmental spending. The maximum annual payment reduction is 4% of gross revenues. This benefit is expected to increase 1995 earnings by approximately $15 million over 1994 levels, subject to the factors noted above. The Government of Alberta will effectively have recovered this benefit when the 30% royalty rate becomes payable.

In both 1994 and 1993 Oil Sands recorded $7 million of earned depletion savings, resulting in a lower provision for income taxes. There will be no similar benefit in 1995.

The net cash surplus increased to $95 million in 1994, up from $1 million in 1993. The increase primarily reflects higher cash from operating activities due to higher earnings ($46 million) and reduced spending on planned maintenance shutdowns ($23 million) and lower overburden expenditures of $16 million. The next maintenance shutdown work is scheduled for 1997; overburden spending is expected to be $5 million higher in 1995.

With the conversion to truck and shovel mining largely completed in 1993, 1994 investing activities declined to $100 million compared to $111 million the previous year. Partially offsetting the truck and shovel investment decrease of $67 million was higher environmental spending and increased expenditures for production improvements.

In 1995 capital expenditures are expected to increase to about $200 million. Over half of this amount will be related to environmental spending as construction of the sulphur dioxide reduction project continues (see Outlook). The balance will be used to maintain and improve production capabilities.

1993 vs 1992

Oil Sands Group earned $59 million in 1993 versus a loss of $74 million in 1992. The 1992 loss included an $85 million restructuring charge (see Note 2 to the consolidated financial statements).

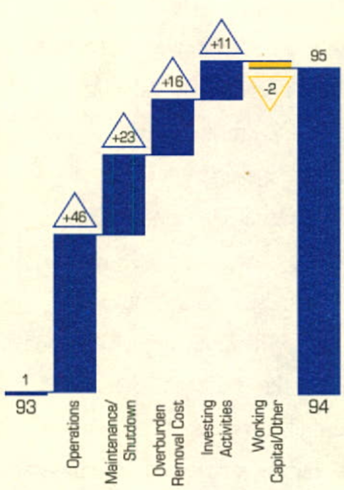
Oil Sands' cash and non-cash expenses were reduced by $29 million in 1993, as a result of the strategic changes announced in 1992 and decreased overburden amortization charges.

1993 production was 22.1 million barrels compared to 21.4 million barrels the previous year. A fire in the upgrader and the partial plant freeze-up in December 1992 reduced 1992 earnings by $24 million. In the fourth quarter of 1993 two fires in the upgrader resulted in an earnings impact of $7 million but had little impact on production. The overall improvement in plant reliability in 1993 resulted in a higher plant utilization and a favourable earnings impact of $17 million.

An earned depletion income tax-related savings of $7 million and lower royalties of $6 million also improved 1993 earnings. These favourable factors were largely offset by lower crude oil prices of $11 million (net of the favourable impact of $13 million in hedging activity).

In 1993 the net cash surplus declined to $1 million from $42 million in 1992, primarily reflecting strategic initiatives and the cost of a planned maintenance shutdown.

Net Cash Surplus Analysis
($ millions)



BENEFITS OF STRATEGIC INITIATIVES AND LOWER PLANNED MAINTENANCE SHUTDOWN EXPENDITURES ARE KEY COMPONENTS OF CASH FLOW IMPROVEMENT.

Cash flow provided from operating activities increased by $9 million primarily reflecting higher earnings and a second quarter legal claim settlement of $18 million. These favourable factors were partially offset by an increase in working capital due to lower liabilities, and a $29 million increase in maintenance shutdown expenditures.

Cash used in investing activities increased from 1992 to 1993 by $50 million primarily due to $81 million in strategic expenditures for mine technology conversion ($72 million) and the elimination of certain production restrictions in the upgrader ($9 million).

OUTLOOK

Suncor's integrated oil sands business produces an average of 68,000 barrels per day of light sweet crude oil and other products. Production involves a surface mining and extraction operation, a bitumen upgrading process, and a utility plant which produces steam and electric power.

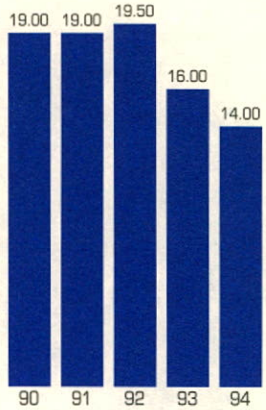
In 1992, Suncor conducted a strategic review of the heavy oil business and Suncor's position within it, including changing requirements with respect to more stringent environmental air standards. As a result, Suncor embarked on a program to increase margins, acquire additional leases and reduce plant-wide sulphur dioxide emissions by 75%.

Cash Margins

Given the high fixed costs of the operation and volatile commodity prices, Suncor concluded that improving cash margins was contingent on a combination of reliably increasing production, lowering costs and increasing the value from sales. By custom blending crude according to customer requirements, ranging from light sour crudes to high-value, low-sulphur diesel, Oil Sands leverages its production, achieves higher margins and enhances marketing flexibility.

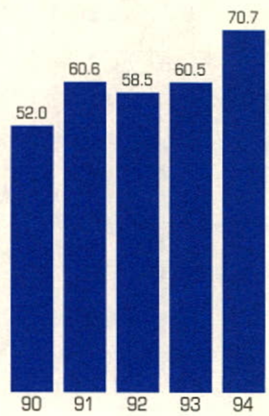
The chart indicates considerable progress in improving margins during a period of lower prices. Cash costs were reduced to $14 per barrel in 1994 from $16 per barrel in 1993 due to record production and lower spending levels. At current production levels cash costs will range between $14 to $15 per barrel as spending to maintain

Cash Costs
($ per barrel)



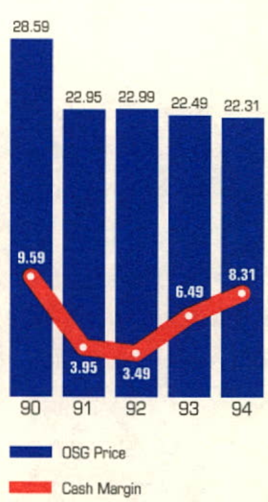
STRATEGIC INITIATIVES INCREASE PRODUCTION AND LOWER UNIT CASH COSTS.

Production
(thousands of barrels per day)



NEW MINING TECHNOLOGY AND MODIFICATIONS TO THE UPGRADER KEY FACTORS IN 1994'S RECORD PRODUCTION.

Cash Margins*
($ per barrel)



CONSIDERABLE PROGRESS IN IMPROVING MARGINS DURING A PERIOD OF LOWER PRICES.

***Cash Margin** – The difference between the price received for products sold and cash cost per barrel. The cash cost per barrel includes cash operating costs, sustaining capital and reclamation costs and the amortization of deferred maintenance shutdown expenditures. Cash cost excludes royalties and strategic capital expenditures.

Price – The average price from the sale of crude oil and related products, including the impact of hedging activities but before deductions for royalty payments.

Note: Royalty expense per barrel for the above years was as follows: 1994 – $1.55; 1993 – $1.44; 1992 – $1.91; 1991 – $1.35; 1990 – $2.12.

production reliability and integrity fluctuates from year-to-year depending upon the nature and timing of work required.

1995 cash costs are expected to be approximately $14.75 per barrel, reflecting higher sustaining capital expenditures for bitumen production and upgrading reliability projects, as well as increased maintenance costs for the new truck and shovel equipment. Suncor now expects that its $12 per barrel target will be achieved in 1998 when production is increased to over 80,000 barrels per day.

Sulphur Dioxide Reductions

Suncor has committed approximately $175 million in capital investments (excluding capitalized interest), starting in 1994, to improve the oil sands operation's environmental performance. The completion of this project in 1996 will allow Suncor to meet its 1996 air license requirements.

The expenditure covers the installation of limestone flue gas scrubbing technology to reduce sulphur dioxide emissions from the utilities plant.

This project, along with $15 million of new sulphur recovery equipment installed in the upgrading area in 1994, is expected to reduce total sulphur dioxide emissions by at least 75%. Regulatory approval for construction has been received.

Future Expansion

By improving the plant's production reliability and reducing costs, Suncor has paved the way for sustained growth in production levels, further reductions in unit cash costs and increased cash margins.

Over the next three years, Suncor plans to invest approximately $250 million to expand oil sands production to over 80,000 barrels per day. These expenditures will position the plant for possible further expansion in the future. The major part of the production increase is expected to occur in 1997 after scheduled maintenance work. This expansion will further reduce unit cash costs and increase the cash margin.

Suncor currently operates on two leases which are expected to be fully mined early in the next century. In the last three years Suncor has acquired additional leases and lots near its existing operations. In the fall of 1994, Suncor announced that its next mine site would be located on a lease directly across the Athabasca River from its existing processing plants.

Geological and engineering assessments of the new mine site confirmed the quality of the mineable bitumen resources on this lease and additional leases purchased in 1992. Feasibility studies during 1995 will determine mine and facility design, infrastructure requirements and cost estimates. Approval from Suncor's board of directors and regulatory agencies are required before site work can commence. Public consultation will occur and an environmental impact assessment will be completed.

Suncor estimates that it will spend up to $200 million over the next five years preparing the site for production, with most of the spending occurring after 1997. The new mine is scheduled for operation by the year 2000 and, together with leases acquired in 1992, is expected to extend production for an additional 50 years.

Labour Relations

Oil Sands Group has 1,379 employees, of whom 850 are unionized. During the first quarter of 1994, the Oil Sands Group successfully reached a new collective agreement with Local 707 of the Communications, Energy and Paperworkers Union. The new agreement is for a three-year period compared to the previous two-year agreement. Suncor believes that the new agreement provides the framework for continuously improving the joint problem-solving initiatives underway with the union and fosters a climate of open communications between the parties involved.

Risk/Success Factors

Financial results continue to be influenced by crude oil prices and production levels. While crude oil prices are not within Suncor's control, the company can improve profitability through higher production and increased reliability as well as product customization and market diversification.

Production outages and slowdowns, particularly those related to severe climactic conditions, can be expected to occur from time to time; however, Suncor continues to work to improve the total annual production and reliability of day-to-day operations. During 1994, for example, the utilization rate averaged about 97% (98% in 1993, excluding the maintenance shutdown period) – meaning Oil Sands met or exceeded production plans for 354 days in 1994.

Environmental Reclamation

Oil Sands Group's regulator-approved reclamation plan includes tailings pond reclamation and all surface reclamation at the site. The major component of the plan relates to the tailings ponds. Suncor is researching technologies which reduce the volume of fine tailings and increase dry landscape reclamation areas. Suncor is currently evaluating the economic viability and technical feasibility of these technologies on a demonstration scale. Suncor expects to have fully tested and evaluated this technology within the next three years.

The proposed reclamation plan is expected to be an integral component of the new mine development application. Further research and testing could result in cost revisions, including higher costs for alternative techniques if this technology does not prove successful.

Site reclamation costs, including the above-noted pond reclamation work, have been estimated and are being recorded over the estimated remaining life of the reserves by charges against earnings on a unit of production basis. Oil Sands Group estimates the total cost for reclamation of the site will be approximately $180 million. This estimate is primarily based on the current approved development and reclamation plan which will expire in 1995.

Oil Sands Group anticipates the necessary operating license will be renewed in 1995.

RESOURCES GROUP

($ millions unless otherwise stated)	**1994**	1993	1992
Revenue	**195**	180	167
Production (thousands BOEs* per day)	**29.3**	27.8	28.1
Average sales price:			
Natural gas ($/thousand cubic feet)	**1.85**	1.67	1.22
Crude oil ($ per barrel)	**20.17**	20.28	20.71
Earnings (Loss)	**21**	28	(141)
Cash provided from operating activities	**96**	98	80
Total assets	**496**	402	386
Capital & exploration expenditures	**169**	100	120

* BOE is a measure which converts gas to oil on the approximate long-term economic equivalent basis that 10,000 cubic feet of gas equals one barrel of oil.

RESULTS OF OPERATIONS AND INVESTING AND EXPLORATION ACTIVITIES

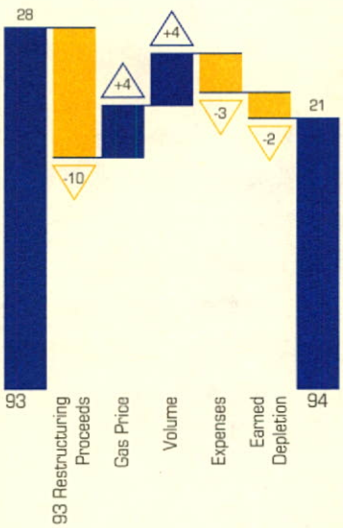
1994 vs 1993

Earnings from Resources Group decreased to $21 million in 1994 from $28 million in 1993. Excluding a $10 million positive adjustment in 1993 (as explained in Note 2 to the consolidated financial statements), 1994 earnings increased $3 million. The other factors affecting earnings are noted below.

An 11% increase in natural gas prices increased earnings in 1994 by $4 million, including the favourable impact from natural gas hedging activities.

One of the objectives of Resources Group has been to increase reserves and production levels. Over the last three years the exploration and development program has added 58 million BOEs of proved reserves. An additional 26 million BOEs of proved reserves have been added through acquisition activities. This success in growing the reserves base, despite

Earnings Analysis
($ millions)



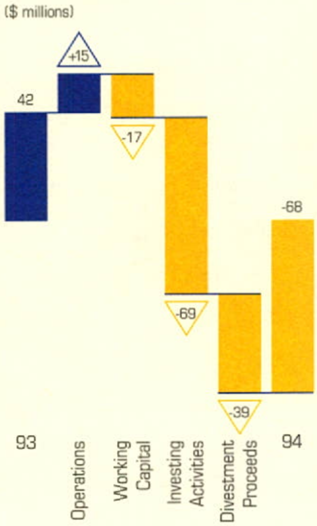
RECORD PRODUCTION OF 29,300 BOEs/DAY AND HIGHER GAS PRICES PARTIALLY OFFSET 1992/1993 DIVESTMENT ACTIVITIES.

a divestment of 14% of proved reserves in 1992/1993, has resulted in a 5% volume increase in 1994 and an earnings increase of $4 million.

Expenses were $3 million higher in 1994 due to a higher level of exploration spending ($1 million), higher non-cash charges primarily due to the higher volumes ($1 million) and a bad debt provision of $1 million.

Earned depletion benefits in 1994 of $5 million were $2 million less than those received in 1993. There will be no benefit recorded from earned depletion in 1995.

Net Cash Surplus (Deficiency) Analysis
($ millions)



REDUCED DIVESTMENT PROCEEDS AND STRATEGY TO CONTINUE TO INCREASE THE RESERVE AND PRODUCTION BASE CREATE CASH DEFICIENCY FOR YEAR.

As mentioned, part of the Group's strategy is to grow the reserve and production base through a focused exploration and development program based upon a successful track record of adding reserves at the first quartile of performance. The net cash deficiency of $68 million in 1994, representing a $110 million higher use of funds compared to 1993, reflects the confidence in the Group's ability to economically add to its reserve base.

Cash flow from operating activities at $96 million was $2 million lower than in 1993. While cash earnings increased $15 million, this was more than offset by a $17 million increase in working capital. The working capital increase was primarily due to higher direct natural gas receivables and lower payables in 1994.

Net capital and exploration investing activities increased by $108 million in 1994 over the 1993 level. The change reflects a combination of $69 million in higher spending, and divestment proceeds of $39 million recorded in 1993 as explained in Note 2 to the consolidated financial statements. The spending increase reflects the goal of increasing production to 40,000 BOEs per day by 1998.

1994 exploration and development drilling replaced production by over 260% with new proved oil and natural gas reserves, improving on the 200%+ performance of 1993. This achievement places Suncor in the top quartile of all Canadian oil and gas producers. Finding and development costs, averaging $5.30 per BOE over the last three years, are also in the top quartile of the industry.

Development activity in 1994 increased by $39 million to $86 million, mostly attributable to work in the Grande Prairie area of Alberta. Grande Prairie production, estimated to be 30 million cubic feet per day of marketable natural gas and 1,200 barrels of natural gas liquids, is expected to begin in the late fall of 1995. Resources Group production is expected to reach 34,000 BOEs in 1995, rising to 40,000 BOEs in 1998.

Capital and exploration expenditures which focus on natural gas exploration and development are expected to increase to the $165 million range in 1995.

1993 vs 1992

Earnings in 1993 were $28 million compared to a loss of $141 million in 1992. The loss included an after-tax restructuring charge of $152 million, as explained in Note 2 to the consolidated financial statements. 1993 saw a favourable adjustment of $10 million against this charge from the sale of properties identified in 1992. Excluding the impact of these items, 1993 earnings improved to $18 million from $11 million in 1992.

The sale of the oil and natural gas properties in 1992/1993 reduced conventional crude oil volumes and 1993 earnings by $2 million. Higher natural gas prices in 1993 increased earnings by $13 million. This improvement was partially offset by a $5 million accounting brokerage loss.

An earned depletion benefit of $5 million reduced the 1993 provision for income taxes. There was no similar benefit in 1992.

In 1992, non-restructuring property sales increased earnings by $3 million. Despite the favourable impact of hedging activity and a lower Canadian dollar, the price received for crude oil decreased from the 1992 level and reduced earnings by $1 million.

In 1993, Resources Group had a net cash surplus of $42 million (including $39 million from asset restructuring proceeds) compared to a 1992 net cash deficiency of $27 million. Cash flow from operating activities increased primarily as a result of the same factors that increased earnings.

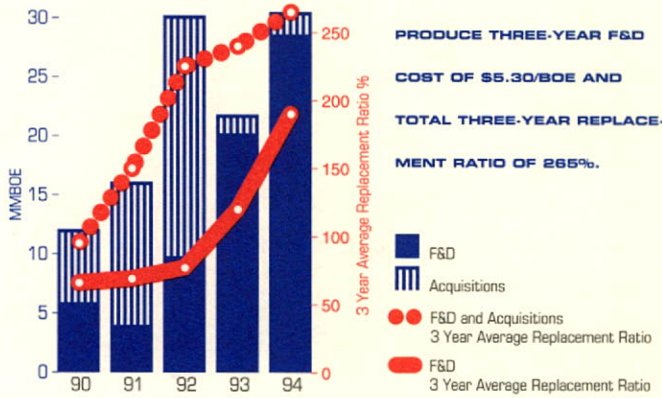
The $20 million decrease in investing activities reflected lower acquisition spending of $40 million from the 1992 level of $47 million. This decline was partially offset by increased exploration and development expenditures.

OUTLOOK

Success/Risk Factors

Oil and natural gas activities can be broken down into components which include development, production and marketing. While these activities, along with commodity pricing, should not be underestimated or viewed as predictable, Resources Group believes the most important

Proved Reserve Additions/
Replacement Ratio



1994 F&D RESERVE ADDS OF 28.6 MILLION BOEs PRODUCE THREE-YEAR F&D COST OF $5.30/BOE AND TOTAL THREE-YEAR REPLACEMENT RATIO OF 265%.

contributor to relative value creation is the ability to consistently find and develop low-cost, quality reserves that can be economically brought on-stream, supplemented by opportunistic acquisitions which enhance the portfolio. Resources Group believes that this result can be achieved with proved finding and development (F&D) costs at or below $6 per BOE and a proved reserves replacement ratio of at least 150% of production. Suncor's F&D three-year average cost for 1994 was $5.30 per BOE, compared to $6.42 per BOE in 1993.

Exploration and development costs can fluctuate as marketplace demand for land and services bids up F&D costs. Suncor believes that focused exploration together with its success in adding reserves will allow it to continue at the first quartile F&D level. The above chart illustrates Resources Group's performance in replacing production through reserve additions.

Resources Group will continue to focus its exploration program in the Western Canadian Sedimentary Basin where its proven geological and geophysical knowledge base should provide value enhancement.

Lifting and Administration Costs

While Resources Group views F&D costs as the most critical success factor, another important factor influencing profitability and cash flow is lifting and administration costs. These costs have decreased from $5.94 per BOE in 1990 to $5 per BOE in 1994. Due to the sour gas nature of new production and the natural decline rate in mature fields, management expects a modest increase in unit lifting costs for 1995.

Natural Gas

The use of natural gas is rising. Its cleaner burning features have led to a 30% increase in U.S. consumption since 1986, a trend which is expected to continue. Since the late 1980s, Resources Group has been expanding its natural gas exploration and marketing efforts. The group's natural gas production is expected to reach 55% of total production by 1995, up substantially from 42% at the end of the 1980s.

During 1994, warm weather and higher production of natural gas caused a downturn in North American gas prices. Management believes that with the dynamic interplay of the market forces of supply and demand, prices will continue to fluctuate. As a result, Suncor will look for opportunities to mitigate price volatility through hedging activities.

Suncor markets to a portfolio of customers and geographical markets to ensure ongoing market access and to manage commodity price risk. Approximately two-thirds of Resources Group's production is sold to markets in the United States.

About 60% of Resources Group's production is marketed on a "direct marketing" basis. The direct sales portfolio includes markets in California and the U.S. Pacific Northwest accessed by Suncor's 40 mmcf/d capacity commitment on the Pacific Gas Transmission Pipeline, and markets in the U.S. Midwest accessed by Suncor's 53 mmcf/d commitment on the Northern Border Pipeline. Suncor's direct Canadian sales are to customers in Alberta, British Columbia, Ontario and Quebec. The Canadian markets include approximately 45 mmcf/d (or 29% of production) sold to Suncor "internal" markets at Suncor's oil sands facility and the Sunoco refinery in Sarnia.

Approximately 40% of Suncor's natural gas production is sold under historical contracts to "aggregators". Under these contracts, third party marketers purchase Suncor's production and Suncor receives a net back price based on the average of the prices received from the aggregator's markets. These arrangements further enhance Suncor's market access and include customers and markets which are not the focus of the direct sales program.

SUNOCO GROUP

($ millions unless otherwise stated)	**1994**	1993	1992
Revenue	**1,384**	1,323	1,342
Refined product sales: (thousands of cubic metres per day)			
Retail gasoline	**4.4**	4.1	4.0
Total	**13.5**	13.1	13.4
Earnings (Loss) breakdown:			
Retail marketing	**0**	(16)*	(11)
Refining	**31**	22	20
Total	**31**	6	9
Cash provided from operating activities	**119**	78	67
Total assets	**867**	860	879
Capital expenditures	**31**	30	29

* Includes $16 million related to the restructuring charge as more fully explained in Note 2 to the consolidated financial statements.

Sunoco's operations are carried out by two business units: the refining (including wholesale) unit and the retail marketing business.

Located in Sarnia, Ontario, the Sunoco refinery has a capacity of 70,000 barrels of crude oil per day. This complex refinery has the flexibility to produce premium transportation fuels and high value petrochemicals.

Over the past four years, the Sarnia refinery achieved more than 90% utilization of crude refining capacity. In its primary markets of Ontario and Quebec, Sunoco's share of total refined product sales is approximately 15% and 4%, respectively.

Production from the refinery is marketed through three distinct branded distribution channels:

- 260 high-volume, branded Sunoco stations in core urban areas, and 125 sites located primarily in secondary markets;
- A 50% joint venture company with Pioneer Petroleums (a leading low-cost independent retailer), that owns and operates 105 Pioneer service stations, and manages 115 Sunoco sites located primarily in secondary markets; and
- UCO Petroleum Inc., a 50% joint venture company with GROWMARK, Inc. (a U.S. agricultural supply and grain marketing co-operative), that operates retail sites in rural Ontario and sells to commercial and farm customers under the Co-Op brand.

Approximately 79% of the Sarnia refinery's gasoline production is sold through these secured distribution channels. Refinery production is also marketed through wholesale, commercial and industrial channels.

RESULTS OF OPERATIONS AND INVESTING ACTIVITIES

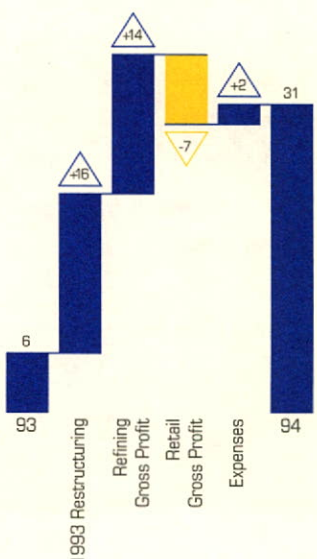
1994 vs 1993

1994 earnings increased to $31 million from $6 million in 1993. Earnings in 1993 were adversely affected by a $16 million charge, related to the retail business, as described in Note 2 to the consolidated financial statements.

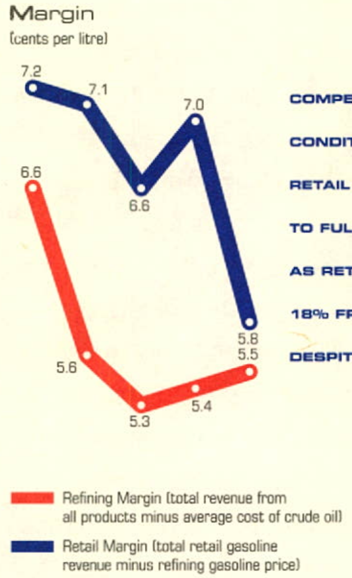
Earnings from refining were $31 million compared to $22 million in 1993. Gross profit increased by $14 million due to higher sales volumes, improved refinery operations and a modest improvement in product margins. Sales volumes increased 3% driven by a 9% increase in gasoline sales, primarily to the Sunoco and Pioneer branded marketing channels. The Sarnia refinery achieved high operating rates and responded effectively to capitalize on specific market opportunities. Crude utilization was 94% of capacity (93% in 1993) and cracking capacity utilization was 95% (90% in 1993). Record distillate production was achieved in the first quarter to meet strong weather-related demands. The hydrocracker unit ran at record levels and the refinery met a high demand for gasoline. Refining margins were extremely volatile due in part to fluctuating crude prices. The overall margin was slightly higher than 1993 with very strong petrochemical margins, particularly in the second half of the year, offsetting generally lower margins for other products.

Sunoco's retail business broke even in 1994 and lost $16 million in 1993, including the $16 million charge described above. Gross profit declined $7 million with significantly lower margins only partially offset by higher gasoline sales. Margins in Sunoco's primary markets of Ontario and Quebec continued to be low despite the economic recovery in 1994 and ongoing rationalization of the industry that resulted in a significant reduction in the number of service stations. In this extremely competitive environment, Sunoco focused on improving its competitiveness by repositioning the Sunoco branded retail network into high-volume sites in core urban areas. In 1994, approximately 105 less profitable sites, or nearly 18% of the network, were closed or divested. Retail gasoline sales increased 8%, despite the reduction in the size of the network, through a combination of increased market

Earnings Analysis
($ millions)



STRATEGIC INITIATIVES ADD $9 MILLION TO EARNINGS, COMPLEMENTING STRONG OPERATIONAL PERFORMANCE AS EARNINGS INCREASE OVER 1993.



COMPETITIVE MARKET CONDITIONS CONTINUE WITH RETAIL BUSINESS UNABLE TO FULLY RECOVER ALL COSTS AS RETAIL MARGIN FALLS 18% FROM 1993 LEVELS DESPITE ECONOMIC RECOVERY.

demand and effective implementation of marketing programs. The combination of higher sales and substantial reduction in operating costs through site rationalization offset the adverse impact of lower margins.

A significant proportion of Sunoco's cash costs vary with production and sales volume. In 1994, Sunoco benefited from the implementation of cost reduction initiatives announced in 1993 as cash costs declined despite higher sales volumes. Repositioning of the Sunoco branded retail network resulted in a 14% reduction in retail cash costs per litre of sales. The elimination of unnecessary work as a result of restructuring operations led to an 8% reduction in administrative costs per litre. Refining cash costs were lower by 1% on a per unit production basis.

Overall expenses were $2 million lower than last year with the favourable impact of lower cash expenses and depreciation partially offset by higher non-cash charges associated with ongoing rationalization of operations.

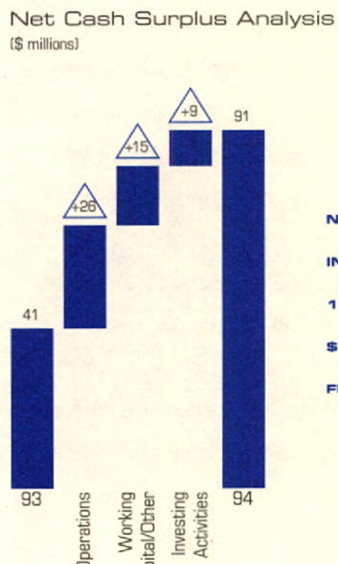
Sunoco Group's net cash surplus more than doubled in 1994, increasing to $91 million from $41 million in 1993. The excess cash generated by Sunoco is currently used to fund the growth of Suncor's upstream businesses.

Stronger earnings and lower maintenance shutdown expenditures increased cash from operations by $26 million. Lower working capital, and the absence of restructuring payments in 1994, increased working capital/other cash by $15 million. Higher year-end liabilities, partially offset by higher inventory levels, accounted for this $15 million increase.

Cash used in investing activities declined in 1994 largely due to investments made in 1993 related to the joint venture entered into with Pioneer Petroleums, a major independent gasoline retailer.

Investing activity in 1995 is expected to increase to $50 million, with $14 million of environmental expenditures planned. About 75% of the total spending is targeted for the refining business with the balance in the retail operation.

Significant maintenance shutdown work at the Sarnia refinery in 1995 is expected to result in cash expenditures of $18 million. Customer demand will be met from inventory and reciprocal product exchange agreements with other refineries.



NET CASH SURPLUS INCREASES 121% OVER 1993 INCLUDING $15 MILLION BENEFIT FROM STRATEGY DECISIONS.

1993 vs 1992

In 1993 earnings declined to $6 million from $9 million in 1992. 1993 earnings were adversely affected by the $16 million charge discussed in Note 2 to the consolidated financial statements.

Earnings from refining were $22 million in 1993 versus $20 million in 1992. Refining gross profit fell by $3 million primarily due to lower sales volume. Sales volumes decreased by 2% driven by reduced heavy fuel oil, petrochemical and other product sales. Reduced wholesale gasoline and chemical margins were offset by higher margins for other products.

Earnings from retail marketing were a loss of $16 million in 1993 due to the above noted $16 million charge, and a loss of $11 million in 1992. Retail gross profit improved by $7 million due to an increase in sales volumes of 2% and a significant increase in margins. Sunoco divested 14 less profitable sites in 1993, with a view to improving its retail marketing competitiveness in its core urban markets of Ontario and Quebec.

Sunoco's expenses fell by $9 million in 1993 versus 1992 due to reduced refining costs and bad-debt provisions.

The net cash surplus increased marginally in 1993 to $41 million, up $1 million from 1992. While higher earnings improved cash flow from operations, $6 million in expenditures associated with the planned maintenance shutdown work partially reduced this benefit. Combined working capital and restructuring-related cash flow impacts resulted in an overall improvement of $8 million. Partially offsetting these favourable items was an increase in inventory levels and lower trade payables.

Cash used in investing activities increased in the year by $10 million, related to the Pioneer joint venture.

OUTLOOK

Management believes that Sunoco will continue to play an important role in Suncor's overall operations by generating cash flow to fuel the company's growth strategies.

In 1993, Sunoco began implementing a non-capital-intensive strategy to position it as a low-cost competitor and improve its earnings and cash flow even in the absence of any improvements in market product demand or margins. The strategy also allows Sunoco to benefit from any demand and margin improvements. The strategy is aimed at positioning the refinery in the top 25% of all North American refineries, its retail marketing business as one of the most competitive in its markets and improving administrative processes. The strategy focuses on increasing cash flow and earnings by lowering costs, increasing the volume of refinery production that is marketed through low-cost distribution channels and maximizing synergies with the oil sands plant. Management continues to review other recommendations for increasing profitability.

Suncor estimates that this strategy will improve earnings in total by $20 million per year and cash flow by $30 million per year by the end of 1996. Substantial progress has already been achieved in implementing the strategy, and to date it has resulted in an increase of about $9 million in earnings and about $15 million in cash flow.

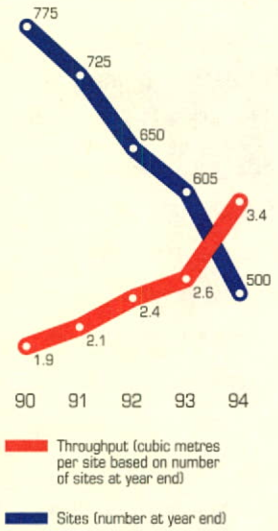
Refining

External benchmarking indicates that Sunoco is in the top 25% of refineries in Canada. In 1994, Sunoco took action to move toward the top 25% of refiners in North America. It reduced its operating costs by negotiating lower energy charges from Ontario Hydro and reducing its workforce by 10%. Work is also underway to capture feedstock cost reduction opportunities with Sun Company's Toledo, Ohio, refinery.

RETAIL MARKETING

Sunoco believes that in order to be profitable in its Ontario and Quebec markets it must have secure, low-cost retail marketing channels. Through its strategy to establish three of these channels, Sunoco increased the amount of the Sarnia refinery's gasoline production that it sells through secure channels from 66% in 1992 to 79% in 1994.

Retail Network Efficiency
(millions of litres/site)



INCREASED THROUGHPUT PER SITE 30% ON STRENGTH OF 18% DECREASE IN SIZE OF NETWORK AND 8% INCREASE IN RETAIL GASOLINE SALES.

In addition, in 1994 Sunoco progressed in repositioning its branded network into high-volume stations in core urban areas by closing or divesting of 105 less profitable sites, or 18% of its network, ahead of schedule. As a result, operating costs have been reduced and volumes at remaining stations have increased by 8% and throughput per site has increased 30%.

Administration

In working toward reducing administrative costs, Sunoco continued to eliminate unnecessary work and implement re-engineering processes introduced in 1993. The majority of the benefits from new systems and sustained efforts to reduce overhead are expected to be fully realized by the end of 1996.

Issues/Risks

As a regional refiner and retail marketer, Sunoco's financial performance is strongly influenced by petroleum product supply and demand fundamentals in its primary markets of Ontario and Quebec. These markets continue to experience low retail margins, despite the economic recovery underway and a reduced number of service stations through industry rationalization. These current low margins are not sufficient to generate acceptable returns and as a result industry restructuring continues.

Approximately 30% of gasolines produced in the U.S. have recently been reformulated to lower emissions through mandated oxygenates, benzene levels and vapour pressure. Sunoco believes that some action to reformulate gasolines in its markets may be necessary and it is developing a comprehensive plan to ensure the Sarnia refinery is well positioned to address new fuels formulation.

In order to ensure access to competitively-priced offshore crude oil, a number of Ontario refiners want the Interprovincial Pipeline from Sarnia to Montreal ("Line 9"), which was formerly used to deliver Western Canadian crude to Montreal but closed in 1991, reopened and reversed.

Timing of the probable reversal of Line 9 is contentious. Suncor has advocated "timely" reversal driven by the supply/demand balance of Western Canadian crudes. The company believes that timely reversal will minimize any negative price impact on upstream producers, by ensuring that supply and demand remain in balance.

CORPORATE AND CONSOLIDATION ADJUSTMENTS

Results of Operations

1994 vs 1993

Corporate expenses increased in 1994 to $21 million, $3 million higher than 1993. Favourable consolidation adjustments, including a tax rate adjustment, were more than offset by higher interest and operating expenses. While interest charges increased due to the higher interest rate on the debentures issued in 1994 compared to borrowing costs in 1993, lower average borrowing levels partially offset the higher rate. Increased administrative expenses reflect higher general costs and lower legal costs in 1993.

Funds used in operating activities decreased by $20 million over the 1993 level of $51 million. The decline was primarily due to a decrease in working capital as a result of higher year-end income tax liabilities.

The higher level of earnings in 1994, and anticipated higher earnings levels in future years, are expected to lead to increased cash tax payments. In 1995, the payment of the balance of 1994 income taxes and installments for 1995 are expected to be approximately $45 million higher than in 1994.

On the consolidated balance sheet, current assets increased to $417 million, or $62 million higher than in 1993. The increase reflects an increase in short-term cash investments and higher trade receivables ($16 million) resulting from higher prices and higher sales volumes, and a $10 million increase in inventory reflecting higher inventory levels and costs. It is expected that the inventory increase will be largely reversed next year.

Year-end current liabilities increased $80 million due to a number of factors. Higher tax liabilities due to the higher earnings and increased taxable sales volumes increased tax liabilities by $44 million. The balance of the increase reflects higher capital accruals primarily related to the sulphur dioxide emissions reduction project and crude payables due to the higher crude prices at the end of 1994 compared to 1993. Over the next two years Suncor's operating income is not expected to generate sufficient funds to finance the expansion of its upstream operations and, accordingly, Suncor expects that it will incur additional debt to finance its upstream operations (see Liquidity and Capital Resources).

1993 vs 1992

Corporate expenses declined by $3 million to $18 million in 1993 due to lower administrative expenses resulting from the settlement of a large legal claim and favourable consolidation adjustments.

Funds used in operating activities were higher by $11 million over the 1992 level of $40 million, mainly due to higher income tax payments of $13 million and higher interest payments, partially offset by lower expenses.

Analysis of Consolidated Statements of Income

1994 vs 1993

Sales and other operating income increased $89 million to $1,635 million. The majority of the increase (64%) was attributable to record upstream and downstream volume levels. Higher natural gas prices, including the positive impact of hedging, were partially offset by lower crude oil prices in part due to lower hedging revenue compared to 1993. The other significant component (31%) in the revenue increase was higher taxable diesel sales which increased excise taxes.

Purchases of crude oil and products were $54 million lower than in 1993. The favourable impact of higher production from the oil sands operations was partially offset by increased costs as a result of higher refined product volumes sold in 1994.

Cost and operating expenses increased $25 million over 1993 levels reflecting increased reliability and maintenance spending at the oil sands operations, higher natural gas consumption and prices due to volume increases, the write-off of some refinery assets and provisions for the closure of the Ottawa terminal in 1995. These factors were partially offset by the reduction of power costs achieved through an agreement with Ontario Hydro.

A 10% increase in the number of net wells drilled was reflected in a similar increase in exploration expenses in 1994.

Selling, administrative and general expenses increased 4% as a result of increased expenses in each of Oil Sands, Resources and Corporate groups. These factors were only partially offset by benefits achieved in the Sunoco downstream operations from their strategic initiatives to lower overhead costs through such efforts as service station closures and employee terminations.

The royalty increase is primarily a reflection of the higher upstream volumes.

Taxes other than income taxes increased by $26 million due to an increase in both volumes sold and a greater proportion of taxable sales versus exempt sales.

Depreciation, depletion and amortization increased, again reflecting higher upstream production volumes, increased exploration activity and a full year's depreciation on the new truck and shovel fleet at the oil sands operation.

1993 vs 1992

Sales and other operating revenues declined by 1% to $1,546 million. The decline primarily reflects a 2% net decline in refined product sales volumes, partially offset by higher upstream crude oil volumes sold under a long-term contract. Lower crude pricing was also a factor in reducing revenue, although this was partially offset by a 7% depreciation of the Canadian dollar versus the U.S. dollar and crude oil hedging. Growing North American demand for natural gas resulted in a 37% price increase in 1993 as prices climbed to $1.67 per thousand cubic feet. This positive factor was partially offset by an accounting brokerage loss caused by meeting fixed price sales contracts with floating spot price purchase contracts and Canadian/U.S. price differentials.

The decline in purchases of crude oil and products in 1993 reflects both lower crude oil and feedstock costs as well as the lower volume of refined products sold.

Cost and operating expense reductions in 1993 primarily reflect lower expenses in the oil sands operations. Contributing factors included lower maintenance and operating expenditures, a reduction of employees and contractors during part of 1993 as new bitumen production technology was phased in, reduced expenses due to an insurance claim associated with the partial plant freeze-up at the end of 1992 and a higher natural gas consolidation elimination due to the increased natural gas prices.

The decline in selling, administrative and general expenses in 1993 was due to lower bad debts, reduced corporate legal expenses and reduced commodity tax assessments. These favourable factors were partially offset by higher advertising expenses in the downstream marketing business.

Royalty expenses decreased in 1993 due to lower crude oil prices and the benefit from the Crown royalty credit associated with approved environmental spending. These factors were partially offset by the impact of higher natural gas royalties resulting from higher natural gas prices.

Taxes other than income taxes increased 10% in 1993 primarily due to increases in taxable diesel fuel sales volumes.

Lower depreciation, depletion and amortization expenses reflected lower depreciation at the oil sands plant. An engineering study revised the amortization period for depreciating certain capital assets over the estimated life of the assets (rather than on the life of proved reserves). Lower maintenance shutdown costs were incurred through lower spending and shifting work from 1993 to 1994. The disposal of certain high-cost properties by Resources Group also reduced non-cash charges in 1993.

COMPANY OUTLOOK

The two principal components, or sensitivities, to Suncor's earnings and cash flow are the production level and price of crude oil. With increasing levels and reliability of crude oil production, Suncor is able to sell all of its production to third parties or use it in its downstream operations. It is the price component, however, that creates uncertainty.

Consequently, Suncor's future financial performance remains heavily dependent on crude oil prices, which are expected to continue to show a high degree of volatility and uncertainty. Because the price in Canada is based on a U.S. dollar benchmark, the U.S./Canadian exchange rate also influences prices received by Suncor. In 1994 the Canadian dollar again depreciated, 5% in 1994 compared to 7% in 1993, partially offsetting the effect of a lower benchmark crude oil price.

Because Suncor lacks control over crude oil and natural gas prices and the U.S./Canadian exchange rate, Suncor's commodity price and foreign exchange risk management program provides for fixing a certain level of foreign exchange and /or oil and natural gas prices while still leaving part of such revenue streams floating. Suncor employs hedging techniques, when considered appropriate, to protect earnings and cash flows. Suncor's hedging program is approved by the board of directors to extend for up to three calendar years in the future, with decreasing volumes/dollars hedged further into the future. For example, management may fix up to a maximum of 50% of the following year's crude oil production.

In 1994, the forward sale of approximately 5 million barrels of crude oil into Canadian dollars combined with foreign exchange hedging increased Suncor's earnings by approximately $4 million (1993 – $15 million). Hedging of natural gas volumes increased earnings by $4 million (1993 – $0).

Suncor is continuously monitoring commodity prices and the U.S./Canadian dollar exchange rate for appropriate hedging opportunities. At December 31, 1994, as noted in Note 17 to the consolidated financial statements, Suncor has hedged an estimated 40% of 1995 crude oil production, or 35,000 barrels per day, at a price of approximately $24 per barrel in Edmonton and effectively converted U.S.$60 million of its 1995 revenue stream into Canadian dollars at an exchange rate of U.S.$0.73. There is a minimal amount of natural gas hedging in place at this time.

Other critical factors affecting Suncor's current and future financial results are the volume of refined product sales, margins on the sale of refined products, natural gas prices, the success of exploration programs and the ability to reduce costs.

In 1994, oil sands production continued to represent 85% of Suncor's crude oil production.

The table on page 28 shows the main factors affecting Suncor's annual pre-tax cash provided from operating activities and after-tax earnings, based on actual levels of operation in 1994. The change does not take into consideration the impact such change would have on the crude oil or foreign exchange hedging programs in place in 1994, which could be significant. A change in one factor may compound or offset other factors. Because the table does not consider these interrelationships, it cannot necessarily be used to predict accurate results.

	1994 Average	Change	Approximate change in: Pre-tax cash from operating activities	Approximate change in: After-tax earnings
			($ millions)	
OIL SANDS				
Price of crude oil ($/barrel)	**22.31**	U.S.1.00	21	13
Production (barrels per day)	**70,700**	1,000	5	3
RESOURCES				
Price of crude oil ($/barrel)	**20.17**	U.S.1.00	5	3
Price of natural gas ($/thousand cubic feet)	**1.85**	0.10	5	3
Production of natural gas (millions of cubic feet per day)	**155**	10	4	2
SUNOCO				
Retail gasoline margin (cents/litre)	**5.8**	0.1	2	1
Refining/wholesale margin (cents/litre)	**5.5**	0.1	5	3
CONSOLIDATED				
Canadian $: U.S.$ exchange rate	**0.73**	0.01	5	3

Liquidity and Capital Resources

Cash flow provided from operating activities has increased in each of the last three years, $379 million in 1994 compared to $237 million in 1993 and $210 million in 1992.

Long-term borrowings at the end of 1994 were $190 million compared to $191 million at the end of 1993 and $171 million at the end of 1992. The ratio of long-term borrowing to capital employed was 10.7% at the end of 1994, compared to 11.3% at the end of 1993 and 10.6% at the end of 1992.

Anticipated capital expenditures, including approximately $150 million for sulphur dioxide reduction at the oil sands plant over the next two years, are expected to raise debt levels to the $325 to $350 million range in 1995 and to the $375 to $400 million range for the following two years before declining. Debt to capital employed is not expected to exceed 20% during this period. The outlook assumes that crude oil prices remain under WTI U.S.$20 per barrel with an exchange rate of U.S.$0.74.

In February 1994, Suncor issued $125 million, 10 year, 7.4% debentures. The proceeds from this issue were used to retire floating rate borrowings. By locking in the interest rate on this component of its debt, management has fixed the future interest costs on a portion of its debt that was at floating interest rates.

Through a variety of means, such as the above-noted debenture offering, cost reductions, production and reliability increases at the oil sands plant and forward selling of a portion of its future revenue, Suncor has increased the predictability of its cash flow and earnings levels.

With an expected decline in debt towards the end of the decade, Suncor has commenced a review of other business growth opportunities related to its current operations and expertise developed with these businesses.

Details of capital and exploration spending for 1993 and 1994, and anticipated spending for 1995, are as follows:

($ millions)	1995 GOAL	**1994 ACTUAL**	1993 ACTUAL
OIL SANDS GROUP			
Sustaining capital	37	**25**	29
Environmental	112	**48**	6
Strategic			
Truck and shovel conversion	–	**5**	72
Production improvements	45	**17**	9
New mine	7	**8**	–
	201	**103**	116
RESOURCES GROUP			
Exploration	50	**66**	44
Acquisition	15	**13**	7
Development	95	**86**	47
Environmental	3	**3**	2
Other	4	**1**	–
	167	**169**	100
SUNOCO GROUP			
Refining	9	**13**	15
Retail marketing	4	**8**	9
Environmental	14	**3**	6
Other	23	**7**	–
	50	**31**	30
TOTAL	418	**303**	246

The actual levels of spending in 1995 will depend on several factors including the levels of cash flow for the year.

Current levels of working capital and lines of credit are expected to be adequate to support Suncor's operations and opportunities in 1995. Funds are available under the $400 million revolving term credit facility described in Note 12 in the consolidated financial statements.

Suncor obtains most of its insurance coverage directly from insurers. The first U.S.$200 million of property coverage, and part of its excess liability coverage, is arranged by Sun Company, Inc. for itself and its subsidiaries, and Suncor bears a proportional share of the costs.

During the third quarter of 1994, Suncor increased its quarterly dividend of $0.26 to $0.27 per share. This policy is reviewed quarterly in light of Suncor's financial position, financing requirements, cash flow and other factors considered relevant by the board of directors.

ENVIRONMENTAL REGULATIONS

Environmental legislation affects nearly all aspects of Suncor's operations. These regulatory regimes are laws of general application that apply to Suncor in the same manner as they apply to other companies and enterprises in the energy resource industry. They require Suncor to obtain operating licenses and impose certain standards and controls on activities relating to oil and gas exploration, development, production and marketing, and the refining and distribution of petroleum products and petrochemicals. Environmental assessments will be required before initiating some new projects or undertaking significant changes to existing projects.

In addition to these specific, known requirements, we expect further changes will likely be required to preserve and protect the environment and quality of life. Some of the issues under discussion include global climate change and the need to stabilize CO_2 emissions, land reclamation and restoration, Great Lakes water quality, and gasoline reformulation to lower toxic emissions. It is expected that any changes in regulation could have an effect on product demand and quality, methods of production and distribution, as well as on the nature of products themselves. For example, cleaner-burning fuels may be required, with additional costs which may or may not be recoverable in the marketplace.

The complexity and breadth of these issues make it extremely difficult to predict their resolution. Some organizations will be better prepared to deal with the potential changes in demand for their products and services, and will be able to recover additional expenditures. Suncor expects to make increased expenditures of both a capital and expense nature as a result of the implementation of new and increasingly stringent regulations pertaining to the protection and restoration of the environment. See the Outlook section of the Oil Sands Group for further specific comments, and the 1994 consolidated financial statements.

Management's Statement on Financial Reporting

The financial statements on pages 31 to 47 which consolidate the financial results of Suncor Inc. and its subsidiaries, and all information in this annual report, are the responsibility of management. The financial statements and Management's Discussion and Analysis have been approved by the Board of Directors.

The financial statements have been prepared in accordance with generally accepted accounting principles in Canada. They include some amounts which are based on best estimates and judgments relating to matters not concluded by year-end. Financial information presented elsewhere in this annual report is consistent with that in the financial statements.

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 integrity of the financial statements, management maintains a system of internal controls and an internal audit program. Management also administers a program of proper business conduct compliance.

Coopers & Lybrand, the company's independent auditors, have audited the accompanying financial statements. Their report is presented below.

The Audit Committee of the Board of Directors, composed primarily of independent directors, meets regularly with management, the internal auditors and Coopers & Lybrand to review their activities and to discuss auditing, internal control, accounting policy and financial reporting matters. The Audit Committee also meets quarterly to review interim financial statements prior to their release. The internal auditors and Coopers & Lybrand have unrestricted access to the company, the Audit Committee and the Board of Directors. The Audit Committee has reviewed the financial statements and Management's Discussion and Analysis and recommended their approval to the Board of Directors.

Richard L. George
PRESIDENT AND CHIEF EXECUTIVE OFFICER
JANUARY 26, 1995

Timothy R. Hughes
SENIOR VICE PRESIDENT, FINANCE

Auditors' Report

To the Shareholders of Suncor Inc.

We have audited the consolidated balance sheets of Suncor Inc. as at December 31, 1994, 1993 and 1992 and the consolidated statements of earnings, retained earnings and cash flows for each of the years then ended. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in Canada. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the company as at December 31, 1994, 1993 and 1992 and the results of its operations and its cash flows for each of the years then ended in accordance with accounting principles generally accepted in Canada.

Coopers & Lybrand
CHARTERED ACCOUNTANTS
TORONTO, ONTARIO
JANUARY 20, 1995

Suncor Inc. is an integrated oil and gas company, whose three operating segments are Oil Sands Group, Resources Group and Sunoco Group.

Oil Sands Group includes the production and marketing of light sweet crude oil and various custom blends from oil sands mined in the Athabasca region of northeastern Alberta.

Resources Group includes the exploration, acquisition, development, production, marketing and transportation of crude oil and natural gas in Canada and the marketing of natural gas throughout North America.

Sunoco Group includes 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.

The significant accounting policies of the company are summarized below:

(A) PRINCIPLES OF CONSOLIDATION

These consolidated financial statements, which are prepared in Canadian dollars, include the accounts of Suncor Inc. and its subsidiaries and the company's proportionate share of the assets, liabilities, revenues and expenses of its oil and gas joint ventures. Other joint ventures are accounted for using the equity method.

(B) CASH EQUIVALENTS AND INVESTMENTS

The company considers all highly liquid investments with a remaining maturity of three months or less at the time of purchase to be cash equivalents. These cash equivalents consist primarily of time deposits and certificates of deposit. Investments with maturities from greater than three months to one year are classified as short-term investments, while those with maturities in excess of one year are classified as long-term investments. Cash equivalents and short-term investments are stated at cost which approximates market value.

(C) REVENUES

The company deems its own production of crude oil, excluding synthetic crude oil sales under long-term agreements, to be used first for internal refinery consumption. Therefore, on consolidation, revenues from sales of crude oil deemed to be for internal consumption are eliminated from sales and other operating revenues and purchases of crude oil and products.

The company also uses a portion of its natural gas production for internal consumption at its oil sands plant and refinery. On consolidation, revenues from these sales are eliminated from sales and other operating revenues and operating expenses.

(D) CAPITAL ASSETS

Capital assets are recorded at cost.

The company follows the successful efforts method of accounting for its crude oil and natural gas operations. Under this method, acquisition costs of proved and unproved properties are capitalized. Costs of unproved properties are transferred to proved properties when proved reserves are confirmed. Exploration costs, including geological and geophysical costs, are expensed as incurred. Exploratory drilling costs are capitalized initially. If it is determined that the well does not contain proved reserves, the capitalized exploratory drilling costs are charged to expense, as dry hole costs, at that time. The related land costs are expensed through the amortization of unproved properties as covered under the Resources section of the following policy. Development costs, which include the costs of wellhead equipment, gas plants and handling facilities, and the costs of acquiring or constructing support facilities and equipment are capitalized. Costs incurred to operate and maintain wells and equipment and to lift oil and gas to the surface are expensed.

(E) DEPRECIATION, DEPLETION AND AMORTIZATION

OIL SANDS

Capital assets are depreciated over their useful lives, except for lease acquisition costs and certain mine assets, which are depreciated over the life of proved reserves. Depreciation over useful lives is on a straight line basis. Depreciation over the life of proved reserves is on a unit of production basis.

The company is depreciating capital assets as follows:

(i) mobile equipment over three to 10 years;

(ii) remaining mine equipment and acquisition costs of operating leases over approximately 205 million barrels of proved reserves;

(iii) other capital assets primarily over 10 to 30 years.

RESOURCES

Unproved properties whose acquisition costs are individually significant are evaluated for impairment by management. Impairment of unproved properties whose acquisition costs are not individually significant is provided for through amortization of the portion not expected to become producing, based on historical experience, over the average projected holding period.

Acquisition costs of proved properties are depleted using the unit of production method based on proved reserves. Capitalized exploratory drilling costs and development costs are depleted on the basis of proved developed reserves. For purposes of the depletion calculation, production and reserves volumes for oil and natural gas are converted to a common unit of measure on the basis of their approximate relative energy content. Support facilities and equipment are depreciated on a straight line basis over their useful lives, which average eight years.

SUNOCO

Depreciation of capital assets is on a straight line basis over their useful lives. The refinery and additions thereto are depreciated over an average of 32 years, service stations and related equipment over an average of 20 years and other facilities and equipment over four to 25 years.

(F) DISPOSALS

Gains or losses on disposals of capital assets are generally recognized in earnings. For oil and gas capital assets accounted for under the successful efforts method, gains or losses are recognized in earnings for significant disposals or disposal of an entire property; however, the acquisition cost of an unproved property surrendered or abandoned which is not individually significant or a partial abandonment of a proved property is charged to accumulated depreciation, depletion or amortization, as appropriate.

(G) DEFERRED CHARGES

Overburden removal costs incurred to expose oil sands for mining, including depreciation on overburden removal equipment, are deferred. These costs are amortized 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 removal cost, determined on a last-in, first-out (LIFO) basis, per unit of overburden.

The cost of major maintenance shutdowns is deferred and amortized on a straight line basis over the period to the next shutdown. Normal maintenance and repair costs are charged to expense as incurred.

(H) FOREIGN CURRENCY TRANSLATION

Long-term monetary liabilities are translated to Canadian dollars at rates of exchange in effect at the end of the period. Unrealized exchange gains and losses arising on translation are deferred and amortized over the remaining terms of the liabilities.

(I) RECLAMATION AND ENVIRONMENTAL REMEDIATION COSTS

Reclamation and environmental remediation costs for identified sites are estimated and charged against earnings when there exists a regulatory or statutory requirement or contractual agreement, or when management has made a decision to decommission or restore a site, providing that assessments indicate that such costs are probable and reasonably estimable.

Estimated reclamation costs in the company's upstream operations are accrued on the unit of production basis. Estimated environmental remediation costs, which are predominantly in the company's downstream operation, are accrued for work at sites based on assessments which indicate that such work is required.

Costs are accrued based upon currently known facts, estimated timing of remedial actions, and existing requirements and technology. Changes in these factors may be significant and will be recognized prospectively when known.

(J) DEFERRED REVENUES

Payments received pursuant to natural gas take or pay contracts without delivery of the related gas are deferred. These amounts will be recorded as revenues when the related gas is delivered.

(K) PENSION EXPENSE

The company has non-contributory defined benefit pension plans and a defined contribution pension plan providing retirement benefits for its eligible employees. Pension expense related to the defined benefit plans includes the current service costs, interest costs and the amortization of adjustments arising from plan amendments, changes in assumptions and experience gains and losses over the expected average remaining service life of the employees. This expense reflects management's best estimates of the pension plans' expected investment yield, salary escalation, mortality of members, terminations and the ages at which members will retire. Company contributions to the defined contribution plan are expensed as incurred.

(L) OTHER POST-RETIREMENT BENEFITS

The company provides certain health care and life insurance benefits for its retired employees and eligible surviving dependents. Costs of these benefits are charged to earnings as payments are made by the company on behalf of retirees and dependents.

(M) INCOME TAXES

By law, some costs and revenues may be deducted from or added to earnings in the calculation of taxable income in years earlier or later than the year that they are actually recorded in the Consolidated Statements of Earnings. The income taxes in the Consolidated Statements of Earnings 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 Balance Sheets as "deferred income taxes".

(N) INVENTORIES

Inventories of crude oil and refined products are valued at the lower of cost using the last-in, first-out (LIFO) method and net realizable value.

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

(O) DERIVATIVE FINANCIAL INSTRUMENTS

The company periodically enters into derivative financial instrument contracts such as forwards, futures and swaps to hedge against the potential adverse impact of low market prices for its petroleum and natural gas products and to protect its Canadian dollar income against adverse U.S./Canadian dollar exchange movements. Gains or losses on hedge contracts are recognized in earnings over the period when the hedged items are recognized in earnings.

Gains or losses resulting from changes in the market value of derivative contracts not accounted for as hedges are recognized in earnings when those changes occur.

(P) INTEREST CAPITALIZATION

Interest costs relating to the construction and pre-operating stages of major development projects and to the portion of non-producing oil and gas properties expected to become producing are capitalized as part of the cost of such capital assets.

Consolidated Statements of Earnings

for the years ended December 31 ($ millions except per share amounts)	**1994**	1993	1992
REVENUES			
Sales and other operating revenues (notes 4 and 7)	**1 635**	1 546	1 559
Interest	**2**	3	3
	1 637	1 549	1 562
EXPENSES			
Purchases of crude oil and products	**261**	315	354
Operating	**373**	348	404
Exploration (note 5)	**24**	22	17
Selling, administrative and general	**242**	233	245
Royalties (note 3)	**68**	57	67
Taxes other than income taxes (note 4)	**288**	262	239
Depreciation, depletion and amortization	**179**	174	190
Interest (note 5)	**16**	15	15
Asset restructuring (note 2)	**–**	8	360
	1 451	1 434	1 891
EARNINGS (LOSS) BEFORE INCOME TAXES	**186**	115	(329)
PROVISION FOR (RECOVERY OF) INCOME TAXES (notes 2 and 6)			
Current	**38**	12	21
Deferred	**27**	28	(122)
	65	40	(101)
NET EARNINGS (LOSS)	**121**	75	(228)
PER COMMON SHARE			
– net earnings (loss)	**2.22**	1.38	(4.19)
– cash dividends	**1.06**	1.04	1.04

See accompanying summary of accounting policies and notes.

Consolidated Statements of Retained Earnings

for the years ended December 31 ($ millions)	**1994**	1993	1992
BALANCE – beginning of year	**470**	452	737
Net earnings (loss) for the year	**121**	75	(228)
	591	527	509
Dividends	**58**	57	57
BALANCE – end of year	**533**	470	452

See accompanying summary of accounting policies and notes.

as at December 31 ($ millions)	**1994**	1993	1992
ASSETS			
CURRENT ASSETS			
Cash and cash equivalents	**36**	–	–
Accounts receivable (notes 5 and 7)	**217**	201	255
Inventories (note 8)	**164**	154	144
Total current assets	**417**	355	399
Capital assets, net (notes 2 and 9)	**1 560**	1 412	1 342
Deferred charges and other (note 10)	**224**	256	232
Total assets	**2 201**	2 023	1 973
LIABILITIES AND SHAREHOLDERS' EQUITY			
CURRENT LIABILITIES			
Short-term borrowings	**31**	25	17
Accounts payable (note 7)	**152**	137	145
Accrued liabilities	**118**	103	99
Income taxes	**43**	19	27
Taxes other than income taxes	**71**	51	53
Current portion of long-term borrowings (note 11)	**5**	5	9
Total current liabilities	**420**	340	350
Long-term borrowings (notes 11 and 12)	**190**	191	171
Accrued liabilities and other (note 13)	**212**	208	212
Deferred income taxes	**344**	314	288
Commitments and contingencies (note 14)			
SHAREHOLDERS' EQUITY			
Share capital (note 15)	**502**	500	500
Retained earnings	**533**	470	452
Total shareholders' equity	**1 035**	970	952
Total liabilities and shareholders' equity	**2 201**	2 023	1 973

See accompanying summary of accounting policies and notes.

Approved on behalf of the Board:

Richard L George

R. L. George, DIRECTOR

B P Davies

B. P. Davies, DIRECTOR

Consolidated Statements of Cash Flows

for the years ended December 31 ($ millions)	**1994**	1993	1992
OPERATING ACTIVITIES			
Cash flow provided from operations*	**331**	225	193
Asset restructuring	**–**	(19)	(22)
Legal claim settlement	**–**	18	–
Decrease (increase) in operating working capital			
Accounts receivable	**(16)**	28	(15)
Inventories	**(10)**	(10)	18
Accounts payable and accrued liabilities	**30**	1	29
Taxes payable	**44**	(6)	7
CASH PROVIDED FROM OPERATING ACTIVITIES	**379**	237	210
CASH USED IN INVESTING ACTIVITIES*	**(292)**	(204)	(195)
NET CASH SURPLUS BEFORE FINANCING ACTIVITIES	**87**	33	15
FINANCING ACTIVITIES			
Increase in short-term borrowings	**6**	8	6
Issuance of 7.4% Debentures, Series C	**125**	–	–
Repayment of 12% Debentures, Series A	**(5)**	(5)	(3)
Repayment of prime minus 1/2% Note	**–**	(4)	(4)
Increase (decrease) in long-term borrowings under or with support of revolving term credit facility	**(121)**	30	46
Decrease in other long-term borrowings	**–**	(5)	–
Redemption of preferred shares (note 15)	**–**	–	(5)
Issuance of common shares (note 15)	**2**	–	–
Dividends paid	**(58)**	(57)	(57)
CASH USED IN FINANCING ACTIVITIES	**(51)**	(33)	(17)
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	**36**	–	(2)
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	**–**	–	2
CASH AND CASH EQUIVALENTS AT END OF YEAR	**36**	–	–

* See Schedules of Segmented Data on page 37.

See accompanying summary of accounting policies and notes.

($ millions)	Oil Sands Group 1994	1993	1992	Resources Group 1994	1993	1992	Sunoco Group 1994	1993	1992	Corporate and Eliminations 1994	1993	1992	Total 1994	1993	1992
EARNINGS															
for the years ended Dec 31															
REVENUES															
Sales and other operating revenues	**147**	132	134	**104**	91	83	**1 384**	1 323	1 342	**–**	–	–	**1 635**	1 546	1 559
Intersegment revenues**	**424**	355	357	**91**	89	84	**–**	–	–	**(515)**	(444)	(441)	**–**	–	–
Interest	**–**	–	–	**–**	–	–	**–**	–	–	**2**	3	3	**2**	3	3
	571	487	491	**195**	180	167	**1 384**	1 323	1 342	**(513)**	(441)	(438)	**1 637**	1 549	1 562
EXPENSES															
Purchases of crude oil and products	**–**	–	–	**–**	–	–	**761**	736	784	**(500)**	(421)	(430)	**261**	315	354
Operating	**242**	224	271	**37**	37	36	**111**	106	108	**(17)**	(19)	(11)	**373**	348	404
Exploration	**–**	–	–	**24**	22	17	**–**	–	–	**–**	–	–	**24**	22	17
Selling, administrative and general	**61**	52	51	**18**	17	14	**141**	146	160	**22**	18	20	**242**	233	245
Royalties	**40**	31	41	**28**	26	26	**–**	–	–	**–**	–	–	**68**	57	67
Taxes other than income taxes	**6**	6	6	**3**	3	2	**279**	253	231	**–**	–	–	**288**	262	239
Depreciation, depletion and amortization	**87**	84	96	**50**	46	51	**42**	44	43	**–**	–	–	**179**	174	190
Interest	**–**	–	–	**–**	–	–	**–**	–	–	**16**	15	15	**16**	15	15
Asset restructuring	**–**	–	129	**–**	(18)	231	**–**	26	–	**–**	–	–	**–**	8	360
	436	397	594	**160**	133	377	**1 334**	1 311	1 326	**(479)**	(407)	(406)	**1 451**	1 434	1 891
EARNINGS (LOSS) BEFORE INCOME TAXES	**135**	90	(103)	**35**	47	(210)	**50**	12	16	**(34)**	(34)	(32)	**186**	115	(329)
Income taxes	**(45)**	(31)	29	**(14)**	(19)	69	**(19)**	(6)	(7)	**13**	16	10	**(65)**	(40)	101
NET EARNINGS (LOSS)	**90**	59	(74)	**21**	28	(141)	**31**	6	9	**(21)**	(18)	(22)	**121**	75	(228)
As at Dec 31															
TOTAL ASSETS	**857**	779	721	**496**	402	386	**867**	860	879	**(19)**	(18)	(13)	**2 201**	2 023	1 973
CAPITAL EMPLOYED	**703**	690	615	**437**	336	343	**594**	642	655	**47**	15	10	**1 781**	1 683	1 623

($ millions)	Oil Sands Group **1994**	1993	1992	Resources Group **1994**	1993	1992	Sunoco Group **1994**	1993	1992	Corporate and Eliminations **1994**	1993	1992	Total **1994**	1993	1992
CASH FLOW BEFORE FINANCING ACTIVITIES															
for the years ended Dec 31															
CASH PROVIDED FROM (USED IN) OPERATING ACTIVITIES:															
Cash flow provided from (used in) operations															
Net earnings (loss)	**90**	59	(74)	**21**	28	(141)	**31**	6	9	**(21)**	(18)	(22)	**121**	75	(228)
Exploration expenses															
Cash	**–**	–	–	**13**	10	11	**–**	–	–	**–**	–	–	**13**	10	11
Dry hole costs	**–**	–	–	**11**	12	6	**–**	–	–	**–**	–	–	**11**	12	6
Non-cash items included in earnings															
Depreciation, depletion and amortization	**87**	84	96	**50**	46	51	**42**	44	43	**–**	–	–	**179**	174	190
Deferred income taxes	**(2)**	29	(50)	**14**	13	(72)	**(7)**	(7)	(11)	**22**	(7)	27	**27**	28	(106)
Current income tax allocation	**47**	2	21	**–**	6	4	**26**	13	18	**(73)**	(21)	(43)	**–**	–	–
Asset restructuring	**–**	–	129	**–**	(18)	231	**–**	26	–	**–**	–	–	**–**	8	360
Other	**(2)**	(3)	–	**(1)**	–	(5)	**1**	(3)	3	**2**	1	2	**–**	(5)	–
Overburden removal outlays	**(10)**	(26)	(31)	**–**	–	–	**–**	–	–	**–**	–	–	**(10)**	(26)	(31)
Increase (decrease) in deferred credits	**5**	3	–	**–**	(7)	(10)	**–**	–	4	**2**	–	–	**7**	(4)	(6)
Deferred maintenance shutdown expenditures	**(13)**	(36)	(7)	**–**	–	–	**(3)**	(6)	–	**–**	–	–	**(16)**	(42)	(7)
Other	**(5)**	–	(2)	**–**	3	–	**3**	(6)	3	**1**	(2)	3	**(1)**	(5)	4
Total cash flow provided from (used in) operations	**197**	112	82	**108**	93	75	**93**	67	69	**(67)**	(47)	(33)	**331**	225	193
Asset restructuring	**–**	(10)	(22)	**–**	–	–	**–**	(9)	–	**–**	–	–	**–**	(19)	(22)
Legal claim settlement	**–**	18	–	**–**	–	–	**–**	–	–	**–**	–	–	**–**	18	–
Decrease (increase) in operating working capital	**(2)**	(8)	43	**(12)**	5	5	**26**	20	(2)	**36**	(4)	(7)	**48**	13	39
Total cash provided from (used in) operating activities	**195**	112	103	**96**	98	80	**119**	78	67	**(31)**	(51)	(40)	**379**	237	210
CASH USED IN INVESTING ACTIVITIES:															
Capital and exploration expenditures	**(103)**	(116)	(65)	**(169)**	(100)	(120)	**(31)**	(30)	(29)	**–**	–	–	**(303)**	(246)	(214)
Proceeds from disposals															
Asset restructuring	**–**	–	–	**–**	39	–	**–**	–	–	**–**	–	–	**–**	39	–
Other	**3**	5	4	**5**	5	13	**1**	4	3	**–**	–	–	**9**	14	20
Joint venture investments/advances	**–**	–	–	**–**	–	–	**2**	(11)	(1)	**–**	–	–	**2**	(11)	(1)
Total cash used in investing activities	**(100)**	(111)	(61)	**(164)**	(56)	(107)	**(28)**	(37)	(27)	**–**	–	–	**(292)**	(204)	(195)
NET CASH SURPLUS (DEFICIENCY) BEFORE FINANCING ACTIVITIES	**95**	1	42	**(68)**	42	(27)	**91**	41	40	**(31)**	(51)	(40)	**87**	33	15

* The company has no foreign geographic segments. See note 5 for information on export sales.

** Intersegment revenues are recorded at prevailing fair market prices.

See accompanying summary of accounting policies and notes.

1. LEGAL CLAIM SETTLEMENT

During 1993, a settlement was reached on all actions initiated by the company in 1989 against defendants for damages caused by the October, 1987 fire at its Oil Sands operation. Accordingly, the financial impact was reflected retroactively in 1987 earnings, and 1992 opening retained earnings were increased by $16 million.

2. ASSET RESTRUCTURING

1993

As a result of a comprehensive review of its Sunoco Group operation, management identified strategic actions that, once implemented, should increase future profitability. As a result of initiating the strategy, a provision for the costs associated with employee terminations and the rationalization of the retail marketing network was required. The impact of the provision was to decrease net earnings by $16 million ($0.29 per common share) after income tax credits of $10 million.

The company divested certain non-core properties identified for sale in 1992 as part of its ongoing strategic review of the Resources Group operation. Proceeds of $39 million from these divestments were greater than estimated in the 1992 asset restructuring charge, primarily as a result of higher natural gas prices. A gain of $18 million was recorded resulting in an increase in net earnings of $10 million ($0.19 per common share) after income taxes of $8 million.

1992

As a result of an extensive heavy oil study carried out during the year, the company decided to proceed with a different mining methodology to lower costs at its Oil Sands operation and to address the need to construct a new utilities plant to meet more stringent air emission standards by mid-1996. As a result of these decisions, certain assets were written down and additional costs were provided for, resulting in a charge of $85 million after income tax credits of $44 million.

The study also concluded that the long-term outlook for North American heavy oil prices made commercial development under existing technology at the Burnt Lake heavy oil project unlikely in the foreseeable future. This outlook, combined with the then recent mixed results from testing "cold" production technology, required the write-off of the carrying value of the project in the amount of $95 million after income tax credits of $48 million.

The ongoing strategic review of the Resources Group's producing and non-producing properties led to the decision in 1992 to divest of certain properties and to write down the carrying value of other properties that no longer were identified as comprising part of the Group's exploration focus. The combined provision resulted in a charge of $58 million after income tax credits of $30 million.

The cumulative effect of the above was to decrease 1992 earnings by $238 million ($4.38 per common share) after income tax credits of $122 million.

3. ROYALTIES

($ millions)	**1994**	1993	1992
Crown			
Oil Sands	**22**	17	23
Resources	**22**	20	20
	44	37	43
Other			
Oil Sands	**18**	14	18
Resources	**6**	6	6
	24	20	24
Total			
Oil Sands	**40**	31	41
Resources	**28**	26	26
	68	57	67

4. TAXES OTHER THAN INCOME TAXES

($ millions)	**1994**	1993	1992
Excise taxes	**271**	244	223
Production, property and other taxes	**17**	18	16
	288	262	239

Excise taxes are included in sales and other operating revenues in the Consolidated Statements of Earnings. Gasoline and diesel fuel taxes and goods and services tax (GST) totalling $634 million (1993 – $600 million; 1992 – $576 million) were collected from customers on behalf of governments and are not shown in the company's revenues and expenses. GST payments remitted to the federal government are net of input tax credits paid to suppliers.

5. SUPPLEMENTAL INFORMATION

($ millions)	**1994**	1993	1992
Export sales	**203**	181	196
Interest expense			
Interest cost – short-term	**–**	1	1
– long-term	**19**	16	19
Less interest capitalized	**(3)**	(2)	(5)
	16	15	15
Cash interest payments	**16**	17	20
Exploration expenses			
Geological and geophysical	**12**	9	10
Other	**1**	1	1
Cash costs	**13**	10	11
Dry hole costs	**11**	12	6
Cash and dry hole costs	**24**	22	17
Leasehold impairment*	**8**	6	5
	32	28	22
Allowance for doubtful accounts	**9**	7	7

* Provisions for leasehold impairment are included in depreciation, depletion and amortization in the Consolidated Statements of Earnings.

7. RELATED PARTY TRANSACTIONS

In transactions with its major shareholder Sun Company, Inc. and its affiliates ("Sun") during 1994, the company was a net seller of crude oil in the amount of $33 million (1993 – $24 million; 1992 – $33 million). Since crude oil revenues are netted against expenses in the Consolidated Statements of Earnings in accordance with the company's accounting policy, they are not shown as export sales in note 5. The company also sold refined products for $12 million (1993 – $3 million; 1992 – $13 million) and purchased feedstocks for $10 million (1993 – $1 million; 1992 – $2 million).

In transactions with Sun Petrochemicals Company ("SPC"), a joint venture with Sun commencing during 1992, the company was a net seller of petrochemicals in the amount of $124 million (1993 – $101 million; 1992 – $94 million).

Amounts due from Sun and SPC at December 31, 1994 totalling $16 million (1993 – $9 million; 1992 – $11 million) are included in accounts receivable. There was no amount due to Sun and SPC at December 31, 1994 (1993 and 1992 – Nil).

The company believes that all transactions with related parties have been carried out on fair and equitable terms.

6. INCOME TAXES

The provision for income taxes reflects an effective tax rate which differs from the statutory tax rate. A reconciliation of the two rates and the dollar effect is as follows:

($ millions)	**1994**		1993		1992	
	Amount	**%**	Amount	%	Amount	%
Federal tax rate	**71**	**38**	44	38	(125)	38
Provincial abatement	**(19)**	**(10)**	(12)	(10)	33	(10)
Federal surtax	**2**	**1**	1	1	(3)	1
Provincial tax rates	**29**	**15**	18	15	(51)	15
STATUTORY TAX AND RATE	**83**	**44**	51	44	(146)	44
Add (deduct) the tax effect of:						
Crown royalties	**24**	**13**	20	18	24	(7)
Resource allowance	**(32)**	**(17)**	(24)	(21)	(16)	5
Depletion allowance	**(10)**	**(5)**	(12)	(10)	–	–
Large corporations tax	**3**	**2**	4	3	3	(1)
Rate differential on asset restructuring	**–**	**–**	–	–	35	(11)
Other	**(3)**	**(2)**	1	1	(1)	1
INCOME TAX AND EFFECTIVE RATE	**65**	**35**	40	35	(101)	31

Cash payments for income taxes were $13, $22 and $4 million in 1994, 1993 and 1992, respectively.

8. INVENTORIES

($ millions)	**1994**	1993	1992
Crude oil	**50**	46	46
Refined products	**70**	64	58
Materials and supplies	**44**	44	40
	164	154	144

9. CAPITAL ASSETS

	1994		1993		1992	
($ millions)	**Cost**	**Accumulated Provision**	Cost	Accumulated Provision	Cost	Accumulated Provision
Oil Sands						
Plant	**781**	**386**	707	370	674	353
Mine and mobile equipment	**363**	**185**	362	191	291	177
	1 144	**571**	1 069	561	965	530
Resources						
Oil and gas properties	**682**	**368**	589	353	590	374
Equipment and other	**240**	**110**	215	100	255	124
	922	**478**	804	453	845	498
Sunoco						
Refinery including petrochemicals	**639**	**243**	627	223	611	203
Marketing and transportation	**272**	**127**	267	120	262	112
	911	**370**	894	343	873	315
Corporate	**3**	**1**	3	1	3	1
	2 980	**1 420**	2 770	1 358	2 686	1 344
Net capital assets		**1 560**		1 412		1 342

Oil Sands Group's cost of $1 144 million includes $24 million, inclusive of capitalized interest, relating to the design and installation of sulphur dioxide scrubbing technology in the plant's steam and electrical generating facility. The amortization of costs related to this project will begin once the facility is put into service in 1996.

10. DEFERRED CHARGES AND OTHER

($ millions)	**1994**	1993	1992
Oil sands overburden removal			
costs (see below)	**96**	118	123
Oil sands preproduction costs	**19**	22	24
Deferred maintenance			
shutdown costs	**40**	44	21
Prepaid gas purchases	**4**	6	8
Investment in joint ventures	**38**	40	30
Other	**27**	26	26
	224	256	232
Oil sands overburden removal costs			
Balance – beginning of year	**118**	123	123
Outlays during year	**10**	26	31
Depreciation on			
equipment during year	**1**	2	3
	129	151	157
Amortization during year	**(33)**	(33)	(34)
Balance – end of year	**96**	118	123

11. LONG-TERM BORROWINGS

($ millions)	**1994**	1993	1992
7.4% Debentures, Series C, maturing in 2004, redeemable at any time, at the company's option	**125**	–	–
12% Debentures, Series A, maturing in 2003, repayable at the rate of $5 million annually	**70**	75	80
Prime minus 1/2% Note, matured in 1993	**–**	–	4
Borrowings with interest at variable rates (1993 – average rate 5.1%; 1992 – average rate 8.0%) under or with support of revolving term credit facility	**–**	121	91
Other	**–**	–	5
	195	196	180
Less current portion of long-term borrowings	**5**	5	9
	190	191	171

Principal repayments of long-term borrowings in each of the next five years are as follows:

	($ millions)
1995	5
1996	5
1997	5
1998	5
1999	5

12. LINES OF CREDIT

The company has a revolving term credit facility with financial institutions aggregating $400 million. This facility is subject to commitment fees, the amounts of which are not material. Revolving credit is available until 1998. Available borrowings unused under and with support of these lines of credit at December 31, 1994 are $400 million.

13. ACCRUED LIABILITIES AND OTHER

($ millions)	**1994**	1993	1992
Reclamation and environmental			
remediation costs*	**116**	115	106
Pension costs	**67**	70	65
Deferred revenues on			
prepaid gas contracts	**1**	1	7
Asset restructuring	**4**	4	21
Other	**24**	18	13
	212	208	212

* Total accrued reclamation and environmental remediation costs also includes $11 million in current liabilities (1993 – $11 million; 1992 – $12 million)

It is estimated that an additional $70 million will be accrued over future years for reclamation and environmental remediation costs in the company's upstream operations.

14. COMMITMENTS AND CONTINGENCIES

The company has non-cancellable operating commitments for service stations, office space, pipeline capacity and other property and equipment. Under contracts existing at December 31, 1994, future minimum annual payments are as follows:

	($ millions)
1995	85
1996	40
1997	40
1998	38
1999	38
Later years	390
	631

The company is subject to various regulatory and statutory requirements relating to the protection of the environment. These requirements, in addition to contractual agreements and management decisions, result in the accrual of estimated reclamation and environmental remediation costs. These costs are accrued at the company's resources and oil sands operations on the unit of production basis. Also accrued are estimated environmental remediation costs at Sunoco sites already closed or where decisions have been made to close them in the future, less estimated proceeds from the sale of these properties. Any changes in these estimates will affect future earnings.

To meet its environmental commitments, the company's Board of Directors approved an investment of $175 million, excluding capitalized interest, spread over the period from 1994 to 1996, to install sulphur dioxide scrubbing technology at the oil sands plant's steam and electrical generating facility.

Under the company's business interruption insurance coverage, the company would bear the first $100 million of any loss arising from a future insured incident at its oil sands operations.

The company is defendant and plaintiff in a number of legal actions that arise in the normal course of business.

Costs attributable to the matters discussed above are expected to be incurred over an extended period of time and to be funded from the company's cash provided from operating activities. Although the ultimate impact of these matters on net earnings could be significant for any one quarter or year, any liabilities which might arise pertaining to such matters would not be expected to have a material effect on the company's consolidated financial position.

15. SHARE CAPITAL

(a) Authorized:

COMMON SHARES

The company is authorized to issue an unlimited number of common shares without nominal or par value.

PREFERRED SHARES

The company is authorized to issue an unlimited number of preferred shares without nominal or par value in series. Shares of one series, Preferred Shares Series A, were issued in prior years.

Following a public distribution of common shares during 1992 by Sun Company, Inc., all remaining outstanding Preferred Shares Series A were redeemed by the company for $24 per share plus accrued and unpaid dividends.

(b) Issued:

	Common Shares		Preferred Shares Series A	
($ millions)	Number	Amount	Number	Amount
Balance as at December 31, 1991	54 374 029	499	234 055	6
Issued on conversion of preferred shares	53 993	1	–	–
Converted to common	–	–	(39 155)	(1)
Redeemed for cash	–	–	(194 900)	(5)
Balance as at December 31, 1992	54 428 022	500	–	–
Issued under stock option plan	19 268	–	–	–
Balance as at December 31, 1993	54 447 290	500	–	–
Issued under stock option plan	74 854	2	–	–
Balance as at December 31, 1994	54 522 144	502	–	–

The following table summarizes information with respect to common share options granted by the company to certain executives of the company and its subsidiaries:

	Shares under option	Option price per share
Outstanding, December 31, 1991	–	–
Granted	287 267	$19.00
Cancelled	(901)	
Outstanding, December 31, 1992	286 366	$19.00
Granted	234 201	$21.57
Exercised	(19 268)	$19.00
Cancelled	(23 394)	
Outstanding, December 31, 1993	477 905	$19.00 – $21.57
Granted	168 026	$30.35 – $31.31
Exercised	(74 854)	$19.00 – $21.57
Cancelled	(12 138)	
Outstanding, December 31, 1994	558 939	$19.00 – $31.31
Exercisable, December 31		
1992	–	–
1993	71 435	$19.00
1994	161 252	$19.00 – $21.57
Available for Grant, December 31		
1992	463 634	
1993	253 902	
1994	1 096 939	

The exercise of options outstanding as at December 31, 1994 would not have a materially dilutive effect on net earnings per share.

16. PENSION COSTS AND OBLIGATIONS

The company has pension plans which cover its eligible employees. These plans consist of non-contributory defined benefit plans, under which a defined pension benefit is provided at retirement based upon years of service and final average earnings, and a defined contribution plan, under which the company makes contributions, based on employees' earnings and participation, to the employees' personal retirement accounts.

DEFINED BENEFIT PENSION PLANS

Pension expense:

($ millions)	**1994**	1993	1992
Service costs	**6**	5	5
Interest cost on projected benefit obligation	**18**	16	17
Actual return on plan assets*	**3**	(35)	1
Net amortization*	**(20)**	22	(16)
	7	8	7

* Estimated returns on assets are used in determining pension expense. Differences between estimated and actual returns are included in net amortization. Also included in net amortization are amortization of the unrecognized net asset at January 1, 1987 and annual experience gains or losses over the expected average remaining service life of employees, which is currently 16 years (1993 and 1992 – 16 years).

Funded status of the company's plans and amounts recognized in the balance sheets at December 31:

($ millions)	**1994**	1993	1992
Funded retirement plan:			
Actuarial present value of benefit obligation			
– Vested	**174**	147	141
– Non-vested	**1**	–	–
Accumulated benefit obligation	**175**	147	141
Effect of projected future salary increases	**32**	44	41
Projected benefit obligation	**207**	191	182
Less market value of plan assets*	**172**	178	152
Projected benefit obligation in excess of plan assets	**35**	13	30
Unfunded supplementary benefit obligations**	**23**	20	20
Net unfunded obligations	**58**	33	50
Unrecognized net asset at January 1, 1987	**39**	42	44
Unrecognized net gain (loss)	**(20)**	7	(23)
Pension liability***	**77**	82	71

* Plan assets consist principally of marketable equity securities, government and corporate bonds and short-term notes.

** Unfunded plans primarily provide supplemental executive retirement benefits.

*** The long-term pension liability of $67 million (1993 – $70 million; 1992 – $65 million) is included in accrued liabilities and other (see note 13) in the consolidated balance sheets. The current pension liability is included in accounts payable and accrued liabilities in the consolidated balance sheets.

Plan funding payments are made as actuarially determined in accordance with regulatory requirements.

Assumptions used in computing pension expense and projected benefit obligations:

(percentages)	**1994**	1993	1992
Discount rate	**8**	8	8
Long-term rate of return on plan assets	**8**	8	8
Rate of compensation increase	**5**	5	5

DEFINED CONTRIBUTION PENSION PLAN

($ millions)	**1994**	1993	1992
Company expense contributions	**3**	3	3

17. FINANCIAL INSTRUMENTS

The company's financial instruments recognized in the consolidated balance sheets consist of cash, accounts receivable, substantially all current liabilities and long-term borrowings.

The estimated fair values of recognized financial instruments have been determined based on the company's assessment of available market information and appropriate valuation methodologies; however, these estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction.

The fair values of financial instruments other than long-term borrowings approximate their carrying amounts due to the short-term maturity of these instruments.

The following table summarizes estimated fair value information about the company's long-term borrowings at December 31:

	1994		1993		1992	
($ millions)	**Carrying amount**	**Fair value**	Carrying amount	Fair value	Carrying amount	Fair value
Long-term borrowings						
– fixed rate	**190**	**175**	75	79	80	84
– variable rate	**–**	**–**	116	116	91	91

The fair value of the company's fixed rate long-term borrowings, which are publicly traded, is based on quoted market prices. The fair value of the company's variable rate long-term borrowings approximates the carrying amount.

Periodically, the company also is a party to certain off-balance-sheet derivative financial instruments, such as crude oil, natural gas and foreign currency swap contracts. The company enters into these contracts for hedging purposes only, in order to protect its Canadian dollar earnings and cash flow on future sales from the potential adverse impact of low petroleum and natural gas prices and an unfavourable U.S./Canadian dollar exchange rate. The swap contracts reduce fluctuations in sales revenues by locking in fixed prices and exchange rates on a portion of its crude oil and natural gas sales. The company had contracts outstanding in respect to these derivative financial instruments as follows:

($ millions except for average price)	Contract Amounts Quantity	Average Price* $ Canadian	Revenue hedged $ Canadian	Hedge period
AS AT DECEMBER 31, 1994				
Crude oil swaps*	35 000 bbl/day	26	326	1995
	3 000 bbl/day	27	29	1996
	2 000 bbl/day	28	21	1997
U.S. dollar swaps	U.S.$60	1.37	80	1995
	U.S.$240	1.38	329	1996
	U.S.$155	1.40	216	1997
AS AT DECEMBER 31, 1993				
Crude oil swaps*	12 500 bbl/day	26	119	1994
U.S. dollar swaps	U.S.$100	1.32	132	1994
	U.S.$25	1.35	34	1995
	U.S.$25	1.35	34	1996
AS AT DECEMBER 31, 1992				
U.S. dollar swaps	U.S.$150	1.31	196	1993

* Average price for crude oil swaps is WTI per barrel at Cushing, Oklahoma.
Outstanding natural gas swap contracts at December 31, 1994, 1993 and 1992 were not material.

The swap contracts do not require the payment of premiums or cash margin deposits prior to settlement. On settlement, these contracts result in cash receipts (payments) by the company for the difference between the contract and market rates for the applicable dollars and volumes hedged during the contract term. Such cash receipts (payments) offset corresponding decreases (increases) in the company's sales revenues. For accounting purposes, amounts received (paid) on settlement are recorded as part of the related hedged sales transactions. The fair value of these hedging financial instruments is the estimated amount, based on brokers' quotes, that the company would receive (pay) to terminate the contracts at the reporting date. Such amounts, which also represent the unrecognized gain (loss) on the contracts, were as follows at December 31:

($ millions)	**1994**	1993	1992
Crude oil swaps	**11**	23	–
U.S. dollar swaps	**(12)**	–	3
	(1)	23	3

The company may be exposed to certain losses in the event of non-performance by counterparties to these contracts; however, the company does not anticipate non-performance by the counterparties as they are major international financial institutions.

18. COMPARATIVE FIGURES

Certain reclassifications have been made to the 1993 and 1992 comparative figures to conform with the current year's presentation.

19. CANADIAN AND UNITED STATES ACCOUNTING PRINCIPLES

The consolidated financial statements have been prepared in accordance with generally accepted accounting principles (GAAP) in Canada. These principles conform in all material respects to those in the United States (U.S.) except for the following:

($ millions)	**1994**	1993	1992
Net earnings (loss) as shown in financial statements	**121**	75	(228)
Impact of U.S. accounting principles:			
Legal claim settlement (1)	**–**	16	–
Pensions – rate effect (2)	**(2)**	–	3
Deferred income taxes			
– SFAS No.109 (3)	**(9)**	50	–
– APB 11 (4)	**–**	–	16
Net earnings (loss) according to U.S. GAAP	**110**	141	(209)
Net earnings (loss) per share (dollars)			
Under accounting principles of:			
Canada	**2.22**	1.38	(4.19)
United States (treasury stock method)	**2.01**	2.59	(3.84)

The adjustments under U.S. GAAP result in changes to the Consolidated Balance Sheets of the company as follows:

	as at December 31, 1994		as at December 31, 1993	
($ millions)	**As reported**	**U.S. GAAP**	As reported	U.S. GAAP
Current assets	**417**	**417**	355	355
Capital assets, net	**1 560**	**1 560**	1 412	1 412
Deferred charges and other	**224**	**224**	256	256
Total assets	**2 201**	**2 201**	2 023	2 023
Current liabilities	**420**	**420**	340	340
Long-term borrowings	**190**	**190**	191	191
Accrued liabilities and other (2)	**212**	**174**	208	166
Deferred income taxes (3)(4)	**344**	**285**	314	248
Shareholders' equity	**1 035**	**1 132**	970	1 078
Total liabilities and shareholders' equity	**2 201**	**2 201**	2 023	2 023

(1) During the second quarter of 1993, a settlement was reached on all actions initiated by the company in 1989 against defendants for damages caused by an October 1987 fire at its Oil Sands operation. For Canadian reporting, the earnings impact of $16 million has been reflected retroactively in 1987.

(2) Defined benefit pension plans expense and projected benefit obligations, under Statement of Financial Accounting Standards (SFAS) No. 87, "Employers' Accounting for Pensions", were determined using the following assumed rates:

(percentages)	**1994**	1993	1992
U.S GAAP			
Discount rate	**9.5**	7.5	9.5
Long-term rate of return on plan assets	**8.0**	8.0	9.5
Rate of compensation increase	**5.0**	5.0	5.0
Canadian GAAP			
Discount rate	**8.0**	8.0	8.0
Long-term rate of return on plan assets	**8.0**	8.0	8.0
Rate of compensation increase	**5.0**	5.0	5.0

In 1994, the cumulative impact of the rate fluctuations resulted in a pension expense that was $4 million higher under U.S. GAAP than under Canadian GAAP. In 1993, the cumulative impact of the rate fluctuations resulted in the same pension expense under both U.S. and Canadian GAAP. The recorded benefit obligations were $38 million lower at December 31, 1994, than recorded under Canadian GAAP (1993 – $42 million lower). The projected benefit obligations at December 31, 1994 were $44 million lower than recorded under Canadian GAAP (1993 – $15 million higher).

(3) Effective January 1, 1993, the company adopted SFAS No.109, "Accounting for Income Taxes", for reporting under U.S. GAAP. Under SFAS No.109, deferred income taxes are computed using the liability method. Under Canadian GAAP, deferred income taxes are computed using the deferred method.

The cumulative effect of the change in accounting for deferred income taxes for years prior to 1993, which has been reflected in the Consolidated Statement of Earnings for 1993 for reporting under U.S. GAAP, was an increase in 1993 net earnings and a reduction of the deferred tax liability of $63 million.

Excluding the cumulative effect, this change decreased 1994 and 1993 net earnings and increased the deferred tax liability at December 31, 1994 and 1993 by $9 million and $13 million, respectively, due to the absence of earned depletion tax benefits. Under Canadian GAAP, such benefits were reported in current period operating results while under SFAS No.109 they were included in the cumulative effect adjustment.

Since the deferred tax assets and liabilities will have to be adjusted for any future enacted changes in tax rates, the company's net earnings under U.S. GAAP may be subject to increased volatility.

Under the liability method of SFAS No.109, the tax effects of temporary differences which comprise the deferred tax assets and liabilities are as follows:

($ millions)	**Dec 31 1994**	Dec 31 1993	Jan 1 1993
Deferred tax assets:			
Pension liabilities	**21**	17	12
Reclamation and environmental remediation costs	**25**	26	28
Other	**25**	23	31
	71	66	71
Deferred tax liabilities:			
Depreciation	**351**	297	266
Other	**5**	17	7
	356	314	273
Net deferred income tax liability	**285**	248	202

(4) Prior to 1993, deferred income taxes were computed using the deferred method in accordance with APB 11, "Accounting for Income Taxes", for reporting under U.S. GAAP. Under APB 11, the income tax effect of the 1992 asset restructuring charge was calculated using the current effective income tax rate, versus the cumulative average effective income tax rate under Canadian GAAP, resulting in an increase of $16 million in 1992 net earnings under U.S. GAAP.

(5) The company provides certain health care and life insurance benefits for its retired employees and eligible surviving dependents. For reporting under both Canadian and U.S. GAAP, costs of these benefits are charged to earnings as payments are made by the company on behalf of retirees and dependents.

In December 1990, SFAS No.106, "Employers' Accounting for Post-Retirement Benefits Other than Pensions" was issued. SFAS No.106 requires that the expected cost of such benefits be actuarially determined and accrued ratably from the date of hire to the date the employee is fully eligible to receive benefits. SFAS No.106 permits recognition of the net obligation existing at the date of adoption (transition obligation) as a cumulative effect of a change in accounting principle in the year of adoption or as a charge against future earnings over a 20-year period.

The company will adopt SFAS No.106 for U.S. reporting purposes in 1995, when adoption is required for plans outside the U.S. Adoption in 1994 would have resulted in an after-tax charge against earnings of approximately $18 million if the transition obligation were recognized as a cumulative effect of a change in accounting principle. In the years subsequent to adoption, post-retirement health care and life insurance benefits expense would be approximately $4 million before-tax. Cash payments in 1994 for such benefits were $1 million (1993 and 1992 – $1 million). Implementation of SFAS No.106 will not affect the company's cash flow or liquidity.

The above estimates are based on the company's existing post-retirement health care and life insurance benefit plan.

ADDITIONAL FINANCIAL STATEMENT DIFFERENCE

Cash Flow

SFAS No. 95, "Statement of Cash Flows", requires that cash provided from operating activities be reported as follows:

($ millions)	**1994**	1993	1992
Net earnings (loss)	**110**	141	(209)
Adjustments to reconcile net earnings (loss) to cash provided from operating activities			
Non-cash items included in earnings			
Depreciation, depletion and amortization	**179**	174	190
Deferred income taxes	**36**	(20)	(122)
Asset restructuring	**–**	(11)	338
Other	**13**	7	3
Overburden removal outlays	**(10)**	(26)	(31)
Increase (decrease) in deferred credits	**7**	(4)	(6)
Deferred maintenance shutdown expenditures	**(16)**	(42)	(7)
Decrease (increase) in operating working capital			
Accounts receivable	**(16)**	28	(15)
Inventories	**(10)**	(10)	18
Accounts payable and accrued liabilities	**30**	1	29
Taxes payable	**44**	(6)	7
Other	**(1)**	(5)	4
Cash provided from operating activities*	**366**	227	199

* Differs from cash provided from operating activities in the company's Statements of cash flows where exploration expenses of $13 million (1993 – $10 million; 1992 – $11 million) are classified as investing activities.

(unaudited)

FINANCIAL DATA

($ millions except per share amounts)	Mar 31 1994	June 30 1994	Sept 30 1994	Dec 31 1994	Total year 1994	Mar 31 1993	June 30 1993	Sept 30 1993	Dec 31 1993	Total year 1993	Mar 31 1992	June 30 1992	Sept 30 1992	Dec 31 1992	Total year 1992
	For the quarter ended					For the quarter ended					For the quarter ended				
REVENUES	**374**	**389**	**444**	**430**	**1 637**	384	387	390	388	1 549	366	367	394	435	1 562
GROSS PROFIT	**104**	**98**	**133**	**124**	**459**	89	73	123	101	386	78	50	82	94	304
NET EARNINGS (LOSS)															
Oil Sands	**9**	**23**	**33**	**25**	**90**	12	2	30	15	59	4	(13)	(74)	9	(74)
Resources	**5**	**4**	**7**	**5**	**21**	2	9	10	7	28	(1)	–	(149)	9	(141)
Sunoco	**13**	**1**	**9**	**8**	**31**	5	2	(5)	4	6	8	2	1	(2)	9
Corporate and eliminations	**(5)**	**(4)**	**(7)**	**(5)**	**(21)**	(6)	(3)	(6)	(3)	(18)	(5)	(4)	(6)	(7)	(22)
	22	**24**	**42**	**33**	**121**	13	10	29	23	75	6	(15)	(228)	9	(228)
PER COMMON SHARE															
– net earnings (loss)	**0.40**	**0.44**	**0.78**	**0.60**	**2.22**	0.24	0.19	0.53	0.42	1.38	0.11	(0.28)	(4.20)	0.18	(4.19)
– cash dividends	**0.26**	**0.26**	**0.27**	**0.27**	**1.06**	0.26	0.26	0.26	0.26	1.04	0.26	0.26	0.26	0.26	1.04
CASH FLOW PROVIDED FROM (USED IN) OPERATIONS															
Oil Sands	**31**	**38**	**70**	**58**	**197**	30	(16)	51	47	112	31	(4)	37	18	82
Resources	**26**	**26**	**30**	**26**	**108**	20	22	24	27	93	10	18	20	27	75
Sunoco	**31**	**11**	**29**	**22**	**93**	18	6	27	16	67	23	20	18	8	69
Corporate and eliminations	**(13)**	**(22)**	**(18)**	**(14)**	**(67)**	(17)	(6)	(9)	(15)	(47)	(9)	(10)	(14)	–	(33)
	75	**53**	**111**	**92**	**331**	51	6	93	75	225	55	24	61	53	193

OPERATING DATA

($ millions except per share amounts)	Mar 31 1994	June 30 1994	Sept 30 1994	Dec 31 1994	Total year 1994	Mar 31 1993	June 30 1993	Sept 30 1993	Dec 31 1993	Total year 1993	Mar 31 1992	June 30 1992	Sept 30 1992	Dec 31 1992	Total year 1992
	For the quarter ended					For the quarter ended					For the quarter ended				
OIL SANDS GROUP															
Production (a)	**66.5**	**68.3**	**72.7**	**75.2**	**70.7**	57.0	47.3	71.0	66.3	60.5	64.3	47.0	63.3	59.6	58.5
Sales (a)															
– light sweet crude oil	**60.9**	**46.2**	**67.0**	**68.3**	**60.7**	56.3	46.5	67.5	55.4	56.5	63.7	31.6	66.4	62.8	56.2
– light sour crude oil	**6.4**	**19.2**	**6.1**	**7.7**	**9.8**	–	–	3.4	9.9	3.3	–	9.1	–	–	2.2
Average sales price (b)															
– light sweet crude oil	**18.91**	**22.63**	**24.65**	**23.43**	**22.50**	23.12	23.08	22.58	22.40	22.77	20.36	23.71	24.54	24.48	23.23
– light sour crude oil	**16.49**	**22.48**	**21.81**	**21.27**	**21.18**	–	–	20.63	16.64	17.65	–	17.05	–	–	17.05
Cash costs (c)	**13.50**	**14.00**	**13.25**	**15.25**	**14.00**	16.75	20.25	13.00	15.25	16.00	16.25	21.75	18.00	18.00	19.50
RESOURCES GROUP															
Gross production															
– crude oil (a)*	**10.6**	**11.8**	**11.2**	**11.7**	**11.3**	10.5	10.7	9.6	10.8	10.4	11.8	11.0	10.9	10.1	10.9
– natural gas liquids (a)	**2.2**	**1.7**	**3.0**	**3.0**	**2.5**	3.2	2.6	2.4	2.4	2.6	2.3	3.0	2.0	2.9	2.5
– natural gas (d)	**147**	**147**	**157**	**169**	**155**	161	147	137	147	148	136	138	134	178	147
Average sales price															
– crude oil (b)	**16.53**	**21.19**	**21.86**	**20.75**	**20.17**	20.70	20.39	20.50	19.56	20.28	17.88	20.89	22.39	22.01	20.71
– natural gas liquids (b)	**11.04**	**8.62**	**17.43**	**14.92**	**13.77**	17.27	16.90	15.89	15.56	16.47	13.22	16.24	18.56	17.58	16.40
– natural gas (e)	**2.15**	**1.92**	**1.74**	**1.65**	**1.85**	1.64	1.56	1.57	1.90	1.67	1.16	1.11	1.15	1.40	1.22
SUNOCO GROUP															
Refined product sales (f)	**13.5**	**13.4**	**13.5**	**13.7**	**13.5**	13.2	12.6	13.2	13.4	13.1	13.5	13.5	12.8	13.7	13.4
Utilization of refining capacity (%)	**99**	**88**	**97**	**94**	**94**	99	86	92	94	93	90	87	93	95	91

* Before deducting 1994 Alberta Crown royalty of 1.2 thousand barrels per day (1993 – 1.0 thousand barrels per day; 1992 – 1.2 thousand barrels per day)

(a) thousands of barrels per day (b) dollars per barrel (c) dollars per barrel rounded to the nearest $0.25 (d) millions of cubic feet per day

(e) dollars per thousand cubic feet (f) thousands of cubic metres per day

(unaudited)

($ millions except for ratios)	**1994**	1993	1992	1991	1990
REVENUES					
Oil Sands	**571**	487	491	519	537
Resources	**195**	180	167	139	151
Sunoco (excluding federal sales tax)*	**1 384**	1 323	1 342	1 355	1 443
Federal sales tax	**–**	–	–	–	102
Corporate and eliminations	**(513)**	(441)	(438)	(447)	(474)
	1 637	1 549	1 562	1 566	1 759
NET EARNINGS (LOSS)					
Oil Sands	**90**	59	(74)	48	78
Resources	**21**	28	(141)	4	18
Sunoco	**31**	6	9	28	51
Corporate and eliminations	**(21)**	(18)	(22)	(3)	(23)
	121	75	(228)	77	124
CASH FLOW PROVIDED FROM OPERATIONS					
Oil Sands	**197**	112	82	158	144
Resources	**108**	93	75	73	80
Sunoco	**93**	67	69	77	104
Corporate and eliminations	**(67)**	(47)	(33)	(5)	(74)
	331	225	193	303	254
CAPITAL AND EXPLORATION EXPENDITURES					
Oil Sands	**103**	116	65	76	31
Resources	**169**	100	120	118	97
Sunoco	**31**	30	29	38	51
	303	246	214	232	179
TOTAL ASSETS	**2 201**	2 023	1 973	2 264	2 285
CAPITAL EMPLOYED					
Long-term borrowings	**190**	191	171	134	222
Deferred income taxes, accrued liabilities and other	**556**	522	500	582	509
Shareholders' equity	**1 035**	970	952	1 242	1 222
	1 781	1 683	1 623	1 958	1 953
RATIOS					
Per common share (dollars)					
– net earnings (loss)	**2.22**	1.38	(4.19)	1.42	2.27
– cash dividends	**1.06**	1.04	1.04	1.05	0.40
Return on capital employed (%)	**7.5**	5.0	(12.3)	4.3	7.4
Return on shareholders' equity (%)	**12.1**	7.8	(20.8)	6.3	10.6
Long-term borrowings to capital employed (%)	**10.7**	11.3	10.6	6.9	11.4
Interest coverage – cash flow basis	**21.6**	16.1	11.1	22.1	7.2

* 1993 and 1992 revenues have been restated to conform with the current year's presentation.

	1994	1993	1992	1991	1990
OIL SANDS GROUP					
PRODUCTION (thousands of barrels per day)	**70.7**	60.5	58.5	60.6	52.0
SALES (thousands of barrels per day)					
Light sweet crude oil	**60.7**	56.5	56.2	61.1	50.7
Light sour crude oil	**9.8**	3.3	2.2	0.4	0.5
AVERAGE SALES PRICE (dollars per barrel)					
Light sweet crude oil	**22.50**	22.77	23.23	23.00	28.65
Light sour crude oil	**21.18**	17.65	17.05	16.41	22.48
CASH COSTS (dollars per barrel rounded to the nearest $0.25)	**14.00**	16.00	19.50	19.00	19.00
OTHER OIL SANDS STATISTICS					
Overburden removed (millions of cubic yards)	**6.2**	12.1	14.6	12.8	12.8
Oil sands mined (millions of tons)	**52.9**	43.5	44.3	45.1	39.2
Average bitumen content of oil sands mined (% by weight)	**11.7**	12.2	11.9	11.9	12.0
Average crude yield of oil sands mined (barrels per ton)	**.488**	.508	.483	.490	.484

SYNTHETIC CRUDE OIL GROSS PROVED RESERVES

(millions of barrels)	
December 31, 1990	283
December 31, 1991	276
Revisions	1
Production before in-plant usage	(21)
December 31, 1992	256
Revisions	(3)
Production before in-plant usage	(22)
December 31, 1993	231
Revisions	–
Production before in-plant usage	(26)
December 31, 1994	205

Gross proved reserves do not reflect deductions in respect of Crown and applicable sublease royalties. Under the Crown Royalty Agreement the Crown royalty rate is dependent on deemed net revenue; therefore, calculations of net reserves would vary depending upon assumed production rates, prices and operating and capital costs.

	1994	1993	1992	1991	1990
RESOURCES GROUP					
PRODUCTION					
Crude oil (thousands of barrels per day)					
– gross	**11.3**	10.4	10.9	10.0	10.6
– net	**8.9**	8.2	8.3	8.1	8.5
Natural gas liquids (thousands of barrels per day)					
– gross	**2.5**	2.6	2.5	1.4	1.2
– net	**1.9**	1.9	1.8	1.0	0.9
Natural gas (millions of cubic feet per day)					
– gross	**155**	148	147	105	89
– net	**119**	116	116	83	70
AVERAGE SALES PRICE					
Crude oil (dollars per barrel)	**20.17**	20.28	20.71	20.59	25.03
Natural gas liquids (dollars per barrel)	**13.77**	16.47	16.40	14.86	18.20
Natural gas (dollars per thousand cubic feet)	**1.85**	1.67	1.22	1.31	1.43
UNDEVELOPED LAND HOLDINGS					
Oil and gas – western provinces (millions of acres)					
– gross	**1.2**	1.2	1.3	1.4	1.3
– net	**0.8**	0.7	0.8	0.8	0.8
NET WELLS DRILLED					
Conventional					
Exploratory – oil	**1**	2	–	2	4
– gas	**8**	8	6	3	4
– dry	**12**	9	7	10	7
Development – oil	**30**	18	15	23	13
– gas	**13**	10	2	6	6
– dry	**9**	7	3	3	7
	73	54	33	47	41

OIL AND GAS DATA

The following supplemental oil and gas disclosure is provided in accordance with the provisions of the United States Financial Accounting Standards Board's Statement No. 69. This statement requires disclosure about conventional oil and gas activities only, and therefore the company's oil sands activities are excluded.

Reserves

	Gross		Net	
	Crude oil and natural gas liquids (millions of barrels)	Natural gas (billions of cubic feet)	Crude oil and natural gas liquids (millions of barrels)	Natural gas (billions of cubic feet)
PROVED				
December 31, 1990	42	404	35	337
December 31, 1991	39	490	32	407
Revisions of previous estimates	1	33	–	2
Purchases of minerals in place	8	122	6	89
Extensions and discoveries	2	36	1	28
Production	(5)	(54)	(4)	(43)
Sales of minerals in place	(3)	(10)	(1)	(8)
December 31, 1992	42	617	34	475
Revisions of previous estimates	1	28	1	26
Purchases of minerals in place	1	6	1	5
Extensions and discoveries	7	93	5	74
Production	(5)	(53)	(4)	(42)
Sales of minerals in place	(2)	(59)	(2)	(46)
December 31, 1993	44	632	35	492
Revisions of previous estimates	4	30	2	34
Purchases of minerals in place	1	6	1	5
Extensions and discoveries	8	134	6	105
Production	(5)	(54)	(4)	(43)
Sales of minerals in place	–	–	–	–
December 31, 1994	52	748	40	593
PROVED DEVELOPED				
December 31, 1990	36	242	30	197
December 31, 1991	33	309	28	256
December 31, 1992	38	474	31	370
December 31, 1993	38	447	30	338
December 31, 1994	42	450	33	357

1. Proved reserves are considered recoverable under current technology and existing economic conditions, from reservoirs that are evaluated on known drilling, geological, geophysical and engineering data.

Proved developed reserves are on production, or reserves that could be recovered from existing wells or facilities, if the company placed them on production.

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

All reserves are located in Canada. There has been no major discovery or other favourable or adverse event which caused a significant change in estimated proved reserves since December 31, 1994. The company has no long-term supply agreements or contracts with governments or authorities in which it acts as producer nor does it have any interest in oil and gas operations accounted for by the equity method.

Capitalized costs

as at December 31 ($ millions)	1994	1993	1992
Proved properties	**683**	582	609
Unproved properties	**206**	191	204
Pipeline	**22**	21	21
Other support facilities and equipment	**11**	10	11
Total capitalized costs	**922**	804	845
Accumulated depreciation, depletion and amortization	**(478)**	(453)	(498)
Net capitalized costs	**444**	351	347

Costs incurred

for the years ended December 31 ($ millions)	1994	1993	1992
Property acquisition costs			
– proved properties	**9**	5	36
– unproved properties	**26**	11	4
Exploration costs	**43**	33	30
Development costs	**89**	49	49
	167	98	119

Results of Operations for Oil and Gas Production

for the years ended December 31 ($ millions)	1994	1993	1992
Revenues			
Sales to unaffiliated customers	**82**	62	48
Transfers to other operations	**80**	87	80
	162	149	128
Expenses			
Production costs	**34**	32	35
Depreciation, depletion and amortization	**42**	40	46
Provision for asset restructuring	–	(18)	231
Exploration	**32**	28	22
Other related costs	**19**	20	4
	127	102	338
Operating profit (loss) before income taxes	**35**	47	(210)
Related income taxes	**14**	19	(69)
Results of operations from exploration and production	**21**	28	(141)

Results of operations for oil and gas production do not totally agree to the segmented information on page 36 due to different classifications of revenues and expenses.

Standardized Measure of Discounted Future Net Cash Flows from Estimated Production of Proved Oil and Gas Reserves after Income Taxes

In computing the standardized measure of discounted future net cash flows from estimated production of proved oil and gas reserves after income taxes, assumptions other than those mandated by SFAS No. 69 could produce substantially different results. The company cautions against viewing this information as a forecast of future economic conditions or revenues.

The standardized measure of discounted future net cash flows is determined by using estimated quantities of proved reserves and taking into account the future periods in which they are expected to be developed and produced based on year-end economic conditions. The estimated future production is priced at year-end prices, except that future gas prices are increased, where applicable, for fixed and determinable price escalations provided by contract or regulation. The resulting estimated future cash inflows are reduced by estimated future costs to develop and produce the proved reserves based on year-end cost levels. In addition, the company has also deducted certain other estimated costs deemed necessary to derive the estimated pretax future net cash flows from the proved reserves including direct general and administrative costs of exploration and production operations and abandonment/dismantlement costs. The estimated pretax future net cash flows are then reduced further by deducting future income tax expenses. Such income taxes are determined by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax cash flows relating to the company's proved oil and gas reserves less the tax basis of the properties involved. The future income tax expenses give effect to permanent differences and tax credits and allowances relating to the company's proved oil and gas reserves. The resultant future net cash flows are reduced to present value amounts by applying the SFAS No. 69 mandated 10% discount factor. The result is referred to as "Standardized Measure of Discounted Future Net Cash Flows from Estimated Production of Proved Oil and Gas Reserves after Income Taxes".

($ millions)	**1994**	1993	1992
Future cash inflows	**1 944**	1 715	1 547
Future production and development costs	**(705)**	(550)	(567)
Other related future costs	**(102)**	(89)	(69)
Future income tax expenses	**(328)**	(306)	(251)
Future net cash flows	**809**	770	660
Discount at 10%	**(326)**	(333)	(292)
Standardized measure of discounted future net cash flows from estimated production of proved oil and gas reserves after income taxes	**483**	437	368

Summary of Changes in the Standardized Measure of Discounted Future Net Cash Flows from Estimated Production of Proved Oil and Gas Reserves after Income Taxes

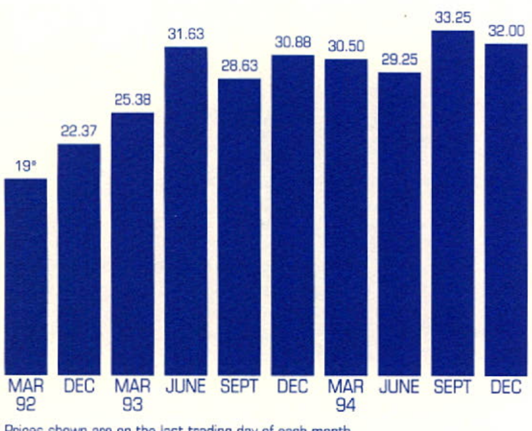
($ millions)	**1994**	1993	1992
Balance, beginning of year	**437**	368	321
Increase (decrease) in discounted future net cash flows:			
Sales and transfers of oil and gas net of related costs	**(127)**	(114)	(94)
Revisions to estimates of proved reserves:			
Prices	**(6)**	49	37
Development costs	**(44)**	(1)	(9)
Production costs	**(12)**	17	2
Quantities	**31**	17	2
Other	**8**	(17)	44
Extensions, discoveries, and improved recovery less related costs	**115**	80	26
Development costs incurred during the period	**89**	49	49
Purchases of reserves in place	**11**	10	36
Sales of reserves in place	**–**	(44)	(7)
Accretion of discount	**59**	49	37
Income taxes	**(78)**	(26)	(76)
Balance, end of year	**483**	437	368

	1994	1993	1992	1991	1990
SUNOCO GROUP					
REFINED PRODUCT SALES (thousands of cubic metres per day)					
Transportation fuels					
Gasoline – retail	**4.4**	4.1	4.0	4.0	3.8
– other	**3.1**	2.7	3.0	2.9	2.8
Jet fuel	**1.1**	0.9	0.6	0.5	0.5
Other	**2.1**	2.4	1.8	1.8	1.5
	10.7	10.1	9.4	9.2	8.6
Petrochemicals	**0.8**	0.8	1.1	1.1	1.0
Heating oils	**0.8**	1.1	1.2	0.9	1.0
Heavy fuel oils	**0.6**	0.4	0.7	0.6	0.7
Other	**0.6**	0.7	1.0	1.0	1.2
	13.5	13.1	13.4	12.8	12.5
CRUDE OIL SUPPLY AND REFINING					
Gross crude oil production as a percentage of crude oil refined for Suncor account	**124**	111	111	112	108
Processed at Suncor refinery (thousands of cubic metres per day)	**10.5**	10.3	10.2	10.2	9.4
Utilization of refining capacity (%)	**94**	93	91	91	84
RETAIL SITES (number at year end)	**500**	605	650	725	775
SUNCOR EMPLOYEES (number at year end)	**2 784**	2 946	3 292	3 463	3 604
SALARIES, WAGES AND EMPLOYEE BENEFITS ($ millions)	**228**	251	256	253	228

	For the quarter ended				For the quarter ended			
	Mar 31 1994	**June 30 1994**	**Sept 30 1994**	**Dec 31 1994**	Mar 31 1993	June 30 1993	Sept 30 1993	Dec 31 1993
SHARE OWNERSHIP								
Average number outstanding, weighted monthly (thousands) (1)	**54 461**	**54 482**	**54 495**	**54 410**	54 428	54 437	54 445	54 447
SHARE PRICE (dollars) (2)								
Toronto Stock Exchange								
High	**33 1/8**	**31 1/4**	**33 1/2**	**35 1/2**	25 7/8	32 1/8	31 3/4	34 7/8
Low	**28 1/8**	**27 1/8**	**27 3/4**	**31 1/4**	23 3/8	25	26 3/8	28 3/4
Close	**30 1/2**	**29 1/4**	**33 1/4**	**32**	25 3/8	31 5/8	28 5/8	30 7/8
SHARES TRADED (thousands) (3)	**3 451**	**5 230**	**3 478**	**5 170**	3 509	13 813	5 340	3 559
PER-SHARE INFORMATION (dollars)								
Net earnings	**0.40**	**0.44**	**0.78**	**0.60**	0.24	0.19	0.53	0.42
Cash dividends	**0.26**	**0.26**	**0.27**	**0.27**	0.26	0.26	0.26	0.26

(1) The company had approximately 1000 holders of record of common stock as at January 31, 1995.
(2) The company's common shares are traded principally on the Toronto Stock Exchange.
(3) The number of shares traded is based on transactions on the Toronto Stock Exchange.

Suncor Share Performance
($)



Prices shown are on the last trading day of each month.
°Fully paid Suncor shares at the initial public offering

INFORMATION FOR SECURITY HOLDERS OUTSIDE CANADA

Cash dividends paid to shareholders resident in countries with which Canada has an income tax convention are usually subject to Canadian non-resident withholding tax of 15%. The withholding tax rate is reduced to 10% on dividends paid to a corporation if it is a resident of the United States which owns at least 10% of the voting shares of the company. In 1995, this rate will be reduced to 7% after the protocol of the Canada-U.S. tax convention is ratified. There will be a further reduction of 1% for each of the years 1996 and 1997.

Investor Information

Stock Trading Symbol SU

Stock Exchange Listings
Toronto, Montreal, Alberta, Vancouver and American

Dividends
Suncor's Board of Directors reviews its dividend policy from time to time, in light of changes that may occur in the company's financial position. In July, 1994, Suncor increased its quarterly dividend by 4% to $0.27 per share from $0.26 per share.

Stock Transfer Agent and Registrar
Montreal Trust Company of Canada in Montreal, Toronto, Calgary, Edmonton, Vancouver

Ownership
Suncor Inc. is a Canadian company whose ownership is divided between Sun Company, Inc. and public shareholders. As of year end 1994, share capital consists of 54.5 million shares, of which 54.9% is indirectly held by Sun Company, Inc. and 45.1% by public shareholders.

Annual Meeting
The annual meeting of shareholders will be held at 11:00 a.m. local time on April 27, 1995, at the King Edward Hotel, Toronto, Ontario.

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To Obtain Annual, Quarterly & Environmental Reports, Form 10-K
Telephone:
1-800-558-9071

Corporate Directors & Officers

DIRECTORS

Robert M. Aiken, Jr. (1)
Philadelphia, Pennsylvania
Senior Vice President
and Chief Financial Officer
Sun Company, Inc.

Harry Booth (1,3)
Calgary, Alberta
Retired Chairman
and Chief Executive Officer
Alberta Natural Gas
Company Ltd.

Robert H. Campbell (2)
Philadelphia, Pennsylvania
Chairman of the Board,
Chief Executive Officer and
President
Sun Company, Inc.

Bryan P. Davies (1,4)
Toronto, Ontario
Senior Vice President
Corporate Affairs
Royal Bank of Canada

Richard L. George (2,3)
Toronto, Ontario
President and Chief
Executive Officer
Suncor Inc.

Allan E. Gotlieb (1,3)
Toronto, Ontario
Chairman, Burson
Marsteller Canada Ltd.;
Consultant, Stikeman
Elliott

Ardagh S. Kingsmill, Q.C. (2,4)
Toronto, Ontario
Senior Partner
McCarthy Tétrault

David E. Knoll (1,4)
Philadelphia, Pennsylvania
Senior Vice President
Corporate Development
Sun Company, Inc.

Bill N. Rutherford (2,4)
Radnor, Pennsylvania
Retired Senior
Vice President
Human Resources
and Administration
Sun Company, Inc.

Robert H. Writz, Jr. (3)
Philadelphia, Pennsylvania
Former Senior
Vice President
Sun Company, Inc.

W. Robert Wyman (2,4)
Vancouver, B.C.
Chairman
Finning Ltd.

(1) AUDIT COMMITTEE
(2) BOARD POLICY, STRATEGIC PLANNING AND GOVERNANCE COMMITTEE
(3) ENVIRONMENT, HEALTH AND SAFETY COMMITTEE
(4) HUMAN RESOURCES AND COMPENSATION COMMITTEE

OFFICERS

Robert H. Campbell
Chairman of the Board

Richard L. George
President and
Chief Executive Officer

Michael W. O'Brien
Executive Vice President
Sunoco Group

Edythe A. (Dee) Parkinson
Executive Vice President
Oil Sands Group

Barry D. Stewart
Executive Vice President
Resources Group

Peter T. Spelliscy
Senior Vice President
Human Resources and
Administration

Donald R. Brown, Q.C.
Vice President and General
Counsel

Timothy R. Hughes
Senior Vice President
Finance

Ardagh S. Kingsmill, Q.C.
Secretary

Anthony A.L. Wright
Treasurer and Assistant
Secretary

INDUSTRY TERMS

BITUMEN/HEAVY OIL:
Tar-like form of oil that cannot be produced by conventional means. When extracted from oil sands, it can be upgraded into light sweet crude and other oil products.

CAPABILITY:
For Oil Sands Group, the maximum output that can be achieved given that provisions must be made for planned maintenance, routine outages and required service.

CAPACITY:
Maximum output that can be achieved given ideal operating conditions.

CONVENTIONAL CRUDE OIL:
Oil produced through wells by normal oil field methods.

DOWNSTREAM:
This business segment manufactures, distributes and markets refined products from crude oil.

DRY HOLE/WELL:
An exploration or development well incapable of producing hydrocarbons, which is plugged, reclaimed and abandoned.

GROSS PRODUCTION/RESERVES:
Suncor's interest before deducting Crown royalties, freehold and overriding royalty interests.

GROSS WELLS/LAND HOLDINGS:
Total in which Suncor has an interest.

HEAVY FUEL OIL:
Residue from refining of conventional crude oil that remains after lighter products such as gasoline, petrochemicals, heating oils have been extracted.

HYDROCRACKING:
A refining process that breaks down heavier, lower-value hydrocarbons, typically known as gas oils, into lighter, higher-value products, such as gasoline and diesel fuel.

LIGHT SOUR CRUDE OIL:
Produced at Oil Sands Group. Requires only partial upgrading and contains a higher sulphur content than light sweet crude oil.

LIGHT SWEET CRUDE OIL:
Blend of hydrocarbons resulting from thermal cracking and purifying of bitumen.

NATURAL GAS LIQUIDS:
Propane, butane or pentane plus, or a combination thereof, obtained from processing of raw gas or condensates.

NET PRODUCTION/RESERVES:
Suncor's interest after deducting Crown royalties, freehold and overriding royalty interests.

NET WELLS/LAND HOLDINGS:
Suncor's interest after deducting interests of partners.

OVERBURDEN:
Material overlying the oil sands that must be removed before mining. Consists of muskeg, glacial deposits and sand.

RESERVOIR:
Body of porous rock containing an accumulation of water, crude oil or natural gas.

UNDEVELOPED OIL AND GAS LANDS:
Lands on which no producing or commercially producible well has been drilled.

UPSTREAM:
These business segments explore for, acquire, develop, produce and market crude oil and natural gas, including the production of light sweet crude and other oil products from the oil sands.

UTILIZATION:
The average use of capability given that unplanned outages and unscheduled maintenance will occur.

WELLS
Development Well:

A well expected to produce from an oil or gas reservoir known to be productive.

Drilled Well:

A well having a defined status: gas well, oil well or dry and abandoned, after reclamation work.

Exploratory Well:

A well in unproved or semi-proved territory to find commercial deposits of crude oil or natural gas in a new reservoir.

ACCOUNTING TERMS

BARREL OF OIL EQUIVALENT (BOE):
Converts gas to oil on the approximate long-term economic equivalent basis that 10,000 cubic feet equals one barrel of oil.

CASH OPERATING COSTS:
For Oil Sands Group, cash operating costs include operating costs and maintenance costs, overburden cash expenditures and the amortization of maintenance shutdown expenditures, but exclude royalties, capital expenditures, other amortization, head office overhead and interest.

COSTS:
Development Costs:

For Resources Group, include all costs associated with moving reserves from other classes to the "proved developed" class.

Finding Costs:

For Resources Group, include the cost of and investment in undeveloped land, geological and geophysical activities, exploratory drilling and direct administrative costs necessary to discover oil and gas reserves.

Lifting Costs:

For Resources Group, include all expenses related to the operation and maintenance of producing or producible wells, gas plants and gathering systems.

INTEREST COVERAGE – CASH FLOW BASIS:
Cash provided from operating activities before interest expense and income tax payments divided by interest expense plus interest capitalized.

NET DEBT:
Long-term borrowings (including the current portion) plus short-term borrowings, less cash and short-term investments.

OPERATING WORKING CAPITAL:
Current assets (excluding cash and cash equivalents) less current liabilities (excluding borrowings).

RETURN ON CAPITAL EMPLOYED:
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:
Earnings as a percentage of average shareholders' equity. Average shareholders' equity is the average of total shareholders' equity at the beginning and end of the year.

TOTAL CASH COSTS:
For Oil Sands Group, total cash costs includes cash operating costs, sustaining capital and reclamation cash costs. It excludes royalties and strategic capital.

METRIC CONVERSION

CRUDE OIL, REFINED PRODUCTS, ETC.
I m3 (cubic metre) = approx. 6.29 barrels

NATURAL GAS
I m3 (cubic metre) = approx. 35.49 cubic feet

LAND HOLDINGS
1 hectare = approx. 2.5 acres

Printed in Canada on paper containing a minimum of 50% recycled material, including a minimum of 10% post-consumer waste.

We Care

Suncor inc.