SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 40-F

(Check One)

o Registration statement pursuant to Section 12 of the Securities Exchange Act of 1934

or

ý Annual report pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934

For fiscal year ended: **December 31, 2003**

Commission File Number: **No. 1-12384**

SUNCOR ENERGY INC.

(Exact name of registrant as specified in its charter)

Canada	**1311,1321,2911, 4613,5171,5172**	**98-0343201**
(Province or other jurisdiction of incorporation or organization)	(Primary standard industrial classification code number, if applicable)	(I.R.S. employer identification number, if applicable)

112 - 4th Avenue S.W.
Box 38
Calgary, Alberta, Canada T2P 2V5
(403) 269-8100
(Address and telephone number of registrant's principal executive office)

CT Corporation System
111 Eighth Avenue
New York, New York, U.S.A. 10011
(212) 894-8940
(Name, address and telephone number of agent for service in the United States)

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

Title of each class	Name of each exchange on which registered:
Common shares	**New York Stock Exchange**

Securities registered or to be registered pursuant to Section 12(g) of the Act:

None

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act:

None

For annual reports, indicate by check mark the information filed with this form:

ý Annual Information Form **ý** Annual Audited Financial Statements

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report:

Common Shares	**December 31, 2003 there were 451,184,087 Common Shares issued and outstanding**
Preferred Shares, Series A	**None**

Indicate by check mark whether the registrant by filing the information contained in this form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934 (the "Exchange Act"). If "Yes" is marked, indicate the file number assigned to the registrant in connection with such rule.

Yes **o** No ý

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13(a) or 15(d) of the Exchange Act during the proceeding 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 in the past 90 days.

Yes **ý** No o

ANNUAL INFORMATION FORM

SUNCOR ENERGY INC. ANNUAL INFORMATION FORM

February 26, 2004

ANNUAL INFORMATION FORM

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GLOSSARY OF TERMS

Bitumen/Heavy Oil

A naturally occurring viscous tar-like mixture, mainly containing hydrocarbons heavier than pentane, that is not recoverable at a commercial rate in its naturally occurring viscous state through a well without using enhanced recovery methods. When extracted bitumen/heavy oil can be upgraded into crude oil and other petroleum products.

Capacity

Maximum output that can be achieved from a facility in ideal operating conditions in accordance with current design specifications.

Coal Bed Methane

Natural gas produced from wells drilled into a coal formation. Also called coal seam methane.

Conventional Crude Oil

Crude oil produced through wells by standard industry recovery methods for the production of crude oil.

Conventional Natural Gas

Natural gas produced from all geological strata, excluding coal bed methane.

Crude Oil

Unrefined liquid hydrocarbons, excluding natural gas liquids.

Developed Reserves

Developed reserves are those proved reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g., when compared to the cost of drilling a well) to put the reserves on production.

Downstream

These business segments manufacture, distribute and market refined products from crude oil.

Dry Hole/Well

An exploration or development well determined, on an economic basis, to be incapable of producing hydrocarbons that will be plugged, abandoned and reclaimed.

Gross Production

Suncor's undivided percentage interest in production/reserves before deducting Crown royalties, freehold and overriding royalty interests.

Gross Wells/Land Holdings

Total number of wells or acres, as the case may be, 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 and heating oils have been extracted.

In-situ Oil

In-situ or "in place" refers to methods of extracting heavy crude oil from deep deposits of oil sands with minimal disturbance of the ground cover.

MD&A

Suncor's Management's Discussion and Analysis dated February 26, 2004, accompanying its audited consolidated comparative financial statements, notes thereto and auditor's report thereon, as at and for the three years in the period ended December 31, 2003, which MD&A is incorporated by reference herein.

Natural Gas

Hydrocarbons that at atmospheric conditions of temperature and pressure are in a gaseous state.

Natural Gas Liquids

Hydrocarbon products recovered as liquids from raw natural gas by processing through extraction plants or recovered from field separators, scrubbers or other gathering facilities. These liquids include the hydrocarbon components ethane, propane, butane and pentane plus, or a combination thereof.

Net Production/Reserves

Suncor's undivided percentage interest in total production or total reserves, as the case may be, after deducting Crown royalties and freehold and overriding royalty interests.

Net Wells/Land Holdings

Suncor's undivided percentage interest in the gross number of wells or gross number of acres, as the case may be, after deducting interests of third parties.

Overburden

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

Probable Reserves(1)

Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely(2) that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

(1) Suncor is subject to Canadian disclosure rules in connection with the reporting of its reserves. However, Suncor has received exemptive relief from Canadian securities administrators permitting it to report its proved reserves in accordance with U.S. disclosure practices. In addition, although U.S. companies do not disclose probable reserves for non-mining properties, Suncor voluntarily discloses its probable reserves for its Firebag in-situ leases as it believes this information is useful to investors. As a result, Suncor's Firebag in-situ reserve estimates may not be directly comparable to those made by U.S. companies.

Proved oil and gas reserves

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty(2) to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e. prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

(i) Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

(ii) Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the “proved” classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

(iii) Estimates of proved reserves do not include the following: (A) oil that may become available from known reservoirs but is classified separately as “indicated additional reserves”; (B) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (C) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and (D) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

Proved Producing Reserves

Proved producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

(2) In estimating Suncor’s proved and probable reserves, Suncor’s independent reserves evaluators, GLJ, have targeted the following levels of certainty: at least 90% probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and at least a 50 % probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves. However, as Suncor’s reserves, consistent with industry practice, have been prepared using deterministic, rather than probabilistic methods, GLJ’s estimates do not provide a mathematically derived quantitative measure of probability, although in principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Reservoir

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

Sour Synthetic Crude Oil

Crude oil produced from oil sands that requires only partial upgrading and contains a higher sulphur content than sweet synthetic crude oil.

Sweet Synthetic Crude Oil

Crude oil produced from oil sands consisting of a blend of hydrocarbons resulting from thermal cracking and purifying of bitumen.

Synthetic Crude Oil

Upgraded or partially upgraded crude oil recovered from oil sands including surface mineable oil sands leases and in-situ heavy oil leases.

Undeveloped Oil and Natural Gas Lands

Undeveloped acreage is considered to be lands on which wells have not been drilled or completed to a point that would permit production of commercial quantities of crude oil and natural gas regardless of whether or not such acreage contains proved reserves.

Upstream

These business segments include acquisition, exploration, development, production and marketing of crude oil, natural gas and natural gas

liquids; and for greater clarity include the production of synthetic crude oil, bitumen and other oil products from oil sands.

Utilization

The average use of capacity taking into consideration planned and unplanned outages and maintenance.

Wells

Development Well

A crude oil or natural gas well drilled in a reservoir known to be productive and expected to produce in the future.

Drilled Well

A well that has been drilled and has a defined status e.g. gas well, shut-in well, producing oil well, producing gas well, suspended well or dry and abandoned well.

Exploratory Well

A well drilled in unproved or semi-proved territory with the intention to discover commercial reservoirs or deposits of crude oil and/or natural gas.

ACCOUNTING TERMS

Barrel of Oil Equivalent (BOE)

Suncor converts natural gas to barrels of oil equivalent (BOE) at a 6:1 ratio (converted on the approximate energy equivalent basis that six million cubic feet of natural gas equals one thousand barrels of oil equivalent). BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Development Costs

Includes all costs associated with moving reserves from other classes such as “proved undeveloped” and “probable” to the “proved developed” class.

Finding Costs

Includes the cost of and investment in undeveloped land, geological and geophysical activities, exploratory drilling and direct administrative costs necessary to discover crude oil and natural gas reserves.

Lifting Costs

Includes all expenses related to the operation and maintenance of producing or producible wells and related facilities, natural gas plants and gathering systems.

Operating Working Capital

Current assets (excluding cash and cash equivalents), less current liabilities (excluding short-term debt and current portion of long-term borrowings).

Return on Capital Employed (ROCE)

Net earnings adjusted for after-tax financing expenses (income) for the twelve-month period ended December 31; divided by average capital employed. Average capital employed is the sum of shareholders’ equity and short-term debt plus long-term debt, less cash and cash equivalents, less capitalized costs related to major projects in progress (as applicable), at the beginning and end of the year, divided by two. See “Non GAAP Financial Measures”, below.

Return on Average Shareholders’ Equity

Net earnings as a percentage of average shareholders’ equity. Average shareholders’ equity is the sum of total shareholders’ equity at the beginning and end of the year, divided by two.

CONVERSION TABLE

1 cubic metre m(3) = 6.29 barrels	1 tonne = 0.984 tons (long)
1 cubic metre m(3) (natural gas) = 35.49 cubic feet	1 tonne = 1.102 tons (short)
1 cubic metre m(3) (overburden) = 1.31 cubic yards	1 kilometre = 0.62 miles

1 hectare = 2.5 acres

Notes:

(1) Conversion using the above factors on rounded numbers appearing in this Annual Information Form may produce small differences from reported amounts.

(2) Some information in this Annual Information Form is set forth in metric units and some in imperial units.

CURRENCY

All references in this Annual Information Form to dollar amounts are in Canadian dollars unless otherwise indicated.

FORWARD-LOOKING STATEMENTS

This Annual Information Form contains certain forward-looking statements that are based on Suncor's current expectations, estimates, projections and assumptions that were made by the company in light of its experience and its perception of historical trends.

All statements that address expectations or projections about the future, including statements about Suncor's strategy for growth, expected and future expenditures, commodity prices, costs, schedules, production volumes, operating and financial results and expected impact of future commitments, are forward-looking statements. Some of the forward-looking statements may be identified by words like "expects," "anticipates," "plans," "intends, "believes," "projects," "indicates," "could," "vision," "goad," "target," "objective" and similar expressions. These statements are not guarantees of future performance and involve a number of risks and uncertainties, some that are similar to other oil and gas companies and some that are unique to Suncor. Suncor's actual results may differ materially from those expressed or implied by its forward-looking statements and you are cautioned not to place undue reliance on them.

The risks, uncertainties and other factors that could influence actual results include but are not limited to: changes in the general economic, market and business conditions, fluctuations in supply and demand for Suncor's products, commodity prices and currency exchange rates, Suncor's ability to respond to changing markets, and to receive timely regulatory approvals, the successful and timely implementation of capital projects including growth projects (for example the Firebag In-situ development and Voyageur) and regulatory projects (for example, the clean fuels refinery modifications projects in Suncor's downstream businesses); the accuracy of cost estimates, some of which are provided at the conceptual or other preliminary stage of projects and prior to commencement of conception of the detailed engineering needed to reduce the margin of error or level of accuracy; the integrity and reliability of Suncor's capital assets, the cumulative impact of other resource development; future environmental laws, the accuracy of Suncor's reserve, resource and future production estimates and its success at exploration and development drilling and related activities; the maintenance of satisfactory relationships with unions, employee associations and joint venture partners, competitive actions of other companies, including increased competition from other oil and gas companies or from companies that provide alternative sources of energy, the uncertainties resulting from potential delays or changes in plans with respect to projects or capital expenditures, actions by governmental authorities including the imposition of taxes or changes to fees and royalties, changes in environmental and other regulations, the ability and willingness of parties with whom Suncor has material relationships to perform their obligations to Suncor, and the occurrence of unexpected events such as fires, blowouts, freeze-ups, equipment failures and other similar events affecting Suncor or other parties whose operations or assets directly or indirectly affect Suncor. The foregoing important factors are not exhaustive.

Many of these risk factors and other specific risks and uncertainties are discussed in further detail throughout this Annual Information Form and in Suncor's MD&A, incorporated by reference herein. Readers are also referred to the risk factors described in other documents Suncor files from time to time with securities regulatory authorities. Copies of these documents are available without charge from the Company at 112 – 4th Avenue S.W., Calgary, Alberta, T2P 2V5, by calling 1-800-558-9071, or by email request to info@suncor.com.

References herein to Suncor's 2003 Consolidated Financial Statements mean Suncor's audited consolidated comparative financial statements, notes thereto and auditor's report thereon, as at and for the three years in the period ended December 31, 2003.

NON GAAP FINANCIAL MEASURES

Certain financial measures referred to in this AIF that are not prescribed by GAAP, namely, ROCE, cash flow from operations per common share and Oil Sands operating costs, are described and reconciled in the "Non GAAP Financial Measures", section of MD&A, incorporated by reference herein.

CORPORATE STRUCTURE

Name and Incorporation

Suncor Energy Inc. (formerly 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*. Suncor's articles were amended in 1995 to move its registered office from Toronto, Ontario, to Calgary, Alberta, and amended again in April 1997, to adopt its current name, "Suncor Energy Inc.". In April 1997, May 2000 and May 2002, Suncor's articles were amended to divide its issued and outstanding shares on a two-for-one basis.

Suncor's registered and principal office is located at 112 - 4th Avenue, S.W. Calgary, Alberta, T2P 2V5.

In this Annual Information Form, references to "Suncor" or the "Company" include Suncor Energy Inc., its subsidiaries and joint venture investments unless the context otherwise requires.

Intercorporate Relationships

Suncor Energy Inc. has two principal subsidiaries.

Suncor Energy Products Inc. ("SEPI") (formerly Sunoco Inc.) is an Ontario corporation that is wholly-owned by Suncor Energy Inc.. SEPI refines and markets petroleum products and petrochemicals directly and indirectly through subsidiaries and joint ventures. SEPI operates its retail business under the Sunoco brand in Canada. SEPI is unrelated to Sunoco, Inc. (formerly known as Sun Company, Inc.), headquartered in Philadelphia, Pennsylvania.

Suncor Energy Marketing Inc.("SEMI"), wholly-owned by SEPI, is incorporated under the laws of Alberta. SEMI markets, mainly to customers in Canada and the United States, the crude oil, diesel fuel and byproducts such as petroleum coke, sulphur and gypsum, produced by Suncor's Oil Sands business unit. It also markets certain third party products, and procures crude oil feedstocks for Suncor's downstream businesses. SEMI also has a petrochemical marketing division that holds a 50% interest in Sun Petrochemicals Company, a petrochemical products joint venture. Commencing in 2002, SEMI procures the natural gas supply for Suncor's Oil Sands and Energy Marketing and Refining ("EM&R") businesses, and administers Suncor's energy trading activities. Commencing in 2003, SEMI began marketing certain natural gas produced by Suncor's Natural Gas ("NG") business unit.

Suncor has a number of other subsidiary companies. However, the total assets of such subsidiaries combined, and their total sales and operating revenues, do not constitute more than 20 per cent of the consolidated assets, or consolidated sales and operating revenues, respectively, of Suncor.

GENERAL DEVELOPMENT OF THE BUSINESS

Overview

Suncor is an integrated energy company, with its corporate headquarters in Calgary, Alberta, Canada. Suncor explores for, acquires, develops, produces and markets crude oil and natural gas, transports and refines crude oil and markets petroleum and petrochemical products. Periodically Suncor also markets third party petroleum products. Suncor also carries on energy trading activities focused principally on buying and selling futures contracts and other derivative instruments based on the commodities Suncor produces. These activities are intended to earn revenues for the Company, optimize returns from assets and improve market intelligence.

Suncor has four principal operating business units. Oil Sands, based near Fort McMurray, Alberta, extracts bitumen from oil sands ore principally through its mining operations, but also periodically acquires bitumen from third parties and, commencing in 2004, through Suncor's in-situ Firebag operations. The bitumen is then upgraded into sweet and sour crude oil and diesel fuel. Natural Gas ("NG"), based in Calgary, Alberta, explores for, acquires, develops and produces natural gas. The sale of NG's production provides a price hedge for natural gas purchased for consumption at Suncor's Oil Sands facility and its refineries in Sarnia, Ontario and near Denver, Colorado. In addition, Suncor's U.S. subsidiary, Suncor Energy (Natural Gas) America Inc., is acquiring land and exploring for coal bed methane in the United States. Energy Marketing and Refining - Canada ("EM&R"), headquartered in Toronto, Ontario, refines crude oil at Suncor's refinery in Sarnia, Ontario, into a broad range of petroleum products, and markets the company's refined products to industrial, wholesale and commercial customers principally in Ontario and Quebec, and to retail customers in Ontario through Sunoco-branded and joint venture operated retail networks. The business also encompasses third party energy marketing activities and energy trading activities. Refining and Marketing – U.S.A. ("R&M"), headquartered in Denver, Colorado transports crude oil on its wholly or partly owned pipelines in Wyoming and Colorado, refines crude oil at Suncor's refinery in Commerce City, Colorado, near Denver, into a broad range of petroleum products, and markets the company's refined products to industrial, wholesale and commercial customers principally in Colorado and to retail customers in Colorado through Phillips 66 - branded sites.

While it provides hydrocarbon-based resources for the immediate energy needs of consumers, Suncor also pursues the development of low-emission and no-emission energy sources that have a reduced environmental impact. Segmented financial data for these activities is reported under the results of Suncor's "Corporate" segment for financial reporting purposes.

In 2003, Suncor produced approximately 251,500 BOE per day, comprised of 220,300 barrels per day (bpd) of crude oil and natural gas liquids and 187 million cubic feet per day of natural gas. In 2002, the most recent period with published results, Suncor was the 7th largest crude oil (approximately 9% of Canada's crude oil production) and natural

gas liquids producer and the 11th largest natural gas producer in Canada.

In 2003, Suncor sold approximately 94,400 bpd (2002 – 91,100 bpd) or 15,000 m^3 per day (2002 - 14,500 m^3 per day) of refined products, mainly in Ontario but also in the United States and Europe through its EM&R business unit. Suncor's refined product sales in Ontario represented approximately 19% (2002-17%) of Ontario's total refined product sales in 2003. Since the August 1, 2003 acquisition of the R&M business, that business sold approximately 56,900 bpd or 9,100 m^3 per day of refined products in Colorado, which includes approximately 43,700

bpd or 7,000 m^3 per day of light oils (gasoline and distillates). R&M supplies approximately 23% of Colorado's light oil product demand.

Three-Year History

Oil Sands

Oil Sands Growth Projects. In late 2001, Suncor completed construction of Project Millennium, an expansion of its Oil Sands plant near Fort McMurray, Alberta. The Project Millennium expansion involved an expanded mine, the addition of mining equipment, and twinning of the bitumen extraction and upgrading process through the construction of a second upgrading train (Upgrader #2). The project increased total design capacity of Suncor's Oil Sands operations to 225,000 bpd. The final capital cost of Project Millennium was $3.4 billion. The capital costs were financed by internally generated cash flow and additional borrowings.

Prior to completion of Project Millennium, Suncor announced a plan to further expand its Oil Sands operations and in 2001 Suncor received regulatory approval to proceed with development of a four-stage in-situ oil sands project on its Firebag oil sands leases ("Firebag"). The approval is conditioned on providing the regulators with project updates at least six months prior to any development on each stage after stage one. Combined with associated investments in the upgrading facility, the first stage of Firebag is expected to contribute to a planned increase in total Oil Sands production capacity to 260,000 bpd in 2005. The first stage of Firebag and the associated addition of a vacuum unit to the Oil Sands Millennium upgrader are estimated to cost approximately $1 billion. Subsequent to the end of 2003, Suncor began upgrading bitumen from the first stage of the Firebag in-situ oil sands development. Firebag stage one is expected to reach full production capacity of 35,000 bpd of bitumen production in 2005.

In late 2001, Suncor issued a public disclosure document for its Voyageur growth strategy, which targets production between 500,000 bpd to 550,000 bpd in 2010 to 2012. When Suncor originally released these plans, the Company stated it would apply for regulatory approval in late 2002. Following initial stakeholder consultation and preliminary engineering, Suncor modified its Voyageur plan, deferring applications for regulatory approval pending development of further details about each stage. Plans for the first stage of Voyageur were submitted to regulators in 2003. On April 3, 2003, Suncor announced details of its first Voyageur development, with plans to spend an estimated $3 billion to further increase production capacity to 330,000 bpd by late 2007. The production increase calls for expansion to Upgrader #2 principally through the addition of a coker unit, and development of three additional stages of Firebag. The $3 billion estimate is preliminary, and is subject to material variances as the plans and the final scope evolve and engineering work progresses to more detailed stages. Suncor's Board must approve the expansion plan and budget prior to construction beginning. A decision by the Board is expected in November 2004.

The final stage of Voyageur, including construction of a third Oil Sands' upgrader and proportionate increases in bitumen supply, is intended to increase production capacity to 500,000 to 550,000 bpd in the 2010 to 2012 timeframe. Preliminary cost estimates for this stage of production growth have not been announced. Contract costs will ultimately be dependent on engineering, market analysis, stakeholder consultation and an environmental and socio-economic impact assessment. All of this work is in its preliminary stages.

Other Highlights. On December 17, 2002, the Government of Canada announced its ratification of the Kyoto Protocol. For a discussion of the Kyoto Protocol and management's assessment of its possible impact on Suncor, refer to the "Outlook – Climate Change" section under "Suncor Overview and Strategic Priorities", in Suncor's MD&A.

On December 11, 2003, Suncor and Petro-Canada announced a 10-year agreement under which Suncor will process, on a fee for service basis, at least 27,000 bpd of Petro-Canada's bitumen into sour crude oil and in addition, sell 26,000 bpd of Suncor sour crude to Petro-Canada. Specific pricing terms of the agreement vary according to market conditions. Processing of bitumen and supply of Suncor sour crude oil pursuant to the terms of this agreement is expected to begin in 2008.

On December 18, 2003, Suncor announced it would launch an Environmental Impact Assessment in January 2004 on a proposed extension of its Oil Sands mining operations. The proposed development, an extension of Suncor's Steepbank Mine, would replace ore production that is expected to be depleted prior to the end of the decade. The proposed extension, which is expected to have an 11-year life, is part of Suncor's strategy to increase oil production through development of three bitumen sources: surface mining, in-situ development and third party sources. Operation is planned for 2010 with capital development costs currently estimated at $350 million. This estimate is preliminary and subject to material variances as plans advance and engineering work progresses to more detailed levels.

Energy Marketing & Refining - Canada (EM&R)

Sarnia Regional Co-Generation Project - In 2001, EM&R entered into a 20-year energy supply agreement with TransAlta Corporation ("TransAlta"). Under the agreement, the TransAlta Sarnia Regional co-generation Project, a multi-user co-generation project in Sarnia, Ontario, that commenced operation in the fourth quarter of 2002, supplies all of the steam and electricity requirements of EM&R's Sarnia Refinery. The agreement is expected to help mitigate EM&R's exposure to increases in energy costs and supply steam to the Sarnia Refinery at a competitive cost, while eliminating the need for EM&R to build its own steam generating boilers.

Sale of Retail Natural Gas Marketing Business - - In the second quarter of 2002, to sharpen its focus on refining and marketing, EM&R sold its retail natural gas marketing business, resulting in an after-tax gain of $35 million. EM&R entered the retail natural gas marketing business in 1997. At the time of sale, the business was supplying natural gas to approximately 125,000 commercial and residential customer accounts in Ontario.

Desulphurization Projects - Federal legislation passed in 1999 mandates sulphur levels in gasoline of an average of 150 parts per million (ppm) from mid-2002 to the end of 2004, and a maximum of 30 ppm by 2005. EM&R finalized an investment plan in 2001 to meet these sulphur content limits. Construction of the 10,250 barrels per day capacity gasoline desulphurization unit was completed in the fourth quarter of 2003 with the unit placed into service before the year-end, at an approximate total installed cost of $40 million.

In 2002, the Canadian government passed legislation limiting the concentration of sulphur in diesel fuel produced or imported for use in on-road vehicles to a maximum of 15 ppm, by June 1, 2006. The current maximum is 500 ppm. To meet these requirements, in October 2003, Suncor and Shell Canada Products Inc. ("Shell") entered into a 20-year agreement under which Suncor will build hydrotreating facilities at its Sarnia refinery to process high-sulphur diesel from both Suncor's and Shell's Sarnia refineries, to produce low sulphur diesel in compliance with the new on-road diesel limits. Under the agreement Shell will pay Suncor a processing fee. Operating a single hydrotreating unit, instead of two separate units, is expected to result in cost synergies to Suncor and Shell and environmental benefits for the Sarnia-Lambton community as one larger unit is expected to consume comparatively less energy and have lower greenhouse gas emissions. Engineering and construction details of the new facilities are in development. Subject to regulatory approval, construction of the new diesel desulphurization facilities is expected to begin in 2004, with project completion expected in early 2006.

The on-road diesel desulphurization project is currently estimated to cost $300 million. As this is a preliminary cost estimate, it is subject to change as scope is finalized and detailed engineering is developed. In Suncor's 2002 Annual Report, the company originally estimated it would cost $225 million to meet diesel desulphurization regulations. The estimate increased after Suncor entered into the agreement with Shell, which required expansion of the project scope to accommodate the higher capacity.

Regulations reducing sulphur in off-road diesel and light fuel oil are also expected to take effect later in the decade. Suncor believes that if the regulations are finalized as currently proposed, the new diesel desulphurization facilities for reducing sulphur in on-road diesel, should also allow it to meet the requirements for reducing sulphur in off-road diesel and light fuel oil.

In combination with the diesel desulphurization project, Suncor is currently assessing plans to modify the Sarnia refinery to permit the processing of additional Oil Sands crude oil. These modifications, as currently envisioned, are expected to increase refinery production capacity by about 10 per cent, and make the refinery more competitive through lower feedstock costs over the long term. Cost estimates for any such modification will be released once preliminary engineering is complete.

Ethanol - Suncor is continuing to review the feasibility of building a proposed ethanol plant in the Sarnia region. The proposed plant would produce approximately 200 million litres of ethanol annually for blending in fuels. The cost of constructing the facility is currently estimated to be $120 million. In February 2004, Suncor announced that its proposal for funding was approved by the federal government Ethanol Expansion Program. Subject to final approvals Suncor will receive a $22 million contribution towards the construction of an ethanol production facility. There are certain performance requirements that will determine if any of these funds may need to be repaid.

Other - In 2001, Suncor commenced an energy marketing business to generate additional income by buying and selling the crude oil and bitumen production of other companies. The activity conducted by this business, which increased Oil Sands revenue by $147 million in 2002, did not have a significant impact on the Company's earnings or cash flow in 2002. In 2003 this activity, with revenue of $132 million in 2003, was reclassified and is now reported in the EM&R business.

In 2002, Suncor's Board of Directors approved commencement of energy trading activities and after developing an appropriate control framework, Suncor began limited energy trading activities in November 2002. A separate risk management function monitors practices and policies and provides independent verification and valuation of Suncor's trading and marketing activities. Trading activities are principally focused on the commodities the Company produces, adding potential for new revenue and

providing a new window into energy product markets . Net trading losses (before tax) were negligible for the period ended December 31, 2002 and were $3 million for the period ended December 31, 2003.

Refining & Marketing – U.S.A.

On August 1, 2003, Suncor acquired a Denver-area refinery and related pipeline and retail assets from ConocoPhillips Company ("ConocoPhillips"). The acquisition is expected to provide Suncor with the flexibility to move additional Oil Sands production into the U.S. marketplace. Suncor paid US$150 million (about Cdn$210 million) for the assets, plus the cost of crude oil, product inventories and other closing adjustments, which totaled approximately US$44 million (about Cdn$62 million).

The acquisition includes:

- a 60,000 bpd refinery located in the Denver area;
- 43 Phillips 66 - branded retail stations, primarily in the Denver area, plus contract agreements with approximately 150 Phillips-branded marketer outlets throughout Colorado; and
- the Rocky Mountain and Centennial pipeline systems, located in Wyoming and Colorado. Suncor has 100% ownership of the 480 kilometre (300 mile) Rocky Mountain pipeline system and 65% ownership of the 140 kilometre (87 mile) Centennial pipeline system.

R&M currently estimates it will spend approximately $250 million to $325 million (approximately US$175 million to US$225 million) between 2003 and 2006 to meet requirements of fuels desulphurization legislation and to enable the refinery to integrate about 20,000 bpd of Oil Sands crude oil blends, with up to 15,000 bpd of Oil Sands sour crude oil. The legislation requires lower diesel sulphur levels (15 ppm) by June 2006 and lower gasoline sulphur levels (30 ppm average, 80 ppm cap) by 2009. The environmental permit application for all these proposed changes has been submitted. Construction for the diesel requirements is planned to be completed in early 2006, and includes a new desulphurization unit, a new hydrogen plant and a new tail gas treating unit for the existing sulphur recovery plants, and modifications to other existing units. Current cost estimates are preliminary and will be updated as scope design and engineering work progresses.

Suncor is currently assessing its plans for potential additional refinery modifications post 2006 in order to have the potential to integrate up to an additional 30,000 bpd of Oil Sands crude oil, including additional barrels of Oil Sands sour crude oil. Cost estimates for this project are not yet available.

As part of the agreement to acquire these assets, Suncor assumed obligations of ConocoPhillips at the refinery pursuant to a Consent Decree with the United States Environmental Protection Agency, the United States Department of Justice and the State of Colorado. These obligations are expected to require expenditures between $35 million to $45 million (approximately US$25 million to $30 million) between 2003 and 2006. The expenditures, intended to reduce air emissions at the refinery, are expected to be primarily capital.

With the acquisition of the R&M assets, Suncor assumed a workforce of approximately 585 employees, including about 300 retail employees, and has added approximately 50 employees since the acquisition.

Suncor also assumed the existing contract with the local Paper, Allied-Industrial Chemical and Energy Workers International Union, which covers approximately 150 employees at the refinery. This four-year contract is scheduled to expire in January 2006.

Other

Financing Activities

In 2001, Suncor issued $500 million in principal amount of Series 2 6.70% Medium Term Notes with a ten-year maturity.

In January 2002, Suncor issued US$500 million principal amount of 7.15% unsecured Notes due February 1, 2032, to investors in the United States (the "US") under it's $1 billion shelf prospectus.

In 2003 Suncor replaced its available credit and term loan facilities of approximately $1.8 billion with new facilities of $1.7 billion. Suncor's undrawn and uncommitted lines of credit at December 31, 2003 were approximately $1.6 billion. Suncor's current long-term debt ratings are A- (Standard & Poor's), A(low) (Dominion Bond Rating Service), and A3 (Moody's Investors Service). All debt ratings have a stable outlook. In 2003 Moody's removed its negative outlook in response to Suncor's debt reduction over the last two years.

In December 2003 Suncor issued US$500 million of 5.95% unsecured Notes under the remaining capacity of its US$1 billion shelf prospectus. Suncor now has utilized the complete capacity that was available under this shelf. The net proceeds of the debt offering, together with borrowings under the company's available credit and term loan facilities will be used to repay the company's 7.4% Debentures maturing February 2004 ($125 million) and to redeem the company's 9.05% and 9.125% Preferred Securities in March 2004 ($276 million and US$162.5 million, respectively).

Other Three Year Highlights

In April 2001, Suncor sold its interest in the Stuart Oil Shale Project to its Australian joint venture co-owners, Southern Pacific Petroleum NL ("SPP") and Central Pacific Minerals NL ("CPM") (together, "SPP/CPM"). Suncor's investment in the Project up to the date of sale, was approximately $285 million, including approximately $10 million invested in SPP/CPM shares. These investments were completely written off by 2002. Under the terms of the sale, Suncor retained a 5% royalty interest in the first stage of the project, and SPP/CPM and Suncor retained worldwide rights to the project technology. Suncor made total payments to SPP/CPM of Aus$7 million (approximately Cdn$5 million) for which Suncor received SPP/CPM shares and options which were subsequently sold or written off.

For further information on developments and issues referred to above and other highlights of 2003, and a discussion of other trends known to Suncor's management that could reasonably be expected to have a material effect on Suncor, refer to the

"Outlook" and other sections of Suncor's MD&A, and to "Risk/Success Factors" in this Annual Information Form.

NARRATIVE DESCRIPTION OF THE BUSINESS

OIL SANDS

Suncor produces a variety of refinery feedstock and diesel fuel by developing the Athabasca oil sands in northeastern Alberta and upgrading the bitumen extracted at its plant near Fort McMurray, Alberta. The Oil Sands operations, accounting for virtually all of Suncor's conventional and synthetic crude oil production in 2002 and 2003, represent a significant portion of Suncor's 2003 capital employed (76%)(3), cash flow from operations (2) (78%) and net earnings (81%). These percentages have been determined excluding the corporate and eliminations segment information.

Operations

Suncor's integrated Oil Sands business involves four operations. Bitumen is supplied from a combination of a mining operation using trucks and shovels, third party bitumen supply and commencing in 2004, supply from the Firebag in-situ operation. Extraction facilities recover the bitumen from the oil sand ore that is mined. A heavy oil upgrading process converts bitumen into crude oil products. Suncor's energy service needs are met through Oil Sands facilities (operated by TransAlta), that provides steam and electricity to the operations along with energy from TransAlta's proprietary natural gas fired co-generation plant that commenced operations in 2001. Suncor uses all of the steam and a portion of the power from the TransAlta co-generation facility. Suncor's energy services facilities primarily use petroleum coke, a by-product of the upgrading process,

as fuel. They also consume natural gas.

The first step of the open pit mining operation is to remove the overburden with trucks and shovels to access the oil sands - a mixture of sand, clay and bitumen. Oil sands ore is then excavated, and transported to one of five sizing plants by a fleet of trucks. The ore is dumped into sizers where it is crushed and sent to the ore preparation plants where it is mixed into a hot water slurry and pumped through hydrotransport pipelines to extraction plants on the east and west sides of the Athabasca River. The bitumen begins to separate from the sand as the slurry is pumped through the lines. Bitumen is extracted from the oil sands ore with a hot water process. After the final removal of impurities and minerals, naphtha is added to the bitumen as diluent to facilitate transportation to the upgrading plant. Periodically bitumen is sold rather than being upgraded. In 2003, approximately 6,400 bpd of bitumen were sold, representing approximately three percent of Oil Sands' 2003 sales. In 2002 bitumen sales of 9,300 bpd represented five percent of Oil Sands' sales.

After the diluted bitumen is transferred to the upgrading plant, the naphtha is removed and recycled to be used again as diluent. The bitumen is upgraded through a coking and distillation process. The upgraded product, referred to as sour crude oil, is either sold directly to customers or is further upgraded into sweet crude oil by removing the sulphur and nitrogen using a hydrogen treating process. Three separate streams of refined crude oil are produced: naphtha, kerosene and gas oil.

(3) Refer to "Non GAAP Financial Measures" on page xi of this AIF.

While there is virtually no finding cost associated with synthetic crude oil, delineation of the resources and development and expansion of production can entail significant outlays of funds. The costs associated with synthetic crude oil production are largely fixed for the same reason and, as a result, operating costs per unit are largely dependent on levels of production. Natural gas is used or consumed in the production of synthetic crude oil, particularly under the steam assisted gravity drainage (SAGD) method of bitumen production from Suncor's Firebag operations, and accordingly natural gas prices are a key variable component of synthetic crude oil production cost. Operating costs to produce synthetic crude oil are generally higher than lifting and administrative costs to produce conventional crude oil from the Western Canada Sedimentary Basin.

Transportation

Oil Sands entered into a transportation service agreement with a subsidiary of Enbridge for a term that commenced in 1999 and extends to 2028. Under the agreement, Suncor's initial pipeline capacity was 60,000 bpd in 1999, increasing to 170,000 bpd in 2005, of synthetic crude oil and bitumen from Fort McMurray, Alberta to Hardisty, Alberta. This pipeline, together with Suncor's proprietary pipeline, is expected to meet Suncor's anticipated crude oil shipping requirements for expected future production levels up to 2008.

Suncor markets its crude oil product blends for sale and distribution to customers in Canada, the United States and periodically, to offshore markets.

Suncor has a 20 year agreement with TransCanada Pipeline Ventures Limited Partnership ("TCPV"), to provide Suncor with firm capacity on a natural gas pipeline that came into service in 1999. The natural gas pipeline ships natural gas to Suncor's Oil Sands facility.

Suncor also transports natural gas to its Oil Sands operations on the Suncor-owned and operated Albersun pipeline, constructed in 1968. It extends approximately 300 kilometres south of the plant and connects with the TCPL Alberta intra-provincial pipeline system. The Albersun pipeline has the capacity to move in excess of 100 mmcf/day of natural gas. Suncor arranges for natural gas supply and controls most of the natural gas on the system under delivery based contracts. The pipeline moves natural gas both north and south for Suncor and other shippers. In 2003, throughput on the Albersun pipeline was approximately 50 mmcf/day.

Suncor's Oil Sands facilities are readily accessible by public road.

Competitive Conditions

Competitive conditions affecting Oil Sands are described under the heading "Competition" in the "Risk/Success Factors" section of this Annual Information Form.

Seasonal Impacts

Severe climatic conditions at Oil Sands can cause reduced production during the winter season and in some situations can result in higher costs.

Sales of Synthetic Crude Oil and Diesel

Aside from on site fuel use, all of Oil Sands' production is sold to, and subsequently marketed by, Suncor Energy Marketing Inc.

In 1997, Suncor entered into a long-term agreement with Koch Industries Inc. ("Koch") to supply Koch with up to 30,000 bpd (approximately 14% of Suncor's average 2003 total production) of sour crude from Suncor's Oil Sands operation. Suncor began shipping the crude to Koch's terminal at Hardisty (from which Koch ships the product to its refinery in Minnesota) under this long-term agreement effective January 1, 1999. The initial term of the agreement extends to January 1, 2009, with month to month evergreen terms thereafter, subject to termination after January 1, 2004, on twenty-four months' notice by either party. Neither party has provided notice at this time.

In 2000, Suncor announced a long term sales agreement with Consumers' Co-operative Refineries Limited ("CCRL") under which Suncor expected to begin supplying CCRL with 20,000 bpd of sour crude oil production from its Project Millennium expansion facilities by late 2002. After certain construction delays, CCRL began accepting delivery of sour crude in the first quarter of 2003.

Prices for sour crude oil under these agreements are set at agreed differentials to market benchmarks.

In 2001, Suncor announced a long-term agreement with Petro-Canada to supply up to 30,000 barrels per day of diluent to dilute bitumen produced by Petro-Canada. Deliveries under the contract have commenced. The agreement is for four years and may be extended unless terminated by either party. The diluent supply agreement is expected to end when the bitumen processing and sour crude oil supply agreement, described below, takes effect.

Bitumen to feed the planned upgrader expansion is expected to be provided under a processing agreement between Suncor and Petro-Canada, expected to take effect in 2008. Under the agreement, Suncor will process at least 27,000 bpd of Petro-Canada bitumen on a fee for service basis. Petro-Canada will retain ownership to the bitumen and resulting sour crude oil production of about 22,000 bpd. In addition, Suncor will sell an additional 26,000 bpd of Suncor proprietary sour crude oil production to Petro-Canada. Both the processing and sales components of the agreement will be for a minimum 10-year term. This agreement with Petro-Canada is subject to regulatory and Board approvals.

There were no customers that represented 10% or more of Suncor's consolidated revenues in 2003. There was one customer in 2002 that represented 10% or more of Suncor's consolidated revenues.

A portion of Oil Sands production is used in connection with Suncor's Sarnia refining operations. During 2003, the Sarnia refinery processed approximately 10% (2002 -12%) of Oil Sands crude oil production. With the acquisition of the Denver area refinery in August 2003, there were some minor sales volumes to this facility.

Environmental Compliance

For a description of the impact of environmental protection requirements on Oil Sands, refer to "Environmental Regulation and Risk" and "Governmental Regulation" in the "Risk/Success Factors" section of this Annual Information Form, and "Reclamation and Environmental Remediation Cost" under "Critical Accounting Policies and Estimates" in the "Suncor Overview and Strategic Priorities" section of MD&A.

NATURAL GAS

Suncor's Natural Gas business, based in Calgary, Alberta, explores for, develops and produces conventional natural gas in western Canada, supplying it to markets throughout North America. The sale of NG's production provides a price hedge for natural gas purchased for consumption at Suncor's Oil Sands facility and its refineries in Sarnia, Ontario and near Denver, Colorado. In addition, Suncor's U.S. subsidiary, Suncor Energy (Natural Gas) America Inc., is acquiring land and exploring for coal bed methane in the United States.

In 2003, natural gas and natural gas liquids accounted for approximately 96% of the NG business unit's production.

NG's exploration program is focused on multiple geological zones in three core asset areas: Northern (northeast British Columbia and northwest Alberta), Foothills (western Alberta and portions of northeast British Columbia) and Central Alberta. Suncor drills primarily medium to high-risk wells focusing on prospects that can be connected to existing infrastructure.

During 2003 NG disposed of its interest in Frontier properties (the Arctic and Northwest Territories) including 28 long-term "significant discovery licences". There was no production from these interests.

Marketing, Pipeline and Other Operations

Suncor operates natural gas processing plants at South Rosevear, Pine Creek, Boundary Lake South, Progress and Simonette with a total design capacity of approximately 206 mmcf/day. Suncor's capacity interest in these gas processing plants is approximately 128 mmcf/day. Suncor also has varying undivided percentage interests in natural gas processing plants operated by other companies and processing agreements in facilities where it does not hold an ownership interest.

Approximately 75% of Suncor's natural gas production is marketed under direct sales arrangements to customers in Alberta, British Columbia, eastern Canada, and the United States. 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. Under these contracts, Suncor is responsible for transportation arrangements to the point of sale. Some of the direct sales arrangements include some of the natural gas consumed in Suncor's Oil Sands plant at Fort McMurray and in the EM&R operations.

Approximately 25% of Suncor's natural gas production is sold under existing contracts to aggregators ("system sales"). Proceeds received by producers under these sales arrangements are determined on a netback basis, whereby each producer receives revenue equal to its proportionate share of sales less regulated transportation charges and a marketing fee. Most of Suncor's system sales volumes are contracted to TransCanada Gas Services and Pan-Alberta Gas Ltd. These companies resell this natural gas primarily to eastern Canadian and Midwest and eastern United States markets.

To provide exposure to the Pacific North West and California markets, Suncor has entered into a long-term gas pipeline transportation contract on the National Energy Group Transmission Pipeline (formerly Pacific Gas Transmission).

NG's conventional crude oil production is generally sold under spot contracts or under contracts that are terminable on relatively short notice. Suncor's conventional crude oil production is shipped on pipelines operated by independent pipeline companies. The NG business currently has no pipeline commitments related to the shipment of crude oil.

Competitive Conditions

Competitive conditions affecting Suncor's NG business are described under the heading "Competition" in the "Risk/Success Factors" section of this Annual Information Form.

Environmental Compliance

For a description of the impact of environmental protection requirements on NG, refer to "Environmental Regulation and Risk" and "Government Regulation" in the "Risk/Success Factors" section of this Annual Information Form, and "Reclamation and Environmental Remediation Cost" under "Critical Accounting Policies and Estimates" in the "Suncor Overview and Strategic Priorities" section of MD&A.

ENERGY MARKETING & REFINING - - CANADA

Suncor's EM&R business unit operates a refining and marketing business in Central Canada, and an energy marketing and trading business. Its refinery in Sarnia, Ontario, refines petroleum feedstock from Oil Sands and other sources into gasoline, distillates, and petrochemicals with the majority of them being distributed in its primary market of Ontario. For information about EM&R's energy marketing business, refer to "Energy Marketing and Refining – Canada (EM&R) Three-Year Highlights", under the "Other" heading.

Approximately 58% of EM&R's petroleum products sales in 2003 (2002 – 62%) was sold through a distribution network in Ontario that sells gasoline and diesel fuel to retail customers. Approximately 37% (2002 – 33%) was sold to industrial, commercial, wholesale and refining customers in Ontario and Quebec, representing primarily jet fuels, diesel and gasoline. The remaining 5% (2002 - 5%) represents petrochemical sales to the United States and Europe through Sun Petrochemicals Company, a 50% joint venture between a Suncor subsidiary and a U.S. company.

EM&R's financial reporting is based on its Rack Back / Rack Forward organizational structure. The Rack-Back division procures and refines crude oil and feedstocks, and sells and distributes refined products to the Sarnia refinery's largest industrial and reseller customers. The Rack-Forward division is comprised of retail operations, retail natural gas marketing (which was sold in the second quarter of 2002), cardlock and industrial / commercial sales, and the UPI Inc. ("UPI") and Pioneer joint venture businesses. UPI is a joint venture company owned 50% by each of EM&R and GROWMARK Inc., a U.S. Midwest agricultural supply and grain marketing cooperative. Pioneer is a 50% joint venture partnership between EM&R and The Pioneer Group Inc.

Procurement of Feedstocks

EM&R's refining operation uses both synthetic and conventional crude oil. In 2003, the Sarnia refinery procured approximately 53% (2002 – 58%) of its synthetic crude oil feedstock from Suncor's Oil Sands production. In 2003, 64% (2002 – 65%) of the crude oil refined at the Sarnia Refinery was synthetic crude oil. The balance of the refinery's synthetic crude oil, as well as its conventional and condensate feedstocks, were purchased from others under month to month contracts. In the event of a significant disruption in the supply of synthetic crude oil, the refinery has the flexibility to substitute other sources of sweet or sour conventional crude oil.

Suncor procures conventional crude oil feedstock for its refinery primarily from western Canada, supplemented from time to time with crude oil from the United States and other countries. Foreign crude oil is delivered to Sarnia via pipeline from the United States Gulf Coast or via the Interprovincial Pipeline from Montreal. Suncor has not made any firm commitments for capacity on these pipeline systems. Crude oil is procured from the market on a spot basis or under contracts terminable on short notice.

In 1998, EM&R signed a 10-year synergistic feedstock agreement with a Sarnia-based petrochemical refinery, Nova Chemicals (Canada) Ltd. Under this buy/sell agreement, EM&R obtains feedstock that is more suitable for production of transportation fuels in exchange for feedstock more suitable for petrochemical cracking. EM&R also enters into reciprocal buy/sell or exchange arrangements with other refining companies from time to time as a means of minimizing transportation costs, balance product availability and enhance refinery utilization. EM&R also purchases refined products in order to meet customer requirements.

Refining Operations

The Sarnia refinery produces transportation fuels (gasoline, diesel, propane and jet fuel), heating fuels, liquefied petroleum gases, residual fuel oil, asphalt feedstock, benzene, toluene, mixed xylenes and orthoxylene, as well as the petrochemicals A-100 and A-150 that are used in the manufacture of paint and chemicals.

The refinery has the capacity to refine 70,000 bpd of crude oil. Refining sales in 2003 averaged approximately 92,100 bpd (2002 – 91,100) from the Sarnia refinery. The refinery is configured to allow for operational flexibility. In addition to conventional sweet and sour crudes, the refinery is capable of processing sweet synthetic crude oil, which yields a more valuable product mix. A hydrocracker, jet fuel tower and low-sulphur diesel tower further increase the refinery's ability to produce premium-value transportation fuels, distillates and naphtha, and its flexibility to vary the gasoline/distillate ratio. The hydrocracker has capacity to process approximately 23,300 barrels per day. Additional flexibility in gasoline, octane and petrochemical production is provided by the complementary operations of an alkylation unit with a capacity of 5,400 barrels per day. The alkylation unit produces a high octane gasoline blending component. The petrochemical facilities have a capacity of 13,100 barrels per day and

produce benzene, toluene, mixed xylenes, orthoxylene and A-100 and A-150. A gasoline desulphurization unit that came into service in the fourth quarter of 2003 has a capacity to process 10,250 bpd of gasoline components.

The refinery has a cracking capacity of 40,200 barrels per day from a Houdry catalytic cracker ("catcracker") and a hydrocracker. Approximately 40% of the cracking capacity is attributable to the catcracker, which uses older cracking technology.

In 2003, EM&R completed a planned maintenance shutdown on a portion of the refinery, involving a crude unit, alkylation unit, and the catcracker. In addition, utilization was less than capacity in 2003 primarily due to impacts of a widespread power outage that struck the northeastern United States and southern Ontario in August. As a result, the refinery operated with lower utilization rates in the last two quarters of the year. In 2004 Suncor will, as part of an ordinary course asset review, conduct a study to assess the catcracker. This unit is one of the original refinery assets built in the 1950's.

Overall, crude utilization averaged 95% for the year, unchanged from 2002. The following chart sets out daily crude input, average refinery utilization rates, and cracking capacity utilization of the Sarnia Refinery over the last two years.

Sarnia Refinery Capacity	2003	2002
Average daily crude input (barrels per day)	66,300	66,400
Average crude utilization rate (%)(1)	95	95
Average cracking capacity utilization (%)(2)	87	91

Notes:

(1) Based on crude unit capacity and input to crude units.

(2) Based on cracking capacity and input to the hydrocracker and catalytic cracker.

The refinery's steam and electricity needs are currently being met by supply from the Sarnia Regional Co-generation Project. For more details, see the EM&R section under "Three Year Highlights" in this Annual Information Form.

Principal Products

Sales of gasoline and other transportation fuels represented 79% of EM&R's consolidated operating revenues in 2003 compared to 77% in 2002. Set forth below is information on daily sales volumes and percentage of EM&R's consolidated operating revenues contributed by product group for the last two years.

Product:	2003		2002	
	(thousands of cubic meters per day)	(% of EM&R's consolidated revenues)	(thousands of cubic meters per day)	(% of EM&R's consolidated revenues)
Transportation Fuels				
Gasoline				
Retail	4.4	32	4.5	33
Joint Ventures	3.1	18	3.2	18
Other	1.1	11	1.2	10
Jet Fuel	0.7	3	0.4	2
Diesel	3.0	15	2.9	14
Sub-total – Transportation Fuels	12.3	79	12.2	77
Petrochemicals	0.8	5	0.6	4
Heating Fuels	0.5	4	0.4	3
Heavy Fuel Oils	0.8	2	0.6	2
Other	0.6	2	0.7	2
Total Refined Products	15.0	92	14.5	88
Other Non-Refined Products(1)		3		6
Energy Marketing & Trading (2)		5		6
Total %		100		100

Notes:

(1) Includes ancillary revenues including non-fuel retail sales.
(2) Includes all energy marketing and trading revenues.

Principal Markets

Approximately 58% (2002 – 62%) of EM&R's total sales volumes are marketed through retail networks, including the EM&R Sunoco-branded retail network, joint-venture operated retail stations and cardlock operations. This network is comprised of:

279 (2002 – 287) Sunoco-branded retail service stations
147 (2002 – 148) Pioneer-operated retail service stations
53 (2002 – 50) UPI-operated service stations and a network of 14 bulk distribution facilities for rural and farm fuels

18 (2002 – 18) Sunoco branded Fleet Fuel Cardlock sites

Refined petroleum products (excluding petrochemicals) are marketed under several brands, including the Company's Canadian "Sunoco" trademark. EM&R's other principal trademarks include "Ultra 94" in respect of its premium high octane gasoline, and "Gold Diesel" used in respect of its premium low sulphur diesel product.

Approximately 37% (2002 – 33%) of EM&R's total sales volumes are sold to industrial, commercial, wholesale, and refining customers, primarily in Ontario. EM&R also supplies industrial and commercial customers in Quebec through long-term arrangements with other regional refiners, or through Group Petrolier Norcan Inc., a 25% EM&R-owned fuels terminal and product supply business in Montreal.

EM&R markets toluene, mixed xylenes, orthoxylene and petrochemicals, primarily in Canada and the U.S., through Sun Petrochemicals Company. EM&R has a 50% interest in Sun Petrochemicals

Company, a petrochemical marketing joint venture that markets products from EM&R's Sarnia Refinery and from a Toledo, Ohio, refinery owned by the joint venture partner. Sun Petrochemicals Company markets petrochemicals used to manufacture plastics, rubber, synthetic fibres, industrial solvents and agricultural products, and as gasoline octane enhancers. All benzene production is sold directly to other petrochemical manufacturers in Sarnia.

EM&R's share of total refined product sales in its primary market of Ontario was approximately 19% in 2003 (2002 – 17%). Transportation fuels accounted for 82% of EM&R's total sales volumes in 2003 (2002 – 83%); and petrochemicals accounted for 5% (2002 – 4%). The remaining volumes included other refined products such as heating fuels, heavy oils and liquefied petroleum gases, and were sold to industrial users and resellers.

EM&R supplies refined petroleum products to the Pioneer and UPI joint ventures. Suncor has a separate supply agreement with each of UPI and Pioneer. These supply agreements are evergreen, subject to termination only in accordance with the various agreements between the parties.

Transportation and Distribution

EM&R uses a variety of transportation modes to deliver products to market, including pipeline, water, rail and road. EM&R owns and operates petroleum transportation, terminal and dock facilities, including storage facilities and bulk distribution plants in Ontario. The major mode of transporting gasoline, diesel, jet fuel and heating fuels from the Sarnia Refinery to core markets in Ontario is the Sun-Canadian Pipe Line, which is 55% owned by Suncor and 45% owned by another refiner. The pipeline operates as a private facility for its owners. It serves terminal facilities in Toronto, Hamilton and London, and has a capacity of 126,000 bpd (20,000 cubic metres). EM&R utilized 53% of this capacity in 2003. Total utilization of the pipeline was 83% in 2003.

EM&R also has direct pipeline access to petroleum markets in the Great Lakes region of the United States by way of connection to a pipeline system in Sarnia operated by a U.S. based refiner. This link to the U.S. allows EM&R to move products to market or obtain feedstocks/products when market conditions are favourable in the Michigan and Ohio markets.

EM&R believes its own storage facilities, and those under long-term contractual arrangements with other parties, are sufficient to meet its current and foreseeable storage needs.

Competitive Conditions

Competitive conditions affecting Suncor's EM&R business are described under the heading "Competition" in the "Risk/Success Factors" section of this Annual Information Form.

Environmental Compliance

For a description of the impact of environmental protection requirements on EM&R, please refer to the sections entitled "Outlook" and "Risk/Success Factors Affecting Performance" in the EM&R section of MD&A. Also refer to "Environmental Regulation and Risk" and "Governmental Regulation" in the "Risk/Success Factors" section and the EM&R "Three Year History" section, of this Annual Information Form, and "Reclamation and Environmental Remediation Cost" under "Critical Accounting Policies and Estimates" in the "Suncor Overview and Strategic Priorities" section of MD&A.

REFINING & MARKETING – U.S.A.

Suncor's R&M business unit, which was acquired August 1, 2003, operates a pipeline transportation, refining and marketing business primarily in Colorado and Wyoming. Its Denver area refinery, located in Commerce City, Colorado, has a crude distillation capacity of 60,000 bpd, processing a mixture of Canadian heavy, high sulphur crudes, and domestic heavy, high sulphur and low sulphur crudes. The majority of the refined products from Suncor's Denver refinery are distributed in its primary market of Colorado.

Approximately 30% of R&M's petroleum products sales from August 1, 2003 until the end of the year were sold through a distribution network in Colorado that sells gasoline and diesel fuel to retail customers. R&M's retail network includes 43 Phillips 66-branded company operated sites, as well as contractual agreements with approximately 150 Phillips 66 - branded marketer outlets throughout Colorado. Approximately 51% of R&M's petroleum product sales were to industrial, commercial, wholesale and refining customers in Colorado, representing primarily jet fuels, diesel and gasoline. Asphalt sales comprise the remaining 19% of R&M's refined product sales for 2003.

Procurement of Feedstocks

R&M's refining operation uses conventional crude oil. Approximately 45% of the Denver refinery's crude oil is purchased from Canadian sources, with the remainder supplied from sources in the United States, primarily in the Rocky Mountain region. The refinery's crude oil purchase contracts have terms ranging from month-to-month to one year. In the event of a significant disruption in the supply of crude oil, the refinery has the flexibility to substitute other sources of sweet or sour crude oil on a spot purchase basis.

R&M has a processing agreement with a third party refinery located in Cheyenne, Wyoming, that has coking capabilities. Under the agreement, which terminates in May 2004, R&M sends residual coke from its refinery to the third party refinery to be processed into coker gas oil, which is then sent to R&M's refinery where it can then be further processed into finished products. R&M is currently reviewing options for renewal or replacement of this contract.

Refining Operations

The Denver refinery has a crude distillation capacity of 60,000 bpd, processing a mixture of Canadian heavy, high sulphur crudes, and domestic heavy, high sulphur and low sulphur crudes. Upgrading units of the Denver refinery include a 19,000 bpd fluidized catalytic cracker, a 12,500 bpd distillate hydrotreater and a 14,000 bpd gas oil hydrotreater. The refined gasoline products from the Denver refinery supply R&M's marketing operations in Colorado. Refining sales in 2003 averaged approximately 56,900 bpd (9,100 m^3 per day).

The Denver refinery is a high conversion refinery that produces a full range of products, including gasoline, jet fuels, diesel and asphalt. The refinery's upgrading units enable it to process a crude slate containing nearly 50 percent heavy, high sulphur crude. Overall, crude utilization averaged 98% for the period from August 1, 2003 to December 31, 2003. The following chart sets out daily crude input, average refinery utilization rates and cracking capacity utilization for this five month period.

Denver Refinery Capacity	August 1, 2003 – December 31, 2003
Average daily crude input (barrels per day)	58,800
Average crude utilization rate (%)(1)	98
Average fluidized catalytic cracker capacity utilization rate (%)(2)	95

Notes:

(1) Based on crude unit capacity and input to crude units.

(2) Based on cracking capacity and input to other units or sales made to customers.

Principal Products

Sales of gasoline and other transportation fuels represented 85% of R&M's consolidated operating revenues in the period from August 1, 2003 to December 31, 2003. Set forth below is information on daily sales volumes and percentage of R&M's consolidated operating revenues contributed by product group for this five-month period.

Product:	August 1, 2003 to December 31, 2003	
	(thousands of cubic meters per day)	(% of R&M's consolidated revenues)
Transportation Fuels		
Gasoline		
Retail	.7	13
Other	3.5	40
Jet Fuel	.5	6
Diesel	2.3	26
Total Transportation Fuels	7.0	85
Asphalt	1.7	10
Other	.4	2
Total Refined Product Sales	9.1	97
Other Non-Refined Product (1)		3
		100

Note:

(1) Ancillary revenues include non-fuel retail sales.

Principal Markets

Approximately 30% of R&M 's total sales volumes are marketed through Phillips 66 - branded retail outlets. This network is comprised of:

- 43 owned Phillips 66 - branded retail sites, which account for approximately 9% of R&M's sales volumes.
- Supply agreements with more than 150 Phillips-66 branded marketer outlets throughout the state of Colorado, which account for approximately 21% of R&M's sales volumes. These agreements are typically for three year terms with provision for automatic three year renewal periods on an evergreen basis.

Suncor has an exclusive license from ConocoPhillips to use the Phillips 66 and related trademarks and brand names in Colorado from August 1, 2003 until December 31, 2012.

The Denver refinery also supplies all of its asphalt production to KC Asphalt, a joint venture between ConocoPhillips and Koch Industries, Inc. Asphalt sales made up about 19% of R&M's total 2003 sales volumes.

Approximately 51% of R&M's total sales volumes are sold to industrial, commercial, wholesale, and

refining customers, primarily in Colorado, of which approximately two thirds was sold under a long-term supply agreement with ConocoPhillips in 2003. Under this agreement, R&M supplies ConocoPhillips with gasoline and distillates. Under the terms of the agreement, the supplied volumes are to decrease over time until approximately half of the current volumes will be supplied in the 10th year of the agreement.

R&M estimates its sales of total light fuels refined product in 2003 represented a market share, in its primary market of Colorado, of approximately 23%. Within this market, R&M's Phillips 66 - branded sites represent a 13% market share.

Transportation and Distribution

Almost all crude oil processed at the Denver refinery is transported via pipeline. R&M owns and operates crude transportation systems from Guernsey, Wyoming to Denver, Colorado. The Rocky Mountain Crude system is a common carrier pipeline that transports crude for the Denver refinery as well as for other shippers. R&M also operates a joint venture crude pipeline from Guernsey, Wyoming to Cheyenne, Wyoming. The joint venture pipeline is approximately 65% owned by Suncor. The other 35% is owned by another area refiner. From August 1, 2003 to December 31, 2003, the Rocky Mountain Crude system utilized more than 100% of capacity due the use of a drag reducing agent, with average throughput of 39,000 barrels per day in the Guernsey to Cheyenne leg of the pipeline, and 70,000 barrels per day in the higher capacity Cheyenne to Denver leg. During the same period, the joint venture pipeline utilized approximately 99% of capacity, with an average throughput of approximately 63,500 barrels per day.

R&M has its own 30,000 bpd capacity truck-loading terminal at the Denver area refinery where customers can pick up product, a one mile long 7,000 bpd jet fuel pipeline that connects to a common carrier pipeline system for deliveries to the Denver International Airport, and a four mile long 14,000 bpd diesel pipeline that delivers diesel product directly to the Union Pacific railroad yard in Denver, Colorado.

R&M believes its own storage facilities, and those under long-term contractual arrangements with other parties, are sufficient to meet its current and foreseeable storage needs.

Competitive Conditions

Competitive conditions affecting Suncor's Refining & Marketing – U.S.A. business are described under the heading "Competition" in the "Risk/Success Factors" section of this Annual Information Form.

Environmental Compliance

Due to increasingly stringent regulations regarding water discharges, the Denver Refinery will have to add additional water treating equipment for the discharge of process waste water. It is estimated that this will cost approximately $3 million and be completed in the 2006-2008 timeframe. For a description of other impacts of environmental protection requirements on Refining & Marketing – U.S.A., please refer to the R&M section of "Three Year History" of this Annual Information Form, and the sections entitled "Outlook" and "Risk/Success Factors Affecting Performance" in the Refining & Marketing – U.S.A. section of the MD&A. Also refer to "Environmental Regulation and Risk" and "Governmental Regulation" in the "Risk/Success Factors" section of this Annual Information Form, and "Reclamation and Environmental Remediation Cost" under "Critical Accounting Policies and Estimates" in the "Suncor Overview and Strategic Priorities" section of MD&A.

RESERVES ESTIMATES

In 2003, Suncor engaged Gilbert Laustsen Jung Associates Ltd. ("GLJ"), independent petroleum consultants, to evaluate, as at December 31, 2003, Suncor's oil and gas reserves. In reports dated February 20, 2004, GLJ evaluated Suncor's proved and probable reserves of synthetic crude oil on its oil sands mining leases and in-situ oil sands Firebag leases. Together, these two reports are the "GLJ Oil Sands Reports". In the GLJ Oil Sands Reports, GLJ estimates Suncor's gross proved plus probable reserves of synthetic crude oil from oil sands mining and in situ leases total 3.9 billion barrels. This total includes estimates from Suncor's mining leases that account for 1.8 billion barrels, consisting of 0.9 billion barrels of proved and 0.9 billion barrels of probable reserves, as well as in-situ leases containing 0.4 billion barrels of proved and 1.7 billion

barrels of probable reserves. These values are before deduction of Crown and other royalties on the leases. The Oil Sands reserves from both mining and in-situ leases are presented in this paragraph on a gross basis for purposes of showing the aggregate estimate of Oil Sands proved and probable reserves. However, as required by U.S. disclosure practices, reserves from our Firebag in-situ leases are presented under "U.S. Oil and Gas Disclosure" on a net basis and accordingly will not be comparable to the gross reserves total referenced in this paragraph.

GLJ's estimates consider recovery from leases for which regulatory approvals have been granted. The mining reserve estimates are based upon a detailed geological assessment and also consider industry practice, drill density, production capacity, extraction recoveries, upgrading yields, mine plans, operating life, and regulatory constraints. For Firebag reserve estimates, GLJ considered similar factors such as Suncor's regulatory approval, project implementation commitments, detailed design estimates, detailed reservoir studies, demonstrated commercial success of analogous commercial projects, and drill density. Suncor's proved and probable reserves are contained within the AEUB approval area. Suncor's proved reserves are delineated with 40 to 80 acre spacing plus 3D seismic control while Suncor's probable reserves are delineated with 80 to 160 acre spacing plus 3D seismic control. Firebag is currently on production in early 2004. The major facility expenditures to develop Suncor's proved undeveloped reserves have obtained final approval by the company's board. Plans to develop the company's probable undeveloped reserves in subsequent phases are under way but have not yet received final approval from the company's board.

GLJ also issued a report dated February 20, 2004, with respect to GLJ's evaluation of Suncor's proved reserves of natural gas, natural gas liquids and crude oil (other than reserves from Suncor's mining leases and the Firebag in-situ reserves) (the "GLJ NG Report") as at December 31, 2003. In the GLJ NG Report, GLJ estimates Suncor's proved reserves of natural gas, natural gas liquids and crude oil (other than reserves from Suncor's mining leases and the Firebag in-situ reserves) total 456

billion cubic feet (bcf) of natural gas and 8 million barrels of crude oil and natural gas liquids for a total of 84 million barrels of oil equivalent. NG reserves are expressed on a net basis, to exclude interests of third parties, and Crown, freehold and other royalties. 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.

Suncor's reserves estimates will continue to be impacted by both drilling data and operating experience, as well as technological developments and economic considerations.

Oil Sands Mining and In-Situ Firebag Res erves Reconciliation

The following table sets out, on a gross(1) basis, a reconciliation of Suncor's proved and probable reserves of synthetic crude oil from its Oil Sands mining leases and its in-situ Firebag leases, from December 31, 2002 to December 31, 2003, based on the GLJ Oil Sands Reports.

(1) See footnote (4) in the Estimated Proved and Probable Reserves Reconciliation below.

Estimated Proved and Probable Oil Sands Reserves Reconciliation

(millions of barrels of synthetic crude oil)(1)	Oil Sands Mining Leases			In-situ Firebag Leases(2)			Total Mining and In-situ(4)
	Proved(3)	Probable	Proved & Probable	Proved(3)	Probable	Proved & Probable	Proved & Probable
December 31, 2002	358	1,563	1,921	144	1,696	1,840	3,761
Revisions of previous estimates	599	(611)	(12)	243	25	268	256
Extensions and discoveries	—	—	—	—	—	—	—
Production	(79)	—	(79)	—	—	—	(79)
December 31, 2003	878	952	1,830	387	1,721	2,108	3,938

Notes:

(1) Synthetic crude oil reserves based upon a net coker, or synthetic crude oil yield of between 80% and 82%.

(2) Suncor has the option of selling the bitumen production from these leases and/or upgrading the bitumen to synthetic crude oil.

(3) All of Suncor's proved mining reserves are classified as proved producing reserves. The reclassification of mining reserves from the probable to proved category in 2003, reflects the 2003 drilling program and use of revised criteria for classifying portions of the ore body as proved. All of Suncor's Firebag In-situ proved reserves are classified as proved non-producing reserves as at December 31, 2003. Subsequent to the end of 2003, Suncor began upgrading bitumen from the first stage of the Firebag in-situ oil sands development. Firebag phase one is expected to reach full production capacity of 35,000 bpd of bitumen production in 2005.

(4) Our Oil Sands reserves from mining leases and in-situ leases are both presented in this reconciliation on a gross basis for purposes of showing the aggregate estimate of Oil Sands proved and probable reserves. However, as required in connection with U.S. disclosure practices, reserves from our Firebag In-situ leases are presented under the heading "U.S. Oil and Gas Disclosure" below on a net basis and accordingly will not be comparable to the gross reserves referenced in this reconciliation.

U.S. OIL AND GAS AND MINING DISCLOSURE

Oil Sands Mining Operations

(millions of barrels of synthetic crude oil)(1)	Oil Sands Mining Leases		
	Proved(2)	Probable	Proved & Probable
December 31, 2002	358	1,563	1,921
Revisions of previous estimates	599	(611)	(12)
Extensions and discoveries	—	—	—
Production	(79)	—	(79)
December 31, 2003	878	952	1,830

(1) Synthetic crude oil reserves based upon a net coker, or synthetic crude oil yield of 80%.

(2) All of Suncor's proved mining reserves are classified as proved producing reserves. The reclassification of mining reserves from the probable to proved category in 2003, reflects the 2003 drilling program and use of revised criteria for classifying portions of the ore body as proved.

These mining reserves have been presented on a gross basis, that is before deducting royalties.

The following table sets out certain operating statistics for the Oil Sands mining operations. Statistics for the Oil Sands Firebag in-situ operations are not included but are addressed in the information below under the heading "Proved Conventional Oil and Gas Reserves" and "Sales, Production, Well Data, Land Holdings and Drilling - Conventional".

	2003	2002	2001
Total mined volume (millions of tonnes)(1)	316.9	291.0	232.2
Mined volume to tar sands ratio(1)	48.1%	50.6%	42.2%
Tar sands mined (millions of tonnes)	152.5	147.3	97.9
Average bitumen grade (weight%)	11.3	11.2	11.1
Crude bitumen in mined tar sands (millions of tonnes)	17.2	16.6	10.1
Average extraction recovery%	92.0%	91.3%	88.0%
Crude bitumen production (millions of cubic meters)(2)	15.7	15.0	8.9
Average upgrading yield% (net)	79.4%	79.1%	80.6%
Gross synthetic crude oil produced (thousands of barrels per day)(3)	216.6	205.8	123.2

Notes:

(1) Includes pre-stripping of mine areas and reclamation volumes.

(2) Crude bitumen production is equal to crude bitumen in mined tar sands multiplied by the average extraction recovery and the appropriate conversion factor.

(3) Cubic meters are converted to barrels at the conversion factor of 6.29.

Proved Conventional Oil and Gas Reserves

The following data is provided on a net basis in accordance with the provisions of the Financial Accounting Standards Board's Statement No. 69 (Statement 69). This statement requires disclosure about conventional oil and gas activities only, and therefore the Company's Oil Sands mining activities are excluded, while in-situ Firebag reserves are included.

	NET PROVED RESERVES			
	Crude Oil, Natural Gas Liquids and Natural Gas			
	Oil Sands business: Firebag – Crude Oil (millions of barrels)	Natural Gas business: Crude Oil and Natural Gas Liquids (millions of barrels)	Total (millions of barrels)	Natural Gas business: Natural Gas (billions of cubic feet)
December 31, 2000	—	11	11	567
Revisions of previous estimates	—	—	—	4
Extensions and discoveries	—	—	—	20
Production	—	(1)	(1)	(45)
Sales of minerals in place	—	—	—	(1)
December 31, 2001	—	10	10	545
Revisions of previous estimates	—	—	—	(18)
Extensions and discoveries	124	1	125	39
Production	—	(1)	(1)	(48)
Sales of minerals in place	—	—	—	(2)

December 31, 2002	124	10	134	516
Revisions of previous estimates	224	(2)	222	(50)
Extensions and discoveries	—	1	1	40
Production	—	(1)	(1)	(50)
Sales of minerals in place	—	—	—	—
December 31, 2003	348	8	356	456
Proved Developed				
December 31, 2000	—	10	10	414
December 31, 2001	—	8	8	416
December 31, 2002	—	8	8	426
December 31, 2003	77	6	83	403

All reserves are located in Canada. There has been no major discovery or other favourable or adverse event that caused a significant change in estimated proved reserves since December 31, 2003. 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 Relating to Oil and Gas Activities

($millions)	For the years ended December 31 2003	2002
Proved properties	2,525	1,723
Unproved properties	114	128
Other support facilities and equipment	18	16
Total cost	2,657	1,867
Accumulated depreciation and depletion	(590)	(532)
Net capitalized costs	2,067	1,335

Costs Incurred in Oil and Gas Acquisition, Exploration and Developmental Activities

($millions)	For the years ended December 31, 2003	2002	2001
Property acquisition costs			
Proved properties	—	2	—
Unproved properties	29	12	5
Exploration costs	46	17	27
Development costs	753	510	256
Total capital and exploration expenditures	828	541	288

Results of Operations for Oil and Gas Production

($millions)	For the years ended December 31, 2003	2002	2001
Revenues			
Sales to unaffiliated customers	319	200	286
Transfers to other operations	61	16	58
	380	216	344
Expenses			
Production costs	44	39	36
Depreciation, depletion and amortization	76	66	61
Exploration	86	27	31
Gain on disposal of assets	(12)	(4)	(8)
Restructuring costs	—	—	(2)
Other related costs	37	10	30
	231	138	148
Operating profit before income taxes	149	78	196
Related income taxes	(40)	(43)	(79)
Results of operations	109	35	117

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 Statement 69 could produce substantially different results. The Company cautions against viewing this information as a forecast of future economic conditions or revenues, and does not consider it to represent the fair market

value of Firebag in-situ and Natural Gas properties. Figures are based on Suncor's actual year-end commodity prices. Readers are cautioned that commodity prices are volatile. To illustrate this volatility, the following table sets out certain commodity benchmark prices over the past three years:

	2003	2002	2001
Year end natural gas price assumptions (AECO- CDN$/GJ)	5.28	5.21	3.55
Year end crude oil price assumption (WTI US$/bbl)	32.50	29.40	19.40

Actual future net cash flows may differ from those estimated due to, but not limited to, the following:

- Production rates could differ from those estimated both in terms of timing and amount;
- Future prices and economic conditions will likely differ from those at year-end;
- Future production and development costs will be determined by future events and may differ from those at year-end; and
- Estimated income taxes and royalties may differ in terms of amounts and timing due to the above factors as well as changes in enacted rates and the impact of future expenditures on unproved properties.

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. At December 31, 2003, no such contractual arrangements existed. 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 reclamation and environmental remediation costs. Deducting future income tax expenses then reduces the estimated pre-tax future net cash flows further. 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 pre-tax cash flows relating to the Company's proved oil and gas reserves less the tax basis of the properties involved. Royalties are determined based upon the appropriate royalty rates and regimes in effect at year end for Firebag and natural gas production, and in the case of Firebag, assumes that Firebag is classified as a separate operation, for royalty purposes, as described in MD&A. (See "Oil Sands Crown Royalties and Cash Income Taxes" in the "Suncor Overview and Strategic Priorities" Section of MD&A). The resultant future net cash flows are reduced to present value amounts by applying the Statement 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)	2003	2002	2001
Future cash flows	11,655	8,964	2,266
Future production and development costs	(5,141)	(3,007)	(652)
Other related future costs	(391)	(314)	(283)
Future income tax expenses	(1,694)	(2,094)	(521)
Subtotal	4,429	3,549	810
Discount at 10%	(2,578)	(1,822)	(370)
Standardized measure of discounted future net cash flows from estimated production of proved oil and gas reserves after income taxes	1,851	1,727	440

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

	2003	2002	2001
		$ millions	
Balance, beginning of year	1,727	440	1,933
Sales and transfers of oil and gas produced, net of production costs	(306)	(192)	(297)
Net changes in prices and production costs	(1,023)	626	(3,114)
Extensions, discoveries and improved recovery, less related costs	95	1,387	23
Development costs incurred during the period	329	112	81
Revisions of previous quantity estimates	712	(45)	(2)
Accretion of discount	260	68	361
Net changes in income taxes	272	(697)	1,472
Other	(215)	28	(17)
Balance, end of year	1,851	1,727	440

Sales, Production, Well Data, Land Holdings and Drilling - Conventional

The following tables set out additional information on the Company's conventional oil and gas producing activities. Information with respect to Suncor's Oil Sands mining operations is not covered by the information below but is addressed in the information above under "Oil Sands Mining Operations".

Sales Prices(1) (Based on working interest production before royalties)

	Average Sales Price(2)		
	2003	2002	2001
Crude Oil ($/bbl)	40.29	31.72	33.92

NGL ($/bbl)	36.08	29.35	34.38
Natural Gas ($/mcf)	6.42	3.91	6.09

Notes:

(1) Production is based in Western Canada.

(2) Prices are calculated using our working interest production after royalties.

Production Costs

($ per BOE of gross production)	2003	2002	2001
Average production (lifting) cost of conventional crude oil and gas(1)	3.48	3.15	2.96

Note:

(1) Production (lifting) costs include all expenses related to the operation and maintenance of producing or producible wells and related facilities, natural gas plants and gathering systems. It does not include an estimate for future reclamation costs. As Suncor's Firebag in-situ leases were not in commercial operations for the year-end December 31, 2003, the above production costs only include the costs associated with Suncor's Natural Gas business.

Producing Oil and Gas Wells

	2003					
	Crude Oil		Natural Gas		Total	
	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
Alberta	40	28	316	180	356	208
British Columbia	22	10	53	25	75	35
Total	62	38	369	205	431	243

Notes:

(1) Gross wells are the total number of wells in which an interest is owned.

(2) Net wells are the sum of fractional interests owned in gross wells.

(3) As Suncor's Firebag in-situ leases were not in commercial operation for the years ended December 31, 2003 and 2002, well information only includes wells associated with Suncor's Natural Gas business.

Oil and Gas Acreage

(thousands of acres)	2003					
	Developed		Undeveloped(1)		Total	
	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
Canada						
Natural Gas	663	531	542	428	1,205	959
Firebag	1	1	290	290	291	291
Total	664	532	832	718	1,496	1,250

Notes:

(1) Undeveloped acreage is considered to be those on which wells have not been drilled or completed to a point that would permit production of commercial quantities of crude oil and natural gas regardless of whether or not such acreage contains proved reserves. Gross acres means all the acres in which Suncor has either an entire or undivided percentage interest in.

(2) Net acres represents the acres remaining after deducting the undivided percentage interest of others from the gross acres.

Drilling Activity

(number of net wells)	2003					
	Net Exploratory			Net Development		
	Productive	Dry Holes	Total	Productive	Dry Holes	Total
Canada						
Natural Gas	3	6	9	17	4	21

Firebag	—	—	—	20	—	20
Total	3	6	9	37	4	41

(number of net wells)	2002					
	Net Exploratory			Net Development		
	Productive	Dry Holes	Total	Productive	Dry Holes	Total
Canada						
Natural Gas	2	4	6	18	4	22
Firebag	—	—	—	—	—	—
Total	2	4	6	18	4	22

(number of net wells)	2001					
	Net Exploratory			Net Development		
	Productive	Dry Holes	Total	Productive	Dry Holes	Total
Canada						
Natural Gas	4	2	6	16	2	18
Firebag	—	—	—	—	—	—
Total	4	2	6	16	2	18

At December 31, 2003, the company was participating in the drilling of 15 gross (8 net) exploratory and development wells.

Future Commitments to Sell or Deliver Crude Oil and Natural Gas

The Company's Natural Gas business has entered into a number of natural gas sale commitments aggregating approximately 62 mmcf/day. These sales commitments consist of both short-and long-term contracts ranging from one year and for one agreement, for the life of a specified production field. All production comes from Suncor's reserves. All pricing under these agreements is based upon both a combination of variable, fixed and index-based terms.

Oil Sands has also entered into long-term contracts to sell crude oil products to customers, some of which are described under the heading, "Sales of Synthetic Crude Oil and Diesel" in the "Oil Sands" section of this Annual Information Form. In addition, the Company enters into crude oil, and periodically foreign currency swap and option contracts to protect its future Canadian dollar earnings and cash flows from the potential adverse impact of low petroleum prices and an unfavourable U.S./Canadian dollar exchange rate. For further particulars of these hedging arrangements, see the information under the heading "Derivative Financial Instruments", under "Risk/Success Factors Affecting Performance" in the "Suncor Corporate Overview and Strategic Priorities" section of the Company's MD&A, and Note 6 to Suncor's 2003 Consolidated Financial Statements, which note is incorporated by reference herein.

SUNCOR EMPLOYEES

The following table shows the distribution of employees among Suncor's four business units and its corporate office for the past two years.

	as at December 31,	
	2003	2002
Oil Sands	2,390	2,324
Natural Gas	187	191
Energy Marketing & Refining – Canada(1)	555	576
Marketing & Refining – U.S.A.	633	—
Corporate (2)	496	331
Total (3)	4,261	3,422

Notes:

(1) Excludes joint venture employees.

(2) The increase in 2003 numbers principally reflect the addition of in-house engineering, procurement, construction and project management personnel.

(3) In addition to Suncor employees, independent contractors supply a range of services to the Company.

The Communications, Energy and Paperworkers Union Local 707 represents approximately 1,500 Oil Sands employees. Suncor entered into a three-year collective agreement with the union effective May 1, 2004. The terms of the agreement include a 9.5 per cent wage increase over a three-year term.

Employee associations represent approximately 170 of EM&R's Sarnia refinery and Sun-Canadian Pipe Line Company employees. In March 2002, a three-year agreement was signed with the Sarnia employee association that will be renegotiated in 2005. The agreement with the employee association of Sun-Canadian Pipe Line Company was signed in 1993, and it is renewed automatically each year unless terminated by written notice by either party at least 60 days prior to the anniversary date of the agreement. No notice under such agreement has been received or given to date. Management believes the agreement will be automatically renewed on its anniversary. The National Automobile, Aerospace, Transportation and General Workers Union of Canada (CAW-Canada) Local 27 represents three employees at EM&R's London Terminal. A three year agreement was signed with the CAW-Canada effective April 1, 2003. Management believes Suncor's positive working relationship with these unions and associations will continue.

The local Paper, Allied-Industrial Chemical and Energy Workers International Union, represents approximately 150 employees at R&M's Denver area refinery. A four-year contract, assumed from ConocoPhillips in August 2003, will expire in January 2006.

RISK/SUCCESS FACTORS

Volatility of Crude Oil and Natural Gas Prices Suncor's future financial performance is closely linked to oil prices, and to a lesser extent natural gas prices. The prices of these commodities can be influenced by global and regional supply and demand factors. Worldwide economic growth, political developments, compliance or non-compliance with quotas imposed upon members of the Organization of Petroleum Exporting Countries and weather, among other things, can affect world oil supply and demand. Natural gas prices realized by Suncor are affected primarily by North American supply and demand and by prices of alternate sources of energy. All of these factors are beyond Suncor's control and can result in a high degree of price volatility not only in crude oil and natural gas prices, but also fluctuating price differentials between heavy and light grades of crude oil, which can impact prices for sour crude oil. Oil and natural gas prices have fluctuated widely in recent years and Suncor expects continued volatility and uncertainty in crude oil and natural gas prices. A prolonged period of low crude oil and natural gas prices could affect the value of Suncor's crude oil and gas properties and the level of spending on growth projects, and could result in curtailment of production at some properties. Accordingly, low crude oil prices in particular could have an adverse impact on Suncor's financial condition and liquidity and results of operations. A key component of Suncor's business strategy is to produce sufficient natural gas to meet or exceed internal demands for natural gas purchased for consumption in its operations, creating a price hedge which reduces Suncor's exposure to gas prices volatility. However, there are no assurances that the Company will be able to continue to increase production to keep pace with growing internal natural gas demands.

Suncor cannot control the factors that influence supply and demand for, or the prices of, crude oil or natural gas. However, the Company has a hedging program that fixes the price or a range of prices for its crude oil, natural gas, and periodically the associated Canada/U.S. dollar exchange rate for a percentage of Suncor's total production volume. Suncor's objective is to manage exposure to market volatility and lend more certainty to the Company's ability to finance growth. If an operational upset occurred that reduced or eliminated crude oil and/or natural gas production for a period of time, Suncor would be required to continue to make payments under its hedging program if the actual price was higher than the hedged price. In addition, Suncor's hedging program is subject to many of the risks described under the heading, "Risks Associated with Energy Trading Activities", below. For particulars of Suncor's hedging position as of year-end 2003, see Note 6 of Suncor's 2003 Consolidated Financial Statements, which note is incorporated by reference herein, as well as Risk/Success Factors Affecting Performance in the Corporate Overview Section of MD&A.

Suncor conducts an assessment of the carrying value of its assets to the extent required by Canadian generally accepted accounting principles. If crude oil and natural gas prices decline, the carrying value of Suncor's assets could be subject to downward revisions, and Suncor's earnings could be adversely affected.

Volatility of Downstream Margins. EM&R and R&M operations are sensitive to wholesale and retail margins for their refined products, including gasoline. Margin volatility is influenced by overall marketplace competitiveness, weather, the cost of crude oil (see "Volatility of Crude Oil and Natural Gas Prices") and fluctuations in supply and demand for refined products. EM&R and R&M expect that margin and price volatility and overall marketplace competitiveness, including the potential for new market entrants, will continue. As a result, our operating results for EM&R and R&M can be expected to fluctuate.

Major Projects. There are certain risks associated with the execution of Suncor's major projects, including without limitation, each of the Firebag stages, the Voyageur growth strategy, and the "clean fuels" environmental capital projects in Suncor's downstream businesses. These risks include: Suncor's ability to obtain the necessary environmental and other regulatory approvals; risks relating to schedule, resources and costs, including the availability and cost of materials, equipment and qualified personnel; the impact of general economic, business and market conditions; the impact of weather conditions; Suncor's ability to finance growth if commodity prices were to stay at low levels for an extended period; the impact of new entrants to the oil sands business which could take the form of competition for skilled people, increased demands on the Fort McMurray, Alberta infrastructure (for example, housing, roads and schools) and price competition for products sold into the marketplace; the potential ceiling on the demand for synthetic crude oil; and the effect of changing government regulation and public expectations in relation to the impact of oil sands development on the environment. The commissioning and integration of new facilities with the existing asset base could cause delays in achieving targets and objectives. Suncor management believes the execution of major projects presents issues that require prudent risk management. There are also risks associated with project cost estimates provided by Suncor. Some cost estimates are provided at the conceptual stage of projects and prior to commencement or completion of the final scope design and detailed engineering needed to reduce the margin of error. Accordingly, actual costs can vary from estimates and the variances can be material.

In-situ Extraction. Current steam-assisted gravity drainage (SAGD) technologies for in-situ recovery of heavy oil and bitumen are energy intensive, requiring significant consumption of natural gas and other fuels in the production of steam which is used in the recovery process. The amount of steam required in the production process can also vary and impact costs. The performance of the reservoir can also impact the timing and levels of production using this technology. Suncor has been advised by GLJ that in 2003, a number of operational commercial SAGD projects were in service, although no such projects have been operational for any extended period of time. Commercial application of this technology is not yet commonplace and accordingly in the absence of operating history there can be no assurances with respect to the sustainability of SAGD operations.

Increased Dependence on Oil Sands business. The Company's significant capital commitment to further its growth projects at Oil Sands, including Firebag and if approved, Voyageur, may require Suncor to forego investment opportunities in other segments of its operations. The completion of future projects to increase production at Oil Sands will further increase the Company's dependence on the Oil Sands segment of its business. For example, in 2003, the Oil Sands business accounted for approximately 86% (86% in 2002) of Suncor's upstream production, 81% (89% in 2002) of Suncor's net earnings and 78% (85% in 2002) of Suncor's cash flow from operations(4). These percentages have been determined excluding the corporate and eliminations segment information.

Interdependence of Oil Sands Systems. The Oil Sands plant is susceptible to loss of production due to the interdependence of its component systems. Through growth projects, Suncor expects to mitigate adverse impacts of its interdependent systems and to reduce the production and cash flow impacts of complete plant-wide shutdowns. For example, Millennium added a second complete processing operation, which provides Suncor with the flexibility to conduct periodic plant maintenance on one operation while continuing to generate production and cash flow from the other.

Competition. The petroleum industry is highly competitive in all aspects, including the exploration for, and the development of, new sources of supply, the acquisition of crude oil and natural gas interests, and the refining, distribution and marketing of petroleum products and chemicals. Suncor competes in virtually every aspect of its business with other energy companies. The petroleum industry also competes with other industries in supplying energy, fuel and related products to consumers. Suncor believes the competition for its crude oil production is other Canadian conventional and synthetic sweet and sour crude oil producers.

A number of other companies have entered or have indicated they are planning to enter the oil sands business and begin production of bitumen and synthetic crude oil, or expand existing operations. It is difficult to assess the number, level of production and ultimate timing of all of the potential new producers or where existing production levels may increase. Based on management's knowledge of other projects derived from publicly available information, Canada's production of bitumen and upgraded synthetic crude oil could increase from approximately 925,000 bpd to almost two and a half million bpd by the end of the decade. The trend toward industry consolidation has created more competitors with financial capacity who may enter into similar and competing oil sands businesses. The expansion of existing operations and development of new projects could materially increase the supply of bitumen and synthetic crude oil and other competing crude oil products in the marketplace. Depending on the levels of future demand, increased supplies could have a negative impact on prices.

In the western Canadian diesel fuel market demand and supply can fluctuate. Margins for diesel fuel are typically higher than the margins for synthetic and conventional crude oil. The above noted expansion plans of Suncor's competitors could result in an increase in the supply of diesel fuel and weaken margins.

(4) Refer to "Non GAAP Financial Measures" on page xi of this AIF.

Historically, the industry-wide oversupply of refined petroleum products and the overabundance of retail outlets have kept pressure on downstream margins. Management expects that fluctuations in demand for refined products, margin volatility and overall marketplace competitiveness will continue. In addition, to the extent that Suncor's downstream business units, EM&R and R&M, participate in new product markets, they could be exposed to margin risk and volatility from either cost and/or selling price fluctuations.

Need to Replace Conventional Natural Gas Reserves. Future natural gas reserves and production of the Company's NG business unit are highly dependent on its success in discovering or acquiring additional reserves and exploiting its current reserve base. This impacts both Suncor's cash flow from such production and its ability to maintain a price hedge against growing consumption of natural gas in its operations. Without natural gas reserve additions through exploration and development or acquisition activities, Suncor's conventional natural gas reserves and production will decline over time as reserves are depleted. For example, in 2003, Suncor's average natural gas reservoir decline rates were in the 24% range (2002 – 25%). Decline rates will vary with the nature of the reservoir, life-cycle of the well, and other factors. Therefore past decline rates are not necessarily indicative of future performance. Exploring for, developing and acquiring reserves is highly capital intensive. To the extent cash flow from operations(3) is insufficient to generate sufficient capital and external sources of capital become limited or unavailable, Suncor's ability to make the necessary capital investments to maintain and expand its conventional natural gas reserves could be impaired. In addition, the long term performance of Suncor's NG business is dependent on its ability to consistently and competitively find and develop low cost, high-quality reserves that can be economically brought on stream. Market demand for land and services can also increase or decrease finding and development costs. There can be no assurance that Suncor will be able to find and develop or acquire additional reserves to replace production at acceptable costs.

Coal Bed Methane. Coal Bed Methane (CBM) exploration is being undertaken by Suncor in Canada, and in the U.S. through a wholly owned subsidiary, Suncor Energy (Natural Gas) America Inc. The identification of gas in coals is necessary but not sufficient for establishing commercial success. Effective production technology, water handling, well productivity and surface access, a requirement for large land blocks, and a pilot production period are risk elements unique to CBM. Other Canadian producers' activities in CBM have progressed to the pilot test stage with several projects that have wells producing saleable gas. Suncor views the ultimate viability and profitability of these plays as uncertain.

CBM is a commercial gas resource in the U.S. The risks associated with CBM activities in the U.S. vary by geographic region but can include: constraints on land access from federal, state and individual land holders; local opposition to well drilling and CBM development; high costs of treating water produced with CBM gas development; limited regional pipeline exit capacity; and strong competition for mineral leases and services. The regulatory framework and stakeholder environment varies by region. The physical

operation of drilling and ultimately producing gas in a location distant from Suncor's key management presents risks of inadequate oversight of

operations. Business activity in the U.S. has different political risks than in Canada, and is conducted in an environment where litigation and legal risk are more prevalent and substantial.

Operating Hazards and Other Uncertainties. Each of Suncor's four principal businesses, Oil Sands, NG, EM&R, and R&M require high levels of investment and have particular economic risks and opportunities. Generally, Suncor's operations are subject to hazards and risks such as fires, explosions, gaseous leaks, migration of harmful substances, blowouts, power outages and oil spills, any of which can cause personal injury, damage to property, equipment and the environment, as well as interrupt operations. In addition, all of Suncor's operations are subject to all of the risks normally incident to the transportation, processing and storing of crude oil, natural gas and other related products.

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(3) Refer to "Non GAAP Financial Measures" on page xi of this AIF

At Oil Sands, mining oil sands and producing bitumen through in-situ methods, extracting bitumen from the oil sands, and upgrading bitumen into synthetic crude oil and other products, involves particular risks and uncertainties. Oil Sands is susceptible to loss of production, slowdowns, shutdowns, or restrictions on its ability to produce higher value products due to the interdependence of its component systems. Severe climatic conditions at Oil Sands can cause reduced production during the winter season and in some situations can result in higher costs. While there is virtually no finding cost associated with oil sands resources, delineation of the resources, the costs associated with production, including mine development and drilling of wells for SAGD operations, and the costs associated with upgrading bitumen into synthetic crude oil, can entail significant capital outlays. The costs associated with production at Oil Sands are largely fixed and, as a result, operating costs per unit are largely dependent on levels of production.

There are risks and uncertainties associated with NG's operations including all of the risks normally incident to drilling for natural gas wells, the operation and development of such properties, including encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, equipment failures and other accidents, sour gas releases, uncontrollable flows of crude oil, natural gas or well fluids, adverse weather conditions, pollution, and other environmental risks.

Suncor's downstream business units, EM&R and R&M are subject to all of the risks normally incident to the operation of a refinery, terminals and other distribution facilities, as well as service stations, including loss of product or slowdowns due to equipment failures or other accidents.

Although Suncor maintains a risk management program, including an insurance component, such insurance may not provide adequate coverage in all circumstances, nor are all such risks insurable. Losses resulting from the occurrence of these risks could have a material adverse impact on Suncor. Refer to note 10(b) to Suncor's 2003

Consolidated Financial Statements, which is incorporated by reference herein, for further description of Suncor's insurance coverage.

Land Claims. First Nations peoples have claimed aboriginal title and rights to a substantial portion of western Canada. Certain First Nations peoples have filed a claim against the Government of Canada, certain governmental entities and the Regional Municipality of Wood Buffalo (which includes the city of Fort McMurray, Alberta), claiming, among other things, a declaration that the plaintiffs have aboriginal title to large areas of lands surrounding Fort McMurray, including the lands on which Oil Sands and most of the other oil sands operations in Alberta are situated. In addition, First Nations peoples have filed claims against industry participants generally, relating in part to land claims which may affect Suncor's Natural Gas business. Suncor is unable to assess the effect, if any, these claims would have on its Oil Sands or other operations. Other than these claims, to Suncor's knowledge the First Nations peoples have asserted no other land claims against Suncor.

Technology Risk. There are risks associated with growth and other capital projects that rely largely or partly on new technologies and the incorporation of such technologies into new or existing operations. The success of projects incorporating new technologies, such as in-situ technology, cannot be assured.

Risks of International Investments. There are also inherent risks, including political and foreign exchange risk, in investing in business ventures internationally. Suncor's capital projects planned for the R&M business are expected to be partially funded from Canadian operations. A weaker Canadian dollar relative to the U.S. dollar would result in a higher funding requirements for these projects. However, a weaker Canadian dollar would positively impact the Canadian dollar value of earnings from R&M. (See "Exchange Rate Fluctuations", below). Other than the R&M business, Suncor does not have material international investments, although it continues to assess downstream integration and coal bed methane opportunities in the U.S.

Interest Rate Risk. Suncor is exposed to fluctuations in short-term Canadian interest rates as a result of the use of floating rate debt. Suncor maintains a substantial portion of its debt capacity in revolving, floating rate bank facilities and commercial paper, with the remainder issued in fixed rate borrowings. To minimize its exposure to interest rate fluctuations, Suncor occasionally enters into interest rate swap agreements and exchange contracts to either effectively fix the interest rate on floating rate debt or to float the interest rate on fixed rate debt. For more details, see the "Liquidity and Capital Resources" section of MD&A.

Exchange Rate Fluctuations. Suncor's 2003 Consolidated Financial Statements are presented in Canadian dollars. Results of operations are affected by the exchange rates between the Canadian dollar and the U.S. dollar. These exchange rates have varied substantially in the last five years. A substantial portion of Suncor's revenue is received by reference to U.S. dollar denominated prices, and a significant portion of Suncor's debt is denominated in U.S. dollars. Crude oil and natural gas prices are generally based in U.S. dollars, while a large portion of Suncor's sales of refined products are in Canadian dollars. Fluctuations in exchange rates between the U.S. and Canadian dollar may therefore give rise to foreign currency exposure, either favorable

or unfavorable, creating another element of uncertainty. In the future, the strength of the Canadian dollar relative to foreign currencies could create additional uncertainties for Suncor.

Environmental Regulation and Risk. Environmental regulation 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 industry. The regulatory regimes require Suncor to obtain operating licenses and permits in order to operate, and impose certain standards and controls on activities relating to mining, oil and gas exploration, development and production, and the refining, distribution and marketing of petroleum products and petrochemicals. Environmental assessments and regulatory approvals are required before initiating most new major projects or undertaking significant changes to existing operations. In addition to these specific, known requirements, Suncor expects future changes to environmental legislation, including anticipated legislation to implement Canada's ratification of the Kyoto Accord, will impose further requirements on companies operating in the energy industry. Some of the issues that are or may in future be subject to environmental regulation include the possible cumulative impacts of oil sands development in the Athabasca region; storage, treatment, and disposal of hazardous or industrial waste; the need to reduce or stabilize various emissions to air and discharges to water; issues relating to global climate change, land reclamation and restoration; Great Lakes water quality; and reformulated gasoline to support lower vehicle emissions (For example, see the discussion relating to Suncor's clean fuels capital projects, under the "Three Year Highlights" section of this AIF.). Changes in environmental regulation could have a potentially adverse effect on Suncor from the standpoint of product demand, product reformulation and quality, methods of production and distribution and costs. For example, requirements for cleaner-burning fuels could cause additional costs to be incurred, which may or may not be recoverable in the marketplace. The complexity and breadth of these issues make it extremely difficult to predict their future impact on Suncor. Management anticipates capital expenditures and operating expenses could increase in the future as a result of the implementation of new and increasingly stringent environmental regulations. Compliance with environmental regulation can require significant expenditures and failure to comply with environmental regulation may result in the imposition of fines and penalties, liability for clean up costs and damages and the loss of important permits.

Suncor is required to and has posted annually with Alberta Environment an irrevocable letter of credit equal to $0.03 per bbl of crude oil produced as of December 31, 2003 ($14 million as at December 31, 2003) as security for the estimated cost of its reclamation activity on Leases 86 and 17. For the Millennium and Steepbank mines, Suncor has posted an irrevocable letter of credit equal to approximately $54 million, representing security for the estimated cost of reclamation activities up to the end of December 2003. For Firebag, Suncor has posted an irrevocable letter of credit equal to approximately $5 million, representing security for the estimated cost of reclamation activities relating to Firebag up to the end of December 2003. For more information about Suncor's reclamation and environmental mediation obligations, refer to "Reclamation and Environmental Remediation Cost" under "Critical Accounting Policies" in the "Suncor Overview and Strategic Priorities" section of MD&A.

Over the past few years, legislation has been passed in Canada and the United States to reduce permitted levels of sulphur in transportation fuels. For a discussion of projects planned or underway at Suncor's EM&R and R&M operations, see the information under the EM&R and R&M sections of "Narrative Description of the Business", and under "Three Year Highlights", in this Annual Information Form. Projects to retrofit existing facilities to comply with these standards are subject to all risks inherent in large capacity projects, and to the additional risk that failure to meet legislated deadlines

could have a material impact on the Company's ability to market its products, potentially having a material impact on revenues and earnings.

Uncertainty of Reserve and Resource Estimates. The reserves data and resource estimates for Suncor's Oil Sands and Natural Gas (NG) business units, included in Suncor's Annual Information Form, represent estimates only. There are numerous uncertainties inherent in estimating quantities and quality of these proved and probable reserves and resources, including many factors beyond the control of Suncor.

In general, estimates of economically recoverable reserves are based upon a number of variable factors and assumptions, such as historical production from the properties, the assumed effect of regulation by governmental agencies, future royalties and future operating costs, all of which may vary considerably from actual results. The accuracy of any reserve estimate is a matter of engineering interpretation and judgment and is a function of the quality and quantity of available data, which may have been gathered over time. In the Oil Sands business unit, reserve and resource estimates are based upon a geological assessment, including drilling and laboratory tests, and also consider current production capacity and upgrading yields, current mine plans, operating life and regulatory constraints. The Firebag reserves and resource estimates are based upon a geological assessment of data gathered from evaluation drilling, the testing of core samples and seismic operations and demonstrated commercial success of the in-situ process. In the NG business unit, reservoir performance subsequent to the date of the estimate may justify revision, either upward or downward. For these reasons, estimates of the economically recoverable reserves attributable to any particular group of properties, and in NG the classification of such reserves based on risk of recovery prepared by different engineers or by the same engineers at different times, may vary substantially. At Oil Sands, the independent evaluation of mining reserves does not take into account the economic aspects of future reserves. Suncor's actual production, revenues, royalties, taxes and development and operating expenditures with respect to its reserves will vary from such estimates, and such variances could be material.

Although Suncor is subject to Canadian disclosure rules in connection with the reporting of its reserves, Suncor has received exemptive relief from Canadian securities administrators permitting it to report its proved reserves in accordance with U.S. disclosure practices. In addition, although U.S. companies do not disclose probable reserves or resources for non-mining properties, Suncor voluntarily discloses its probable reserves and resources for its Firebag in-situ leases as it believes this information is useful to investors. As a result, Suncor's Firebag in-situ estimates may not be directly comparable to those made by U.S. companies.

Labour Relations. Suncor's hourly employees at its Oil Sands facility near Fort McMurray, its London terminal operation, its Sarnia refinery, its Denver refinery, and Sun-Canadian Pipeline Company are represented by labour unions or employee associations. Any work interruptions involving Suncor's employees, or contract trades utilized in its projects or operations, could materially and adversely affect Suncor's business and financial position.

Energy Trading Activities. The nature of trading activities creates exposure to financial risks. These include risks that movements in prices or values will result in a financial

loss to the Company; a lack of counterparties will leave the Company unable to liquidate or offset a position, or unable to do so at or near the previous market price; the Company will not receive funds or instruments from its counterparty at the expected time; the counterparty will fail to perform an obligation owed to the Company; the Company will suffer a loss as a result of human error or deficiency in its systems or controls; or the Company will suffer a loss as a result of contracts being unenforceable or transactions being inadequately documented. A separate risk management function within Suncor develops and monitors practices and policies and provides independent verification and valuation of Suncor's trading and marketing activities. However, Suncor may experience significant financial losses as a result of these risks.

Governmental Regulation. The oil and gas industry in Canada and the United States, including the oil sands industry and the downstream segment of the Company, operates under federal, provincial, state and municipal legislation. This industry is also subject to regulation and intervention by governments in such matters as land tenure, royalties, government fees, production rates, environmental protection controls, the reduction of greenhouse gas emissions, the export of crude oil, natural gas and other products, the awarding or acquisition of exploration and production, oil sands or other interests, the imposition of specific drilling obligations, environmental protection controls, control over the development and abandonment of fields and mine sites (including restrictions on production) and possibly expropriation or cancellation of contract rights. Before proceeding with most major projects, including significant changes to existing operations, Suncor must obtain regulatory approvals. The regulatory approval process can involve stakeholder consultation, environmental impact assessments and public hearings, among other things. In addition, regulatory approvals may be subject to conditions including security deposit obligations and other commitments. Failure to obtain regulatory approvals, or failure to obtain them on a timely basis, could result in delays, abandonment or restructuring of projects and increased costs, all of which could negatively affect future earnings and cash flow. Such regulations may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the crude oil and natural gas industry could reduce demand for crude oil and natural gas, increase Suncor's costs and have a material adverse effect on its financial condition.

SELECTED CONSOLIDATED FINANCIAL INFORMATION

Selected Consolidated Financial Information

The following selected consolidated financial information for each of the years in the three-year period ended December 31, 2003 is derived from Suncor's 2003 Consolidated Financial Statements. Suncor's consolidated financial statements for each of the years in the three-year period ended December 31, 2003 have been audited by PricewaterhouseCoopers LLP, Chartered Accountants. The information set forth below should be read in conjunction with MD&A and Suncor's 2003 Consolidated Financial Statements.

($ millions except per share amounts)	Year ended December 31,(1) 2003	2002	2001
Revenues	6,306	5,032	4,294
Net earnings	1,084	761	388
Per common share (undiluted)	2.43	1.64	0.79
Per common share (diluted)	2.26	1.61	0.78
Cash flow from operations(1)	2,081	1,440	831
Capital, acquisition and exploration expenditures	1,588	877	1,678

(1) See non-GAAP financial measures on page xi

($ millions)	Year ended December 31, 2003	2002	2001
Total assets	10,427	8,683	8,094
Long-term debt	2,448	2,686	3,113
Accrued liabilities and other(1)	296	226	251
Common shareholders' equity(2)	3,949	2,935	2,255

Notes:

(1) See Note 7 to Suncor's 2003 Consolidated Financial Statements, which Notes are incorporated by reference herein.

(2) Excludes Preferred Securities issued in 1999. See Dividend Policy and Record.

The following table sets forth, for each of the two most recently completed financial years, the revenues for each category of Suncor's principal products or services that accounted for 15 per cent or more of Suncor's total consolidated revenues.

Revenues from	2003 ($ millions)	%	2002 ($ millions)	%
Transportation fuel sales	2,983	47	2,266	45
Crude oil sales	2,368	38	2,082	41
Other	949	15	682	14
Total	**6,300(1)**	**100**	**5,030(1)**	**100**

Note:

(1) Excludes interest income.

Dividend Policy and Record

Suncor's Board of Directors has established a policy of paying dividends on a quarterly basis. This policy is reviewed from time to time in light of Suncor's financial position, its financing requirements for growth, its cash flow and other factors considered relevant by Suncor's Board of Directors.

During 1999, the Company completed a Canadian offering of $276 million of 9.05% preferred securities and a U.S. offering of U.S.$162.5 million of 9.125% preferred securities, the proceeds of which totaled Canadian $507 million after issue costs of $17 million ($10 million after income tax credits of $7 million). The preferred securities are unsecured junior subordinated debt of the Company, due in 2048 and redeemable at the Company's option on or after March 15, 2004 for proceeds equal to the original principal amount of the preferred securities plus any accrued and unpaid interest as at the date of redemption. The Company has given notice of its intention to redeem the preferred securities as of March 15, 2004. For accounting purposes, the preferred securities are classified as share capital in the consolidated balance sheet and the interest distributions thereon, net of income taxes, are classified as dividends in the Company's 2003 Consolidated Financial Statements, but generally treated as interest income to the recipient for Canadian or U.S. tax purposes.

The following table sets forth the per share amount of dividends paid by Suncor during the last three years.

	Year ended December 31,		
	2003	2002	2001
Common Shares cash dividends	$ 0.1925	$ 0.17	$ 0.17
Preferred securities cash interest distributions(1)	$ 0.10	$ 0.11	$ 0.11
Dividends paid in common shares	—	—	—

Note:

(1) Per share preferred securities cash interest distributions are calculated as total preferred securities dividends divided by the weighted average outstanding common shares in the year.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Suncor's MD&A, dated February 26, 2004, is incorporated by reference into and forms an integral part of this Annual Information Form, and should be read in conjunction with Suncor's 2003 Consolidated Financial Statements and the notes thereto.

MARKET FOR THE SECURITIES OF THE ISSUER

The common shares of Suncor are listed on the Toronto Stock Exchange in Canada, and on the New York Stock Exchange in the United States. To the best of management's knowledge, approximately 40% of Suncor's common shares are beneficially held by residents of the United States. Suncor's 9.05% preferred securities are listed on the Toronto Stock Exchange in Canada, and Suncor's 9.125% preferred securities are listed on the New York Stock Exchange in the United States.

DIRECTORS AND EXECUTIVE OFFICERS

Directors

Reference is made to the information under the heading, "Election of Directors" on pages 2 - 6 inclusive of Suncor's Management Proxy Circular dated February 26, 2003 for information regarding Suncor's directors, which information is incorporated by reference into this Annual Information Form.

Executive Officers

The following are the executive officers of the Corporation. Except where otherwise indicated, the persons named in the table below held the offices set out opposite their respective names as at December 31, 2003 and as of the date hereof.

Name and Municipality of Residence	Office(1)
J. KENNETH ALLEY Calgary, Alberta	Senior Vice President and Chief Financial Officer

MIKE M. ASHAR Denver, Colorado	Executive Vice President, Refining and Marketing – U.S.A.
DAVID W. BYLER Cochrane, Alberta	Executive Vice President, Natural Gas and Renewable Energy

Name and Municipality of Residence	Office(1)
RICHARD L. GEORGE Calgary, Alberta	President and Chief Executive Officer
TERRENCE J. HOPWOOD Calgary, Alberta	Senior Vice President and General Counsel
SUE LEE Calgary, Alberta	Senior Vice President, Human Resources and Communications
KEVIN D. NABHOLZ Calgary, Alberta	Senior Vice President, Major Projects
THOMAS L. RYLEY Toronto, Ontario	Executive Vice President, Energy, Marketing and Refining – Canada
STEVEN W. WILLIAMS Fort McMurray, Alberta	Executive Vice President, Oil Sands

Notes:

(1) Offices shown are positions held by the officers in relation to business units of Suncor Energy Inc. and its subsidiaries on a consolidated basis. On a legal entity basis, Mr. Ashar is President of Suncor Energy (U.S.A.) Inc., Suncor's U.S. based downstream subsidiary, Mr. Ryley is the President of Suncor's marketing Canada based downstream subsidiaries, Suncor Energy Marketing Inc. and Suncor Energy Products Inc., respectively, and Mr. Nabholz is President of Suncor Energy Services Inc., which provides major projects and other shared services to the Suncor group of companies.

All of the foregoing executive officers of the Company have, for the past five years, been actively engaged as executives or employees of Suncor or its affiliates, except Mr. Williams, who joined the Company in May 2002. Prior to joining Suncor, Mr. Williams held various executive positions with Octel Corporation, a global chemicals company. Prior to joining Octel Corporation in 1995, Mr. Williams held executive positions with Esso Petroleum Company Limited, an affiliate of Exxon.

The percentage of Common Shares of Suncor owned beneficially, directly or indirectly, or over which control or direction is exercised by Suncor's directors and executive officers, as a group, is less than 1%.

Additional Disclosure for Directors and Executive Officers

To the best of our knowledge, having made due inquiry, Suncor confirms that, as at December 31, 2003:

(i) in the last ten years, no director or executive officer of Suncor is or has been a director or officer of another issuer that, while that person was acting in that capacity,

(a) was the subject of a cease trade or similar order, or an order that denied the other issuer access to any exemptions under Canadian securities legislation for a period of more than 30 consecutive days; or

(b) became bankrupt or made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangements or compromises with creditors or had a receiver, receiver manager or trustee appointed to hold its assets, other than Mr. Canfield, a director of Suncor who was a director of Royal Trust Co. in 1994 when it entered into a plan of arrangement with creditors and Mr. Korthals, a director of Suncor who was a director of Anvil Range Mining Corporation, which sought protection under the Companies Creditors Arrangement Act (Canada) in 1998;

(ii) no director or executive officer of Suncor has

(a) been subject to any penalties or sanctions imposed by a court relating to Canadian securities legislation or by a Canadian securities regulatory authority or has entered into a settlement agreement with a Canadian securities regulatory authority; or

(b) has been subject to any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision;

(iii) no director or executive officer of Suncor nor any personal holding company controlled by such person has become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold the assets of the director or executive officer; and

(iv) no director or executive officer has any direct or indirect material interest in respect of any matter that has materially affected or will materially affect Suncor or any of its subsidiaries.

FEES PAID TO AUDITORS

Fees Paid to Auditors

Reference is made to the information under the heading, "Appointment of Auditors" on page 27 of Suncor's Management Proxy Circular dated February 26, 2004 for information regarding fees paid by Suncor to its auditors for the last two completed fiscal years, which information is incorporated by reference into this Annual Information Form.

Audit Committee Pre-Approval Policies for Non Audit Services

Suncor's Audit Committee has considered whether the provision of services other than audit services is compatible with maintaining the auditors' independence and has a policy governing the provision of these services. The policy requires that all non-audit services provided by Suncor's auditors be approved by the Audit Committee in compliance with the *Sarbanes Oxley Act of 2002*. For the year ended December 31, 2003, all non-audit fees were approved by the audit committee pursuant to paragraph (c)(7)(i)(A) of Rule 2-01 of Regulation S-X, with the exception of approximately 1% of non-audit fees (approximately $2,500 out of a total $186,000 in non-audit fees) which were approved by the Audit Committee pursuant to paragraph (c)(7)(i)(C) of Rule 2-01 of Regulation S-X.

RELIANCE ON EXEMPTIVE RELIEF

Suncor is reporting its reserves data in accordance with, and is relying on, the terms of the following MRRS Decision Document: In the Matter of the Securities Legislation of Alberta, British Columbia, Saskatchewan, Manitoba, Ontario, Quebec, Nova Scotia, Newfoundland and Labrador, Yukon, Northwest Territories and Nunavut AND In the Matter of The Mutual Reliance Review System for Exemptive Relief Applications AND In the Matter of Suncor Energy Inc., December 22, 2003 (the "Decision Document").

Suncor's reserves data consists of the following:

- net proved working interest oil and gas reserve quantities relating to oil and gas operations, other than mining, estimated as at December 31, 2003 using constant prices and costs, and the related standardized measure; and
- gross proved and probable working interest oil reserve quantities relating to surface mineable oil sands operations estimated as at December 31, 2003.

Suncor's estimates of reserves and related standardized measure of discounted future net cash flows (the "standardized measure") were evaluated or reviewed in accordance with the standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") modified to the extent necessary to reflect the terminology and standards of US disclosure requirements, including:

- the information required by the United States Financial Accounting Standards Board, including Financial Accounting Standard No. 69;
- the information required by SEC Industry Guide 2 Disclosure of Oil and Gas Operations, as amended from time to time; and
- certain other information required in accordance with US disclosure practices.

If Suncor had been reporting its' reserves data in accordance with National Instrument 51-101 and had not been relying on the terms of the Decision Document, it would have been required to report gross and net reserves data consisting of the following:

- proved working interest oil and gas reserve quantities relating to oil and gas operations using constant prices and costs and related net present value of future net revenue, discounted at 10%; and
- proved and probable working interest oil and gas reserve quantities relating to oil and gas operations using forecast prices and costs and related net present value of future net revenue, discounted at 5%, 10%, 15% and 20%.

ADDITIONAL INFORMATION

Copies of the documents set out below may be obtained by any person upon request to the Secretary of the Company at 112 - 4 Avenue S.W., Calgary, Alberta, T2P 2V5, by calling 1-800-558-9071, or by e-mail request to info@suncor.com.

(i) The current Suncor Annual Information Form together with any pertinent information incorporated by reference therein;

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

(iii) Suncor's management proxy circular in respect of its most recent annual meeting of shareholders that involved the election of directors;

and

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

Copies of such documents will be made available without charge at any time when Suncor's securities are in the course of distribution pursuant to a short form prospectus. At any other time Suncor reserves the right to impose a reasonable charge for requests by persons other than security holders. Such documents are available electronically on Suncor's web site at www.suncor.com.

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of Suncor's securities, options to purchase securities and interests of insiders in material transactions, where applicable, is contained in Suncor's most recent management proxy circular for its most recent annual meeting of its shareholders that involved the election of directors. Additional financial information is provided in Suncor's 2003 Consolidated Financial Statements.

Further information about Suncor, filed with Canadian securities commissions and the United States Securities and Exchange Commission (SEC), including periodic quarterly and annual reports and the Annual Information (AIF/40-F) is available online at www.sedar.com and www.sec.gov.

FORM 51-101F3
REPORT OF
MANAGEMENT AND DIRECTORS
ON RESERVES DATA AND OTHER INFORMATION

This is the form referred to in item 3 of section 2.1 of National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("*NI 51-101*"), as amended pursuant to the MRRS Decision Document dated December 22, 2003, *In the Matter of Suncor Energy Inc.* (the "Decision Document").

Terms to which a meaning is ascribed in the Decision Document have the same meaning in this form.

Management of Suncor Energy Inc. (the "Company") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas and surface mineable oil sands activities in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

(a) proved working interest oil and gas reserve quantities relating to oil and gas operations, other than mining, estimated as at December 31, 2003 using constant prices and costs, and the related standardized measure; and

(b) proved and probable working interest oil reserve quantities relating to surface mineable oil sands operations estimated as at December 31, 2003.

Gilbert Laustsen Jung Associates Ltd., independent qualified reserves evaluators, have evaluated the Company's reserves data. The report of the independent qualified reserves evaluators will be filed with securities regulatory authorities concurrently with this report.

The Audit Committee of the board of directors of the Company has

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluators;

(b) met with the independent qualified reserves evaluators to determine whether any restrictions affected the ability of the independent qualified reserves evaluators to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluators.

The Audit Committee of the board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas and surface mineable oil sands activities and has reviewed that information with management. The board of directors has, on the recommendation of the Audit Committee, approved

(a) the content and filing with securities regulatory authorities of the reserves data and other oil and gas and surface mineable oil sands information;

(b) the filing of the report of the independent qualified reserves evaluators on the reserves data; and

(c) the content and filing of this report.

Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

"RICHARD L. GEORGE"
RICHARD L. GEORGE
President and Chief Executive Officer

"J. KENNETH ALLEY"
J. KENNETH ALLEY
Senior Vice President and Chief Financial Officer

"JOHN T. FERGUSON"
JOHN T. FERGUSON
Director

"JR SHAW"
JR SHAW
Chairman of the Board of Directors

February 26, 2004



Gilbert Laustsen Jung

Associates Ltd. Petroleum Consultants

4100, 400 - 3rd Avenue S.W., Calgary, Alberta, Canada T2P 4H2(403) 266-9500Fax (403) 262-1855

February 26, 2004

Suncor Energy Inc.
P.O. Box 38
112 – 4th Avenue S.W.
Calgary, AB T2P 2V5

To: **The Board of Directors of Suncor Energy Inc.**

Re: **Form 51-101F2, as modified in accordance with exemptions from National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101") contained in the MRRS Decision Document dated December 22, 2003, *In the Matter of Suncor Energy Inc.* (the "Decision Document")**

We are providing this report in accordance with the terms of the Decision Document and any capitalized terms, not otherwise defined in this report, shall have the same meaning as set out in the Decision Document.

We have evaluated the Company's reserves data as at December 31, 2003. The reserves data consist of the following:

(a) **proved working interest oil and gas reserve quantities relating to oil and gas operations, other than mining, estimated as at December 31, 2003 using constant prices and costs, and the related standardized measure; and**

(b) **proved and probable working interest oil reserve quantities relating to surface mineable oil sands operations estimated as at December 31, 2003**

The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

We evaluated or reviewed the Company's estimates of reserves and related future net revenue (or, where applicable, related standardized measure of discounted future net cash flows (the standardized measure)) in accordance with the standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") modified to the extent necessary to reflect the terminology and standards of the US Disclosure Requirements.

Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook, as modified to the extent necessary to reflect the terminology and standards of the US Disclosure Requirements.

The following table sets forth the estimated standardized measure of future cash flows (before deducting income taxes) attributed to proved oil and gas reserve quantities not related to mining operations, estimated using constant prices and costs and calculated using a discount rate of 10

percent, included in the reserves data of the Company evaluated for the year ended, December 31, 2003:

		Standardized Measure of Future Cash Flows for Proved Oil and Gas Reserve Quantities (before income taxes, 10% discount rate)		
Preparation Date of Report	Location of Reserves	Evaluated	Reviewed	Total
February 20, 2004	**Canada**	**$ 2,533 million**	**$ 84 million**	**$ 2,617 million**
		(97)%	**(3)%**	**(100)%**

In addition, all proved plus probable company gross reserves have been evaluated for Suncor's oilsands mining properties located in Canada and all reserves and resources have been evaluated or reviewed for all of Suncor's oil and gas plus mining operations.

In our opinion, the reserves data evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, as modified or amended as set out above. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

We have no responsibility to update our reports evaluating reserves data of the Company by us for the year ended December 31, 2003 for events and circumstances occurring after the preparation dates of our reports.

Reserves are estimates only, and not exact quantities. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

GILBERT LAUSTSEN JUNG ASSOCIATES LTD.,
Calgary, Alberta, Canada

Per: ORIGINALLY SIGNED BY

Dana B. Laustsen, P. Eng.
Executive Vice-President

UNDERTAKING AND CONSENT TO SERVICE OF PROCESS

A. Undertaking

Suncor Energy Inc. (the "Registrant") undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the staff of the Securities and Exchange Commission ("SEC"), and to furnish promptly, when requested to do so by the SEC staff, information relating to the securities in relation to which the obligation to file an annual report on Form 40-F arises, or transactions in said securities.

B. Consent to Service of Process

The Registrant has filed previously with the SEC a Form F-3 in connection with the Common Shares.

DISCLOSURE CONTROLS AND PROCEDURES

See Exhibits 6 and 7 hereof.

AUDIT COMMITTEE FINANCIAL EXPERT

See page 7 of Appendix A of Exhibit 3.

CODE OF ETHICS

See pages 25 and 26 of Exhibit 3.

FEES PAID TO PRINCIPAL ACCOUNTANT

See page 27 of Exhibit 3.

AUDIT COMMITTEE PRE-APPROVAL POLICIES

See page 45 of Registrant's AIF.

APPROVAL OF NON-AUDIT SERVICES

See page 45 of Registrant's AIF.

OFF-BALANCE SHEET ARRANGEMENTS

See pages 21 and 22 of Exhibit 2.

TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS

See page 21 of Exhibit 2.

IDENTIFICATION OF THE AUDIT COMMITTEE

See page 3 of Exhibit 3.

SIGNATURES

Pursuant to the requirements of the Exchange Act, the registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this annual report to be signed on its behalf by the undersigned, thereto duly authorized.

SUNCOR ENERGY INC.

DATE: April 13, 2004

PER: "RICHARD L. GEORGE"
RICHARD L. GEORGE
President and Chief Executive Officer

EXHIBIT INDEX

Exhibit No.	Description
1	Audited Consolidated Financial Statements of Suncor Energy Inc. for the fiscal year ended December 31, 2003, including reconciliation to U.S. GAAP (Note 19)
2	Management's Discussion and Analysis for the fiscal year ended December 31, 2003, dated February 26, 2004
3	Pages 3, 25 to 27 and Appendix A inclusive of Suncor Energy Inc.'s Management Proxy Circular dated March 8, 2004
4	Consent of PricewaterhouseCoopers LLP
5	Consent of Gilbert Laustsen Jung Associates Ltd.
6	Certificate of President and Chief Executive Officer Pursuant to Exchange Act Rules 13a-15(e) and 15d-15(e)
7	Certificate of Senior Vice President and Chief Financial Officer Pursuant to Exchange Act Rules 13a-15(e) and 15d-15(e)
8	Certificate of the President and Chief Executive Officer Pursuant to 18 U.S.C. Section 1350, as Enacted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
9	Certificate of the Senior Vice President and Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as Enacted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

EXHIBIT 1

Audited Consolidated Financial Statements of Suncor Energy Inc. for the fiscal year ended December 31, 2003, including reconciliation to U.S. GAAP (Note 19)

Management's Statement of Responsibility for Financial Reporting

The management of Suncor Energy Inc. is responsible for the presentation and preparation of the accompanying consolidated financial statements of Suncor Energy Inc. on pages 54 to 89 and all related financial information contained in this Annual Report, including Management's Discussion and Analysis.

We, as Suncor Energy Inc.'s Chief Executive Officer and Chief Financial Officer, will certify Suncor's annual disclosure document filed with the United States Securities and Exchange Commission (Form 40-F) as required by the United States Sarbanes-Oxley Act.

The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles. They include certain amounts that are based on estimates and judgments relating to matters not concluded by year-end. Financial information presented elsewhere in this Annual Report is consistent with that contained in the consolidated financial statements.

In management's opinion, the consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the significant accounting policies adopted by management as summarized on pages 54 to 57. If alternate accounting methods exist, management has chosen those policies it deems the most appropriate in the circumstances. In discharging its responsibilities for the integrity and reliability of the financial statements, management maintains and relies on a system of internal controls designed to ensure that transactions are properly authorized and recorded, assets are safeguarded against unauthorized use or disposition and liabilities are recognized. These controls include quality standards in hiring and training of employees, formalized policies and procedures, a corporate code of conduct and associated compliance program designed to establish and monitor conflicts of interest, the integrity of accounting records and financial information among others, and employee and management accountability for performance within appropriate and well-defined areas of responsibility.

The system of internal controls is further supported by the professional staff of an internal audit function who conduct periodic audits of all aspects of the company's operations.

In order to provide their opinion on the accompanying consolidated financial statements, PricewaterhouseCoopers LLP, the independent external auditors, review the company's system of internal controls and conduct their work to the extent that they consider appropriate. The company also retains independent petroleum consultants, Gilbert Laustsen Jung Associates Ltd., to conduct independent evaluations of the company's oil and gas reserves.

The Audit Committee of the Board of Directors, currently composed of four independent directors, reviews the effectiveness of the company's financial reporting systems, management information systems, internal control systems and the internal auditors. It recommends to the Board of Directors the external auditors to be appointed by the shareholders at each annual meeting and reviews the independence and effectiveness of their work. In addition, it reviews with management and the external auditors any significant financial reporting issues, the presentation and impact of significant risks and uncertainties, and key estimates and judgments of management that may be material for financial reporting purposes. The Audit Committee appoints the independent petroleum consultants. The Audit Committee meets at least quarterly to review and approve interim financial statements prior to their release, as well as annually to review Suncor's annual financial statements and Management's Discussion and Analysis, Annual Information Form/Form 40-F, and annual reserves estimates, and recommend their approval to the Board of Directors. The internal auditors and PricewaterhouseCoopers LLP have unrestricted access to the company, the Audit Committee and the Board of Directors.

/s/ Richard L. George	/s/ J. Kenneth Alley
Richard L. George President and Chief Executive Officer	**J. Kenneth Alley** Senior Vice President and Chief Financial Officer

January 27, 2004

Auditors' Report

TO THE SHAREHOLDERS OF SUNCOR ENERGY INC.

We have audited the Consolidated Balance Sheets of Suncor Energy Inc. as at December 31, 2003 and 2002 and the consolidated statements of earnings, cash flows and changes in shareholders' equity for each of the years in the three year period ended December 31, 2003. 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 Canadian generally accepted auditing standards. 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, 2003 and 2002 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2003, in accordance with Canadian generally accepted accounting principles.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta

January 27, 2004

COMMENTS BY AUDITORS FOR U.S. READERS ON CANADA – U.S. REPORTING DIFFERENCES

In the United States, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) when there is a change in accounting principles that has a material effect on the comparability of the company's financial statements, such as the change described in note 1 to the consolidated financial statements. Our report to the shareholders dated January 27, 2004 is expressed in accordance with Canadian reporting standards which do not require a reference to such a change in accounting principles in the Auditors' Report when the change is properly accounted for and adequately disclosed in the financial statements.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta

January 27, 2004

Summary of Significant Accounting Policies

Suncor Energy Inc. is an integrated Canadian energy company comprised of four operating segments: Oil Sands, Natural Gas, Energy Marketing and Refining – Canada, and Refining and Marketing – U.S.A.

Oil Sands includes the production of light sweet and light sour crude oil, diesel fuel and various custom blends from oil sands mined in the Athabasca region of northeastern Alberta, and the marketing of these products substantially in Canada and the United States.

Natural Gas includes the exploration, acquisition, development, production, transportation and marketing of natural gas and crude oil in Canada and the United States.

Energy Marketing and Refining – Canada 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.

Refining and Marketing – U.S.A. includes the manufacture, transportation and marketing of petroleum products, primarily in Colorado.

The significant accounting policies of the company are summarized below:

(a) Principles of Consolidation and the Preparation of Financial Statements
These consolidated financial statements are prepared and reported in Canadian dollars in accordance with Canadian generally accepted accounting principles (GAAP), which differ in some respects from GAAP in the United States. These differences are quantified and explained in note 19.

The consolidated financial statements include the accounts of Suncor Energy Inc. and its subsidiaries and the company's proportionate share of the assets, liabilities, revenues, expenses and cash flows of its joint ventures.

The timely preparation of financial statements requires that management make estimates and assumptions, and use judgment regarding assets, liabilities, revenues and expenses. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur.

(b) Cash Equivalents and Investments
Cash equivalents consist primarily of term deposits, certificates of deposit and all other highly liquid investments with a maturity at the time of purchase of three months or less. Investments with maturities 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
Crude oil sales from upstream operations (Oil Sands and Natural Gas) to downstream operations (Energy Marketing and Refining – Canada and Refining and Marketing – U.S.A.) are based on actual product shipments. On consolidation, revenues and purchases related to these sales transactions are eliminated from 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 Sarnia refinery. On consolidation, revenues from these sales are eliminated from operating revenues, crude oil and products purchases, and operating, selling and general expenses.

Revenues associated with sales of crude oil, natural gas, petroleum and petrochemical products and all other items not eliminated on consolidation are recorded when title passes to the customer and delivery has taken place. Revenues from oil and natural gas production from properties in which the company has an interest with other producers are recognized on the basis of the company's net working interest.

(d) Property, Plant and Equipment and Intangible Assets
Cost
Property, plant and equipment and intangible assets are recorded at cost.

Expenditures to acquire and develop Oil Sands mining properties are capitalized. Development costs to expand the capacity of existing mines or to develop mine areas substantially in advance of current production are also capitalized.

The company follows the successful efforts method of accounting for its conventional and in-situ oil sands crude oil and natural gas operations. Under the successful efforts 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 initially capitalized. 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. Related land costs are expensed through the amortization of unproved properties as covered under the Natural Gas section of the depreciation, depletion and amortization policy below.

Development costs, which include the costs of wellhead equipment, development drilling costs, gas plants and handling facilities, applicable geological and geophysical costs 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 as operating costs.

Costs incurred at the inception of operations are expensed.

Interest Capitalization
Interest costs relating to major capital projects in progress and to the portion of non-producing oil and gas properties expected to become producing are capitalized as part of property, plant and equipment. Capitalization of interest ceases when the capital asset is substantially complete and ready for its intended productive use.

Leases
Leases that transfer substantially all the benefits and risks of ownership to the company are recorded as capital leases and classified as property, plant and equipment with offsetting long-term debt. All other leases are classified as operating leases under which leasing costs are expensed in the period incurred.

Gains and losses on the sale and leaseback of assets recorded as capital leases are deferred and amortized to earnings in proportion to the amortization of leased assets.

Depreciation, Depletion and Amortization
OIL SANDS Property, plant and equipment are depreciated over their useful lives on a straight-line basis, commencing when the assets are placed into service. Mine and mobile equipment is depreciated over periods ranging from three to 20 years and plant and other property and equipment, including leases in service, primarily over four to 40 years. Capitalized costs related to the in-progress phase of projects are not depreciated until the facilities are substantially complete and ready for their intended productive use.

NATURAL GAS Acquisition costs of unproved properties that are individually significant are evaluated for impairment by management. Impairment of unproved properties that are not individually significant is provided for through amortization over the average projected holding period for that portion of acquisition costs not expected to become producing. The average projected holding period of five years is based on historical experience.

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. Gas plants, support facilities and equipment are depreciated on a straight-line basis over their useful lives, which average 12 years.

DOWNSTREAM OPERATIONS (INCLUDING ENERGY MARKETING AND REFINING – CANADA AND REFINING AND MARKETING – U.S.A.) Depreciation of property, plant and equipment is provided on a straight-line basis over the useful lives of assets. The Sarnia and Denver refineries and additions thereto are depreciated over an average of 30 years, service stations and related equipment over an average of 20 years and pipeline facilities and other equipment over three to 40 years. Intangible assets with determinable useful lives are amortized over a maximum period of four years. The amortization is included within depreciation expense in the Consolidated Statements of Earnings.

Reclamation and Environmental Remediation Costs
For the years ended December 31, 2003, reclamation and environmental remediation costs for identified downstream sites were estimated and charged against earnings when a regulatory or statutory requirement or contractual agreement existed, or when management made a decision to decommission or restore a site, providing that assessments indicated that such costs were probable and reasonably estimable.

Estimated reclamation costs in the company's upstream operations were accrued on the unit of production basis. Estimated environmental remediation costs, which were predominantly in the company's downstream operations, were accrued during the period for those sites where assessments indicated that such work was required.

Costs were accrued based on currently known information, estimated timing of remedial actions, and existing regulatory requirements and technology.

See the section "Recently Issued Canadian Accounting Standards" for further details on the adoption of a new accounting policy for Asset Retirement Obligations.

Impairment
Property, plant and equipment are reviewed for impairment whenever events or conditions indicate that their net carrying amount, less related provisions for reclamation and environmental remediation costs and future income taxes, may not be recoverable from estimated undiscounted future cash flows. If it is determined that the estimated net recoverable amount is less than the net carrying amount, a write-down to the estimated net recoverable amount is recognized during the period, with a charge to earnings.

Disposals
Gains or losses on disposals of non-oil and gas property, plant and equipment are recognized in earnings. For oil and gas property, plant and equipment, 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 that is not individually significant, or a partial abandonment of a proved property, is charged to accumulated depreciation, depletion or amortization.

(e) Deferred Charges and Other
Overburden removal may precede mining of the oil sands deposit by as much as two years. Accordingly, the company employs a deferral method of accounting for overburden removal costs where all such costs are initially recorded as a deferred charge (see note 4), rather than expensing overburden removal costs as incurred. These deferred charges are allocated to the mining activity in the year on a last-in, first-out (LIFO) basis using a life-of-mine approach for each mine pit whereby all of the overburden to be removed is related to all of the oil sands proven and probable ore reserves. This expense is reported as part of the depreciation, depletion and amortization expense in the Consolidated Statements of Earnings. Stripping ratios are regularly reviewed to reflect changes in operating experience and other factors.

The cost of major maintenance shutdowns is deferred and amortized on a straight-line basis over the period to the next shutdown, which varies from three to seven years. Normal maintenance and repair costs are charged to expense as incurred.

(f) Employee Future Benefits
The company's employee future benefit programs consist of defined benefit and defined contribution pension plans, as well as other post-retirement benefits.

The estimated future cost of providing defined benefit pension and other post-retirement benefits is actuarially determined using management's best estimates of demographic and financial assumptions, and such cost is accrued ratably from the date of hire of the employee to the date the employee becomes fully eligible to receive the benefits. The discount rate used to determine accrued benefit obligations is based on a year-end market rate of interest. Company contributions to the defined contribution plan are expensed as incurred.

(g) Inventories
Inventories of crude oil and refined products are valued at the lower of cost (using the LIFO method) and net realizable value.

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

(h) Derivative Financial Instruments
The company periodically enters into derivative financial instrument commodity contracts such as forwards, futures, swaps and options to hedge against the potential adverse impact of changing market prices due to changes in the underlying commodity indices. The company also periodically enters into derivative financial instrument contracts such as interest rate swaps as part of its risk management strategy to manage exposure to interest rate fluctuations.

These derivative contracts are initiated within the guidelines of the company's risk management policies, which require stringent authorities for approval and commitment of contracts, designation of the contracts by management as hedges of the related transactions, and monitoring of the effectiveness of such contracts in reducing the related risks. Contract maturities are consistent with the settlement dates of the related hedged transactions.

Derivative contracts accounted for as hedges are not recognized in the Consolidated Balance Sheets. Gains or losses on these contracts, including realized gains and losses on hedging derivative contracts settled prior to maturity, are recognized in earnings and cash flows when the related sales revenues, costs, interest expense and cash flows are recognized. Gains or losses resulting from changes in the fair value of derivative contracts that do not qualify for hedge accounting are recognized in earnings and cash flows when those changes occur.

Commencing in the fourth quarter of 2002, the company began to use energy derivatives, including physical and financial swaps, forwards and options to gain market information and to earn trading revenues. Trading activities are accounted for at fair value.

(i) Foreign Currency Translation
Monetary assets and liabilities in foreign currencies are translated to Canadian dollars at rates of exchange in effect at the end of the period. Other assets and related depreciation, depletion and amortization, other liabilities, revenues and expenses are translated at rates of exchange in effect at the respective transaction dates. The resulting exchange gains and losses are included in earnings.

The company's new Refining and Marketing – U.S.A. operations are classified as self-sustaining and are translated into Canadian dollars using the current rate method. Assets and liabilities are translated at the period end exchange rate, while revenues and expenses are translated using average exchange rates during the period. Translation gains or losses are included in cumulative foreign exchange adjustments in the Consolidated Statements of Changes in Shareholders' Equity.

(j) Stock-based Compensation Plans
Under the company's common share option programs (see note 12), common share options are granted to executives, employees and non-employee directors.

Compensation expense is recorded in the Consolidated Statements of Earnings for all common share options granted to employees and non-employee directors on or after January 1, 2003, with a corresponding increase recorded as contributed surplus in the Consolidated Statements of Changes in Shareholders' Equity. Compensation expense for options granted during 2003 and thereafter is determined based on the fair values at the time of grant, the cost of which is recognized in the Consolidated Statements of Earnings over the estimated vesting periods of the respective options. For common share options granted prior to January 1, 2003 ("pre-2003 options"), compensation expense is not recognized. The company continues to disclose the pro forma earnings impact of related stock-based compensation expense for pre-2003 options. Consideration paid to the company on exercise of options is credited to share capital.

Stock-based compensation awards that are to be settled in cash are measured using the fair value based method of accounting.

(k) Recently Issued Canadian Accounting Standards
Hedging Relationships
Canadian Accounting Guideline 13 (AcG 13) "Hedging Relationships" is applicable to the company's hedging relationships in 2004 and subsequent fiscal years. AcG 13 specifies the circumstances in which hedge accounting is appropriate, including the identification, documentation, designation and effectiveness of hedges, as well as the discontinuance of hedge accounting. The Guideline does not specify hedge accounting methods. The company believes its hedging documentation and tests of effectiveness are prepared in accordance with the provisions of AcG 13.

Asset Retirement Obligations
Effective January 1, 2004, the company will adopt the new Canadian standard "Asset Retirement Obligations" (ARO), which substantially harmonizes Canadian GAAP with U.S. GAAP (see note 19). This standard requires recognition of a liability for the future retirement obligations associated with the company's property, plant and equipment. The fair value of the asset retirement obligations are to be recorded on a discounted basis. This amount is to be capitalized as part of the cost of the related asset and amortized to expense over its useful life. The liability accretes until the company settles the obligation. The impact of adopting this standard will be an increase to property, plant and equipment of $211 million, an increase to future tax assets of $110 million, an increase to accrued liabilities of $318 million, an increase to future tax liabilities of $73 million, and a decrease to retained earnings of $70 million.

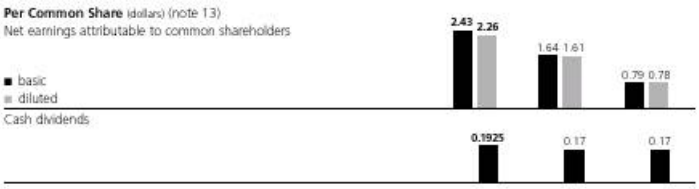
Variable Interest Entities
In 2003, Canadian Accounting Guideline 15 (AcG 15) "Consolidation of Variable Interest Entities (VIEs)" was issued. Effective January 1, 2005 AcG 15 requires consolidation of a VIE where the company will absorb a majority of a VIEs losses, receive a majority of its returns, or both. The company will be required to consolidate the VIE related to the sale of equipment as described in note 10(c). The company does not expect a significant impact on net earnings on consolidation of the equipment VIE. The impact on the balance sheet will be an increase to property, plant and equipment and an increase to long-term liabilities of approximately $20 million. The VIE involving the sale of crude oil inventory terminates June 25, 2004, prior to the effective date of AcG 15. The accounts receivable securitization program, as currently structured, does not meet the AcG 15 criteria for consolidation by Suncor.

Liabilities and Equity
In 2003, the Canadian Accounting Standards Board approved an amendment to its Handbook Section 3860 "Financial Instruments – Disclosure and Presentation" requiring certain obligations that must or could be settled with an entity's own equity instruments to be presented as liabilities. The amendment, effective for the company's 2005 fiscal year, affects the company's current presentation of Preferred Securities as equity (see note 11). The reclassification of the Preferred Securities from equity to long-term debt is expected to reduce equity by $485 million, increase long-term debt by $486 million, and increase deferred charges by $1 million.

Consolidated Statements of Earnings

for the years ended December 31 ($ millions)	2003	2002	2001
Revenues			
Operating revenues (notes 6, 16, 17 and 18)	**6 171**	4 883	4 204
Energy marketing and trading activities (note 6c)	**129**	147	85
Interest	**6**	2	5
	6 306	5 032	4 294
Expenses			
Purchases of crude oil and products	**1 570**	1 156	1 510

Operating, selling and general	**1 507**	1 292	1 012
Energy marketing and trading activities	**132**	142	85
Transportation and other costs (note 16)	**133**	128	95
Depreciation, depletion and amortization	**611**	585	360
Exploration (note 18)	**51**	26	22
Royalties	**139**	98	134
Taxes other than income taxes (note 18)	**426**	374	367
(Gain) on disposal of assets	**(17)**	(2)	(7)
(Gain) on sale of retail natural gas marketing business (note 18)	**—**	(38)	—
Project start-up costs	**16**	3	141
Write-off of oil shale assets	**—**	—	48
Restructuring	**—**	—	(2)
Financing expenses (income) (note 14)	**(66)**	124	16
	4 502	3 888	3 781
Earnings Before Income Taxes	**1 804**	1 144	513
Provision for income taxes (note 9)			
Current	**38**	74	4
Future	**682**	309	121
	720	383	125
Net Earnings	**1 084**	761	388
Dividends on Preferred Securities, net of tax (note 11)	**(27)**	(28)	(26)
Revaluation of US$ Preferred Securities, net of tax	**37**	1	(11)
Net earnings attributable to common shareholders	**1 094**	734	351



See accompanying Summary of Significant Accounting Policies and Notes.

Consolidated Balance Sheets

as at December 31 ($ millions)	2003	2002
Assets		
Current assets		
Cash and cash equivalents	**388**	15
Accounts receivable (notes 10c and 18)	**505**	403
Inventories (note 15)	**371**	266
Future income taxes (note 9)	**28**	38
Total current assets	**1 292**	722
Property, plant and equipment, net (note 3)	**8 725**	7 641
Deferred charges and other (note 4)	**286**	185
Future income taxes (note 9)	**124**	135
Total assets	**10 427**	8 683
Liabilities and Shareholders' Equity		
Current liabilities		
Short-term debt	**31**	—
Accounts payable and accrued liabilities (notes 7 and 8)	**972**	716
Income taxes payable	**9**	34
Taxes other than income taxes	**49**	37
Future income taxes (note 9)	**14**	10
Total current liabilities	**1 075**	797
Long-term debt (note 5)	**2 448**	2 686
Accrued liabilities and other (notes 7 and 8)	**296**	226
Future income taxes (note 9)	**2 183**	1 516
Total liabilities	**6 002**	5 225
Commitments and contingencies (note 10)		
Shareholders' equity		
Preferred Securities (note 11)	**476**	523
Share capital (note 12)	**604**	578
Contributed surplus (note 12)	**7**	—
Cumulative foreign currency translation	**(26)**	—
Retained earnings	**3 364**	2 357
Total shareholders' equity	**4 425**	3 458
Total liabilities and shareholders' equity	**10 427**	8 683

See accompanying Summary of Significant Accounting Policies and Notes.

Approved on behalf of the Board of Directors:

/s/ R. L. George	/s/ J. T. Ferguson
R. L. George	**J. T. Ferguson**
Director	Director

Consolidated Statements of Cash Flows

for the years ended December 31 ($ millions)	2003	2002	2001
Operating Activities			
Cash flow from operations (a)	**2 081**	1 440	831
Decrease (increase) in operating working capital (net of effects of acquisition of Denver refinery and related assets)			
Accounts receivable	**(105)**	(97)	101
Inventories	**(19)**	(8)	(66)
Accounts payable and accrued liabilities	**256**	44	(37)
Taxes payable	**5**	77	(17)
Cash flow from operating activities	**2 218**	1 456	812
Cash Used in Investing Activities (a)	**(1 702)**	(861)	(1 680)
Net Cash Surplus (Deficiency) Before Financing Activities	**516**	595	(868)
Financing Activities			
Increase (decrease) in short-term debt	**31**	(31)	(33)
Proceeds from issuance of long-term debt	**651**	797	500
Net increase (decrease) in other long-term debt	**(716)**	(1 245)	486
Issuance of common shares under stock option plans	**20**	19	15
Dividends paid on Preferred Securities	**(45)**	(48)	(48)
Dividends paid on common shares	**(81)**	(73)	(72)
Cash flow from (used in) financing activities	**(140)**	(581)	848
Increase (Decrease) in Cash and Cash Equivalents	**376**	14	(20)
Effect of Foreign Exchange on Cash and Cash Equivalents	**(3)**	—	—
Cash and Cash Equivalents at Beginning of Year	**15**	1	21
Cash and Cash Equivalents at End of Year	**388**	15	1

(a) See Schedules of Segmented Data on pages 64 and 65.

See accompanying Summary of Significant Accounting Policies and Notes.

Consolidated Statements of Changes in Shareholders' Equity

for the years ended December 31 ($ millions)	Preferred Securities	Share Capital	Contributed Surplus	Cumulative Foreign Currency Translation	Retained Earnings
At December 31, 2000	510	537	—	—	1 424
Net earnings	—	—	—	—	388
Dividends paid on Preferred Securities, net of tax	—	—	—	—	(26)
Dividends paid on common shares	—	—	—	—	(72)
Issued for cash under stock option plans	—	15	—	—	—
Issued under dividend reinvestment plan	—	3	—	—	(3)
Revaluation of US$ Preferred Securities	15	—	—	—	(11)
At December 31, 2001	525	555	—	—	1 700
Net earnings	—	—	—	—	761
Dividends paid on Preferred Securities, net of tax	—	—	—	—	(28)
Dividends paid on common shares	—	—	—	—	(73)
Issued for cash under stock option plans	—	19	—	—	—
Issued under dividend reinvestment plan	—	4	—	—	(4)
Revaluation of US$ Preferred Securities	(2)	—	—	—	1
At December 31, 2002	**523**	**578**	**—**	**—**	**2 357**
Net earnings	**—**	**—**	**—**	**—**	**1 084**
Dividends paid on Preferred Securities, net of tax	**—**	**—**	**—**	**—**	**(27)**
Dividends paid on common shares	**—**	**—**	**—**	**—**	**(81)**
Issued for cash under stock option plans	**—**	**20**	**—**	**—**	**—**
Issued under dividend reinvestment plan	**—**	**6**	**—**	**—**	**(6)**
Stock-based compensation expense	**—**	**—**	**7**	**—**	**—**
Foreign currency translation adjustment	**—**	**—**	**—**	**(26)**	**—**
Revaluation of US$ Preferred Securities	**(47)**	**—**	**—**	**—**	**37**

At December 31, 2003	**476**	**604**	**7**	**(26)**	**3 364**

See accompanying Summary of Significant Accounting Policies and Notes.

Schedules of Segmented Data (a)

for the years ended December 31 ($ millions)	Oil Sands			Natural Gas			Energy Marketing and Refining Canada		
	2003	2002	2001	2003	2002	2001	2003	2002	2001
EARNINGS									
Revenues (b)									
Operating revenues (note 16)	**2 676**	2 241	1 214	**436**	279	405	**2 542**	2 361	2 585
Energy marketing and trading activities	**—**	—	—	**—**	—	—	**129**	147	85
Intersegment revenues (c)	**385**	375	158	**76**	60	76	**—**	—	3
Interest	**—**	—	—	**—**	—	—	**—**	—	—
	3 061	2 616	1 372	**512**	339	481	**2 671**	2 508	2 673
Expenses									
Purchases of crude oil and products	**12**	7	14	**—**	16	9	**1 679**	1 564	1 721
Operating, selling and general	**890**	806	481	**77**	69	64	**359**	352	350
Energy marketing and trading activities	**—**	—	—	**—**	—	—	**132**	142	85
Transportation and other costs (note 16)	**101**	104	72	**24**	24	23	**3**	—	—
Depreciation, depletion and amortization	**451**	450	233	**91**	75	70	**59**	58	56
Exploration	**11**	9	—	**40**	17	22	**—**	—	—
Royalties	**33**	33	30	**106**	65	104	**—**	—	—
Taxes other than income taxes	**24**	23	12	**3**	2	3	**342**	348	351
(Gain) loss on disposal of assets	**(1)**	2	1	**(12)**	(4)	(8)	**(4)**	—	—
(Gain) on sale of retail natural gas marketing business	**—**	—	—	**—**	—	—	**—**	(38)	—
Project start-up costs	**10**	3	141	**—**	—	—	**—**	—	—
Write-off of oil shale assets	**—**	—	—	**—**	—	—	**—**	—	—
Restructuring	**—**	—	—	**—**	—	(2)	**—**	—	—
Financing expenses (income)	**—**	—	—	**—**	—	—	**—**	—	—
	1 531	1 437	984	**329**	264	285	**2 570**	2 426	2 563
Earnings (loss) before income taxes	**1 530**	1 179	388	**183**	75	196	**101**	82	110
Provision for income taxes	**(642)**	(389)	(105)	**(54)**	(40)	(79)	**(48)**	(18)	(30)
Net earnings (loss)	**888**	790	283	**129**	35	117	**53**	64	80
As at December 31									
TOTAL ASSETS	**7 762**	6 896	6 409	**784**	765	722	**1 079**	968	934
CAPITAL EMPLOYED (d)	**4 078**	4 540	1 398	**436**	449	317	**558**	491	483

(a) Accounting policies for segments are the same as those described in the Summary of Significant Accounting Policies.

(b) There were no customers that represented 10% or more of the company's 2003 consolidated revenues (2002 – one customer represented 10% or more ($641 million); 2001 – one customer represented 10% or more ($450 million)).

(c) Intersegment revenues are recorded at prevailing fair market prices and accounted for as if the sales were to third parties.

(d) Capital Employed – the sum of shareholders' equity and short-term plus long-term debt less cash and cash equivalents, less capitalized costs related to major projects in progress (as applicable).

See accompanying Summary of Significant Accounting Policies and Notes.

for the years ended December 31 ($ millions)	Refining and Marketing U.S.A.			Corporate and Eliminations			Total		
	2003	2002	2001	2003	2002	2001	2003	2002	2001
EARNINGS									
Revenues (b)									
Operating revenues (note 16)	**515**	—	—	**2**	2	—	**6 171**	4 883	4 204
Energy marketing and trading activities	**—**	—	—	**—**	—	—	**129**	147	85
Intersegment revenues (c)	**—**	—	—	**(461)**	(435)	(237)	**—**	—	—
Interest	**—**	—	—	**6**	2	5	**6**	2	5
	515	—	—	**(453)**	(431)	(232)	**6 306**	5 032	4 294
Expenses									
Purchases of crude oil and products	**342**	—	—	**(463)**	(431)	(234)	**1 570**	1 156	1 510
Operating, selling and general	**68**	—	—	**113**	65	117	**1 507**	1 292	1 012
Energy marketing and trading activities	**—**	—	—	**—**	—	—	**132**	142	85

Transportation and other costs (note 16)	**5**	—	—	**—**	—	—	**133**	128	95
Depreciation, depletion and amortization	**6**	—	—	**4**	2	1	**611**	585	360
Exploration	**—**	—	—	**—**	—	—	**51**	26	22
Royalties	**—**	—	—	**—**	—	—	**139**	98	134
Taxes other than income taxes	**57**	—	—	**—**	1	1	**426**	374	367
(Gain) loss on disposal of assets	**—**	—	—	**—**	—	—	**(17)**	(2)	(7)
(Gain) on sale of retail natural gas marketing business	**—**	—	—	**—**	—	—	**—**	(38)	—
Project start-up costs	**6**	—	—	**—**	—	—	**16**	3	141
Write-off of oil shale assets	**—**	—	—	**—**	—	48	**—**	—	48
Restructuring	**—**	—	—	**—**	—	—	**—**	—	(2)
Financing expenses (income)	**—**	—	—	**(66)**	124	16	**(66)**	124	16
	484	—	—	**(412)**	(239)	(51)	**4 502**	3 888	3 781
Earnings (loss) before income taxes	**31**	—	—	**(41)**	(192)	(181)	**1 804**	1 144	513
Provision for income taxes	**(13)**	—	—	**37**	64	89	**(720)**	(383)	(125)
Net earnings (loss)	**18**	—	—	**(4)**	(128)	(92)	**1 084**	761	388
As at December 31									
TOTAL ASSETS	**438**	—	—	**364**	54	29	**10 427**	8 683	8 094
CAPITAL EMPLOYED (d)	**270**	—	—	**52**	138	34	**5 394**	5 618	2 232

	Oil Sands			Natural Gas			Energy Marketing and Refining Canada		
for the years ended December 31 ($ millions)	**2003**	**2002**	**2001**	**2003**	**2002**	**2001**	**2003**	**2002**	**2001**
CASH FLOW BEFORE FINANCING ACTIVITIES									
Cash from (used in) operating activities:									
Cash flow from (used in) operations									
Net earnings (loss)	**888**	790	283	**129**	35	117	**53**	64	80
Exploration expenses									
Cash	**—**	—	—	**8**	6	12	**—**	—	—
Dry hole costs	**—**	—	—	**32**	11	10	**—**	—	—
Non-cash items included in earnings									
Depreciation, depletion and amortization	**451**	450	233	**91**	75	70	**59**	58	56
Future income taxes	**628**	379	89	**52**	37	76	**20**	(35)	18
Current income tax provision allocated to Corporate	**14**	10	16	**2**	3	3	**28**	53	12
(Gain) loss on disposal of assets	**(1)**	2	1	**(12)**	(4)	(8)	**(4)**	—	—
(Gain) on sale of retail natural gas marketing business	**—**	—	—	**—**	—	—	**—**	(38)	—
Write-off of oil shale assets	**—**	—	—	**—**	—	—	**—**	—	—
Restructuring	**—**	—	—	**—**	—	(3)	**—**	—	
Stock-based compensation expense	**—**	—	—	**—**	—	—	**—**	—	—
Other	**8**	12	(4)	**(2)**	2	3	**9**	9	2
Overburden removal outlays	**(175)**	(160)	(31)	**—**	—	—	**—**	—	—
Overburden removal outlays – Project Millennium (start-up period)	**—**	—	(88)	**—**	—	—	**—**	—	—
Increase (decrease) in deferred credits and other	**(10)**	(8)	(13)	**—**	(1)	—	**(1)**	1	(3)
Total cash flow from (used in) operations	**1 803**	1 475	486	**300**	164	280	**164**	112	165
Decrease (increase) in operating working capital (net of effects of acquisition of Denver refinery and related assets)	**51**	(116)	(35)	**9**	22	44	**—**	(15)	17
Total cash from (used in) operating activities	**1 854**	1 359	451	**309**	186	324	**164**	97	182
Cash from (used in) investing activities:									
Capital and exploration expenditures	**(948)**	(617)	(1 479)	**(183)**	(163)	(132)	**(122)**	(60)	(54)
Acquisition of Denver refinery and related assets	**—**	—	—	**—**	—	—	**—**	—	—
Deferred maintenance shutdown expenditures	**(100)**	(9)	(5)	**—**	—	(2)	**(17)**	(18)	(9)
Deferred outlays and other investments	**(10)**	(4)	(2)	**—**	—	(1)	**(2)**	(18)	(9)
Proceeds from disposals	**3**	—	10	**17**	5	22	**6**	62	1
Total cash (used in) investing activities	**(1 055)**	(630)	(1 476)	**(166)**	(158)	(113)	**(135)**	(34)	(71)
Net cash surplus (deficiency) before financing activities	**799**	729	(1 025)	**143**	28	211	**29**	63	111

(a) Accounting policies for segments are the same as those described in the Summary of Significant Accounting Policies.

See accompanying Summary of Significant Accounting Policies and Notes.

for the years ended December 31 ($ millions)	Refining and Marketing U.S.A. 2003	2002	2001	Corporate and Eliminations 2003	2002	2001	Total 2003	2002	2001
CASH FLOW BEFORE FINANCING ACTIVITIES									
Cash from (used in) operating activities:									
Cash flow from (used in) operations									
Net earnings (loss)	**18**	—	—	**(4)**	(128)	(92)	**1 084**	761	388
Exploration expenses									
Cash	**—**	—	—	**—**	—	—	**8**	6	12
Dry hole costs	**—**	—	—	**—**	—	—	**32**	11	10
Non-cash items included in earnings									
Depreciation, depletion and amortization	**6**	—	—	**4**	2	1	**611**	585	360
Future income taxes	**1**	—	—	**(19)**	(72)	(62)	**682**	309	121
Current income tax provision allocated to Corporate	**12**	—	—	**(56)**	(66)	(31)	**—**	—	—
(Gain) loss on disposal of assets	**—**	—	—	**—**	—	—	**(17)**	(2)	(7)
(Gain) on sale of retail natural gas marketing business	**—**	—	—	**—**	—	—	**—**	(38)	—
Write-off of oil shale assets	**—**	—	—	**—**	—	48	**—**	—	48
Restructuring	**—**	—	—	**—**	—	—	**—**	—	(3)
Stock-based compensation expense	**—**	—	—	**7**	—	—	**7**	—	—
Other	**(2)**	—	—	**(163)**	(3)	7	**(150)**	20	8
Overburden removal outlays	**—**	—	—	**—**	—	—	**(175)**	(160)	(31)
Overburden removal outlays – Project Millennium (start-up period)	**—**	—	—	**—**	—	—	**—**	—	(88)
Increase (decrease) in deferred credits and other	**(1)**	—	—	**11**	(44)	29	**(1)**	(52)	13
Total cash flow from (used in) operations	**34**	—	—	**(220)**	(311)	(100)	**2 081**	1 440	831
Decrease (increase) in operating working capital (net of effects of acquisition of Denver refinery and related assets)	**46**	—	—	**31**	125	(45)	**137**	16	(19)
Total cash from (used in) operating activities	**80**	—	—	**(189)**	(186)	(145)	**2 218**	1 456	812
Cash from (used in) investing activities:									
Capital and exploration expenditures	**(31)**	—	—	**(32)**	(37)	(13)	**(1 316)**	(877)	(1 678)
Acquisition of Denver refinery and related assets	**(272)**	—	—	**—**	—	—	**(272)**	—	—
Deferred maintenance shutdown expenditures	**—**	—	—	**—**	—	—	**(117)**	(27)	(16)
Deferred outlays and other investments	**3**	—	—	**(14)**	(2)	(7)	**(23)**	(24)	(19)
Proceeds from disposals	**—**	—	—	**—**	—	—	**26**	67	33
Total cash (used in) investing activities	**(300)**	—	—	**(46)**	(39)	(20)	**(1 702)**	(861)	(1 680)
Net cash surplus (deficiency) before financing activities	**(220)**	—	—	**(235)**	(225)	(165)	**516**	595	(868)

Notes to the Consolidated Financial Statements

1. CHANGE IN ACCOUNTING POLICY

During the year, the company adopted a new accounting policy for stock-based compensation related to common share options. Pursuant to new transitional rules approved by the Canadian Institute of Chartered Accountants, the company now records stock-based compensation expense in the company's Consolidated Statements of Earnings for all common share options granted to employees and non-employee directors on or after January 1, 2003 ("2003 options"), with a corresponding increase recorded as contributed surplus in the Consolidated Statements of Changes in Shareholders' Equity. Pro forma compensation-related earnings impacts of pre-2003 options are determined in the same manner as 2003 options. (See note 12)

This change in accounting policy has increased operating, selling and general expenses and contributed surplus by $7 million for the year ended December 31, 2003. The disclosures relating to pro forma earnings impacts for these periods have been adjusted by a corresponding amount.

2. ACQUISITION OF REFINERY AND RELATED ASSETS

On August 1, 2003, the company acquired a Denver refinery, 43 retail stations and associated storage, pipeline and distribution facilities, and inventory from ConocoPhillips for cash consideration of $272 million. The purchase price was determined through a competitive bid process. The results of operations for these assets have been included in the consolidated financial statements from the date of acquisition.

The acquisition was accounted for by the purchase method of accounting. The allocation of fair value to the assets acquired and liabilities assumed was:

($ millions)	
Property, plant and equipment, and intangible assets	242
Inventory	88
Other assets	9
Total assets acquired	339
Liabilities assumed	(67)
Net assets acquired	272

Suncor recorded an environmental liability of $9 million at the acquisition date for the estimated costs of environmental clean-up work currently under way. A $9 million receivable was also recorded as ConocoPhillips agreed to indemnify Suncor for these costs. The recorded liability is part of an agreement between Suncor and ConocoPhillips whereby Suncor will be indemnified for any reclamation work identified prior to closing for a period up to 10 years from acquisition date, and up to $30 million. Additional costs ordered by a governmental agency are subject to indemnification from ConocoPhillips on a rolling 10-year limitation period from the date the contamination is discovered by Suncor. There is no time or dollar limit for any third party claims against Suncor for which ConocoPhillips is liable.

Additionally, a $39 million liability was recorded at acquisition for environmental work required pursuant to a consent decree between ConocoPhillips, the Colorado Department of Public Health and the Environment and the United States Environmental Protection Agency.

For segmented reporting purposes, the results of the new Denver-based operations since the date of acquisition are reported in a new operating segment (Refining and Marketing – U.S.A.) in the accompanying Schedules of Segmented Data.

3. PROPERTY, PLANT AND EQUIPMENT

	2003		2002	
($ millions)	**Cost**	**Accumulated Provision**	**Cost**	**Accumulated Provision**
Oil Sands				
Plant	**5 424**	**828**	5 340	691
Mine and mobile equipment	**1 267**	**426**	1 154	381
Pipeline	**100**	**46**	81	26
Capital leases	**130**	**18**	121	12
Major projects in progress	**1 396**	**—**	702	—
	8 317	**1 318**	7 398	1 110
Natural Gas				
Proved properties	**1 206**	**552**	1 074	480
Unproved properties	**114**	**38**	129	41
Pipeline	**—**	**—**	20	18
Other support facilities and equipment	**18**	**12**	16	11
	1 338	**602**	1 239	550
Energy Marketing and Refining – Canada				
Refinery	**874**	**443**	800	417
Marketing	**494**	**239**	461	229
	1 368	**682**	1 261	646
Refining and Marketing – U.S.A.				
Refinery and intangible assets	**165**	**2**	—	—
Marketing	**39**	**1**	—	—
Pipeline	**27**	**—**	—	—
	231	**3**	—	—
Corporate	**86**	**10**	55	6
	11 340	**2 615**	9 953	2 312
Net property, plant and equipment		**8 725**		7 641

4. DEFERRED CHARGES AND OTHER

($ millions)	**2003**	**2002**
Oil Sands overburden removal costs (see below)	**51**	68
Deferred maintenance shutdown costs	**137**	44
Other	**98**	73
Total deferred charges and other	**286**	185
Oil Sands overburden removal costs		
Balance – beginning of year	**68**	101
Outlays during the year	**175**	160
Depreciation on equipment during year	**16**	9
	259	270
Amortization during year	**(208)**	(202)
Balance – end of year	**51**	68

5. LONG-TERM DEBT

($ millions)	2003	2002
Fixed-term debt, redeemable at the option of the company		
5.95% Notes, denominated in U.S. dollars, due in 2034 (a)	**646**	—
7.15% Notes, denominated in U.S. dollars, due in 2032 (a)	**646**	790
6.70% Series 2 Medium Term Notes, due in 2011 (b)	**500**	500
6.80% Medium Term Notes, due in 2007 (b)	**250**	250
6.10% Medium Term Notes, due in 2007 (b)	**150**	150
7.40% Debentures, Series C, due in 2004	**125**	125
	2 317	1 815
Revolving-term debt, with interest at variable rates (see Credit Facilities)		
Commercial Paper (interest at December 31, 2002 – 2.9%) (c)	**—**	548
Bank debt (interest at December 31, 2002 – 3.5%)	**—**	199
Total unsecured long-term debt	**2 317**	2 562
Secured long-term debt with interest rates averaging 5.6% (2002 – 6.1%)	**4**	5
Capital leases (d), (e)	**127**	119
Total long-term debt	**2 448**	2 686

(a) In 2003, the company issued 5.95% Notes with a principal amount of $US500 million (Cdn$ equivalent of $651 million). In 2002, the company issued 7.15% Notes with a principal amount of $US500 million (Cdn$ equivalent of $797 million).

(b) The company has entered into various interest rate swap transactions at December 31, 2003. The swap transactions result in an average effective interest rate that is different from the stated interest rate of the related underlying long-term debt instruments.

Description of Swap Transaction	Principal Swapped ($ millions)	Swap Maturity	2003 Effective Interest Rate
Swap of 6.10% Medium Term Notes to floating rates	150	2007	4.3%
Swap of 6.80% Medium Term Notes to floating rates	250	2007	4.9%
Swap of 6.70% Medium Term Notes to floating rates	200	2011	4.2%

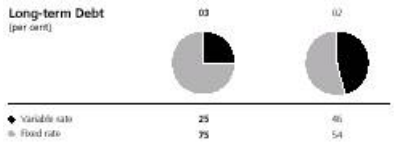
(c) The company is also authorized to issue commercial paper to a maximum of $900 million having a term not to exceed 364 days. Commercial paper is supported by unutilized credit and term loan facilities.

(d) Obligations under capital leases are as follows:

($ millions)	2003	2002
Energy services assets lease with interest at 6.82%, maturing in 2004	**101**	101
Other equipment leases with interest rates between prime plus 0.5% and 12.4% and maturity dates ranging from 2008 to 2029	**26**	18
	127	119

(e) Future minimum amounts payable under capital leases and other long-term debt are as follows:

($ millions)	Capital Leases	Other Long-term debt
2004	117	125
2005	3	1
2006	3	—
2007	3	400
2008	3	—
Later years	28	1 795
Total minimum payments	157	2 321
Less amount representing imputed interest	30	
Present value of obligation under capital leases	127	



Credit Facilities

At December 31, 2003, the company had available credit and term loan facilities of $1,730 million, of which $1,577 million was undrawn, as follows:

($ millions)	
Facility that is fully revolving for 364 days, has a term period of one year and expires in 2005	750

Facility that is fully revolving for a period of three years and expires in 2006	750
Facility that is fully revolving for 364 days, has a term period of one year and expires in 2005	200
Facilities that can be terminated at any time at the option of the lenders	30
Total available credit facilities	1 730
Drawn from credit facilities	31
Credit facilities supporting outstanding commercial paper and standby letters of credit	122
Total undrawn credit facilities	1 577

At December 31, 2003, the company had issued $122 million in letters of credit to various third parties.

6. FINANCIAL INSTRUMENTS

Derivatives are financial instruments that either imitate or counter the price movements of stocks, bonds, currencies, commodities, and interest rates. Suncor uses derivatives to reduce (hedge) its exposure to fluctuations in commodity prices and foreign currency exchange rates and to manage interest or currency-sensitive assets and liabilities. Suncor also uses derivatives for trading purposes. When used in a trading activity, the company is attempting to realize a gain on the fluctuations in the market value of the derivative.

Forwards and futures are contracts to purchase or sell a specific item at a specified date and price. When used as hedges, forwards and futures manage the exposure to losses that could result if commodity prices or foreign currency exchange rates change adversely. An option is a contract where its owner, for a fee, has purchased the right (but not the obligation) to buy or sell a specified item at a fixed price during a specified period. Options used as hedges can protect against adverse changes in commodity prices, interest rates, or foreign currency exchange rates.

A costless collar is a combination of two option contracts that limits the holder's exposure to changes in prices to within a specific range. The "costless" nature of this derivative is achieved by buying a put option (the right to sell) for consideration equal to the premium received from selling a call option (the right to purchase).

A swap is a contract where two parties exchange commodity, currency, interest or other payments in order to alter the nature of the payments. For example, fixed interest rate payments on debt may be converted to payments based on a floating interest rate, or vice versa; a domestic currency debt may be converted to a foreign currency debt.

See below for more technical details and amounts.

(a) Balance Sheet Financial Instruments
The company's financial instruments recognized in the Consolidated Balance Sheets consist of cash and cash equivalents, accounts receivable, derivative contracts not accounted for as hedges, substantially all current liabilities (except for the current portions of income taxes payable, future income taxes and reclamation and environmental remediation costs), and long-term debt.

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 following table summarizes estimated fair value information about the company's financial instruments recognized in the Consolidated Balance Sheets at December 31:

	2003		2002	
($ millions)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Cash and cash equivalents	**388**	**388**	15	15
Accounts receivable	**505**	**505**	403	403
Derivatives receivable	**49**	**49**	22	22
Derivatives payable	**19**	**19**	—	—
Current liabilities	**978**	**978**	705	705
Investments in Southern Pacific Petroleum	**—**	**—**	1	1
Long-term debt				
Fixed term	**2 317**	**2 502**	1 815	1 991
Revolving term	**—**	**—**	747	747
Other	**4**	**4**	5	5
Capital leases	**127**	**127**	119	119

The fair values of the company's fixed and revolving-term long-term debt, capital leases, and other long-term debt were determined through comparisons to similar debt instruments.

(b) Unrecognized Derivative Financial Instruments
The company is also a party to certain derivative financial instruments, which are not recognized in the Consolidated Balance Sheets, as follows:

Revenue and Margin Hedges
Suncor operates in a global industry where the market price of its petroleum and natural gas products is determined based on floating benchmark indices denominated in U.S. dollars. The company periodically enters into derivative financial instrument contracts such as forwards,

futures, swaps and options to hedge against the potential adverse impact of changing market prices due to changes in the underlying indices. Specifically, the company manages crude price variability by entering into U.S. dollar West Texas Intermediate (WTI) derivative transactions and has historically, in certain instances, combined U.S. dollar WTI derivative transactions and Canadian/U.S. foreign exchange derivative contracts. As at December 31, 2003, the company had hedged a portion of its forecasted Canadian dollar denominatedcash flows subject to U.S. dollar WTI commodity price risk for up to two years. The company had not hedged anyportion of the foreign exchange component of these forecasted cash flows.

The financial instrument contracts do not require the payment of premiums or cash margin deposits prior to settlement. On settlement, these contracts result in cash receipts or 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 or payments offset corresponding decreases or increases in the company's sales revenues or crude oil purchase costs. For accounting purposes, amounts received or paid on settlement are recorded as part of the related hedged sales or purchase transactions.

Contracts outstanding at December 31 were as follows:

Crude Oil Hedges	Quantity (bbl/day)	Average Price(a)	Revenue Hedged ($ millions)	Hedge Period
As at December 31, 2003				
Crude oil swaps	**68 000**	**24**	**772**(c)	**2004**
Costless collars	**11 000**	**21 – 24**	**109 – 125**(c)	**2004**
Crude oil swaps	**36 000**	**23**	**390**(c)	**2005**
As at December 31, 2002				
Crude oil swaps	10 000	30	57(c)	2003(b)
Crude oil swaps	15 000	24	208(c)	2003
Costless collars	60 000	21 – 26	726 – 899(c)	2003
Crude oil swaps	25 000	23	332(c)	2004
Costless collars	11 000	21 – 24	133 – 152(c)	2004
Crude oil swaps	21 000	22	266(c)	2005
As at December 31, 2001				
Crude oil swaps	40 576	20	444(d)	2002
Crude oil swaps	424	21	5(c)	2002
Costless collars	43 000	22 – 27	550 – 675(c)	2002
Costless collars	44 000	21 – 26	537 – 665(c)	2003
Costless collars	11 000	21 – 24	134 – 153(c)	2004
Crude oil swaps	15 000	22	192(c)	2005

Margin Hedges	Quantity (bbl/day)	Average Margin US$/bbl	Margin Hedged	Hedge Period
Refined product sale and crude purchase swaps				
As at December 31, 2003	**6 600**	**5**	**3(c)**	**2004(e)**
As at December 31, 2002	20 700	5	9(c)	2003(f)
As at December 31, 2001	—	—	—	—

Natural Gas Hedges	Quantity (GJ/day)	Average Price Cdn$/GJ	Revenue Hedged	Hedge Period
Swaps and costless collars				
As at December 31, 2003	**30 000**	**6**	**16**	**2004(g)**
As at December 31, 2002	25 000	4 – 6	9 – 14	2003(h)
As at December 31, 2001	—	—	—	—

(a) Average price for crude oil swaps is US$ WTI per barrel at Cushing, Oklahoma.
(b) For the period January to April 2003, inclusive. All other crude oil positions are for the full year.
(c) The revenue and margin hedged is translated to Cdn$ at the year-end exchange rate for convenience purposes.
(d) The revenue hedged was fixed in Cdn$ as the company had foreign exchange swaps in place for these crude oil swaps.
(e) For the period January and February 2004.
(f) For the period January and February 2003.
(g) For the period January to March 2004.
(h) For the period January to March 2003.

Interest Rate Hedges

The company periodically enters into interest rate and cross-currency interest rate swap contracts as part of its risk management strategy to manage its exposure to interest rates. The interest rate swap contracts involve an exchange of floating rate and fixed rate interest payments between the company and investment grade counterparties. The cross- currency swap contracts involve an exchange of Canadian dollar interest payments and U.S. dollar interest payments, and an exchange of Canadian and U.S. dollar principal amounts at the maturity date of the underlying borrowing to which the swaps relate. The differentials on the exchange of periodic interest payments are recognized in the accounts as an adjustment to interest expense.

The notional amounts of interest rate swap contracts outstanding at December 31, 2003 are detailed in note 5, Long-term Debt.

Fair Value of Derivative Financial Instruments
The fair value of hedging derivative financial instruments is the estimated amount, based on third party market data that the company would receive (pay) to terminate the contracts. Such amounts, which also represent the unrecognized and unrecorded gain (loss) on the contracts, were as follows at December 31:

($ millions)	2003	2002
Revenue hedge swaps and collars	**(285)**	(133)
Margin hedge swaps	**2**	1
Interest rate and cross-currency interest rate swaps	**32**	35
	(251)	(97)

(c) Energy Marketing and Trading Activities
In November 2002, Suncor commenced energy trading activities. In addition to those financial derivatives used for hedging activities, the company also uses energy derivatives, including physical and financial swaps, forwards and options to gain market information and earn trading revenues. These energy trading activities are accounted for using the mark-to-market method and as such physical and financial energy contracts are recorded at fair value at each balance sheet date. For the year ended December 31, 2003 a net pretax loss of $3 million (2002 – $nil) from the settlement and revaluation of these contracts was reported as energy trading and marketing activities in the Consolidated Statements of Earnings.

The fair value of unsettled energy trading assets and liabilities at December 31 are as follows:

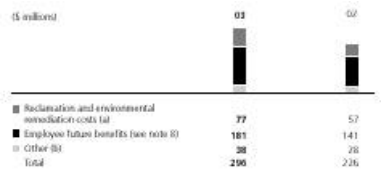
($ millions)	2003	2002
Energy trading assets	**5**	2
Energy trading liabilities	**5**	2

The source of the valuations of the above contracts is based on actively quoted prices.

(d) Counterparty Credit Risk
The company may be exposed to certain losses in the event that counterparties to the derivative financial instruments are unable to meet the terms of the contracts. The company's exposure is limited to those counterparties holding derivative contracts with positive fair values at the reporting date. The company minimizes this risk by only entering into agreements with investment grade counterparties, and through regular management review of potential exposure to, and credit ratings of, such counterparties. At December 31, the company had exposure to credit risk with counterparties as follows:

($ millions)	2003	2002
Derivative contracts not accounted for as hedges	**30**	28
Unrecognized derivative contracts	**27**	23
	57	51

7. ACCRUED LIABILITIES AND OTHER



(a) Reclamation and Environmental Remediation Costs
Total accrued reclamation and environmental remediation costs also include $60 million in current liabilities (2002 – $32 million). Payments during 2003 totalled $27 million (2002 – $15 million; 2001 – $28 million), while expense recorded in 2003 was $31 million (2002 – $20 million; 2001 – $15 million). Reclamation expense in 2003 was based on estimated total costs of $950 million (2002 – $650 million).

(b) Employee and Director Incentive Plans
Included in accrued liabilities and other is accrued compensation expense related to the company's employee long-term incentive plans (see note 12b). Accrued liabilities and other also include accrued compensation expense in the form of deferred share units received under the directors' compensation plan. Accrued directors' compensation expense is not significant.

8. EMPLOYEE FUTURE BENEFITS LIABILITY

Suncor employees are eligible to receive certain pension, health care and insurance benefits when they retire. The related ***Benefit Obligation*** *or commitment that Suncor has to employees and retirees at December 31, 2003 was $685 million.*

As required by government regulations and plan performance, Suncor sets aside funds, with an independent trustee, to meet certain of these

obligations. At the end of December 2003, ***Plan Assets*** *to meet the* ***Benefit Obligation*** *were $336 million.*

The excess of the ***Benefit Obligation*** *over* ***Plan Assets*** *of $349 million represents the* ***Net Unfunded Obligation.***

See below for more technical details and amounts.

Defined Benefit Pension Plans and Other Post-retirement Benefits
The company's defined benefit pension plans provide non-indexed pension benefits at retirement based on years of service and final average earnings. These obligations are met through funded registered retirement plans and through unfunded, unregistered supplementary benefits that are paid directly to recipients. Company contributions to the funded plans are deposited with independent trustees who act as custodians of the funded pension plans' assets, as well as the disbursing agents of the benefits to recipients. Plan assets are managed by a pension committee on behalf of beneficiaries. The committee retains independent managers and advisors.

Funding of the registered retirement plans complies with applicable regulations that require actuarial valuations of the pension funds at least once every three years in Canada and every year in the United States.

The company's other post-retirement benefits programs, which are unfunded, include certain health care and life insurance benefits provided to retired employees and eligible surviving dependants. Retirees share in the cost of providing these benefits.

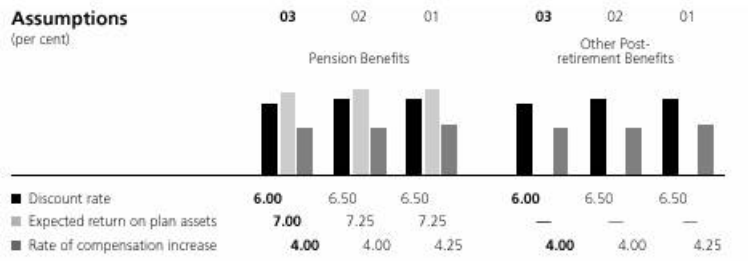
The expense and obligations for both funded and unfunded benefits are determined in accordance with Canadian generally accepted accounting principles and actuarial principles. Obligations are based on the projected benefit method of valuation that includes employee service to date and present pay levels, as well as a projection of salaries and service to retirement.

In 2003, in connection with the acquisition of the Denver refinery and related assets from ConocoPhillips (see note 2), the company assumed a pension benefit obligation of $14 million and other post-retirement benefit obligations of $6 million. No pension plan assets were acquired.

Obligations and Funded Status
The following table presents information about obligations recognized in the Consolidated Balance Sheets and the funded status of the plans at December 31:

	Pension Benefits		Other Post-retirement Benefits	
($ millions)	**2003**	**2002**	**2003**	**2002**
Change in benefit obligation				
Benefit obligation at beginning of year	**489**	461	**97**	93
Service costs	**18**	17	**3**	4
Interest costs	**32**	30	**6**	6
Plan participants' contributions	**3**	4	**—**	—
Acquisition	**14**	—	**6**	—
Foreign exchange	**(1)**	—	**—**	—
Amendments	**—**	—	**—**	(34)
Actuarial (gain) loss	**37**	(1)	**8**	30
Benefits paid	**(24)**	(22)	**(3)**	(2)
Benefit obligation at end of year (a), (e)	**568**	489	**117**	97
Change in plan assets (b)				
Fair value of plan assets at beginning of year	**273**	301	**—**	—
Actual return (loss) on plan assets	**45**	(24)	**—**	—
Employer contributions	**36**	14	**—**	—
Plan participants' contributions	**3**	4	**—**	—
Benefits paid	**(21)**	(22)	**—**	—
Fair value of plan assets at end of year (e)	**336**	273	**—**	—
Net unfunded obligation	**(232)**	(216)	**(117)**	(97)
Items not yet recognized in earnings:				
Unamortized net actuarial loss (c)	**133**	142	**50**	46
Unamortized past service costs (d)	**—**	—	**(31)**	(34)
Accrued Benefit Liability	**(99)**	(74)	**(98)**	(85)

(a) Obligations are based on the following assumptions:



A 1% change in the assumptions at which pension benefits and other post-retirement benefits liabilities could be effectively settled is as follows:

($ millions)	Rate of Return on Plan Assets 1% increase	Rate of Return on Plan Assets 1% decrease	Discount Rate 1% increase	Discount Rate 1% decrease	Rate of Compensation Increase 1% increase	Rate of Compensation Increase 1% decrease
Increase (decrease) to net periodic benefit cost	(3)	3	(8)	10	4	(3)
Increase (decrease) to benefit obligation	—	—	(83)	95	24	(22)

In order to measure the expected cost of other post-retirement benefits, a 12% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2003. It is assumed that this rate will decrease by 0.5% annually, to 5% for 2017, and remain at that level thereafter.

Assumed health care cost trend rates have a significant effect on the amounts reported for other post-retirement benefit obligations. A one percent change in assumed health care cost trend rates would have the following effects:

($ millions)	1% increase	1% decrease
Increase (decrease) to total of service and interest cost components of net periodic post-retirement health care benefit cost	1	(1)
Increase (decrease) to the health care component of the accumulated post-retirement benefit obligation	12	(10)

(b) Pension plan assets are not the company's assets and therefore are not included in the Consolidated Balance Sheets.

(c) The unamortized net actuarial loss represents annually calculated differences between actual and projected plan performance. These amounts are amortized as part of the net periodic benefit cost over the expected average remaining service life of employees of 12 years for pension benefits (2002 and 2001 – 13 years), and over the expected average future service life to full eligibility age of 12 years for other post-retirement benefits (2002 – 12 years; 2001 – 11 years).

(d) Effective April 1, 2003, the company implemented amendments to its post-retirement benefits program to manage its exposures to future health care and life insurance costs. Certain of the company's employees will continue to receive post-retirement benefits under the old plan provisions. These plan amendments reduced the company's other post-retirement benefits obligation at December 31, 2002, by $34 million.

(e) The company uses a measurement date of December 31 to value the plan assets and accrued benefit obligation.

The above benefit obligation at year-end includes funded and unfunded plans, as follows:

($ millions)	Pension benefits 2003	Pension benefits 2002	Other Post-retirement Benefits 2003	Other Post-retirement Benefits 2002
Funded plan	**498**	423	**—**	—
Unfunded plans	**70**	66	**117**	97
Benefit obligation at end of year	**568**	489	**117**	97

Components of Net Periodic Benefit Cost

($ millions)	Pension Benefits 2003	Pension Benefits 2002	Pension Benefits 2001	Other Post-retirement Benefits 2003	Other Post-retirement Benefits 2002	Other Post-retirement Benefits 2001
Current service costs	**18**	17	14	**3**	4	3
Interest costs	**32**	30	28	**6**	6	6
Expected return on plan assets (a)	**(20)**	(22)	(23)	**—**	—	—
Amortization of transitional asset	**—**	—	(8)	**—**	—	—
Amortization of net actuarial loss	**22**	15	9	**1**	2	1
Net periodic benefit cost	**52**	40	20	**10**	12	10

(a) The expected return on plan assets is the expected long-term rate of return on plan assets for the year based on plan assets at the beginning of the year that have been adjusted on a weighted average basis for contributions and benefit payments expected for the year. The expected return on plan assets is included in the net periodic benefit cost for the year to which it relates, while the difference between it and the actual return realized on plan assets in the same year is amortized over the expected average remaining service life of employees of 12 years for pension benefits, and over the expected average future service life to full eligibility age of 10 years for post-retirement benefits.

To estimate the expected long-term rate of return on plan assets, the company considered the current level of expected returns on the fixed income portion of the portfolio, the historical level of the risk premium associated with other asset classes in which the portfolio is invested and the expectation for future returns on each asset class. The expected return for each asset class was weighted based on the policy asset mix to develop an expected long-term rate of return on asset assumption for the portfolio.

Plan Assets and Investment Objectives

Suncor's long-term investment objective is to secure the defined pension benefits while managing the variability and level of the company's contributions. The portfolio is rebalanced periodically as required, while ensuring that the maximum equity content is 65% at any time. Plan assets are managed by external managers, who report to a pension committee, and are restricted to those permitted by applicable legislation. Investments are made through pooled, mutual or segregated funds.

The company's pension plan asset allocation based on market values as at December 31, 2003 and 2002, and the target allocation for 2004 is as follows:

Asset Category	Target Allocation% 2004	Percentage of Plan Assets 2003	2002
Canadian equities	20	**20**	20
U.S. equities	22	**22**	22
International equities	18	**19**	18
Canadian fixed income	40	**39**	40
Total	100	**100**	100

Equity securities do not include any direct investments in Suncor shares.

Cash Flows
The company expects that contributions to its pension plans in 2004 will be $50 million. Expected contributions for other post-retirement benefits in 2004 are $3 million.

Defined Contribution Pension Plan
The company has a Canadian defined contribution plan and a U.S. 401(k) savings plan, under which both the company and employees make contributions. Company contributions and corresponding expense totalled $6 million in 2003 (2002 – $5 million; 2001 – $4 million).

9. INCOME TAXES

The assets and liabilities shown on Suncor's balance sheets are calculated in accordance with Canadian generally accepted accounting principles. Suncor's income taxes are calculated according to government tax laws and regulations, which results in different values for certain assets and liabilities for income tax purposes. These differences are known as ***temporary differences,*** *because eventually these differences will reverse.*

The amount shown on the balance sheets as ***future income taxes*** *represent income taxes that will eventually be payable or recoverable in future years when these temporary differences reverse.*

See below for more technical details and amounts.

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

($ millions)	2003 Amount	2003 %	2002 Amount	2002 %	2001 Amount	2001 %
Federal tax rate	**667**	**37**	435	38	195	38
Provincial abatement	**(180)**	**(10)**	(114)	(10)	(51)	(10)
Federal surtax	**20**	**1**	13	1	6	1
Provincial tax rates	**226**	**13**	150	13	69	14
Statutory tax and rate	**733**	**41**	484	42	219	43
Adjustment of statutory rate for future rate reductions	**(100)**	**(6)**	—	—	—	—
	633	**35**	484	42	219	43
Add (deduct) the tax effect of:						
Crown royalties	**50**	**3**	39	3	48	9
Resource allowance	**(31)**	**(2)**	(34)	(3)	(28)	(5)
Temporary difference in resource allowance	**—**	**—**	(120)	(10)	(49)	(10)
Large corporations tax	**19**	**1**	17	1	16	3
Tax rate changes on opening future income taxes	**89**	**5**	(10)	(1)	(52)	(11)
Attributed Canadian royalty income	**(8)**	**—**	(2)	—	(6)	(1)
Non-deductible foreign expenses	**—**	**—**	—	—	(17)	(3)
Assessments and adjustments	**—**	**—**	10	1	(11)	(2)
Capital gains	**(34)**	**(2)**	—	—	—	—
Other	**2**	**—**	(1)	—	5	1
Income taxes and effective rate	**720**	**40**	383	33	125	24

In 2003 net income tax payments totalled $45 million (2002 – $8 million refund; 2001 – $23 million payment).

The resource allowance is a federal tax deduction allowed as a proxy for non-deductible provincial Crown royalties. As required by generally accepted accounting principles in Canada, resource allowance is accounted for by adjusting the statutory tax rate by the resource allowance rate.

Effective January 1, 2003, the Canadian government enacted changes to the federal taxation policies relating to the resource sector. The changes are to be phased in over the next five years and include a 7% reduction of the federal tax rate, deductibility of provincial Crown royalties and the elimination of the federal resource allowance deduction. For 2003, a 1% federal rate reduction was effected.

Effective April 1, 2003, the Alberta provincial corporate rate decreased by 0.5%. The Ontario general corporate tax rate and manufacturing and

processing tax rate were increased by 1.5% and 1% respectively, effective January 1, 2004.

Accordingly, the company revalued its future income tax liabilities and recognized an increase in future income tax expense of $100 million (including $89 million related to the revaluation of opening future income tax liabilities).

At December 31, future income taxes were comprised of the following:

	2003		2002	
($ millions)	Current	Non-current	Current	Non-current
Future income tax assets:				
Employee future benefits	**4**	**57**	4	48
Reclamation and environmental remediation costs	**9**	**7**	16	28
Alberta royalties	**—**	**47**	—	43
Employee incentive plans	**—**	**13**	—	16
Inventories	**15**	**—**	18	—
	28	**124**	38	135
Future income tax liabilities:				
Depreciation	**—**	**2 095**	—	1 473
Overburden removal costs	**—**	**16**	—	20
Maintenance shutdown costs	**—**	**41**	—	15
Inventories	**1**	**—**	—	—
Other	**13**	**31**	10	8
	14	**2 183**	10	1 516

10. COMMITMENTS, CONTINGENCIES AND GUARANTEES

(a) Operating Commitments

In order to ensure continued availability of, and access to, facilities and services to meet its operational requirements, the company periodically enters into transportation service agreements for pipeline capacity and energy services agreements as well as non-cancellable operating leases for service stations, office space and other property and equipment. Under contracts existing at December 31, 2003, future minimum amounts payable under these leases and agreements are as follows:

($ millions)	Pipeline Capacity and Energy Services (a)	Operating Leases
2004	149	38
2005	167	32
2006	179	27
2007	184	25
2008	202	19
Later years	3 691	62
	4 572	203

(a) Includes annual tolls payable under a transportation service agreement with a major pipeline company to use a portion of its pipeline capacity and tankage for the shipment of crude oil from Fort McMurray to Hardisty, Alberta. The agreement commenced in 1999 and extends to 2028. As the initial shipper on the pipeline, Suncor's tolls payable under the agreement are subject to annual adjustments.

To meet the energy needs of its oil sands operation, Suncor has a commitment under long-term energy agreements to obtain a portion of the power and all of the steam generated by a cogeneration facility owned by a major energy company. Since October 1999, this company has managed the operations of Suncor's existing energy services facility.

(b) Contingencies

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 recognition of estimated reclamation and environmental remediation costs. Up to December 31, 2003, these costs were accrued at the company's Natural Gas and Oil Sands operations on the unit of production basis. A provision was not made for currently operated facilities such as the Oil Sands processing facilities, the Sarnia and Denver refineries and service stations. The company had determined that until there was cessation of operations and completion of site investigations for these facilities, reclamation and environmental remediation costs would not be estimable. Effective January 1, 2004, the company adopted new Canadian accounting standards that required recognition of a liability for the future retirement obligations associated with the company's property, plant and equipment (see Summary of Significant Accounting Policies). Estimates of future environmental remediation costs can change significantly based on such factors as operating experience, changes in legislation and regulations and cost.

To mitigate its exposure to property and business interruption losses, the company has purchased insurance policies with a combined coverage of up to US$1,150 million, net of deductible amounts. The policies stipulate a property loss deductible of US$10 million per incident, and a business interruption loss deductible per incident, based on the greater of US$50 million or 30 days of gross earnings lost (as defined in the respective insurance policies). Gross earnings can be influenced by such factors as production levels, commodity prices and the U.S. dollar exchange rate.

The company is defendant and plaintiff in a number of legal actions that arise in the normal course of business. The company believes that any liabilities that might arise pertaining to such matters would not have a material effect on its consolidated financial position.

Costs attributable to these commitments and contingencies 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 cannot be determined at this time, the impact may be material.

(c) Variable Interest Entities and Guarantees
At December 31, 2003, the company had various off-balance sheet arrangements with Variable Interest Entities and indemnification agreements with third parties as described below.

The company has a securitization program in place to sell, on a revolving, fully serviced and limited recourse basis, up to $170 million of accounts receivable having a maturity of 45 days or less, to a third party. The third party is a multiple party securitization vehicle that provides funding for numerous asset pools. As at December 31, 2003, $170 million in outstanding accounts receivable had been sold under the program. Under the recourse provisions, the company will provide indemnification against credit losses to a maximum of $70 million. A liability has not been recorded for this indemnification as the company believes it has no significant exposure to credit losses. Proceeds received from new securitizations and proceeds from collections reinvested in securitizations on a revolving basis for the year ended December 31, 2003, were nil and approximately $2,328 million, respectively. The company recorded an after-tax loss of approximately $3 million on the securitization program in each of the last three years.

In 1999, the company sold 2,130,000 barrels of its crude oil inventory for $49 million to a third party while retaining the right to use the inventory for its operations through a usage agreement for a five-year period. The third party's sole asset is the inventory sold to it by the company. The company pays an annual usage fee of $7 million to the third party and receives a $4 million annual storage fee. The company has the right, but is not obligated, to repurchase the inventory at the spot price at the end of the agreement in June 2004. In order to reduce the exposure to the spot price should it elect to repurchase the inventory, the company has entered into crude oil and U.S. dollar swap contracts fixing the purchase price of the crude oil on June 25, 2004 at Cdn$49 million.

In 1999, the company entered into an equipment sale and leaseback arrangement with a third party for proceeds of $30 million. The third party's sole asset is the equipment sold to it and leased back by the company. The initial lease term covers a period of seven years and is accounted for as an operating lease. The company has provided a residual value guarantee on the equipment of up to $7 million should it elect not to repurchase the equipment at the end of the lease term. An early termination purchase option allows for the repurchase of the equipment at specified dates in 2003, 2004 and 2005. Had the company elected to terminate the lease at December 31, 2003, the total cost would have been $30 million. Annualized equipment lease payments in 2003 were $4 million (2002 and 2001 – $2 million).

The company has agreed to indemnify holders of the 9.125% Preferred Securities, the 7.15% Notes, the 5.95% Notes and the company's credit facility lenders (see note 5) for added costs relating to taxes, assessments or other government charges or conditions, including any required withholding amounts. Similar indemnity terms apply to the receivables securitization program, the crude oil inventory monetization agreement and certain facility and equipment leases.

There is no limit to the maximum amount payable under the indemnification agreements described above. The company is unable to determine the maximum potential amount payable as government regulations and legislation are subject to change without notice. Under these agreements, Suncor has the option to redeem or terminate these contracts if additional costs are incurred.

11. PREFERRED SECURITIES

During 1999, the company completed a Canadian offering of $276 million of 9.05% Preferred Securities and a U.S. offering of US$162.5 million of 9.125% Preferred Securities for net proceeds of Cdn$507 million after issue costs of $17 million ($10 million after income taxes). The Preferred Securities are comprised of unsecured junior subordinated debentures, due in 2048 and redeemable at the company's option. Accordingly, the Preferred Securities are classified as share capital in the Consolidated Balance Sheet and the interest distributions thereon, net of income taxes, are classified as dividends. On January 15, 2004, the company gave formal notice to the holders of the Preferred Securities that it will redeem the securities for cash consideration on March 15, 2004.

In 2003, dividends of $45 million were paid on the Preferred Securities (2002 – $48 million; 2001 – $48 million).

12. 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 in series, without nominal or par value.

(b) Issued:
The number of common shares and common share options outstanding, common share prices and per share calculations, for both current and prior periods, reflect a two-for-one split of the company's common shares during 2002.

	Common Shares	
	Number (thousands)	Amount ($ millions)
Balance as at December 31, 2001	445 956	555
Issued for cash under stock option plans	1 777	19
Issued under employee long-term incentive plan	1 090	—
Issued under dividend reinvestment plan	149	4
Balance as at December 31, 2002	448 972	578
Issued for cash under stock option plans	**1 977**	**20**

Issued under dividend reinvestment plan	235	6
Balance as at December 31, 2003	**451 184**	**604**

Common Share Options

A common share option gives the holder the right, but not the obligation, to purchase common shares at a predetermined price over a specified period of time.

After the date of grant, employees that hold options must earn the right to exercise them. This is done by the employee fulfilling a time requirement for service to the company, and with respect to certain options, subject to accelerated vesting should the company meet predetermined performance criteria. Once this right has been earned, these options are considered vested. Options granted to non-employee directors vest and are exercisable immediately.

The predetermined price at which an option can be exercised is equal to or greater than the market price of the common shares on the date the options are granted.

See below for more technical details and amounts on the company's stock option plans.

(i) EXECUTIVE STOCK PLAN Under this plan, the company granted 1,902,000 common share options in 2003 (2002 – 1,803,000) to non-employee directors and certain executives and other senior employees of the company (see note 1). The exercise price of an option is equal to the market value of the common shares at the date of grant. Options granted to non-employee directors have a 10-year life and are exercisable immediately. Options granted to employees have a 10-year life and vest annually over a three-year period.

(ii) SUNSHARE PERFORMANCE STOCK OPTION PLAN During 2003, the company granted 1,305,000 options (2002 – 8,938,000) to all eligible permanent full-time and part-time employees, both executive and non-executive, under its new employee stock option incentive plan ("SunShare"). Under SunShare, meeting specified performance targets may accelerate the vesting of some or all options, such that 20% of outstanding options may vest as early as 2004, up to an additional 20% of outstanding options may vest as early as 2005 and the remaining 60% of outstanding options may vest on April 30, 2008. All unvested options, which have not previously expired or been cancelled, will automatically vest on January 1, 2012.

(iii) EMPLOYEE LONG-TERM INCENTIVE PLAN Suncor's previous employee long-term incentive plan matured in 2002. At maturity, employees received 1,090,000 common shares from treasury for nil cash consideration, along with aggregate cash payments of $34 million. In addition, 2,132,000 common share options, previously granted to senior employees, vested and became exercisable. No compensation expense was recorded related to the employees' receipt of common shares from treasury as these common shares were treated as stock option grants.

In addition, 1,462,000 deferred share units (DSUs) with a cash settlement value of $42 million, which had previously been granted to certain executives, vested. These executives also received cash payments of $44 million.

DSUs are only redeemable at the time a unitholder ceases employment. In 2003, 185,000 (2002 – 220,000) DSUs were redeemed for cash consideration of $5 million (2002 – $6 million). Over time, DSU unitholders are entitled to receive additional DSUs equivalent in value to future notional dividend reinvestments. Final DSU redemption amounts are subject to change depending on the company's share price at the time of exercise. Accordingly, the company revalues the DSUs on each reporting date, with any changes in value recorded as an adjustment to compensation expense in the period. As at December 31, 2003, 1,071,000 DSUs were outstanding with a total liability of $35 million, all of which was classified as long-term (see note 7).

During 2003, total pretax compensation expense related to the above-noted long-term incentive plan was $8 million (2002 – $10 million; 2001 – $42 million).

(iv) REVISED EMPLOYEE INCENTIVE COMPENSATION PLAN In November 2003, Suncor's Board of Directors approved a revised employee incentive compensation program to be implemented in 2004. The revised program consists of a combination of time-vesting common share options and performance-vesting share units (PSUs) to replace the current program whereby only time-vesting common share options are granted.

The exercise price of a time-vested option will continue to be equal to the market value of the common shares at the date of grant. Options granted will have a 10-year life and vest annually over a three-year period.

PSUs will be payable in cash three years from grant date, based on meeting certain corporate performance measures compared to a peer group of companies.

The following tables cover all common share options granted by the company for the years indicated:

	Number (thousands)	Range of Exercise Price ($)	Weighted-average Exercise Price Per Share ($)
Outstanding, December 31, 2000	11 722	2.38 – 19.28	10.28

Granted	2 181	15.94 – 21.35	17.63
Exercised	(2 029)	2.38 – 16.48	7.30
Cancelled	(106)	10.13 – 20.20	14.21
Outstanding, December 31, 2001	11 768	2.38 – 21.35	12.12
Granted	10 741	23.93 – 28.14	27.08
Exercised	(1 777)	2.38 – 17.45	10.42
Cancelled	(406)	13.04 – 27.65	26.48
Outstanding, December 31, 2002	20 326	3.80 – 28.14	19.89
Granted	3 207	23.65 – 29.85	26.70
Exercised	(1 977)	3.80 – 23.93	10.35
Cancelled	(540)	10.13 – 27.93	20.94
Outstanding, December 31, 2003	**21 016**	**4.11 – 29.85**	**21.69**
Exercisable, December 31, 2003	**8 191**	**4.11 – 28.14**	**13.77**

Common shares authorized for issuance by the Board of Directors that remain available for the granting of future options, at December 31:

The following table is an analysis of outstanding and exercisable common share options as at December 31, 2003:

	Outstanding			Exercisable	
Exercise Prices ($)	**Number (thousands)**	**Weighted-average Remaining Contractual Life**	**Weighted-average Exercise Price Per Share ($)**	**Number (thousands)**	**Weighted-average Exercise Price Per Share ($)**
4.11 – 7.85	1 333	3	6.53	1 333	6.53
10.13 – 15.69	4 649	5	12.83	4 649	12.83
15.75 – 23.98	3 496	8	20.40	1 994	19.45
24.09 – 29.85	11 538	8	27.40	215	26.32
Total	21 016	7	21.69	8 191	13.77

(v) FAIR VALUE OF OPTIONS GRANTED The fair values of all common share options granted are estimated as at the grant date using the Black-Scholes option-pricing model. The weighted-average fair values of the options granted during the year and the weighted-average assumptions used in their determination are as noted below:

	2003	2002	2001
Annual dividend per share	**$ 0.1925**	$ 0.17	$ 0.17
Risk-free interest rate	**4.39%**	5.39%	5.07%
Expected life	**7 years**	8 years	5 years
Expected volatility	**32%**	31%	35%
Weighted-average fair value per option	**$ 9.94**	$ 12.08	$ 6.41

The company's reported net earnings attributable to common shareholders and earnings per share prepared in accordance with the fair value method of accounting for stock-based compensation would have been reduced for all common share options granted prior to 2003 to the pro forma amounts stated below:

($ millions, except per share amounts)	**2003**	**2002**	**2001**
Net earnings attributable to common shareholders - as reported	**1 094**	734	351
Less: compensation cost under the fair value method for pre-2003 options	**30**	32	9
Pro forma net earnings attributable to common shareholders for pre-2003 options	**1 064**	702	342
Basic earnings per share			
As reported	**2.43**	1.64	0.79
Pro forma	**2.37**	1.57	0.77
Diluted earnings per share			
As reported	**2.26**	1.61	0.78
Pro forma	**2.20**	1.54	0.76

13. EARNINGS PER COMMON SHARE

The following is a reconciliation of basic and diluted earnings per common share:

($ millions)	**2003**	**2002**	**2001**
Net earnings attributable to common shareholders	**1 094**	734	351
Dividends on Preferred Securities, net of tax	**27**	28	—(a)
Revaluation of US$ Preferred Securities, net of tax	**(37)**	(1)	—(a)
Adjusted net earnings attributable to common shareholders	**1 084**	761	351

(millions of common shares)

Weighted-average number of common shares	**450**	448	445
Dilutive securities:			
Options issued under stock-based compensation plans	**8**	5	6
Redemption of Preferred Securities by the issuance of common shares	**22**	20	—(a)
Weighted-average number of diluted common shares	**480**	473	451
(dollars per common share)			
Basic earnings per share (b)	**2.43**	1.64	0.79
Diluted earnings per share	**2.26**(c)	1.61(c)	0.78(a)

Common share and earnings per common share amounts in the above table reflect a two-for-one share split effective May 15, 2002.

Note: An option will have a dilutive effect under the treasury stock method only when the average market price of the common stock during the period exceeds the exercise price of the option.

(a) For the year ended December 31, 2001, diluted earnings per share is the net earnings attributable to common shareholders divided by the weighted-average number of diluted common shares. Dividends on Preferred Securities, the revaluation of US$ Preferred Securities and the redemption of Preferred Securities by the issuance of common shares have an anti-dilutive impact, therefore they are not included in the calculation of diluted earnings per share.

(b) Basic earnings per share is the net earnings attributable to common shareholders divided by the weighted-average number of common shares.

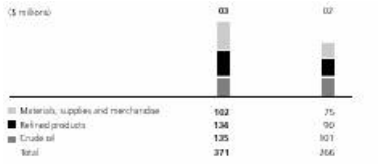
(c) Diluted earnings per share is the adjusted net earnings attributable to common shareholders, divided by the weighted-average number of diluted common shares.

14. FINANCING EXPENSES (INCOME)

($ millions)	**2003**	**2002**	**2001**
Interest on debt	**140**	155	143
Capitalized interest	**(57)**	(22)	(125)
Net interest expense	**83**	133	18
Foreign exchange (gain) loss on long-term debt	**(166)**	(9)	—
Other foreign exchange (gain) loss	**17**	—	(2)
Total financing expenses (income)	**(66)**	124	16

Cash interest payments in 2003 totalled $139 million (2002 – $134 million; 2001 – $129 million).

15. INVENTORIES



As at December 31, 2003, the replacement cost of crude oil and refined product inventories, valued using the LIFO cost method, exceeded their carrying value by $48 million (2002 – $84 million).

16. TRANSPORTATION COSTS AND OTHER COMPARATIVE FIGURES

Effective January 2003, transportation costs billed to customers are classified as revenues with the related transportation costs classified as transportation and other costs in the Consolidated Statements of Earnings. Previously, these costs were netted against revenue. Prior period amounts have been reclassified for comparative purposes.

Certain other prior period comparative figures have also been reclassified to conform to the current period presentation.

17. RELATED PARTY TRANSACTIONS

The following table summarizes the company's related party transactions after eliminations for the year. These transactions are in the normal course of operations and have been carried out on the same terms as would apply with unrelated parties.

($ millions)	**2003**	**2002**	**2001**
Operating revenues			
Sales to Energy Marketing and Refining – Canada segment joint ventures:			
Refined products	**301**	321	300
Petrochemicals	**187**	142	131

The company has supply agreements with two Energy Marketing and Refining – Canada segment joint ventures for the sale of refined products. The company also has a supply agreement with an Energy Marketing and Refining – Canada segment joint venture for the sale of

petrochemicals.

At December 31, 2003, amounts due from Energy Marketing and Refining – Canada segment joint ventures were $36 million (2002 – $30 million).

Sales to and balances with Energy Marketing and Refining – Canada segment joint ventures are established and agreed to by the various parties and approximate fair value.

18. SUPPLEMENTAL INFORMATION

($ millions)	2003	2002	2001
Export sales (a)	**549**	501	590
Exploration expenses			
Geological and geophysical	**18**	13	11
Other	**1**	2	1
Cash costs	**19**	15	12
Dry hole costs	**32**	11	10
Cash and dry hole costs (b)	**51**	26	22
Leasehold impairment (c)	**16**	10	9
	67	36	31
Taxes other than income taxes			
Excise taxes (d)	**388**	340	343
Production, property and other taxes	**38**	34	24
	426	374	367
Allowance for doubtful accounts	**4**	3	

(a) Sales of crude oil, natural gas and refined products to customers in the United States and sales of petrochemicals to customers in the United States and Europe.

(b) Included in exploration expenses in the Consolidated Statements of Earnings.

(c) Included in depreciation, depletion and amortization in the Consolidated Statements of Earnings.

(d) Included in operating revenues in the Consolidated Statements of Earnings.

In 2002, the company sold its retail natural gas marketing business in the Energy Marketing and Refining – Canada segment for cash consideration of $62 million, net of related closing costs and adjustments of $4 million, resulting in an after-tax gain of $35 million.

19. DIFFERENCES BETWEEN CANADIAN AND U.S. GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The consolidated financial statements have been prepared in accordance with Canadian GAAP. The application of United States GAAP (U.S. GAAP) would have the following effects on earnings and comprehensive income as reported:

($ millions)	Notes	2003	2002	2001
Net earnings as reported, Canadian GAAP		**1 084**	761	388
Adjustments net of applicable income taxes				
Derivatives and hedging activities	(a)	**(120)**	6	(55)
Stock-based compensation	(b)	**(2)**	(12)	(14)
Preferred Securities	(c)	**12**	(29)	(27)
Accounting for income taxes	(d)	**—**	—	6
Write-off of oil shale assets	(e)	**—**	—	64
Start-up costs	(f)	**—**	—	10
Asset retirement obligations	(g)	**(4)**	—	—
Cumulative effect of change in accounting principles	(g)	**(66)**	—	47
Net earnings attributable to discontinued operations	(i)	**—**	(56)	5
Net earnings from continuing operations, U.S. GAAP		**904**	670	424
Net earnings (loss) from discontinued operations, U.S. GAAP	(i)	**—**	56	(5)
Derivatives and hedging activities, net of income taxes of $7 (2002 – $54; 2001 – $16)	(a)	**18**	(118)	29
Minimum pension liability, net of income taxes of $nil (2002 – $10; 2001 – $11)	(h)	**7**	(20)	(26)
Foreign currency translation adjustment	(j)	**(26)**	—	—
Comprehensive income, U.S. GAAP		**903**	588	422

per common share (dollars)	2003	2002	2001
Net earnings per share from continuing operations			
Basic	**2.01**	1.50	0.95
Diluted	**1.86**	1.47	0.94
Net earnings per share from discontinued operations			
Basic	**—**	0.12	(0.01)

Diluted	—	0.12	(0.01)

The application of U.S. GAAP would have the following effects on the Consolidated Balance Sheets as reported:

	Notes	December 31, 2003 As Reported	December 31, 2003 U.S. GAAP	December 31, 2002 As Reported	December 31, 2002 U.S. GAAP
Current assets	(a)	**1 292**	**1 388**	722	767
Property, plant and equipment, net	(c,g)	**8 725**	**8 974**	7 641	7 674
Deferred charges and other	(a,c,h)	**286**	**333**	185	231
Future income taxes	(a,g,h)	**124**	**266**	135	165
Total assets		**10 427**	**10 961**	8 683	8 837
Current liabilities	(a)	**1 075**	**1 364**	797	933
Long-term borrowings	(a,c)	**2 448**	**2 967**	2 686	3 251
Accrued liabilities and other	(g,h)	**296**	**690**	226	306
Future income taxes	(a,c,g)	**2 183**	**2 281**	1 516	1 539
Preferred Securities	(c)	**476**	**—**	523	—
Share capital	(b)	**604**	**652**	578	626
Contributed surplus	(b)	**7**	**9**	—	—
Cumulative foreign currency translation	(j)	**(26)**	**—**	—	—
Retained earnings		**3 364**	**3 136**	2 357	2 319
Accumulated other comprehensive income	(a,h,j)	**—**	**(138)**	—	(137)
Total liabilities and shareholders' equity		**10 427**	**10 961**	8 683	8 837

(a) Derivative Financial Instruments
The company accounts for its derivative financial instruments under Canadian GAAP as described in note 6. Financial Accounting Standards Board Statement (Statement) 133 "Accounting for Derivative Instruments and Hedging Activities," as amended by Statements 138 and 149 (the Standards), establishes U.S. GAAP accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. Generally, all derivatives, whether designated in hedging relationships or not, and excluding normal purchases and normal sales, are required to be recorded on the balance sheet at fair value. If the derivative is designated as a fair value hedge, changes in the fair value of the derivative and changes in the fair value of the hedged item attributable to the hedged risk are recognized in the Consolidated Statements of Earnings. If the derivative is designated as a cash flow hedge, the effective portions of the changes in fair value of the derivative are initially recorded in other comprehensive income ("OCI") and are recognized in the Consolidated Statements of Earnings when the hedged item is recognized. Accordingly, ineffective portions of changes in the fair value of hedging instruments are recognized in net earnings immediately for both fair value and cash flow hedges. Gains or losses arising from hedging activities, including the ineffective portion, are reported in the same earnings statement caption as the hedged item.

The determination of hedge effectiveness and the measurement of hedge ineffectiveness for cash flow hedges is based on internally derived valuations. The company uses these valuations to estimate the fair values of the underlying physical commodity contracts.

Commodity Price Risk
As described in note 6, Suncor manages crude price variability by entering into U.S. dollar WTI derivative transactions and has historically, in certain instances, combined U.S. dollar WTI derivative transactions and Canadian/U.S. foreign exchange derivative contracts. As at December 31, 2003, the company had hedged a portion of its forecasted Canadian dollar denominated cash flows subject to U.S. dollar WTI commodity price risk for up to two years. The company had not hedged any portion of the foreign exchange component of these forecasted cash flows.

While the company's current strategic intent is to only manage the exposure relating to changes in the U.S. dollar WTI component of its crude oil sales, U.S. GAAP requires the company to consider all cash flows arising from forecasted Canadian dollar denominated crude oil sales when measuring the ineffectiveness of its cash flow hedges. In periods of significant Canadian/U.S. dollar foreign exchange fluctuations, material hedge ineffectiveness can result from unhedged foreign exchange exposures. This ineffectiveness arises despite the company's assessment that its U.S. dollar WTI hedging instruments are highly effective in achieving offsetting changes in cash flows attributable to its forecasted Canadian dollar denominated crude oil sales.

Under U.S. GAAP, for the year ended December 31, 2003, the company would have recognized $141 million of hedge ineffectiveness relating to forecasted cash flows in 2004 and 2005 primarily due to foreign exchange fluctuations during the period. The net earnings impact of this ineffectiveness will not be recognized for Canadian GAAP purposes until the related forecasted crude oil sales occur.

Interest Rate Risk
The company periodically enters into derivative financial instrument contracts such as interest rate swaps as part of its risk management strategy to minimize exposure to changes in cash flows of interest-bearing debt. At December 31, 2003, the company had interest rate derivatives classified as fair value hedges outstanding for up to eight years relating to fixed rate debt.

De-designated Hedging Instruments
During 2003, the company de-designated and monetized purchased crude oil call option hedging instruments for net proceeds of $28 million. For Canadian GAAP purposes, as it is probable that the underlying forecasted crude oil sales will occur, the related $28 million pretax gain on monetization of the call options has been deferred and will be recognized as additional crude oil revenues during 2004. For U.S. GAAP

purposes, the company would have recognized the $28 million pretax gain as hedge ineffectiveness income during 2003.

Non-designated Hedging Instruments
In 1999, the company sold inventory and subsequently entered into a derivative contract with an option to repurchase the inventory at the end of five years. The company realized an economic benefit as a result of liquidating a portion of its inventory. The derivative did not qualify for hedge accounting as the company does not have purchase price risk associated with the repurchase of the inventory. This derivative does not represent a U.S. GAAP difference as the company records this derivative at fair value for Canadian purposes.

During the fourth quarter of 2001, the company made a payment of $29 million to terminate a long-term natural gas contract. The contract had been designated as a hedge under Canadian GAAP, and the resulting settlement loss of $18 million, net of income taxes of $11 million, was to be deferred and recognized as the hedged item was settled. During 2002, in connection with the sale of the company's retail natural gas marketing business (see note 18), the company disposed of the related hedged item. Accordingly, for Canadian GAAP purposes, the company recognized the entire settlement loss of $18 million during 2002. For U.S. GAAP purposes, the long-term contract would have been designated as a normal purchase and sale transaction, and the after-tax loss of $18 million would have been recognized in 2001 on the initial settlement of the contract.

Accumulated OCI and U.S. GAAP Net Earnings Impacts
A reconciliation of changes in accumulated OCI attributable to derivative hedging activities for the years ended December 31 is as follows:

($ millions)	2003	2002
OCI attributable to derivatives and hedging activities, beginning of the period, net of income taxes of $41 (2002 – $13)	**(89)**	29
Current period net changes arising from cash flow hedges, net of income taxes of $26 (2002 – $57)	**(54)**	(123)
Net hedging losses at the beginning of the period reclassified to earnings during the period, net of income taxes of $33 (2002 – $3)	**72**	5
OCI attributable to derivatives and hedging activities, end of period, net of income taxes of $34 (2002 – $41)	**(71)**	(89)

For the year ended December 31, 2003, assets increased by $139 million and liabilities increased by $332 million as a result of recording all derivative instruments at fair value.

The loss associated with realized and unrealized hedge ineffectiveness on derivative contracts designated as cash flow hedges during the period was $199 million, net of income taxes of $93 million (2002 – $19 million, net of income taxes of $9 million). The company estimates that $55 million of after-tax hedging losses will be reclassified from OCI to current period earnings within the next 12 months as a result of forecasted sales occurring.

For the year ended December 31, 2003, U.S. GAAP net earnings would have been reduced by $120 million, net of income taxes of $56 million (2002 – increased net earnings of $6 million, net of income taxes of $4 million; 2001 – decreased net earnings of $55 million, net of income taxes of $37 million) to reflect the impact of the above items.

(b) Stock-based Compensation
Under Canadian GAAP, compensation expense has not been recognized for common share options granted prior to January 1, 2003, including options issued in connection with both the company's new SunShare long-term incentive plan, as well as those common shares and common share options awarded to employees under the company's previous long-term incentive program that matured April 1, 2002. Under U.S. GAAP, certain of the SunShare options would have been accounted for using the variable method of accounting for employee stock compensation. Further, for U.S. GAAP purposes, compensation expense would have been recognized ratably over the life of the previous long-term incentive program for those options and common shares awarded under that plan. For the year ended December 31, 2003, U.S. GAAP net earnings would have been reduced by $2 million (2002 – $12 million; 2001 – $14 million) to reflect additional stock-based compensation expense.

As described in note 1, the company adopted a new stock-based compensation accounting policy for Canadian GAAP. The company now expenses the compensation cost of all common share options issued after January 1, 2003 ratably over the estimated vesting period of the respective options. For U.S. GAAP purposes, the company would have adopted Statement 148 in 2003, permitting the company to expense common share options issued after January 1, 2003 in a manner consistent with Canadian GAAP.

Consistent with Canadian GAAP, for U.S. GAAP purposes the company would have continued to disclose pro forma stock-based compensation cost for common stock options awarded prior to January 1, 2003 ("pre-2003 options") as if the fair value method had been adopted. Under U.S. GAAP, had the company accounted for its pre-2003 options using the fair value method (excluding the earnings effect of the SunShare and long-term employee incentive options described above), pro forma net earnings and pro forma basic earnings per share for the year ended December 31, 2003 would have been reduced by $27 million (2002 – $24 million; 2001 – $9 million) and $0.06 per share (2002 – $0.05; 2001 – $0.02), respectively.

(c) Preferred Securities
Under Canadian GAAP, Preferred Securities are classified as share capital and the interest distributions thereon, net of income taxes, are accounted for as dividends. Under U.S. GAAP, the Preferred Securities would have been classified as long-term debt and the interest distributions thereon would have been accounted for as financing expenses. Preferred Securities denominated in U.S. dollars of US$163 million would have been revalued at the rate in effect at the related balance sheet date, with any foreign exchange gains (losses) recognized in the Consolidated Statements of Earnings. Further, under U.S. GAAP the interest distributions would have been eligible for interest capitalization.

Under Canadian GAAP, issue costs of the Preferred Securities, net of the related income tax credits, were charged against share capital. Under U.S. GAAP, these issue costs would have been deferred and amortized to earnings over the term of the related long-term debt.

For U.S. GAAP purposes, these differences would have increased net earnings for the year ended December 31, 2003 by $12 million, including an income tax recovery of $8 million (2002 – a reduction to net earnings of $29 million, net of income taxes of $20 million; 2001 – a reduction to net earnings of $27 million, net of income taxes of $18 million).

Under Canadian GAAP, the 2003 interest distributions on the Preferred Securities for the year ended December 31, 2003 of $45 million (2002 – $48 million; 2001 – $48 million) are classified as financing activities in the Consolidated Statements of Cash Flows. Under U.S. GAAP, the interest distributions of $45 million (2002 – $48 million; 2001 – $48 million) and the amortization of issue costs for the year ended December 31, 2003 of $3 million (2002 – $3 million; 2001 – $3 million) would have been classified as operating activities.

The Preferred Securities, which are publicly traded, had a fair value, based on quoted market prices, of $493 million at December 31, 2003 (2002 – $568 million; 2001 – $575 million).

(d) Income Taxes
Under Canadian GAAP, changes in tax laws and rates are recognized when they are considered substantially enacted, whereas under U.S. GAAP, changes in tax laws and rates are only considered after they have been enacted into law. This GAAP difference would have no impact on U.S. GAAP net earnings for the year ended December 31, 2003 (2002 – no impact; 2001 – an increase of $6 million).

(e) Asset Impairment
Under Canadian GAAP, the company reduced the carrying amount of its interest in the Stuart Oil Shale Project in 2000, based on a non-discounted cash flow analysis. Had the carrying amount been determined using a discounted cash flow analysis as required under U.S. GAAP, an additional write-down of $64 million, net of income taxes of $55 million, would have been recorded in 2000. Effective April 5, 2001, the company sold its interest in the project. Due to the difference in determining the carrying value of the project for Canadian and U.S. GAAP purposes in 2000, net earnings for U.S. GAAP purposes for the year ended December 31, 2001 would have increased by $64 million.

(f) Start-up Costs
In 2001, under Canadian GAAP, all remaining capitalized start-up costs associated with the Stuart Oil Shale Project were written down. Under U.S. GAAP, these start-up costs would have been fully expensed in 1999. As a result, net earnings for U.S. GAAP purposes for 2001 would have been increased by $10 million, net of income taxes of $7 million.

(g) Asset Retirement Obligations
For the years ended December 31, 2003, for Canadian GAAP purposes, estimated reclamation costs in the company's upstream operations were accrued on the unit of production basis. Estimated environmental remediation costs, which are predominantly in the company's downstream operations, were accrued during the period for those sites where assessments indicated that such work was required. On January 1, 2003, the company would have adopted Statement 143 "Accounting for Asset Retirement Obligations" for U.S. GAAP reporting purposes. Statement 143 requires recognition of a liability for the future retirement obligations associated with the company's property, plant and equipment. The fair value of the asset retirement obligations are recorded on a discounted basis as incurred. This amount is capitalized as part of the cost of the related asset and amortized to expense over its useful life. The liability accretes until the company settles the obligation.

For U.S. GAAP purposes, the company's adoption of Statement 143 effective January 1, 2003 would have increased total assets by $331 million, increased total liabilities by $397 million, and decreased net income due to the cumulative effect of a change in accounting principles by $66 million, net of income taxes of $34 million.

Had Statement 143 been applied during all periods presented, the company's asset retirement obligation would have been $388 million at January 1, 2002, $400 million at December 31, 2002 and $401 million at December 31, 2003.

Under Canadian GAAP, net earnings for the year ended December 31, 2003 include site restoration and abandonment expense of $19 million, net of income taxes of $10 million (2002 – $12 million, net of income taxes of $5 million; 2001 – $6 million, net of income taxes of $3 million). Under U.S. GAAP, net earnings for the year ended December 31, 2003 would have reflected accretion expense of $17 million (2002 – $16 million; 2001 – $16 million) and depreciation, depletion and amortization expense of $6 million (2002 – $6 million; 2001 – $6 million), net of taxes of $12 million (2002 – $10 million; 2001 – $11 million). On a pro forma basis, this would have decreased net earnings per common share by $0.01 (2002 – $0.02; 2001 – $0.04). Under U.S. GAAP, at December 31, 2003, the company would have recorded a decrease to total liabilities of $6 million.

The company owns interests in several assets for which the fair value of the asset retirement obligation cannot be reasonably determined because the assets currently have an indeterminate life. The asset retirement obligation for these assets will be recorded in the first period in which the lives of the assets are determinable.

(h) Minimum Pension Liability
Under U.S. GAAP, recognition of an additional minimum pension liability is required when the accumulated benefit obligation exceeds the fair value of plan assets to the extent that such excess is greater than accrued pension costs otherwise recorded. The accumulated benefit obligation does not incorporate projections of future compensation increases in the determination of the obligation. No such adjustment is required under Canadian GAAP.

Under U.S. GAAP, at December 31, 2003, the company would have recognized a minimum pension liability of $76 million (2002 – $80 million), an intangible asset of $13 million (2002 – $10 million) and other comprehensive loss of $41 million, net of income taxes of $22 million (2002 – $48 million, net of income taxes of $22 million). Other comprehensive income for the year ended December 31, 2003 would have increased by $7 million, net of income taxes of $nil (2002 –a decrease in other comprehensive income of $20 million, net of income taxes of $10 million; 2001 – a decrease in other comprehensive income of $26 million, net of income taxes of $11 million).

(i) Discontinued Operations
During 2002, the company disposed of its retail natural gas business for net proceeds of $62 million, and recognized an after-tax gain on sale of $35 million for Canadian GAAP purposes. The retail natural gas marketing business was not considered significant to the company's overall

business operations, and was not classified as a business segment for the purposes of discontinued operations reporting. Accordingly, financial results of the retail natural gas marketing business were not segregated from the financial results of the company's other operations prior to the date of disposal of the business.

For U.S. GAAP purposes, the company would have adopted Statement 144 "Accounting for the Impairment and Disposal of Long-Lived Assets" effective January 1, 2002. For the purposes of Statement 144, the retail natural gas business would have been considered a distinguishable component of the company, and reflected as a discontinued operation for the year ended December 31, 2002. For segmented reporting purposes, the retail natural gas marketing business was included in the Energy Marketing and Refining – Canada operating segment in 2002 and 2001.

Selected financial information regarding the discontinued retail natural gas business is as follows for the year ended December 31:

($ millions)	2003	2002	2001
Revenues included in discontinued operations	—	81	196
Income from retail natural gas business operations, net of income taxes of $nil (2002 – $4; 2001 – recovery of $3)	—	8	(5)
Gain on disposal of retail natural gas business, net of income taxes of $nil (2002 – $10; 2001 – $nil)	—	48	—

There were no remaining assets or liabilities related to the discontinued operations at December 31, 2003 or at December 31, 2002.

(j) Cumulative Foreign Currency Translation

Under Canadian GAAP, foreign currency losses of $26 million arising on translation of the company's Denver-based foreign operations have been recorded directly to shareholders' equity. Under U.S. GAAP, these foreign currency translation losses would be included as a component of comprehensive income.

Recently Issued Accounting Standards

Consolidation of Variable Interest Entities

In January 2003, the Financial Accounting Standards Board issued interpretation 46 ("FIN 46"), "Consolidation of Variable Interest Entities (VIEs)." VIEs, commonly referred to as Special Purpose Entities or SPEs, are entities in which the equity investors do not have a controlling financial interest or do not have sufficient equity at risk to absorb future losses. Effective for 2004, FIN 46 requires consolidation of a VIE where the company will absorb a majority of a VIEs losses, receive a majority of its returns, or both. The company will be required to consolidate the VIE related to the sale of equipment as described in note 10(c). The company does not expect a significant impact on net income on consolidation of the equipment VIE. The impact on the balance sheet would be an increase to property, plant and equipment and an increase to long-term liabilities. The VIE involving the sale of crude oil inventory terminates June 25, 2004, and is not anticipated to have a significant impact on Suncor's reported results of operations or financial position for U.S. GAAP purposes. The accounts receivable securitization program, as currently structured, does not meet the FIN 46 criteria for consolidation by Suncor.

Quarterly Summary (unaudited)

FINANCIAL DATA

	For the Quarter Ended					For the Quarter Ended				
($ millions except per share amounts)	Mar 31 2003	June 30 2003	Sept 30 2003	Dec 31 2003	Total Year 2003	Mar 31 2002	June 30 2002	Sept 30 2002	Dec 31 2002	Total Year 2002
Revenues	**1 676**	**1 292**	**1 700**	**1 638**	**6 306**	1 077	1 289	1 257	1 409	5 032
Net earnings (loss)										
Oil Sands	**306**	**67**	**261**	**254**	**888**	111	201	233	245	790
Natural Gas	**28**	**37**	**27**	**37**	**129**	5	12	1	17	35
Energy Marketing and Refining – Canada	**21**	**16**	**10**	**6**	**53**	7	27	10	20	64
Refining and Marketing – U.S.A. (c)	**—**	**—**	**14**	**4**	**18**	—	—	—	—	—
Corporate and eliminations	**13**	**1**	**(17)**	**(1)**	**(4)**	(33)	(11)	(60)	(24)	(128)
	368	**121**	**295**	**300**	**1 084**	90	229	184	258	761
Per common share										
Net earnings attributable to common shareholders										
Basic	**0.84**	**0.29**	**0.64**	**0.67**	**2.43**	0.18	0.52	0.38	0.56	1.64
Diluted	**0.77**	**0.26**	**0.62**	**0.61**	**2.26**	0.18	0.49	0.37	0.55	1.61
Cash dividends	**0.0425**	**0.05**	**0.05**	**0.05**	**0.1925**	0.0425	0.0425	0.0425	0.0425	0.17

Cash flow from (used in) operations										
Oil Sands	**541**	**321**	**488**	**453**	**1 803**	213	366	443	453	1 475
Natural Gas	**88**	**66**	**80**	**66**	**300**	34	41	36	53	164
Energy Marketing and Refining – Canada	**49**	**41**	**27**	**47**	**164**	28	—	35	49	112
Refining and Marketing – U.S.A. (c)	**—**	**—**	**25**	**9**	**34**	—	—	—	—	—
Corporate and eliminations	**(65)**	**(70)**	**(36)**	**(49)**	**(220)**	(94)	(55)	(67)	(95)	(311)
	613	**358**	**584**	**526**	**2 081**	181	352	447	460	1 440

OPERATING DATA

	For the Quarter Ended					For the Quarter Ended				
	Mar 31 2003	**June 30 2003**	**Sept 30 2003**	**Dec 31 2003**	**Total Year 2003**	**Mar 31 2002**	**June 30 2002**	**Sept 30 2002**	**Dec 31 2002**	**Total Year 2002**
OIL SANDS (thousands of barrels per day)										
Production	**211.1**	**188.2**	**231.5**	**235.2**	**216.6**	179.3	207.6	207.9	227.6	205.8
Sales										
Light sweet crude oil	**120.7**	**86.4**	**109.0**	**132.7**	**112.3**	96.8	90.8	114.1	116.7	104.7
Diesel	**30.1**	**22.9**	**24.8**	**27.2**	**26.3**	20.2	23.8	22.4	25.6	23.0
Light sour crude oil	**60.4**	**73.9**	**77.5**	**81.3**	**73.3**	70.8	73.8	54.8	73.9	68.3
Bitumen	**—**	**1.2**	**16.1**	**8.3**	**6.4**	0.3	8.9	15.4	12.2	9.3
	211.2	**184.4**	**227.4**	**249.5**	**218.3**	188.1	197.3	206.7	228.4	205.3
Average sales price (1) (dollars per barrel)										
Light sweet crude oil	**46.69**	**39.87**	**37.96**	**36.67**	**40.26**	33.55	37.07	39.80	39.02	37.56
Other (diesel, light sour crude oil and bitumen)	**40.62**	**32.94**	**32.92**	**30.72**	**33.93**	25.53	30.33	30.86	31.04	29.58
Total	**44.09**	**36.19**	**35.34**	**33.89**	**37.19**	29.66	33.43	35.79	35.12	33.65
Total (a)	**48.77**	**38.14**	**38.05**	**36.63**	**40.22**	30.62	36.68	40.40	39.11	36.94

	For the Quarter Ended					For the Quarter Ended				
	Mar 31 2003	**June 30 2003**	**Sept 30 2003**	**Dec 31 2003**	**Total Year 2003**	**Mar 31 2002**	**June 30 2002**	**Sept 30 2002**	**Dec 31 2002**	**Total Year 2002**
OIL SANDS (continued) (dollars per barrel sold rounded to the nearest $0.05)										
Cash operating costs and total operating costs										
New definition:										
Cash costs	**9.20**	**10.70**	**8.20**	**9.45**	**9.30**	11.25	9.50	9.35	8.30	9.50
Natural gas	**3.10**	**2.40**	**1.65**	**1.60**	**2.15**	2.25	1.40	1.05	1.75	1.55
Imported bitumen	**0.10**	**0.10**	**—**	**—**	**0.05**	—	—	—	0.15	0.05
Cash operating costs (2)	**12.40**	**13.20**	**9.85**	**11.05**	**11.50**	13.50	10.90	10.40	10.20	11.10
Depreciation, depletion and amortization	**6.20**	**6.25**	**5.20**	**5.30**	**5.70**	6.15	5.50	6.25	6.05	6.00
Total operating costs (3)	**18.60**	**19.45**	**15.05**	**16.35**	**17.20**	19.65	16.40	16.65	16.25	17.10
As previously defined:										
Cash costs	**9.35**	**10.70**	**8.10**	**9.65**	**9.40**	11.05	9.40	9.15	8.55	9.45
Natural gas	**3.10**	**2.50**	**1.65**	**1.50**	**2.15**	2.15	1.45	1.05	1.75	1.60
Cash overburden spending	**2.30**	**3.20**	**1.70**	**1.85**	**2.20**	3.15	1.75	1.75	2.00	2.10
Imported bitumen	**0.10**	**0.10**	**—**	**—**	**0.05**	—	—	—	0.15	0.05

Project start-up costs	**0.10**	**0.15**	**0.15**	**0.10**	**0.10**	—	—	0.10	0.05	0.05
Cash operating costs (4)	**14.95**	**16.65**	**11.60**	**13.10**	**13.90**	16.35	12.60	12.05	12.50	13.25
Depreciation, depletion and amortization (net of cash overburden spending)	**3.90**	**3.25**	**3.65**	**3.10**	**3.45**	2.70	4.05	4.50	4.05	3.90
Total operating costs (5)	**18.85**	**19.90**	**15.25**	**16.20**	**17.35**	19.05	16.65	16.55	16.55	17.15
NATURAL GAS										
Gross production (b)										
Natural gas (millions of cubic feet per day)	**184**	**175**	**194**	**194**	**187**	175	179	181	182	179
Natural gas liquids (thousands of barrels per day)	**2.4**	**2.1**	**2.5**	**2.4**	**2.3**	2.5	2.5	2.3	2.4	2.4
Crude oil (thousands of barrels per day)	**1.4**	**1.6**	**1.6**	**1.0**	**1.4**	1.4	1.7	1.3	1.5	1.5
Total (barrel of oil equivalent per day at 6:1 for natural gas)	**34.5**	**32.8**	**36.4**	**35.7**	**34.9**	33.0	34.0	33.8	34.2	33.7
Average sales price (1)										
Natural gas (dollars per thousand cubic feet)	**7.54**	**6.63**	**6.07**	**5.53**	**6.42**	3.21	3.92	3.56	4.91	3.91
Natural gas (a) (dollars per thousand cubic feet)	**7.59**	**6.65**	**6.04**	**5.51**	**6.42**	3.21	3.92	3.56	4.91	3.91
Natural gas liquids (dollars per barrel)	**41.65**	**33.45**	**33.50**	**35.45**	**36.08**	22.53	28.25	31.66	35.14	29.35
Crude oil – conventional (dollars per barrel)	**47.75**	**37.82**	**38.31**	**36.91**	**40.29**	29.15	30.99	33.57	33.20	31.72

	For the Quarter Ended					For the Quarter Ended				
	Mar 31 2003	**June 30 2003**	**Sept 30 2003**	**Dec 31 2003**	**Total Year 2003**	**Mar 31 2002**	**June 30 2002**	**Sept 30 2002**	**Dec 31 2002**	**Total Year 2002**
ENERGY MARKETING AND REFINING – CANADA										
Refined product sales (thousands of cubic metres per day)	**15.7**	**14.9**	**15.2**	**14.2**	**15.0**	13.5	14.9	14.1	15.8	14.5
Margins										
Refining (6) (cents per litre)	**7.5**	**4.7**	**6.5**	**7.0**	**6.5**	4.1	3.8	4.4	6.6	4.8
Refining (6), (a) (cents per litre)	**7.8**	**4.2**	**6.4**	**6.9**	**6.4**	4.1	3.8	4.4	6.6	4.8
Retail (7) (cents per litre)	**7.0**	**6.2**	**7.0**	**6.3**	**6.6**	6.1	6.8	6.9	6.5	6.6
Utilization of refining capacity (%)	**103**	**100**	**91**	**86**	**95**	102	70	100	108	95
REFINING AND MARKETING – U.S.A. (c)										

Refined product sales (thousands of cubic metres per day)	—	—	**9.8**	**8.6**	**9.1**	—	—	—	—	—
Margins										
Refining (6) (cents per litre)	—	—	**7.9**	**4.6**	**5.9**	—	—	—	—	—
Refining (6), (a) (cents per litre)	—	—	**7.9**	**4.6**	**5.9**	—	—	—	—	—
Retail (7) (cents per litre)	—	—	**6.4**	**4.8**	**5.6**	—	—	—	—	—
Utilization of refining capacity (%)	—	—	**101**	**96**	**98**	—	—	—	—	—

(a) Excludes the impact of hedging activities.

(b) Currently all Natural Gas production is located in the Western Canada Sedimentary Basin.

(c) Refining and Marketing – U.S.A. reflects the results of operations since acquisition on August 1, 2003.

Definitions

(1) Average sales price – This operating statistic is calculated before royalties and net of related transportation costs (including or excluding the impact of hedging activities as noted).

(2) Cash operating costs – Include cash costs that are defined as operating, selling and general expenses (excluding inventory changes), taxes other than income taxes and the cost of bitumen imported from third parties. Per barrel amounts are based on production volumes. For a detailed annual reconciliation of this non-GAAP financial measure see page 50 of Management's Discussion and Analysis (MD&A).

(3) Total operating costs – Include cash operating costs as defined in (2) above and non-cash operating costs. Per barrel amounts are based on production volumes.

(4) Cash operating costs (as previously defined) – Included cash costs that were defined as operating, selling and general expenses (including inventory changes), certain financing expenses, taxes other than income taxes and cash overburden spending. Per barrel amounts were based on sales volumes.

(5) Total operating costs (as previously defined) – Included cash operating costs as defined in (4) above and non-cash operating costs (excluding cash overburden spending). Per barrel amounts were based on sales volumes.

(6) Refining margin – This operating statistic is calculated as the average wholesale unit price from all products less the average unit cost of crude oil.

(7) Retail margin – This operating statistic is calculated as the average street price of Sunoco (Energy Marketing and Refining – Canada) and Phillips 66-branded (Refining and Marketing – U.S.A.) retail gasoline net of federal excise tax and other adjustments, less refining gasoline transfer price.

Metric conversion

Crude oil, refined products, etc. – $1m^3$ (cubic metre) = approx. 6.29 barrels
Natural gas – $1m^3$ (cubic metre) = approx. 35.49 cubic feet

Five-year Financial Summary (unaudited)

($ millions except for ratios)	2003(a)	2002	2001	2000	1999
Revenues					
Oil Sands	**3 061**	2 616	1 372	1 402	923
Natural Gas	**512**	339	481	458	337
Energy Marketing and Refining – Canada	**2 671**	2 508	2 673	2 604	1 779
Refining and Marketing – U.S.A.	**515**	—	—	—	—
Corporate and eliminations	**(453)**	(431)	(232)	(980)	(587)
	6 306	5 032	4 294	3 484	2 452
Net earnings (loss)					
Oil Sands	**888**	790	283	315	167
Natural Gas	**129**	35	117	98	41
Energy Marketing and Refining – Canada	**53**	64	80	81	27
Refining and Marketing – U.S.A.	**18**	—	—	—	—
Corporate and eliminations	**(4)**	(128)	(92)	(117)	(49)
	1 084	761	388	377	186
Cash flow from (used in) operations					
Oil Sands	**1 803**	1 475	486	655	405
Natural Gas	**300**	164	280	238	172
Energy Marketing and Refining – Canada	**164**	112	165	174	103

Refining and Marketing – U.S.A.	**34**	—	—	—	—
Corporate and eliminations	**(220)**	(311)	(100)	(109)	(89)
	2 081	1 440	831	958	591
Capital and exploration expenditures					
Oil Sands	**948**	617	1 479	1 808	1 057
Natural Gas	**183**	163	132	127	200
Energy Marketing and Refining – Canada	**122**	60	54	45	42
Refining and Marketing – U.S.A.	**31**	—	—	—	—
Corporate	**32**	37	13	18	51
	1 316	877	1 678	1 998	1 350
Total assets	**10 427**	8 683	8 094	6 833	5 176
Capital employed (b)					
Short-term and long-term debt, less cash and cash equivalents	**2 091**	2 671	3 143	2 235	1 334
Shareholders' equity	**4 425**	3 458	2 780	2 472	2 108
	6 516	6 129	5 923	4 707	3 442
Less capitalized costs related to major projects in progress	**(1 122)**	(511)	(3 691)	(2 497)	(1 084)
	5 394	5 618	2 232	2 210	2 358
Total Suncor employees (number at year-end)	**4 372**	3 422	3 307	3 043	2 796
Dollars per common share					
Net earnings attributable to common shareholders	**2.43**	1.64	0.79	0.78	0.39
Cash dividends	**0.1925**	0.17	0.17	0.17	0.17
Cash flow from operations	**4.63**	3.22	1.87	2.16	1.34
Cash flow from operations after deducting dividends paid on Preferred Securities	**4.53**	3.11	1.76	2.06	1.26

	2003	2002	2001	2000	1999
Ratios					
Return on capital employed (%) (c)	**18.3**	14.6	17.8	16.6	8.3
Return on capital employed (%) (d)	**15.9**	13.8	7.5	9.3	6.4
Return on shareholders' equity (%) (e)	**27.5**	24.4	14.8	16.5	10.3
Debt to debt plus shareholders' equity (f) (%)	**35.9**	43.7	53.1	47.7	38.9
Net debt to cash flow from operations (times) (g)	**1.0**	1.9	3.8	2.3	2.3
Interest coverage – cash flow basis (times) (h)	**15.7**	10.6	5.9	9.0	9.1
Interest coverage – net earnings basis (times) (i)	**13.5**	8.2	3.7	5.6	5.1

(a) Refining and Marketing – U.S.A. reflects the results of operations since acquisition on August 1, 2003.

(b) Capital employed – see page 62.

(c) Net earnings adjusted for after-tax financing expenses (income) for the 12-month period ended, divided by average capital employed. Average capital employed is the sum of shareholders' equity and short-term debt plus long-term debt less cash and cash equivalents, less capitalized costs related to major projects in progress (as applicable), at the beginning and end of the year, divided by two. For a detailed annual reconciliation of this non-GAAP financial measure see page 50 of MD&A.

(d) If return on capital employed were to include capitalized costs related to major projects in progress, it would be as stated on this line.

(e) Net earnings as a percentage of average shareholders' equity. Average shareholders' equity is the sum of total shareholders' equity at the beginning and end of the year divided by two.

(f) Short-term debt plus long-term debt, divided by the sum of short-term debt, long-term debt and shareholders' equity.

(g) Short-term debt plus long-term debt less cash and cash equivalents, divided by cash flow from operations for the year then ended.

(h) Cash flow from operations plus current income taxes and interest expense, divided by the sum of interest expense and capitalized interest.

(i) Net earnings plus income taxes and interest expense, divided by the sum of interest expense and capitalized interest.

Share Trading Information (unaudited)

Common shares are listed on the Toronto Stock Exchange and New York Stock Exchange under the symbol SU.

The following share trading information reflects a two-for-one split of the company's common shares during 2002.

	For the Quarter Ended				For the Quarter Ended			
	Mar 31 2003	June 30 2003	Sept 30 2003	Dec 31 2003	Mar 31 2002	June 30 2002	Sept 30 2002	Dec 31 2002
Share ownership								
Average number outstanding, weighted monthly (thousands) (a)	**449 187**	**449 485**	**449 756**	**450 505**	446 270	447 685	448 412	448 839
Share price (dollars)								
Toronto Stock Exchange								
High	**27.50**	**26.60**	**27.14**	**32.85**	30.00	29.50	28.51	27.20
Low	**23.87**	**23.31**	**24.75**	**25.07**	23.31	24.66	22.30	22.56
Close	**25.61**	**25.34**	**24.93**	**32.50**	28.75	26.60	27.31	24.70
New York Stock Exchange – US$								
High	**18.50**	**19.68**	**19.59**	**25.42**	18.57	18.57	18.25	17.16
Low	**15.32**	**16.10**	**17.86**	**18.57**	14.68	16.10	13.95	14.20
Close	**17.47**	**18.75**	**18.55**	**25.06**	18.08	17.86	16.95	15.67
Shares traded (thousands)								
Toronto Stock Exchange	**83 756**	**67 815**	**64 875**	**93 538**	108 140	96 043	93 144	91 947
New York Stock Exchange	**23 600**	**23 369**	**21 725**	**27 138**	16 971	23 680	19 420	19 933
Per common share information (dollars)								
Net earnings attributable to common shareholders	**0.84**	**0.29**	**0.64**	**0.67**	0.18	0.52	0.38	0.56
Cash dividends	**0.0425**	**0.05**	**0.05**	**0.05**	0.0425	0.0425	0.0425	0.0425

(a) The company had approximately 2,154 holders of record of common shares as at January 30, 2004.

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 5% on dividends paid to a corporation if it is a resident of the United States that owns at least 10% of the voting shares of the company.

Supplemental Financial and Operating Information (unaudited)

	2003	2002	2001	2000	1999
OIL SANDS					
Production (thousands of barrels per day)	**216.6**	205.8	123.2	113.9	105.6
Sales (thousands of barrels per day)					
Light sweet crude oil	**112.3**	104.7	56.2	64.3	52.7
Diesel	**26.3**	23.0	14.8	9.3	8.2
Light sour crude oil	**73.3**	68.3	42.0	35.8	37.5
Bitumen	**6.4**	9.3	8.5	6.2	3.8
	218.3	205.3	121.5	115.6	102.2
Average sales price (dollars per barrel)					
Light sweet crude oil	**40.26**	37.56	34.17	35.31	26.06
Other (diesel, light sour crude oil and bitumen)	**33.93**	29.58	24.86	27.09	21.48
Total	**37.19**	33.65	29.17	31.67	23.84
Total (a)	**40.22**	36.94	34.21	41.29	25.89
Cash operating costs – new definition (b)	**11.50**	11.10	11.10	11.25	9.90
Total operating costs – new definition (b)	**17.20**	17.10	16.25	16.80	14.50
Cash operating costs – as previously defined (b)	**13.90**	13.25	17.00	13.55	11.70
Total operating costs – as previously defined (b)	**17.35**	17.15	19.60	17.25	15.05
Return on capital employed (%) (c)	**20.6**	16.8	20.1	22.8	12.9
Return on capital employed (%) (d)	**17.3**	15.6	6.4	10.6	9.2

(a) Excludes the impact of hedging activities.

(b) Dollars per barrel rounded to the nearest $0.05. See definitions on page 92.

(c) See definitions on page 94.

(d) If capital employed were to include capitalized costs related to major projects in progress, the return on capital employed would be as stated on this line.

	2003	2002	2001	2000	1999
NATURAL GAS					
Production					
Natural gas (millions of cubic feet per day)					
Gross	**187**	179	177	200	226
Net	**142**	124	124	142	170
Natural gas liquids (thousands of barrels per day)					
Gross	**2.3**	2.4	2.4	3.0	4.2
Net	**1.7**	1.7	1.7	2.1	3.0
Crude oil (thousands of barrels per day)					
Gross	**1.4**	1.5	1.5	4.2	9.2
Net	**1.1**	1.2	1.1	3.3	7.5
Total (thousands of boe (a) per day)					
Gross	**34.9**	33.7	33.4	40.5	51.1
Net	**26.4**	23.6	23.5	29.1	38.8
Average sales price					
Natural gas (dollars per thousand cubic feet)	**6.42**	3.91	6.09	4.72	2.44
Natural gas (dollars per thousand cubic feet) (b)	**6.42**	3.91	6.12	4.73	2.48
Natural gas liquids (dollars per barrel)	**36.08**	29.35	34.38	36.66	19.32
Crude oil – conventional (dollars per barrel)	**40.29**	31.72	33.92	29.50	20.94
Return on capital employed (%) (e)	**29.2**	9.2	32.1	17.2	5.5
Undeveloped landholdings (c)					
Oil and gas (millions of acres)					
Western provinces					
Gross	**0.5**	0.5	0.6	1.4	1.5
Net	**0.4**	0.4	0.5	1.1	1.2
International					
Gross	**0.9**	1.2	1.7	1.3	—
Net	**0.2**	0.7	1.3	1.1	—
Net wells drilled (d)					
Exploratory					
Oil	**—**	—	—	—	1
Gas	**2**	2	4	1	5
Dry	**31**	19	16	15	13
Development					
Oil	**1**	—	—	2	2
Gas	**16**	18	16	14	4
Dry	**4**	4	2	3	1
	54	43	38	35	26

(a) Barrel of oil equivalent – converts natural gas to oil on the approximate energy equivalent basis that 6,000 cubic feet equals one barrel of oil.

(b) Excludes the impact of hedging activities.

(c) Metric conversion: Landholdings – 1 hectare = approximately 2.5 acres.

(d) Excludes interests in one net exploratory well and three net development wells in progress at the end of 2003.

(e) See definitions on page 94.

	2003	2002	2001	2000	1999
ENERGY MARKETING AND REFINING – CANADA					
Refined product sales (thousands of cubic metres per day)					
Transportation fuels					
Gasoline					
Retail (b)	**4.4**	4.5	4.3	4.2	4.1
Other	**4.2**	4.4	4.4	4.0	3.7
Jet fuel	**0.7**	0.4	0.7	1.1	1.1
Diesel	**3.0**	2.9	3.1	3.1	2.7
	12.3	12.2	12.5	12.4	11.6
Petrochemicals	**0.8**	0.6	0.5	0.6	0.7
Heating oils	**0.5**	0.4	0.4	0.4	0.4

Heavy fuel oils	**0.8**	0.6	0.8	0.6	0.5
Other	**0.6**	0.7	0.6	0.6	0.6
	15.0	14.5	14.8	14.6	13.8
Margins (cents per litre)					
Refining	**6.5**	4.8	5.7	5.9	4.0
Refining (c)	**6.4**	4.8	5.7	5.9	4.0
Retail	**6.6**	6.6	6.6	6.6	7.4
Crude oil supply and refining					
Processed at Sarnia refinery (thousands of cubic metres per day)	**10.5**	10.6	10.2	10.9	10.6
Utilization of refining capacity (%)	**95**	95	92	98	95
Return on capital employed (%) (d)	**10.2**	12.5	18.4	20.5	6.0
Retail outlets (e) (number at year-end)	**379**	384	400	402	415
REFINING AND MARKETING – U.S.A. (a)					
Refined product sales (thousands of cubic metres per day)					
Transportation fuels					
Gasoline					
Retail (b)	**0.7**	—	—	—	—
Other	**3.5**	—	—	—	—
Jet fuel	**0.5**	—	—	—	—
Diesel	**2.3**	—	—	—	—
	7.0	—	—	—	—
Asphalt	**1.7**	—	—	—	—
Other	**0.4**	—	—	—	—
	9.1	—	—	—	—
Margins (cents per litre)					
Refining	**5.9**	—	—	—	—
Refining (c)	**5.9**	—	—	—	—
Retail	**5.6**	—	—	—	—
Crude oil supply and refining					
Processed at Denver refinery (thousands of cubic metres per day)	**9.4**	—	—	—	—
Utilization of refining capacity (%)	**98**	—	—	—	—
Retail outlets (f) (number at year-end)	**43**	—	—	—	—

(a) For the year ended 2003, Refining and Marketing – U.S.A. reflects the results of operations since acquisition from August 1 to December 31, 2003.

(b) Excludes sales through joint venture interests.

(c) Excludes the impact of hedging activities.

(d) See definitions on page 94.

(e) Sunoco-branded service stations, other private brands managed by EM&R and EM&R's interest in service stations managed through joint ventures. Outlets are located mainly in Ontario.

(f) Phillips-66 branded service stations. Outlets are located primarily in the Denver, Colorado area.

Investor Information

Stock Trading Symbols and Exchange Listing
Common shares are listed on the Toronto Stock Exchange and New York Stock Exchange under the symbol SU.

Dividends
Suncor's Board of Directors reviews its dividend policy regularly. Effective the second quarter of 2003, dividends were increased to $0.05 per share from $0.0425 per share resulting in an aggregate 2003 dividend of $0.1925 per common share.

Dividend Reinvestment and Common Share Purchase Plan
Suncor's Dividend Reinvestment and Common Share Purchase Plan enables shareholders to invest cash dividends in common shares or acquire additional shares through optional cash payments without payment of brokerage commissions, service charges or other costs associated with administration of the plan. For more information, call Computershare Trust Company of Canada at 1-888-267-6555 or visit the investor information section of our web site at www.suncor.com.

Stock Transfer Agent and Registrar
In Canada, Suncor's agent is Computershare Trust Company of Canada, with locations in Calgary, Edmonton, Toronto, Montreal and Vancouver. In the United States, Computershare Trust Company, Inc. is located in Denver, Colorado.

Independent Auditors
PricewaterhouseCoopers LLP

Independent Petroleum Consultants
Gilbert Laustsen Jung Associates Ltd.

Annual Meeting
Suncor's annual and special meeting of shareholders will be held at 10:30 a.m. MT on April 29, 2004, at the Hotel Macdonald, 10065 - 100 Street, Edmonton, Alberta. Presentations from the meeting will be web-cast live at www.suncor.com

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For further information, to subscribe or cancel duplicate mailings
In addition to Annual and Quarterly Reports, Suncor publishes a biennial Report on Sustainability. All of Suncor's publications, as well as updates on company news as it happens, are available on our web site at www.suncor.com To subscribe to Suncor e-news, go to the newsroom section of our web site. To order copies of Suncor's print materials call 1-800-558-9071.

Sometimes shareholders receive more than one copy of our Annual Report. If you receive but do not require more than one mailing, call Computershare Trust Company of Canada at 1-888-267-6555. Computershare will update your account information accordingly.

Shareholders can help reduce mailing costs and paper waste by electing to receive Suncor's Annual Report and other documents electronically. To register for electronic delivery, go to www.investordeliverycanada.com and follow the instructions for enrollment. You will need the 12-character control number enclosed with the Voting Instruction Form sent to shareholders. If you hold Suncor shares in multiple accounts, you will receive meeting packages and a corresponding control number for each account. You must register for each account.

Corporate Directors and Officers

Providing strategic guidance to the company, setting policy direction and ensuring Suncor is fairly reporting its progress are central to the work of Suncor's Board of Directors.

The Board's oversight role encompasses Suncor's strategic planning process, risk management, communication with investors and other stakeholders, and standards of business conduct. Suncor's Board is also responsible for selecting, monitoring and evaluating executive leadership and aligning management's decision making with long-term shareholder interest. A comprehensive description of Suncor's governance practices is available in the company's annual proxy circular on Suncor's web site at www.suncor.com or by calling 1-800-558-9071.

Independence
As of December 31, 2003, Suncor's Board of Directors comprised 12 directors, 10 of whom have been determined by the Board to be independent of management under the guidelines established by the Toronto Stock Exchange and New York Stock Exchange. The role of chair is assumed by an independent director and is separate from the role of chief executive officer. Independent directors also chair the four committees of the Board.

Committee	Key Responsibilities
Board Policy, Strategy Review and Governance Committee >>	Reviews preliminary stages of key strategic initiatives and projects. Reviews and assesses processes relating to long-range planning and budgeting. Oversees key matters pertaining to corporate values, beliefs and standards of ethical conduct. Reviews key matters pertaining to governance, including organization, composition and effectiveness of the Board.
Human Resources and Compensation Committee >>	Reviews and ensures Suncor's overall goals and objectives are supported by appropriate executive compensation philosophy and programs; annually evaluates the performance of the Chief Executive Officer (CEO) against predetermined goals and criteria, and recommends to the Board the total compensation for the CEO. The committee also annually reviews the CEO's evaluation and recommendations for total compensation of the other executive roles, the executive succession planning process and results, and all major Human Resource programs.
Environment, Health and Safety Committee	Reviews the effectiveness with which Suncor meets its obligations pertaining to environment, health and safety including the establishment of appropriate policies with regard to legal, industry and community standards and related management systems and compliance.

Audit Committee >>	Oversees external audit and reviews annual disclosure documents such as financial statements, management's discussion and analysis (MD&A) and the annual information form, including reserves data; approves quarterly financial disclosure documents including quarterly financial statements and MD&A.

>> comprised entirely of independent directors as of December 31, 2003.

In 2003, the Board of Directors met six times. With the exception of one Board member absent from one meeting, all members attended all Board meetings in 2003. Committees of the Board generally meet four or five times per year with the exception of the Audit Committee, which meets more frequently.

Share Ownership
The Board has set guidelines for its own, as well as executive share ownership. Shares held by each Board member and guidelines for executive share ownership are reported annually in Suncor's Proxy Circular.

Board of Directors

JR Shaw (2,3)
Calgary, Alberta
Chairman of the Board of Directors
Director since 1998
JR Shaw has been the chairman of the Board of Suncor since 2001. He is also the executive chair of Shaw Communications Inc. Mr. Shaw is also a director of the Shaw Foundation.

Mel E. Benson (3,4)
Calgary, Alberta
Director since 2000
Mel Benson is president of Mel E. Benson Management Services Inc., an international management consulting firm based in Calgary, Alberta. From 1996 to 2000 Mr. Benson was the senior operations advisor, African Development, Exxon Co. International. Mr. Benson is also an active member of several charitable and Aboriginal organizations, including the Counsel for Advancement of Native Development Officers, the Canadian Aboriginal Professional Association and the National Aboriginal Business Association.

Brian A. Canfield (2,3)
Point Roberts, Washington
Chair, Human Resources and Compensation Committee
Director since 1995
Brian Canfield is the chairman of TELUS Corporation. In addition to serving on Suncor's Board, Mr. Canfield is also on the boards of Terasen Inc. and the Toronto Stock Exchange.

Susan E. Crocker (2,3)
Toronto, Ontario
Director since 2003
Susan Crocker is a corporate director and management consultant who serves as a director on the boards of Brascan Financial Corporation and RioCan Real Estate Investment Trust. Ms. Crocker also serves as a director of a number of arts and community organizations, including Canadian Stage Theatre Company, and the Toronto Community Foundation. She is a managing director and founder of IQ Alliance, a strategic advisory firm formed in 2002. From 1996 to 1999, she was senior vice president, Equity and Derivative Markets with the Toronto Stock Exchange and from 1999 to 2001 was the president and chief executive officer of the Hospitals of Ontario Pension Plan.

Bryan P. Davies (1,4)
Toronto, Ontario
Director 1991 to 1996 and since 2000
Bryan Davies is superintendent, Financial Services and chief executive officer of the Financial Services Commission of Ontario, an agency of the Ontario government that regulates pensions, insurance companies and deposit institutions. Prior to that he was senior vice president, Regulatory Affairs with the Royal Bank Financial Group. Mr. Davies is also active in a number of not-for-profit charitable organizations, including serving as chair of the Canadian Merit Scholarship Foundation and as a director of the National Gallery Foundation.

Brian A. Felesky (1,4)
Calgary, Alberta
Director since 2002
Brian Felesky is a partner in the law firm of Felesky Flynn in Calgary, Alberta. Mr. Felesky also serves as a director on the board of TransCanada Power, L.P. Mr. Felesky is actively involved in not-for-profit and charitable organizations. He is the chair of Homefront on Domestic Violence, a director of the United Way of Calgary and Area and the Canada West Foundation, as well as a member of the Board of Governors of the Council for Canadian Unity.

John T. Ferguson (1,2)
Edmonton, Alberta
Chair, Audit Committee
Director since 1995
John Ferguson is chairman of Princeton Developments Ltd., a real estate company in Edmonton, Alberta, as well as chairman of TransAlta Corporation. Mr. Ferguson is also a director of Bellanca Developments Ltd. and the Royal Bank of Canada. He is a director of the C.D. Howe Institute and an advisory member of the Canadian Institute for Advanced Research. His involvement in the community includes acting as

chancellor of the University of Alberta.

Richard L. George
Calgary, Alberta
Director since 1991
Richard George is president and chief executive officer of Suncor. Mr. George is also a director of Enbridge Inc. and GlobalSantaFe Corporation. Mr. George serves as the chairman of the Canadian Council of Chief Executives.

John R. Huff (2,3)
Houston, Texas
Chair, Board Policy, Strategy Review and Governance Committee
Director since 1998
John Huff is chairman and chief executive officer of Oceaneering International Inc., an oil field services company. Mr. Huff is also a director of BJ Services Company. He is active in a variety of non-profit organizations, serving as a director for the American Bureau of Shipping and the Marine Resources Foundation, Key Largo. He is a trustee for the Houston Museum of Natural Science.

Robert W. Korthals (1,2)
Toronto, Ontario
Director since 1996
Robert Korthals is the former president of the Toronto-Dominion Bank. He is currently chairman of the Ontario Teachers' Pension Plan, and is also a director of Jannock Properties Limited, Rogers Communications Inc., Cognos Inc., and several publicly traded investment funds sponsored by Mulvihill Investments. He is a commissioner with the Ontario Securities Commission and also serves as a director of the Canadian Parks and Wilderness Foundation.

M. Ann McCaig (3,4)
Calgary, Alberta
Chair, Environment, Health and Safety Committee
Director since 1995
Ann McCaig is the president of VPI Investments Ltd., a private investment holding company. Ms. McCaig is actively involved with charitable and community activities. She is currently chair of the Alberta Adolescent Recovery Centre, co-chair of the Alberta Children's Hospital Foundation "All for One-All for Kids $50 million Campaign," and a trustee of the Killam Estate. She is also chancellor emeritus of the University of Calgary.

Michael W. O' Brien (4)
Canmore, Alberta
Director since 2002
Michael O'Brien is the former executive vice president, Corporate Development and chief financial officer of Suncor, having retired in 2002. Prior to that, Mr. O'Brien was executive vice president of Suncor's wholly owned subsidiary, Suncor Energy Products Inc. (formerly Sunoco Inc.) from 1992 to 2000. Mr. O'Brien also serves on the boards of PrimeWest Energy Inc., Terasen Inc. and Shaw Communications Inc. In addition, he is currently a director and past chair of the Nature Conservancy of Canada.

(1) Audit Committee
(2) Board Policy, Strategy Review and Governance Committee
(3) Human Resources and Compensation Committee
(4) Environment, Health and Safety Committee

EXHIBIT 2

Management's Discussion and Analysis for the fiscal year ended December 31, 2003, dated February 26, 2004

Management's Discussion and Analysis
February 26, 2004

This Management's Discussion and Analysis (MD&A) contains forward-looking statements. These statements are based on certain estimates and assumptions and involve risks and uncertainties. Actual results may differ materially. See page 51 for additional information.

This MD&A should be read in conjunction with Suncor's audited consolidated financial statements and the accompanying notes. All financial information is reported in Canadian dollars (Cdn$) and in accordance with Canadian generally accepted accounting principles (GAAP) unless noted otherwise. The financial measures cash flow from operations, return on capital employed (ROCE) and cash operating costs referred to in this MD&A, are not prescribed by GAAP and are outlined and reconciled in Non-GAAP Financial Measures on page 50.

Certain amounts in prior years have been reclassified to enable comparison with the current year's presentation.

Natural gas converts to crude oil equivalent at a ratio of six thousand cubic feet to one barrel.

References to "Suncor" or "the company" mean Suncor Energy Inc., its subsidiaries and joint venture investments, unless the context otherwise requires.

The tables and charts in this document form an integral part of this MD&A.

Additional information about Suncor filed with Canadian securities commissions and the United States Securities and Exchange Commission (SEC), including periodic quarterly and annual reports and the Annual Information Form (AIF/40-F) is available on-line at www.sedar.com and www.sec.gov.

Suncor Overview and Strategic Priorities

Suncor Energy Inc. is an integrated energy company headquartered in Calgary, Alberta. The company operates four business segments:

- **Oil Sands** Suncor's core business, located near Fort McMurray, Alberta, produces bitumen from oil sands and upgrades it to refinery feedstock, diesel fuel and byproducts.

- **Natural Gas** (NG) produces natural gas in Western Canada, providing revenues and creating a price hedge against the company's purchased natural gas consumption.

- **Energy Marketing and Refining – Canada** (EM&R) operates a 70,000 barrel per day (bpd) capacity refinery in Sarnia, Ontario, and markets refined petroleum products to customers primarily in Ontario and Quebec, including retail customers in Ontario under the Sunoco brand. (Sunoco in Canada is separate and unrelated to Sunoco in the United States, which is owned by Sunoco, Inc. of Philadelphia.) EM&R also manages energy marketing and trading activities and sales of all Oil Sands and NG production. Financial results relating to the sales of Oil Sands and NG production are reported in those business segments.

- **Refining and Marketing – U.S.A.** (R&M) operates a 60,000 bpd capacity refinery in the Denver, Colorado area as well as related pipeline assets. R&M markets refined petroleum products under the Phillips 66-brand to customers primarily in Colorado and Wyoming, including retail customers in the Denver metropolitan area.

Suncor strategic priorities are:

Operational:
- Developing Suncor's Oil Sands resource base through mining and in-situ technology and supplementing Suncor bitumen production with third party supply.

- Expanding Oil Sands extraction and upgrading facilities to increase crude oil production.

- Developing new refining and marketing opportunities that further integrate Suncor's production into the marketplace.

- Managing environmental and social performance to earn continued stakeholder support for Suncor's ongoing operations and growth plans.

- Maintaining a strong focus on worker, contractor and community safety as an overriding operational priority.

Financial:
- Controlling costs through a strong operational focus, economies of scale and improved management of engineering, procurement and construction of major projects.

- Reducing risk associated with natural gas price volatility by producing volumes that meet or exceed purchases.

- Maintaining debt at a target of 2.0 times cash flow from operations based on mid-cycle crude oil prices of US$22 West Texas Intermediate (WTI).

- Targeting opportunities that support a minimum 15% ROCE at US$22 WTI crude oil prices.

Selected Financial Information

ANNUAL FINANCIAL DATA

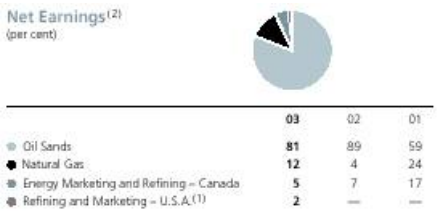
Year ended December 31 ($ millions except per share data)	2003	2002	2001
Revenues	**6 306**	5 032	4 294
Net earnings	**1 084**	761	388
Total assets	**10 427**	8 683	8 094
Long-term debt	**2 448**	2 686	3 113
Dividends			
Common shares	**87**	77	75
Preferred Securities	**45**	48	48
Net earnings attributable to common shareholders per share – basic	**2.43**	1.64	0.79
Net earnings attributable to common shareholders per share – diluted	**2.26**	1.61	0.78
Cash dividends per share	**0.19**	0.17	0.17

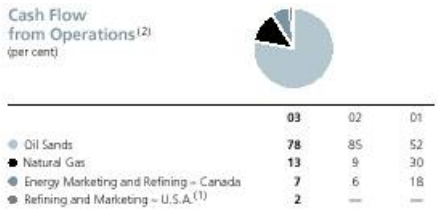
OUTSTANDING SHARE DATA

(as at December 31, 2003)	
Number of common shares	451,184,087
Number of common share options	21,015,567
Number of common share options – exercisable	8,190,714
Preferred securities	$ 476million

QUARTERLY FINANCIAL DATA

	2003 Quarter ended				2002 Quarter ended			
($ millions except per share data)	Mar. 31	June 30	Sept. 30	Dec. 31	Mar. 31	June 30	Sept. 30	Dec. 31
Revenues	**1 676**	**1 292**	**1 700**	**1 638**	1 077	1 289	1 257	1 409
Net earnings	**368**	**121**	**295**	**300**	90	229	184	258
Net earnings attributable to common shareholders per share								
Basic	**0.84**	**0.29**	**0.64**	**0.67**	0.18	0.52	0.38	0.56
Diluted	**0.77**	**0.26**	**0.62**	**0.61**	0.18	0.49	0.37	0.55







(1) Refining and Marketing – U.S.A. data reflects five months of operations since acquisition on August 1, 2003.
(2) Excludes Corporate and Eliminations segment.

Quarterly net earnings for 2003 and 2002 have fluctuated due to a number of factors:

- The impact of winter weather resulted in Oil Sands production tending to be lower in the first quarter of both 2003 and 2002. There were

also operational challenges in bringing the expanded Oil Sands facilities to production capacity in the first three quarters of 2002. Further, in the second quarter of 2003 there was a planned 30-day maintenance shutdown on Upgrader #1 that reduced production capacity.

- Fluctuations in commodity and refined product prices were influenced by seasonal demand variations. In the downstream this was reflected by higher demands for vehicle fuels and asphalt in summer, and heating fuels in winter. Fluctuations also occurred as a result of global and regional supply and demand.

- Commodity prices were unfavourably impacted in 2003 by an increase in the Canadian dollar compared to the U.S. dollar, which reduced the Canadian dollar revenue earned. The stronger Canadian dollar also increased foreign exchange gains on U.S. dollar denominated debt in 2003 compared to 2002.

- The 2003 acquisition of R&M increased earnings for the third and fourth quarters of 2003.

- Income tax changes in the second quarter of 2003 reduced earnings by $86 million ($100 million for the full year).

CONSOLIDATED FINANCIAL ANALYSIS

The following sets out an overview of Suncor's consolidated financial results for 2003 compared to 2002. For a detailed analysis, see the various business segment discussions.

Net Earnings

Suncor's net earnings increased to $1.08 billion in 2003, compared with $761 million in 2002. The increase was primarily due to record production from Oil Sands, higher benchmark crude oil and natural gas prices, higher foreign exchange gains and higher downstream margins. Net earnings were also positively impacted by contributions from the new R&M operations and lower interest charges. These impacts were partially offset by an increase in non-cash future income tax expense, a stronger Canadian dollar relative to the U.S. dollar, higher cash and non-cash operating expenses, and the absence in 2003 of an after-tax gain on the sale of Suncor's retail natural gas marketing business in 2002.

NET EARNINGS COMPONENTS

Year ended December 31 ($ millions)	2003	2002	2001
Net earnings before the following items:	**1 047**	708	336
Sale of retail natural gas marketing business	**—**	35	—
Foreign exchange gains on U.S. dollar denominated long-term debt	**137**	8	—
Impact of income tax rate changes – favourable (unfavourable)	**(100)**	10	52
Net earnings	**1 084**	761	388

The above table is intended to enhance a reader's understanding of some of the factors impacting Suncor's net earnings. For comparability purposes, readers should rely on the reported net earnings, which are prepared and presented in the Consolidated Financial Statements in accordance with GAAP.

INDUSTRY INDICATORS

(Average for the year unless otherwise noted)	2003	2002	2001
WTI crude oil US$/barrel at Cushing	**31.05**	26.10	25.90
Canadian 0.3% par crude Cdn$/barrel at Edmonton	**43.55**	40.75	39.34
Light/heavy crude oil differential US$/barrel WTI @ Cushing/Bow River @ Hardisty	**8.00**	5.95	9.50
Natural gas US$/thousand cubic feet (mcf) at Henry Hub	**5.45**	3.25	4.40
Natural gas (Alberta spot) Cdn$/mcf at AECO	**6.70**	4.05	6.30
New York Harbour 3-2-1 crack US$/barrel (1)	**5.30**	3.35	4.45
Refined product demand (Ontario) percentage change over prior year (2)	**2.3**	0.6	(2.6)
Exchange rate: Cdn$/US$	**0.72**	0.64	0.64

(1) New York Harbour 3-2-1 crack is an industry indicator measuring the margin on a barrel of oil for gasoline and distillate. It is calculated by taking two times the New York Harbour gasoline margin plus one times the New York Harbour distillate margin and dividing by three.

(2) Figures for 2002 and 2001 are based on published government data. Figures for 2003 are internal estimates, based on preliminary government data.

Revenues were $6.3 billion in 2003, compared with $5.0 billion in 2002. The increase resulted primarily from the following:

- Increased crude oil production that drove higher sales volumes. In 2003, Oil Sands sales averaged 218,300 bpd of crude oil, compared with 205,300 bpd in 2002. Sales volumes were negatively impacted by a planned 30-day maintenance shutdown during the year. In 2002, challenges in bringing the expanded Oil Sands facilities to capacity in the first three quarters of the year resulted in lower than capacity production.

- Higher benchmark prices for crude oil and natural gas. Oil Sands crude oil price realization was also favourably impacted by a better sales mix of higher value products (light sweet crude oil and diesel fuel) in 2003 (63%) compared with 2002 (62%).

- Lower realized crude oil pricing differentials. During 2002 the challenges in bringing the expanded Oil Sands' facilities to capacity resulted in some production being sold in markets with less favourable pricing.

- Higher refined product wholesale and retail prices due to higher crude oil prices. In addition, a 3% increase in refined product sales volumes had a positive impact on revenue.

- Additional revenues from the August 1, 2003 acquisition of the R&M assets.

Partially offsetting these increases were:

- Lower realizations on Suncor's crude oil sales basket and natural gas sales as a result of a stronger Canadian dollar compared to the U.S. dollar. Because crude oil and natural gas are primarily sold based on U.S. dollar benchmark prices, a narrowing of the exchange rate difference reduced the Canadian dollar value of Suncor's products.

- The absence in 2003 of $81 million in revenues from EM&R's retail natural gas marketing business, which was sold in 2002.

Purchases of crude oil and products increased to $1.6 billion in 2003 compared with $1.2 billion a year earlier. The increase was primarily due to the following:

- An increase in purchases of crude oil from third parties to meet the feedstock requirements of the R&M refinery.

- Higher benchmark crude oil prices.

- A 3% sales volume increase in EM&R resulting in higher crude oil and other feedstock requirements. In addition, a power outage at the Sarnia refinery required third party purchases of finished product to ensure customer requirements were met.

The above factors were partially offset by the absence in 2003 of purchases for the retail natural gas marketing business that was sold in 2002.

Operating, selling and general expenses increased to $1.5 billion in 2003 from $1.3 billion in 2002. The primary reasons for the increase were:

- Expenses that resulted from the acquisition of the R&M operations.

- Increased planned maintenance activity due to higher production levels as well as unplanned maintenance activities in Oil Sands and EM&R's Sarnia refinery.

- Increased reclamation costs at Oil Sands and NG.

- Higher operating expenses, including higher energy costs in all businesses.

- Higher compensation costs resulting from increased employee benefit costs (including pensions) and an increase in the number of employees, primarily as a result of the acquisition of the R&M assets and work force.

- Other expense increases including higher research and development (R&D) and information technology costs, higher charitable donations and higher insurance costs.

Transportation and other expenses increased to $133 million in 2003 from $128 million in 2002. The increase primarily reflects shipments by R&M, partially offset by lower Oil Sands pipeline toll costs. Increases in pipeline tolls due to Oil Sands sales volume increases were more than offset by the first time receipt of initial shipper toll adjustments. The toll adjustments are currently expected to continue until 2007.

Depreciation, depletion and amortization increased to $611 million in 2003 compared with $585 million in 2002. The increase was primarily due to higher NG depletion reflecting higher production levels and a higher depletion base. Depreciation associated with the R&M operations also contributed to the increase.

Exploration expenses in 2003 increased to $51 million from $26 million in 2002 primarily due to higher dry hole and seismic costs.

Royalty expenses increased to $139 million from $98 million in 2002. Higher royalties due to higher benchmark commodity prices and increased volumes, were partially offset by the absence of royalties related to one of Oil Sands' original mining leases. Mining on this lease was completed in 2002. For a discussion about the expected impact of Crown royalties in future years, see Outlook on page 23.

Taxes other than income tax expense increased in 2003 to $426 million from $374 million in 2002, primarily due to additional excise taxes related to R&M operations.

The gain on disposal of assets increased to $17 million from $2 million in 2002. This primarily reflects the sale by NG of non-producing assets in 2003.

Financing (income) expenses reflected income of $66 million in 2003 compared with an expense of $124 million in 2002. The expense decrease was primarily due to the strengthening of the Canadian dollar versus the U.S. dollar, which resulted in a year-over-year foreign exchange gain of $157 million on U.S. dollar denominated debt. As well, lower levels of debt partially offset by higher variable interest rates and an increase in the level of capitalized interest on capital projects contributed to lower net interest expense.

Income tax expense increased to $720 million in 2003, compared with $383 million in 2002. Suncor's effective income tax rate in 2003 was 40% compared to 33% in 2002. The higher effective rate in 2003 was primarily due to changes in both federal and provincial taxation policies that resulted in a combined non-cash tax charge of $100 million. The federal and provincial governments' changes to resource sector taxation policies, to be phased in over the period 2003 to 2007, include a 7% reduction in the federal tax rate and introduction of the deductibility of Crown royalties. This was offset by the elimination of the federal and provincial resource allowance deduction.

With the above changes enacted in 2003, Suncor currently anticipates its effective tax rate in 2004 will be about 36%.

Corporate Office Expenses

After-tax corporate office expenses decreased to $4 million in 2003 from $128 million in 2002. Lower financing costs (discussed above) were partially offset by higher operating, selling and general expenses.

The increases in operating, selling and general expenses were comprised of higher compensation costs, including the costs associated with expensing employee stock options and deferred share units as well as higher R&D, information technology costs, charitable donations and insurance.

The corporate office had a net cash deficiency of $235 million in 2003, compared with $225 million in 2002. The higher deficiency primarily stems from information technology projects and R&D spending.

Cash Flow from Operations

Cash flow from operations increased in 2003 to $2.08 billion from $1.44 billion in 2002. Excluding the impacts of foreign exchange gains and non-cash future income tax expense, the increase was primarily due to the same factors that improved net earnings, as well as the absence in 2003 of payments made in 2002 under Suncor's long-term employee incentive plans.

Dividends

In the second quarter of 2003, Suncor's Board of Directors approved an increase in the quarterly dividend to $0.05 per share, from $0.0425 per share. Total dividends paid during 2003 were $0.1925 per share, compared with $0.17 in 2002. The Board periodically reviews the dividend policy, taking into consideration Suncor's capital spending profile, financial position, financing requirements, cash flow and other relevant factors.

LIQUIDITY AND CAPITAL RESOURCES

Suncor's capital resources at December 31, 2003, primarily consisted of cash flow from operations and available lines of credit. Suncor's level of earnings and cash flow from operations depend on many factors, including commodity prices, production levels, downstream margins related to the operations of EM&R and R&M and Cdn$/US$ exchange rates.

At December 31, 2003, Suncor's net debt (short and long-term debt less cash and cash equivalents) was approximately $2.1 billion, a reduction of $580 million from December 31, 2002 year-end net debt of $2.7 billion and a reduction of more than $1 billion from year-end 2001 levels. Approximately $425 million of the reduction during 2003, and $890 million for the two-year period, was generated from cash flow, with the balance of both years' reductions attributable to foreign exchange gains.

In 2003, Suncor replaced its available credit and term loan facilities of approximately $1.8 billion with new facilities of $1.7 billion. Suncor's undrawn and uncommitted lines of credit at December 31, 2003, were approximately $1.6 billion. Suncor's current long-term senior debt ratings are A- (Standard & Poor's), A(low) (Dominion Bond Rating Service) and A3 (Moody's Investors Service). All debt ratings have a stable outlook. In 2003, Moody's removed its negative outlook in response to Suncor's debt reduction over the last two years.

In December 2003, Suncor issued US$500 million of 5.95% Notes under an outstanding US$1 billion shelf prospectus. Suncor has now utilized the complete capacity that was available under this shelf. The net proceeds of the debt offering, together with borrowings under the company's available credit and term loan facilities, will be used to repay the company's 7.4% Debentures maturing February 2004 ($125 million) and to redeem the company's 9.05% and 9.125% Preferred Securities in March 2004 ($276 million and US$162.5 million, respectively).

In 2000, Suncor entered into a financing arrangement with a third party. Under this arrangement Suncor sold an undivided interest in Oil Sands energy services assets for $101 million and leased the assets back from the third party. Suncor intends to repurchase the assets in 2004 and refinance the repurchase through revolving term debt facilities. Since this lease was capitalized for accounting purposes, it has been included in Suncor's debt at the end of 2003.

Interest expense on debt continues to be influenced by the composition of the company's debt portfolio, with Suncor benefiting from short-term floating interest rates continuing at near historic lows. To manage its fixed versus floating rate exposure, Suncor has entered into interest rate swaps with investment grade counterparties, resulting in the swapping of $600 million of fixed rate debt to variable rate borrowings.

Management of debt levels continues to be a priority given Suncor's growth plans. The company believes a phased approach to future growth projects should improve its ability to manage project costs and debt levels. Suncor's long-term target ratio for net debt to cash flow from operations is a maximum 2.0 times at mid-cycle crude oil pricing (US$22 WTI per barrel). At the end of 2003 this ratio (based on actual 2003 results) was 1.0 times compared with 1.9 times at year-end 2002. Strong commodity prices and record Oil Sands sales were key factors in this improvement. If the ratio included the company's Preferred Securities it would have been 1.3 times in 2003.

Suncor believes it has the capital resources to fund its 2004 capital spending program of $1.7 billion and to meet current working capital requirements. Suncor believes a combination of cash flow from operations and its borrowing capacity will support this level of capital spending.



AGGREGATE CONTRACTUAL OBLIGATIONS AND OFF-BALANCE SHEET FINANCING

	Payments Due by Period				
($ millions)	**Total**	**2004**	**2005-2006**	**2007-2008**	**Later years**
Non-cancellable capital spending commitments	85	85	—	—	—
Fixed-term debt and capital leases	2 448	220	6	405	1 817
Operating lease agreements and pipeline capacity and energy services commitments	4 775	187	405	430	3 753
Total	**7 308**	**492**	**411**	**835**	**5 570**

The company is subject to financial and operating covenants related to its public market and bank debt. Failure to meet the terms of one or more of these covenants may constitute an Event of Default as described in the respective debt agreements, potentially resulting in accelerated repayment of one or more of the debt obligations.

In addition, a very limited number of the company's commodity purchase agreements, off-balance sheet arrangements and derivative financial instrument agreements, contain provisions linked to debt ratings that may result in settlement of the outstanding transactions should the company's debt ratings fall below investment grade status.

At December 31, 2003, the company was in compliance with all material covenants and its debt ratings were investment grade.

VARIABLE INTEREST ENTITIES AND GUARANTEES

At December 31, 2003, the company had various off-balance sheet arrangements with Variable Interest Entities (VIE) and indemnification agreements with third parties as described below.

The company has a securitization program in place to sell, on a revolving, fully serviced and limited recourse basis, up to $170 million of accounts receivable having a maturity of 45 days or less, to a third party. The third party is a multiple party securitization vehicle that provides funding for numerous asset pools. At December 31, 2003, $170 million in outstanding accounts receivable had been sold under the program. Under the recourse provisions, the company will provide indemnification against credit losses to a maximum of $70 million. A liability has not been recorded for this indemnification as the company believes it has no significant exposure to credit losses. Proceeds received from new securitizations and proceeds from collections reinvested in securitizations on a revolving basis for the year ended December 31, 2003, were nil and approximately $2.3 billion, respectively. The company recorded an after-tax loss of approximately $3 million on the securitization program in each of the last three years. There is no penalty to terminate this program. Management currently intends to keep this program in place for the foreseeable future.

In 1999, the company sold 2.13 million barrels of its crude oil inventory for $49 million to a third party while retaining the right to use the inventory for its operations through a five-year usage agreement. The third party's sole asset is the inventory sold to it by the company. The company pays an annual usage fee of $7 million to the third party and receives a $4 million annual storage fee. The company has the right, but is not obligated, to repurchase the inventory at the spot price at the end of the agreement in June 2004. In order to reduce exposure to the spot price should it elect to repurchase the inventory, the company has entered into crude oil and U.S. dollar swap contracts fixing the purchase price of the crude oil on June 25, 2004, at Cdn$49 million.

In 1999, the company entered into an equipment sale and leaseback arrangement with a third party for proceeds of $30 million. The third party's sole asset is the equipment sold to it and leased back by the company. The initial lease term covers a period of seven years and is accounted for as an operating lease. The company has provided a residual value guarantee on the equipment of up to $7 million should it elect not to repurchase the equipment at the end of the lease term. An early termination purchase option allows for the repurchase of the equipment at specified dates in 2003, 2004 and 2005. Had the company elected to terminate the lease at December 31, 2003, the total cost would have been $30 million. Annualized equipment lease payments in 2003 were $4 million (in each of 2002 and 2001 – $2 million).

The company has agreed to indemnify holders of the 9.125% Preferred Securities, the 7.15% Notes, the 5.95% Notes and the company's credit facilities for added costs relating to taxes, assessments or other government charges or conditions, including any required withholding amounts. Similar indemnity terms apply to the receivables securitization program, the crude oil inventory monetization agreement and certain facility and equipment leases.

There is no limit to the maximum amount payable under the indemnification agreements described above. The company is unable to determine the maximum potential amount payable as government regulations and legislation are subject to change without notice. Under these agreements, Suncor has the option to redeem or terminate these contracts if additional costs are incurred.

OUTLOOK

Oil Sands is expected to operate at or near capacity in 2004, with production targeted between 225,000 and 230,000 bpd for the year.

Production growth through expansion is not expected until 2005, when the company plans to increase Oil Sands capacity to 260,000 bpd. To achieve this goal, Suncor must achieve full production from the first phase of its Firebag in-situ operations and increase upgrading capacity through the construction of a vacuum unit. Both components of this expansion project are proceeding on schedule and costs are expected to approximate the budget estimate of $1 billion.

Expansion plans to increase production beyond 260,000 bpd are also being developed through an expansion known as the Voyageur growth strategy. In the first quarter of 2004, Suncor received regulatory approval to proceed with an expansion to Upgrader #2 that is expected to increase production capacity to 330,000 bpd in late 2007. The cost of the project is currently estimated at $3 billion including approximately $1.5 billion for the expansion to Upgrader #2 and $1.5 billion for development of additional Firebag in-situ stages, mining and extraction. As these cost estimates are based on preliminary scope and engineering, actual amounts may differ and the differences may be material. Suncor's Board must approve the expansion plan and budget prior to construction beginning. A decision by the Board is expected in November 2004. (For further details, see page 39).

The final phase of Voyageur, including construction of a third Oil Sands upgrader and proportionate increases in bitumen supply, is intended to increase production capacity to 500,000 to 550,000 bpd in the 2010 to 2012 time frame. Preliminary cost estimates for this phase of production growth have not been made and are dependent on scope and engineering, market analysis, stakeholder consultation and environmental and socioeconomic impact assessments.

Production growth at Oil Sands is also expected to coincide with further investments at Suncor's other businesses. Capital investment in NG may be required to increase natural gas production to meet its goal of exceeding internal purchases. In downstream operations, investments will be necessary to integrate Oil Sands production into refined product markets and to meet environmental legislation.

Suncor anticipates its growth plan to be largely financed from internal cash flow, which is dependent on commodity prices and other factors. Suncor is projecting an annual capital spending program of approximately $1.7 billion to $1.9 billion until about 2011 to support its growth strategy and sustain operations. Actual spending is subject to change due to such factors as internal and external approvals and capital availability. Refer to the discussion under Risk/Success Factors Affecting Performance on page 24 for additional factors that can have an impact on Suncor's ability to generate funds to support investing activities.

Oil Sands Crown Royalties and Cash Income Taxes

Crown royalties in effect for oil sands operations require payments to the Government of Alberta, based on gross revenues less related transportation costs (R), less allowable costs (C), including the deduction of capital expenditures (the 25% R-C royalty), subject to a minimum payment of 1% of R. Suncor is currently in discussions with the government on several interrelated aspects of the company's Oil Sands royalty structure. These discussions include finalizing the terms of Suncor's option to transition to the generic bitumen-based royalty regime in 2009, which could include a reduction in allowable costs for royalty purposes. Discussions also include the royalty treatment of Suncor's Firebag in-situ operations. The government currently classifies Firebag as a separate project from Suncor's existing operations while Suncor believes Firebag is an expansion of its existing operations. Classification of Firebag as a separate project would result in a timing difference in royalty payments, whereby higher royalties would be payable in earlier years and lower royalties would be payable thereafter.

Absolute royalties payable for a particular period are impossible to accurately predict as they are highly sensitive to, among other factors, crude oil prices, foreign exchange rates and capital and operating costs. In 2003, Suncor paid royalties of $33 million, reflecting the minimum payment of 1% of R.

If Firebag is treated as a separate project, at just over US$26 per barrel WTI, the 25% R-C royalty formula would exceed the 1% of gross revenues minimum and royalties of $28 million would become payable during 2004, based on the following assumptions: a natural gas price of US$5.50 per mcf at Henry Hub;

a light/heavy oil differential to U.S. Gulf Coast of US$8 per barrel; and Cdn$/US$ exchange rate of 0.78. Using these same assumptions, for every US$1 per barrel increase in WTI, Suncor's royalty payments would increase by approximately $25 million. Further, under these assumptions, the 25% R-C royalty would continue to apply to existing oil sands operations, other than Firebag, in future years. After 2009, the royalty would be based on bitumen value if Suncor exercised its option to transition to the generic royalty regime.

This sensitivity analysis incorporates operating and capital cost assumptions included in the company's current budget and long-range plan, and is not an estimate, forecast or prediction of actual future events or circumstances.

The royalty provisions do not impact Suncor's expectations for income taxes. For example, at US$33 per barrel WTI, based on prior years' investment levels, future investment plans and the other assumptions stated, Suncor would not expect its Oil Sands operations to be cash taxable until well into the next decade.

Climate Change

Suncor's effort to reduce greenhouse gas emissions is reflected in its pursuit of greater internal energy efficiency, investment in emissions offsets and carbon capture research and development.

Suncor continues to consult with governments about the impact of the Kyoto Protocol and plans to continue to actively manage its greenhouse gas emissions. The company currently estimates that in 2010 the impact of the Kyoto Protocol on Oil Sands cash operating costs would be an increase of about $0.20 to $0.27 per barrel. This estimate assumes a reduction obligation of 15% from 2010 business-as-usual energy intensity(1) and that the maximum price for carbon credits would, as the Government of Canada indicated in late 2002, be capped at $15 per tonne of carbon dioxide equivalent until 2012. Based on these assumptions, Suncor does not currently anticipate that the cost implications of federal and provincial climate change plans will have a material impact on its business or future growth plans.

The ultimate impact of Canada's implementation of the Kyoto Protocol, however, remains subject to numerous risks, uncertainties and unknowns. These include the outcome of discussions between the federal and provincial governments, the form, impact and effectiveness of

implementing legislation, the ultimate allocation of reduction obligations among economic sectors, and other details of Canada's implementation plan, as well as international developments. In addition, the Government of Canada has not yet indicated what, if any, limitations will be placed on the price of carbon credits after 2012. It is not possible to predict how these and other Kyoto related issues will ultimately be resolved.

RISK/SUCCESS FACTORS AFFECTING PERFORMANCE

Suncor's financial and operational performance is potentially affected by a number of factors including, but not limited to, commodity prices and exchange rates, environmental regulations, stakeholder support for growth plans, extreme cold in winter weather, regional labour issues and other issues discussed within Risk/Success Factors for each Suncor business segment. A more detailed discussion of risk factors is presented in the company's most recent AIF/40-F, filed with securities regulatory authorities.

Commodity Prices, Refined Product Margins and Exchange Rates

Suncor's future financial performance remains closely linked to hydrocarbon commodity prices, which can be influenced by many factors including global and regional supply and demand, worldwide political events and the weather. These factors, among others, can result in a high degree of price volatility. For example, from 2001 to 2003 the monthly average price for benchmark WTI crude oil ranged from a low of US$19.40 per barrel to a high of US$35.75 per barrel. While the highs and lows were not as pronounced in 2003 (US$28.10 to US$35.75 per barrel), these fluctuations create uncertainty from a planning perspective. During the same three-year period, the natural gas Henry Hub benchmark monthly average price ranged from a low of US$1.90 per thousand cubic feet (mcf) to a high of US$9.80 per mcf. In addition to supply and demand impacts, a degree of this variation was due to seasonality factors. Suncor currently believes commodity price volatility will continue.

Crude oil and natural gas prices are based on U.S. dollar benchmarks that result in Suncor's realized prices being influenced by the Cdn$/US$ currency exchange rate, thereby creating an element of uncertainty for the

(1) Reflects the level of greenhouse gas emissions that would have occurred in the absence of energy efficiency and process improvements after 2000.

company. Should the Canadian dollar strengthen compared to the U.S. dollar, the negative effect on net earnings would be partially offset by foreign exchange gains on the company's U.S. dollar denominated debt and U.S. dollar denominated Preferred Securities. Conversely, should the Canadian dollar weaken compared to the U.S. dollar, the positive effect on net earnings would be partially offset by foreign exchange losses on the company's U.S. dollar denominated debt and U.S. dollar denominated Preferred Securities. Cash flow from operations is not impacted by the effects of foreign currency fluctuations on the the company's U.S. dollar denominated debt and U.S. dollar denominated Preferred Securities.

Changes to the Cdn$/US$ exchange rate relationship can create significant volatility in foreign exchange gains or losses. On the outstanding US$1 billion in U.S. dollar denominated debt at the end of 2003, a $0.01 change in the Cdn$/US$ exchange rate would change earnings by approximately $15 million after-tax.

During 2003, the strengthening of the Canadian dollar against the U.S. dollar resulted in a $137 million after-tax foreign exchange gain on the company's U.S. dollar denominated debt, and a $37 million after-tax foreign exchange gain on the U.S. dollar denominated Preferred Securities.

Suncor's U.S. capital projects are expected to be partially funded from Canadian operations. A weaker Canadian dollar would result in a higher funding requirement for these projects.

SENSITIVITY ANALYSIS (1)

	2003 Average	Change	Approximate Change in Pretax Cash Flow from Operations	Approximate Change in After-tax Earnings
Oil Sands				
Price of crude oil ($/barrel) (2)	$ 37.19	US$ 1.00	64	42
Sweet/sour differential ($/barrel)	$ 7.92	US$ 1.00	27	17
Sales (bpd)	218 300	1 000	12	8
Natural Gas				
Price of natural gas ($/mcf) (2)	$ 6.42	0.10	5	3
Production of natural gas (mmcf/d)	187	10	15	8
Energy Marketing and Refining – Canada				
Retail gasoline margins cents per litre (cpl)	6.6	0.1	2	1
Refining/wholesale margin (cpl) (2)	6.5	0.1	5	3
Refining and Marketing – U.S.A.				
Retail gasoline margins (cpl)	5.6	0.1	—	—
Refining/wholesale margin (cpl)	5.9	0.1	2	1
Consolidated				
Exchange rate: Cdn$/US$	0.72	0.01	44	35

(1) The sensitivity analysis shows the main factors affecting Suncor's annual pretax cash flow from operations and after-tax earnings based on actual 2003 operations. The table illustrates the potential financial impact of these factors applied to Suncor's 2003 results. A change in any one factor could compound or offset other factors.

(2) Includes the impact of hedging activities.

Derivative Financial Instruments
The company periodically enters into commodity-based derivative financial instruments such as forwards, futures, swaps and options to hedge against the potential adverse impact of changing market prices due to variations in the underlying commodity indices. The company also periodically enters into derivative financial instrument contracts such as interest rate swaps as part of its risk management strategy to manage exposure to interest rate fluctuations.

Commencing in the fourth quarter of 2002, the company began to use energy derivatives, including physical and financial swaps, forwards and options to gain market information and to earn trading revenues. Trading activities are accounted for at fair value in the company's consolidated financial statements.

Derivative contracts accounted for as hedges are not recognized in the consolidated balance sheets. Realized and unrealized gains or losses on these contracts, including realized gains and losses on derivative hedging

contracts settled prior to maturity, are recognized in earnings and cash flows when the related sales revenues, costs, interest expense and cash flows are recognized.

Gains or losses resulting from changes in the fair value of derivative contracts that do not qualify for hedge accounting are recognized in earnings and cash flows when those changes occur.

Commodity Hedging Activities Suncor cannot control or accurately predict the prices of crude oil or natural gas. For this reason, the company has a hedging program that fixes a price or range of prices for crude oil and natural gas for specified periods of time for a percentage of Suncor's total production. As at December 31, 2003, the company did not have any outstanding foreign currency hedges.

Suncor's risk management objective with its hedging program is to reduce exposure to market volatility and support the company's ability to finance growth. The Audit Committee and the Board of Directors meet with management regularly to assess Suncor's hedging thresholds in light of its price forecast and cash requirements. To add more certainty to Suncor's ability to finance future capital programs and manage debt, the Board authorized the hedging of 35% of the company's crude oil volumes in 2004 and up to 30% for the period 2005 to 2007.

The company's derivative hedging instruments do not require the payment of premiums or cash margin deposits prior to settlement. On settlement, these contracts result in cash receipts to the company, or payments by the company, for the difference between the derivative contract and market rates for the applicable volumes hedged during the contract term. Such cash receipts or payments offset corresponding decreases or increases in the company's sales revenues or crude oil purchase costs. For accounting purposes, amounts received or paid on settlement are recorded as part of the related hedged sales or purchase transactions in the consolidated statements of earnings. In 2003, crude oil hedging decreased Suncor's net earnings by $155 million. In 2002, hedging decreased net earnings by $160 million.

Crude oil hedge contracts outstanding at December 31, 2003, were as follows:

	Quantity (bpd)	Average Price (a)	Revenue Hedged ($ millions)	Hedge Period
As at December 31, 2003				
Crude oil swaps	68 000	24	772(b)	2004
Costless collars	11 000	21 – 24	109 – 125(b)	2004
Crude oil swaps	36 000	23	390(b)	2005

(a) Average price of crude oil swaps is US$WTI per barrel at Cushing, Oklahoma.
(b) The revenue hedged is translated to Cdn$ at the year-end exchange rate for convenience purposes.

Financial Hedging Activities Suncor periodically enters into interest rate and cross-currency interest rate swap contracts as part of its strategy to manage exposure to interest rates. The interest rate swap contracts involve an exchange of floating rate and fixed rate interest payments between the company and investment grade counterparties. The cross-currency swap contracts can also involve an exchange of Canadian dollar interest payments and U.S. dollar interest payments, and an exchange of Canadian and U.S. dollar principal amounts at the maturity date of the underlying borrowing to which the swaps relate. The differentials on the exchange of periodic interest payments are recognized as an adjustment to interest expense.

The company has entered into various interest rate swap transactions at December 31, 2003. The swap transactions result in an average effective interest rate that is different from the stated interest rate of the related underlying long-term debt instruments.

Description of swap transaction	Principal Swapped ($ millions)	Swap Maturity	2003 Effective Interest Rate
Swap of 6.10% Medium Term Notes to floating rates	150	2007	4.3%
Swap of 6.80% Medium Term Notes to floating rates	250	2007	4.9%
Swap of 6.70% Medium Term Notes to floating rates	200	2011	4.2%

In 2003, these interest rate swap transactions reduced 2003 pretax interest expense by $12 million.

Fair Value of Derivative Hedging Instruments
The fair value of derivative hedging instruments is the estimated amount, based on third party market data, that the company would receive (pay)

to terminate the contracts. Such amounts, which also represent the unrecognized and unrecorded gain (loss) on the contracts, were as follows at December 31:

($ millions)	2003	2002
Revenue hedge swaps and collars	**(285)**	(133)
Margin hedge swaps	**2**	1
Interest rate and cross-currency interest rate swaps	**32**	35
	(251)	(97)

Energy Trading Activities In November 2002, Suncor commenced energy trading activities, focused on the commodities the company produces. These energy-trading activities are accounted for using the mark-to-market method and, as such, physical and financial energy contracts are recorded at fair value at each balance sheet date. For the year ended December 31, 2003, a net pretax loss of $3 million (2002 – $nil) from the settlement and revaluation of these contracts was reported as energy trading and marketing activities in the consolidated statements of earnings.

The fair value of unsettled energy trading assets and liabilities at December 31 are as follows:

($ millions)	2003	2002
Energy trading assets	**5**	2
Energy trading liabilities	**5**	2

The valuation of the above contracts was based on actively quoted prices.

Counterparty Credit Risk The company may be exposed to certain losses in the event that counterparties to derivative financial instruments are unable to meet the terms of the contracts. The company's exposure is limited to those counterparties holding derivative contracts with net positive fair values at the reporting date. The company minimizes this risk by only entering into agreements with investment grade counterparties, and through regular management review of potential exposure to, and credit ratings of, such counterparties. At December 31, the company had exposure to credit risk with counterparties as follows:

($ millions)	2003	2002
Derivative contracts not accounted for as hedges	**30**	28
Unrecognized derivative contracts	**27**	23
	57	51

Environmental Regulations
Environmental laws affect nearly all aspects of Suncor's operations, imposing certain standards and controls on activities relating to oil and gas mining and conventional exploration, development and production. Environmental laws also affect refining, distribution and marketing of petroleum products and petrochemicals and require companies engaged in those activities to obtain necessary permits to operate. Environmental assessments and approvals are required before initiating most new projects or undertaking significant changes to existing operations.

In addition to these specifically known requirements, Suncor expects that changes to environmental laws could impose further requirements on companies operating in the energy industry. Some of the issues include the possible cumulative impacts of oil sands development in the Athabasca region; the need to reduce or stabilize various emissions; issues relating to global climate change, including the uncertainties and risks associated with Canada's implementation of the Kyoto Protocol, and uncertainties associated with predicting emission intensity levels from Suncor's future production; and other potential impacts of government regulation in areas such as land reclamation and restoration, water quality and usage, and reformulated fuels to support lower vehicle emissions. Changes in environmental laws could have an adverse effect on Suncor in terms of product demand, product formulation and quality, methods of production, and distribution and operating costs. The complexity of these issues makes it difficult to predict their future impact on the company.

Management anticipates capital expenditures and operating expenses could increase in the future as a result of the implementation of new and increasingly stringent environmental regulations.

Regulatory Approvals
Before proceeding with most major projects, Suncor must obtain regulatory approvals. The regulatory approval process can involve stakeholder consultation, environmental impact assessments and public hearings, among other factors. Failure to obtain regulatory approvals, or failure to obtain them on a timely basis, could result in delays, abandonment, or restructuring of projects and increased costs, all of which could negatively impact future earnings and cash flow.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Suncor's critical accounting policies are defined as those that are both important to the portrayal of the company's financial position and operations and those that require management to make judgments based on underlying estimates and assumptions about future events and their effects. Underlying estimates and assumptions are based on historical experience and other factors that management believes to be reasonable under the circumstances. These estimates and assumptions are subject to change as new events occur, as more industry experience is acquired, as additional information is obtained and as Suncor's operating environment changes. The company believes the following are the most critical accounting policies and estimates used in the preparation of its consolidated financial statements.

Property, Plant and Equipment
Suncor accounts for its Oil Sands in-situ and NG exploration and production activities using the "successful efforts" method. This policy was selected over the alternative full-cost method because Suncor believes it provides a more timely accounting of the success or failure of exploration and production activities.

The application of the successful efforts method of accounting requires Suncor's management to determine the proper classification of activities designated as developmental or exploratory, which ultimately determines the appropriate accounting treatment of the costs incurred. The results from a drilling program can take considerable time to analyze and the determination that commercial reserves have been discovered requires both judgment and industry experience. Where it is determined that exploratory drilling will not result in commercial production, the exploratory "dry hole" costs are written off and reported as part of Oil Sands and NG exploration expenses in the consolidated statements of earnings. Dry hole expense can fluctuate from year to year due to such factors as the level of exploratory spending, the level of risk sharing with third parties participating in the exploratory drilling and the degree of risk in drilling in particular areas.

Properties that are assumed to be productive may, over a period of time, actually deliver oil and gas in quantities different than originally estimated because of changes in reservoir performance and/or adjustments in reserves. Such changes can require a test for the potential impairment of capitalized properties, based on estimates of future cash flow from the properties.Estimates of future cash flows are subject to significant management judgment concerning oil and gas prices, production quantities and operating costs.

Where management assesses that a property is fully or partially impaired, the book value of the property is reduced to fair value and either completely removed from the company's records ("written off") or partially removed from the company's records ("written down") and reported as part of Oil Sands and NG depreciation, depletion and amortization (DD&A) expenses in the consolidated statements of earnings.

The company's plant and equipment are depreciated on a straight-line basis over the estimated useful life of the assets. Firebag and NG property costs are depleted on a unit of production (UOP) basis. In each case the expense is shown on the DD&A line in both the consolidated statements of earnings and in the schedules of segmented earnings. The straight-line basis reflects asset usage as a function of time rather than production levels. For example, the useful life of plant and equipment at Oil Sands and Firebag operations are not based on recorded reserves as the company has access to other undeveloped properties, and bitumen feedstock from third parties, as well as the ability to provide processing services for other producers' bitumen. UOP amortization is used where that method better matches the asset utilization with production that the asset is associated with.

The company determines useful life based on prior experience with similar assets and, as necessary, in consultation with others who have expertise with the assets in question. However, the actual useful life of the assets may differ from management's original estimate due to factors such as technological obsolescence, regulatory requirements and maintenance activity. As the majority of assets are depreciated on a straight-line

basis, a 10% reduction in the useful life of plant and equipment would increase annual DD&A by approximately 10%. This impact would be reflected in all business segments with the majority of the impact being in Oil Sands.

Negative revisions in NG reserve estimates will result in an increase in depletion expenses.

Overburden

As part of the process of mining oil sands, it is necessary to remove surface material such as muskeg, glacial deposits and sand. Overburden removal may precede mining of the oil sands deposit by as much as two years. Accordingly, the quantity of overburden removed in a given period may not bear any relationship to the quantity of oil sands mined in the period, and as such the cash outlays can be different than the amount amortized. In 2003, the overburden amortization charge was $208 million compared with actual cash overburden spending of $175 million. Oil Sands overburden amortization is reported as part of DD&A in the consolidated statements of earnings. Deferred overburden costs are reported as part of "deferred charges and other assets" in the consolidated balance sheets.

In order to ensure a proper matching of costs with revenues (such that each tonne of oil sands mined is allocated a proportionate share of overburden removal costs), the company has adopted the deferral method of accounting for overburden removal costs whereby all such costs are initially set up as a deferred charge.

To allocate the deferred overburden charges, a life-of-mine approach has been adopted for each mine pit, relating the removal of all overburden to the mining of all of the oil sands ore on leases where there is regulatory approval. By adopting this approach, an overburden stripping ratio is calculated that allows for the matching of revenues and expenses such that overburden removal costs are averaged over the life of the mine. Over time, through a combination of increased mine areas, additional drilling activity and operational experience, the company has seen its stripping ratios vary, which can increase or decrease the overburden amortization costs charged to the earnings statement. In 2003 the stripping ratio decreased by about 2% due to new operational information and mine plan changes. This favourable impact of about $4 million partially offset the increase due to higher production levels and higher operating costs.

Reclamation and Environmental Remediation Costs

Suncor's reclamation and environmental remediation costs represent the costs of reclaiming the environment or restoring a site to a useful and acceptable condition, as determined by statutory or regulatory authorities, by contractual agreement, or by Suncor management. The scope of the activities and the nature of the costs are normally outlined in the current reclamation or environmental remediation plan. These include costs specifically related to the reclamation or environmental remediation project and any other costs that can be clearly identified with the project.

For 2003 and prior years, estimated reclamation costs at Oil Sands and NG were accrued on the unit of production basis based on proved and probable reserves. Estimated environmental remediation costs in EM&R and R&M were accrued in the period for sites where assessments indicated that such work was required. No accrual was made for assets with indeterminate lives, including Oil Sands upgrading and processing assets and downstream refining and marketing assets. Reclamation and environmental remediation costs were charged against earnings and reported as operating, selling and general expenses in the consolidated statements of earnings and the schedules of segmented data. These costs primarily affect the Oil Sands and NG segments. The accrued liability was included in the "accrued liabilities and other" line in the consolidated balance sheets.

In connection with company and external party reviews of Oil Sands and NG completed in the fourth quarter of 2003, Suncor increased its

reclamation cost estimate to approximately $950 million, from the previous estimate of $650 million. Approximately $230 million of the increase was due to a change in the Oil Sands estimate to $840 million. The increase in estimated reclamation costs reflects changes in the scope, cost and timing of reclamation recovery activities, including consolidated tailings technology at Oil Sands and gas plant and facilities reclamation at NG. The majority of the costs in Oil Sands are projected to occur over a time horizon extending up to approximately 2060. In the fourth quarter of 2003, prospective changes in the reclamation cost estimate resulted in additional after-tax expense of approximately $2 million.

The greatest area of judgment and uncertainty with respect to the company's reclamation cost estimates relates to its Oil Sands mining leases where there is a requirement to provide for land productivity equivalent to predisturbed conditions. To reclaim tailings ponds, Suncor is using a process referred to as consolidated tailings technology. At this time, no ponds have been fully reclaimed using this technology, although work is under way. The success and time to reclaim the tailings ponds could increase or decrease the current reclamation cost estimates. The company continues to monitor and assess other possible technologies and/or modifications to the consolidated tailings process now being used.

Refer to Recently Issued Canadian Accounting Standards on page 34 for a discussion of the financial accounting impacts of Suncor's adoption of its new accounting policy for Asset Retirement Obligations, effective January 1, 2004.

Reserve Estimates

On an annual basis Suncor engages Gilbert Laustsen Jung Associates Ltd. (GLJ), independent petroleum consultants, to evaluate its oil and gas reserves. Subsequent to 2003, Suncor received GLJ's evaluation reports of its Oil Sands mining reserves, Firebag in-situ reserves and its conventional NG reserves.

The accuracy of any reserve estimate is a function of the quality and quantity of available data, interpretation and judgment. As commodity prices fluctuate, the quantity of reserves recorded can vary, as the economic recoverability of oil and gas reserves is impacted by price fluctuations.

In reporting its reserves data, Suncor is relying on exemptive relief from Canadian Securities regulators contained in the Mutual Reliance Review System decision document dated December 22, 2003.

Oil Sands Mining Reserves

Proved and probable reserves estimates on Oil Sands mining leases are based on a detailed geological assessment, including drilling density. Estimates also consider production capacity and upgrading yields, mine plans, operating life and regulatory constraints. GLJ's 2003 Oil Sands' mining reserve evaluation report, dated February 20, 2004, included a reclassification of probable reserves to proved reserves reflecting the 2003 drilling program and the use of revised criteria for classifying portions of the ore body.

Suncor reports its Oil Sands mining reserves on a gross basis (that is prior to deductions of royalties). A reconciliation of gross Oil Sands mining reserves for each of the three years ended December 31, 2003, is as follows:

GROSS OIL SANDS MINING RESERVES (1)

Millions of synthetic crude oil barrels	Proved	Probable	Proved + Probable
December 31, 2000	422	2 034	2 456
Revisions of previous estimates	(1)	(5)	(6)
Extensions and discoveries	—	—	—
Production	(45)	—	(45)
Sales of minerals in place	—	—	—
December 31, 2001	376	2 029	2 405
Revisions of previous estimates	54	(511)	(457)
Extensions and discoveries	3	45	48
Production	(75)	—	(75)
Sales of minerals in place	—	—	—
December 31, 2002	358	1 563	1 921
Revisions of previous estimates	599	(611)	(12)
Extensions and discoveries	—	—	—
Production	(79)	—	(79)
Sales of minerals in place	—	—	—
December 31, 2003	**878**	**952**	**1 830**

(1) Gross reserves means Suncor's undivided percentage interest in reserves before deducting Crown royalties, freehold and overriding royalty interests.

Firebag In-situ Reserves

GLJ's Firebag in-situ Oil Sands reserves evaluation report dated February 20, 2004, of Suncor's Firebag in-situ reserves included an approximate 15% increase of proved and probable reserves. All of the reserves at the end of 2003 were categorized as non-producing and reflect a reclassification of a portion of probable reserves to proved status, now that the first stage of operations is capable of producing bitumen. Subsequent to 2003, Suncor began to produce small amounts of bitumen from Firebag.

Suncor reports its Firebag in-situ reserves net of projected royalties. A reconciliation of net Firebag in-situ reserves for each of the three years

ended December 31, 2003 is as follows:

NET FIREBAG IN-SITU RESERVES (1)

Millions of barrels	Proved	Probable (2)	Proved + Probable
December 31, 2000	—	—	—
Revisions of previous estimates	—	—	—
Extensions and discoveries	—	—	—
Production	—	—	—
Sales of minerals in place	—	—	—
December 31, 2001	—	—	—
Revisions of previous estimates	—	—	—
Extensions and discoveries	124	1 410	1 534
Production	—	—	—
Sales of minerals in place	—	—	—
December 31, 2002	124	1 410	1 534
Revisions of previous estimates	224	72	296
Extensions and discoveries	—	—	—
Production	—	—	—
Sales of minerals in place	—	—	—
December 31, 2003	**348**	**1 482**	**1 830**

(1) Net reserves means Suncor's undivided percentage interest in total reserves after deducting Crown royalties, freehold and overriding royalty interests. The calculation of these third party interests is uncertain and based on assumptions about future oil prices, production levels, operating costs and capital expenditures. For a more detailed description of these royalties, see page 23, Oil Sands Crown Royalties and Cash Income Taxes.

(2) Although Suncor is subject to Canadian disclosure rules in connection with the reporting of its reserves, Suncor has received exemptive relief from Canadian securities administrators permitting it to report its proved reserves in accordance with U.S. disclosure practices. In addition, although U.S. companies do not disclose probable reserves for non-mining properties, Suncor voluntarily discloses its probable reserves for its Firebag in-situ leases as it believes this information is useful to investors. As a result, Suncor's Firebag in-situ reserve estimates may not be directly comparable to those made by U.S. companies. See Reliance on Exemptive Relief in Suncor's Annual Information Form/Form 40-F dated February 26, 2004 and incorporated by reference herein.

NG Reserves

GLJ's NG reserve evaluation report dated February 20, 2004, (comprised of both natural gas as well as crude oil and natural gas liquids) resulted in a net natural gas reserve decrease (excluding reductions due to current year production) of 3% for 2003. This reduction includes a decrease of approximately 11% due to technical revisions reflecting lower than expected performance, and additions of approximately 8% due to extensions and discoveries.

Suncor reports its NG proved reserves net of projected royalties and interests of third parties in accordance with U.S. disclosure practices. A reconciliation of Suncor's net NG reserves for each of the three years ended December 31, 2003 is as follows:

NET NATURAL GAS PROVED RESERVES (1)

	Crude Oil and Natural Gas Liquids (millions of barrels)	Natural Gas (billions of cubic feet)
December 31, 2000	11	567
Revisions of previous estimates	—	4
Extensions and discoveries	—	20
Production	(1)	(45)
Sales of minerals in place	—	(1)
December 31, 2001	10	545
Revisions of previous estimates	—	(18)
Extensions and discoveries	1	39
Production	(1)	(48)
Sales of minerals in place	—	(2)
December 31, 2002	10	516
Revisions of previous estimates	(2)	(50)
Extensions and discoveries	1	40
Production	(1)	(50)
Sales of minerals in place	—	—
December 31, 2003	**8**	**456**

(1) Net reserves means Suncor's undivided percentage interest in total reserves after deducting interests of third parties, including Crown royalties, freehold and overriding royalty interests. The calculation of these third party interests is uncertain and based on assumptions about future natural gas prices, production levels, operating costs and capital expenditures.

Employee Future Benefits

The company provides a range of benefits to its employees and retired employees, including pensions and other post-retirement health care and life insurance benefits. The determination of obligations under the company's benefit plans and related expenses requires the use of actuarial valuation methods and assumptions. Assumptions typically used in determining these amounts include, as applicable, rates of employee turnover, future claim costs, discount rates, future salary and benefit levels, return on plan assets, mortality rates and future medical costs. The fair value of plan assets is determined using market values. Actuarial valuations are subject to management judgment. Management continually reviews the assumptions in light of actual experience and expectations for the future. Changes in assumptions are accounted for on a prospective basis. Employee future benefit costs are reported as part of operating, selling and general expenses in the company's consolidated statements of earnings and schedules of segmented earnings. The accrued benefit liability is reported as part of "accrued liabilities and other" in the consolidated balance sheets.

The assumed rate of return on plan assets considers the current level of expected returns on the fixed income portion of the plan assets portfolio, the historical level of risk premium associated with other asset classes in

the portfolio and the expected future returns on each asset class. The discount rate assumption is based on the year-end interest rate on high quality bonds with maturity terms equivalent to the benefit obligations. The rate of compensation increases is based on management's judgment. The accrued benefit obligation and net periodic benefit cost for both pensions and other post-retirement benefits may differ significantly if different assumptions are used, as noted below.

A 1% change in the assumptions at which pension benefits and other post-retirement benefit liabilities could be effectively settled is as noted below.

	Rate of Return on Plan Assets		Discount Rate		Rate of Compensation Increase	
($ millions)	1% Increase	1% Decrease	1% Increase	1% Decrease	1% Increase	1% Decrease
Increase (decrease) to net periodic benefit cost	(3)	3	(8)	10	4	(3)
Increase (decrease) to benefit obligation	—	—	(83)	95	24	(22)

Health care costs comprise a significant element of Suncor's post-employment benefit obligation and an area where there is increasing cost pressure due to an aging North American society. Suncor has assumed a 12% annual rate of increase in the per capita cost of covered health care benefits for 2003, with an assumption that this rate will decrease by 0.5% annually, to 5% by 2017, and remain at that level thereafter.

A 1% change in the assumed health care cost trend rate would have the following effects:

($ millions)	1% Increase	1% Decrease
Increase (decrease) to total of service and interest cost components of net periodic post-retirement health care benefit cost	1	(1)
Increase (decrease) to the health care component of the accumulated post-retirement benefit obligation	12	(10)

Control Environment

Based on their evaluation as of December 31, 2003, Suncor's Chief Executive Officer and Chief Financial Officer concluded that Suncor's disclosure controls and procedures (as defined in Rules 13(a)-15(e) and 15(d)-15(e) under the United States Securities Exchange Act of 1934 (the Exchange Act)) are effective to ensure that information required to be disclosed by Suncor in reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the United States Securities and Exchange Commission (SEC) rules and forms. In addition, other than as described below, as of December 31, 2003, there were no changes in Suncor's internal controls over financial reporting that occurred during 2003 that have materially affected, or are reasonably likely to materially affect its internal controls over financial reporting. Suncor will continue to periodically evaluate its disclosure controls and procedures and internal controls over financial reporting and will make any modifications from time to time as deemed necessary.

The company is in the process of implementing two major programs. Both include the review and design of processes, systems and controls. Suncor is implementing an Enterprise Resource Planning (ERP) system in all of its businesses to support the company's growth plan. The phased implementation is currently planned to be complete by 2006. Implementing an ERP system on a widespread basis involves significant changes in business processes and extensive organizational training. The company currently believes a phased-in approach reduces the risks associated with making these changes. Suncor believes it is taking the necessary steps to monitor and maintain appropriate internal controls during this transition period. These steps include deploying resources to mitigate internal control risks and performing additional verifications and testing to ensure data integrity.

The company is also undertaking a comprehensive review of its existing internal controls over financial reporting, with a view to the upcoming effectiveness

certification and attestation requirements of Section 404 of the United States Sarbanes-Oxley Act of 2002. As a result of these initiatives, the company expects there will be a significant redesign of its business processes during 2004 and 2005, some of which relate to internal controls over financial reporting and disclosure controls and procedures.

The company has identified the need to implement an effective and functioning control environment to support financial reporting and disclosure processes in the R&M business unit. At December 31, 2003, certain of the compensating controls and processes that were initially put in place at the time of the acquisition have been enhanced. Further development of, and enhancements to, control processes and computerized systems are expected to be completed during 2004.

Change In Accounting Policies
During 2003, the company adopted a new accounting policy for stock-based compensation related to common share options. Pursuant to new transitional rules approved by the Canadian Institute of Chartered Accountants (CICA) in 2003, the company now records stock-based compensation expense in the company's consolidated statements of earnings for all common share options granted to employees and non-employee directors on or after January 1, 2003 ("2003 options"), with a corresponding increase recorded as contributed surplus in the consolidated statements of changes in shareholders' equity.

This change in accounting policy increased operating, selling and general expenses and contributed surplus by $7 million for the year ended December 31, 2003.

The CICA transitional rules allowed for either retroactive application, with or without restatement, or the prospective application chosen by the company. If compensation expense had been recorded for pre-2003 options on a retroactive basis, the company would have reported additional compensation costs under the fair value method of $30 million in 2003, $32 million in 2002 and $9 million in 2001.

RECENTLY ISSUED CANADIAN ACCOUNTING STANDARDS

Hedging Relationships
Canadian Accounting Guideline 13 (AcG 13) "Hedging Relationships" is applicable to the company's hedging relationships in 2004 and subsequent fiscal years. AcG 13 specifies the circumstances in which hedge accounting is appropriate, including the identification, documentation, designation and effectiveness of hedges, as well as the discontinuance of hedge accounting. The Guideline does not specify hedge accounting methods. The company believes its hedging documentation and effectiveness testing are prepared in accordance with the provisions of AcG 13.

Asset Retirement Obligations
Effective January 1, 2004, the company will adopt, as required, the new Canadian standard "Asset Retirement Obligations" (ARO), which substantially harmonizes Canadian GAAP with U.S. GAAP in this area. This standard requires recognition of a liability for the future retirement obligations associated with the company's property, plant and equipment. The fair value of the asset retirement obligations is to be recorded on a discounted basis (6.5% in 2004). This amount is capitalized as part of the cost of the related asset and amortized to expense over its useful life. The liability accretes until the company settles the obligation.

On an annual basis at Oil Sands and NG, the most probable costs of reclamation are estimated in as-spent dollars based on current information, the estimated timing of remedial actions, existing regulatory requirements and technology.

The impact of adopting this standard will be an increase to property, plant and equipment of $211 million, an increase to future tax assets of $110 million, an increase to accrued liabilities of $318 million, an increase to future tax liabilities of $73 million, and a decrease to retained earnings of $70 million. The company is required by the standard to restate retroactively the financial statements of prior years.

The adoption of this standard in 2004 is not expected to have a significant effect on after-tax expenses in 2004 compared with 2003. These costs for 2004 will be classified as both DD&A and operating, selling and general expenses. This change in classification will impact Oil Sands cash operating costs per barrel as a portion of these costs will now be allocated to non-cash DD&A.

Variable Interest Entities
In 2003, Canadian Accounting Guideline 15 (AcG 15) "Consolidation of Variable Interest Entities (VIEs)" was issued. Effective January 1, 2005, AcG 15 requires consolidation of a VIE where the company will absorb a majority of a VIEs losses, receive the majority of its returns, or both. Restatement of prior years, although encouraged, is not required. The company plans to prospectively apply AcG15 from adoption on January 1, 2005. The company will be required to consolidate the VIE related to the sale and leaseback of equipment described earlier on page 22. The company does not expect a significant impact on net earnings on consolidation of the equipment VIE. The impact on the balance sheet will be an increase to property, plant and equipment and an increase to long-term liabilities of approximately $20 million. The VIE involving the sale of crude oil inventory terminates June 25, 2004, prior to the effective date of AcG 15. The accounts receivable securitization program, as currently structured, does not meet the AcG 15 criteria for consolidation by Suncor.

Liabilities and Equity
In 2003, the Canadian Accounting Standards Board approved an amendment to Handbook Section 3860 "Financial Instruments – Disclosure and Presentation" requiring certain obligations that must or could be settled with an entity's own equity instruments to be presented as liabilities. The new standard will require financial instruments such as the company's 9.05% and 9.125% Preferred Securities to be classified as long-term debt rather than as equity. On January 15, 2004, the company gave formal notice to the holders of its Preferred Securities that it will redeem the securities on March 15, 2004. Notwithstanding that the Preferred Securities will have been redeemed by the time the new accounting standards become effective in 2005, Suncor will be required to restate its comparative financial statements for 2003 and 2004 to reflect the Preferred Securities as long-term debt rather than as equity. Based on year-end 2003 data, the reclassification is expected to reduce equity by $485 million, increase long-term debt by $486 million and increase deferred charges by $1 million. Preferred security dividends in 2003 of $45 million pretax ($27 million after-tax), reported as a reduction of retained earnings, will be reported as financing expense. Net earnings attributable to common shareholders in 2004 and 2003 are not expected to be materially affected.

Oil Sands

Located near Fort McMurray, Alberta, Suncor's Oil Sands business forms the foundation of Suncor's growth strategy and represents the most significant portion of the company's assets. The business recovers bitumen through mining and in-situ development and upgrades it into refinery feedstock, diesel fuel and byproducts.

Oil Sands strategy focuses on:

- Acquiring long-life mineral leases with substantial bitumen resources in place.
- Sourcing low-cost bitumen supply through mining, in-situ development and third party supply agreements, and upgrading this bitumen supply into high value crude oil products that meet market demand.
- Increasing production capacity and improving reliability through staged expansion of oil sands upgrading facilities.
- Reducing costs through the application of technologies, economies of scale, direct management of growth projects, strategic alliances with key suppliers and continuous improvement of operations.

Highlights

SUMMARY OF RESULTS

Year ended December 31

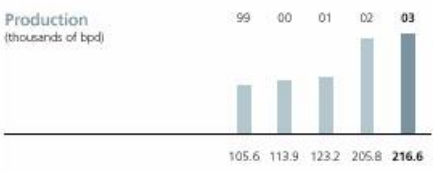
($ millions unless otherwise noted)	2003	2002	2001
Revenue	**3 061**	2 616	1 372
Production (thousands of bpd)	**216.6**	205.8	123.2
Average sales price ($/barrel)	**37.19**	33.65	29.17
Net earnings	**888**	790	283
Cash flow from operations	**1 803**	1 475	486
Total assets	**7 762**	6 896	6 409
Cash used in investing activities	**1 055**	630	1 476
Net cash surplus	**799**	729	(1 025)
ROCE (%) (1)	**20.6**	16.8	20.1
ROCE (%) (2)	**17.3**	15.6	6.4

(1) Excludes capitalized costs related to major projects in progress. ROCE for Suncor's operating segments is calculated in a manner consistent with consolidated ROCE as reconciled in Non-GAAP Financial Measures. See page 50.

(2) Includes capitalized costs related to major projects in progress.

SIGNIFICANT DEVELOPMENTS IN 2003

- Crude oil production increased by 5% to an average 216,600 bpd in 2003 compared with 205,800 bpd in 2002.
- Cash operating costs averaged $11.50 per barrel in 2003 compared with $11.10 per barrel in 2002. Higher natural gas prices more than offset the impact of efficiency initiatives and higher production levels.
- Construction of stage one of Suncor's Firebag in-situ operation was completed on schedule. Steam injection began in the fourth quarter of 2003 and the first bitumen production was delivered to the upgrader for processing early in 2004. Full production capacity of 35,000 bpd of bitumen is expected in 2005.
- A maintenance shutdown was successfully completed on Upgrader #1. During the shutdown, a new fractionator was tied in to the upgrader. Both of these projects are expected to improve production reliability in the upgrader.
- A 10-year processing and sales agreement was signed with Petro-Canada, whereby Suncor will process approximately 27,000 bpd of bitumen for Petro-Canada into approximately 22,000 bpd of sour crude and sell an additional 26,000 bpd of Suncor sour crude. This agreement is slated to commence in 2008 (see page 40).
- Oil Sands announced plans for extension of the Steepbank mine, which would replace ore production that is expected to be depleted prior to the end of the decade.
- In the first quarter of 2004, Suncor negotiated a new three-year contract with its largest union representing approximately 1,500 employees at the Oil Sands operation.



ANALYSIS OF NET EARNINGS

Net earnings in 2003 increased to $888 million from $790 million in 2002. The increase was largely driven by higher benchmark commodity prices and record sales levels. These positive factors were partially offset by a year-over-year tax rate change of $133 million, higher cash expenses, increased project start-up expenses and the impact of a stronger Canadian dollar.



Oil Sands average production increased to 216,600 bpd in 2003, compared with 205,800 bpd in 2002. As expected, production was slightly lower than the 225,000 bpd capacity primarily due to a scheduled 30-day maintenance shutdown of Upgrader #1 in the second quarter. Sales levels for the year averaged 218,300 bpd compared with 205,300 bpd in 2002. Higher sales volumes increased earnings by $128 million.

Sales prices averaged $37.19 per barrel in 2003 (including the impact of pretax hedging losses of $239 million) compared with $33.65 per barrel in 2002 (including the impact of pretax hedging losses of $243 million). The average price realization was impacted by the following positive factors:

- A strengthening of WTI benchmark crude oil prices.
- An improved mix of the more valuable sweet crude oil and diesel fuel, which increased to 63% of total Oil Sands sales from 62% in 2002.
- Lower realized crude oil pricing differentials. During 2002, the challenges in bringing Oil Sands expanded facilities to capacity resulted in some production streams being sold in markets with less favourable pricing.

These positive factors were partially offset by a strengthening of the Canadian dollar against the U.S. dollar particularly in the second half of the year. Because crude oil is sold primarily based on U.S. dollar benchmark prices, the narrowing exchange rate decreased the Canadian dollar value of crude oil products.

The net impact of the above pricing factors increased earnings by $159 million in 2003.

Royalties
Pretax royalty expense in 2003 was $33 million, the same level as 2002. In both 2003 and 2002, Oil Sands was subject to the minimum 1% rate. For a discussion about Alberta Crown royalties, including the expected impact of Crown royalties in future years, see Outlook on page 23.

Cash Expenses
Cash expenses increased to $1.05 billion from $954 million in 2002. Expenses were higher year over year due to the following factors:

- Natural gas costs increased to $169 million in 2003, compared with $119 million in 2002. This was the result of higher natural gas prices, partially offset by a decreased reliance on purchased natural gas. Natural gas purchases decreased due to the use of more internally generated fuel.
- Higher energy costs and higher maintenance costs in the mine and extraction plants as a result of increased production volumes.
- Unplanned maintenance during 2003.

These higher expenses were partially offset by improved productivity from the truck and shovel fleet.

Transportation costs were unchanged. As an initial shipper on a major pipeline, Suncor's tolls are subject to annual adjustments. In 2003, a first-time toll adjustment offset toll increases experienced in 2003. The toll adjustments are currently expected to continue until 2007.

Combined, the above factors resulted in a net increase in cash expenses that reduced earnings by $51 million.

Start-up Expenses
Project start-up costs in 2003 increased by $5 million, after-tax, reflecting the commissioning and start-up of Firebag.

Non-Cash Expenses
Non-cash DD&A expense, including overburden amortization expense increased marginally, to $451 million from $450 million in 2002.

In 2003, Oil Sands average overburden removal stripping ratio was 0.46 cubic metres of overburden for every tonne of ore mined. In 2002, this ratio was 0.47 cubic metres per tonne. While the lower stripping ratio reduced overburden amortization cost in 2003 compared with 2002, there was a net increase in the amortization charge due to higher volumes mined in 2003 and higher removal costs. Overburden amortization was $208 million in 2003 compared with $202 million in 2002.

Stripping ratios are expected to increase until 2006 as proportionately more mining activity is conducted on the company's Millennium mine, which has a higher stripping ratio. From 2006 to 2010 it is expected that all of the mining production will come from the Millennium mine and the overburden amortization cost will increase. (For a discussion of stripping ratios see page 29.)

The impact of the expected higher overburden amortization costs is expected to be partially offset by a higher bitumen ore grade and a lower fines content per tonne mined.

Due to the use of judgment and the extended time frame associated with the company's stripping ratio and bitumen recovery estimates, actual results may differ, and these differences may be material.

Tax Adjustments
The negative tax adjustment in 2003 compared with 2002 of $133 million primarily related to changes in the federal government's taxation policies for the resource sector.

Operating Costs
Effective January 2003, Suncor revised its definition of cash and total operating costs to report only those costs directly related to producing a barrel of oil including natural gas and imported bitumen costs.

Under the new definition, cash operating costs increased to $911 million in 2003 compared with $835 million a year earlier primarily as a result of higher natural gas costs. Cash operating costs rose in 2003 to $11.50 per barrel from $11.10 per barrel in 2002.

Natural gas purchases decreased to 71 million cubic feet per day (mmcf/d) in 2003 from 79 mmcf/d in 2002, but Oil Sands costs rose to $6.95 per mcf in 2003 from $4.19 per mcf in 2002. This equates to a $0.90 per barrel increase in cash costs.

Non-cash costs per barrel decreased to $5.70 in 2003 from $6.00 in 2002 due to increased production volumes.

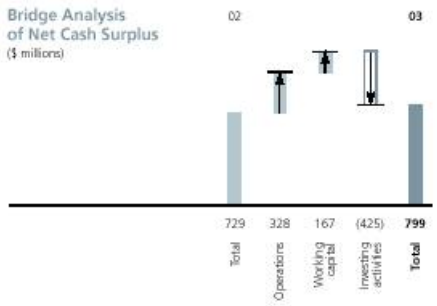
NET CASH SURPLUS ANALYSIS

Cash flow from operations increased to $1.8 billion during the year from $1.5 billion in 2002. The increase was due to the same factors that increased net earnings as well as payments made in 2002 under the employee long-term incentive plan, partially offset by increased cash overburden removal charges and increased reclamation spending in 2003.

Working capital decreased by $51 million in 2003 compared with an increase of $116 million in 2002. The net year-over-year reduction of $167 million is primarily due to the larger accounts receivable balance in 2002, as a result of record sales and comparatively higher price realizations at the end of 2002 compared with 2003.

Investing activities increased to slightly more than $1 billion in 2003 from $630 million in 2002. The increase was due to higher capital expenditures associated with Firebag and related upgrader expansions and improvements. Investing activities in 2003 also increased due to $97 million in higher costs resulting from the 30-day planned maintenance shutdown and $91 million to buy out leased mining equipment.

Combined, the above factors resulted in a net cash surplus of $799 million in 2003, compared with a surplus of $729 million in 2002.



OUTLOOK

Suncor's Oil Sands operations continue to be the focus of the company's business strategy. Independent evaluations currently place total Oil Sands mining and in-situ recoverable bitumen reserves and resources(1) at 12 billion barrels, including proved and probable in-situ and mining bitumen. This is equivalent to approximately 10 billion barrels of synthetic crude oil based on current processing yields.

Suncor's future plans for Oil Sands remain focused on activities and investments expected to increase production, decrease operating costs and improve environment, health and safety performance.

Production Growth Plans

In 2004, Oil Sands production is expected to average 225,000 to 230,000 bpd from existing upgrading assets. The addition of a vacuum unit to Upgrader #2 and bitumen feed from Firebag stage one is planned to increase production capacity to 260,000 bpd by 2005. Both components of this expansion project are proceeding on schedule and costs are expected to approximate the budget estimate of $1 billion.

As part of its Voyageur growth strategy to increase production to 500,000 to 550,000 bpd in 2010 to 2012, Suncor announced plans to further boost production capacity to 330,000 bpd by late 2007. This increase to 330,000 bpd is expected to cost an estimated $3 billion including approximately $1.5 billion for expansions to Upgrader #2 and $1.5 billion for development of additional Firebag in-situ stages, mining and extraction. As these cost estimates are based on preliminary engineering, actual amounts will differ and the differences may be material.

The upgrading component of this project includes construction of a pair of coke drums, a sulphur recovery plant and other crude oil processing equipment. Plans have been submitted to regulators and were approved in the first quarter of 2004. Subject to Board of Directors approval, construction is scheduled to begin in late 2004.

Cost estimates for future stages of the Voyageur growth strategy, including potential construction and expansion of a third upgrading train, will be provided once preliminary engineering is completed. Ultimate development of these future stages requires approval of regulators and Suncor's Board of Directors.

PRODUCTION PLAN

Description	Regulatory Approval	Board of Directors Approval	Cost Estimate(2) ($ billions)	Production Capacity (bpd)	Status
Firebag in-situ – stage one and upgrader vacuum unit	Yes	Yes	$ 1	260,000 in 2005	Firebag stage 1 construction complete. Vacuum unit under construction. Project is on schedule and on budget.
Additional Firebag in-situ stages and upgrader coker unit expansion	Yes	Firebag stage 2 approved. Additional stages and coker unit subject to approval.	$ 3	330,000 in late 2007	Firebag stage 2 construction under way.
Potential third upgrader – asset configuration still tobedetermined	No	No	Not available	500,000 to 550,000 in 2010 to 2012	

(1) Resource volumes include quantities of oil and gas that are estimated, on a given date, to be potentially recoverable from known accumulations, but lack specific criteria to be classified as reserves. The criteria for not classifying these volumes as reserves include items such as insufficient drilling density and lack of near term development plans. U.S. companies are prohibited from disclosing estimates of probable reserves and resources for non-mining properties in filings with the United States Securities and Exchange Commission. As a result, Suncor's aggregate reserve and resource estimates may not be comparable to those made by U.S. companies.

(2) These cost estimates are based on preliminary engineering. Actual amounts will differ and the differences may be material.

Mine Extension

Suncor announced an Environmental Impact Assessment on a proposed extension of its oil sands mining operations in January 2004. The proposed development, an extension of Suncor's Steepbank mine, would replace ore production that is expected to be depleted prior to the end of the decade. Suncor is seeking regulatory approval by the end of 2006 with construction planned to commence in 2007. The mine is expected to be fully operational in 2010. Currently, capital development costs are estimated at $350 million. As these cost estimates are preliminary, actual amounts will differ and the differences may be material. Final approval from Suncor's Board of Directors is also required before construction can proceed.

Third Party Bitumen

Incremental bitumen to feed the planned upgrader expansion is also expected to be provided under a processing agreement between Suncor and Petro-Canada, slated to take effect in 2008. Under the agreement, Suncor will process at least 27,000 bpd of Petro-Canada bitumen on a fee-for-service basis. Petro-Canada will retain ownership of the bitumen and resulting sour crude oil production of about 22,000 bpd. In addition,

Suncor will sell an additional 26,000 bpd of Suncor proprietary sour crude oil production to Petro-Canada. Both the processing and sales components of the agreement will be for a minimum 10-year term.

Operating Costs
Suncor will continue to focus on reducing operating costs and is targeting a cash operating cost of $10.75 to $11.75 per barrel in 2004 (excluding project start-up costs). Oil Sands production targets do not reflect bitumen production from Firebag. Start-up of in-situ operations will occur throughout 2004 with full production expected in 2005. It is not possible to accurately predict production during the start-up period.

The cash operating cost outlook assumes a price of US$5.50 per mcf of natural gas at Henry Hub. Continued high natural gas prices will pose a significant challenge to achieving the 2004 operating cost target. A change of US$1.00 per mcf in the Henry Hub price of natural gas would result in a change of approximately Cdn$0.50 per barrel to cash operating costs.

RISK/SUCCESS FACTORS AFFECTING PERFORMANCE

Certain issues Suncor must manage that may affect performance include, but are not limited to, the following:

- Suncor's ability to finance Oil Sands growth in a volatile commodity pricing environment. Also refer to Suncor Overview, Liquidity and Capital Resources on page 20.
- The ability to complete future projects both on time and on budget. This could be impacted by competition from other projects (including other oil sands projects) for skilled people, increased demands on the Fort McMurray infrastructure (housing, roads, schools, etc.), or higher prices for the products and services required to operate and maintain the operations. Suncor continues to address these issues through a comprehensive recruitment and retention strategy, working with the community to determine infrastructure needs, designing Oil Sands expansion to reduce unit costs, seeking strategic alliances with service providers and maintaining a strong focus on engineering, procurement and project management.
- Potential changes in the demand for refinery feedstock and diesel fuel. Suncor believes it can reduce the impact of this issue by entering into long-term supply agreements with major customers, expanding its customer base and offering a variety of blends of refinery feedstock to meet customer specifications.
- Volatility in crude oil and natural gas prices and exchange factors and the light/heavy and sweet/sour crude oil differentials. Prices and differentials are difficult to predict and impossible to control.
- Unplanned production or operational outages and slowdowns. Outages can impact both production levels and costs.
- Suncor's relationship with its trade unions. Work disruptions have the potential to adversely affect Oil Sands operations and growth projects.

These factors and estimates are subject to certain risks, assumptions and uncertainties discussed on page 51 under Forward-looking Statements. Also refer to Suncor Overview, Risk/Success Factors Affecting Performance on page 24.

Natural Gas

Suncor's NG business primarily produces conventional natural gas in Western Canada. NG's production provides a price hedge that affords the company a degree of protection from volatile market prices of natural gas purchased for internal consumption.

NG's strategy is focused on:

- Building competitive operating areas.
- Improving base business efficiency.
- Creating new, low-capital business opportunities.

NG's long-term goals are to achieve a sustainable ROCE of 12% at mid-cycle prices (US$3.50 to US$4.00/mcf) and to ensure natural gas production keeps pace with company-wide natural gas purchases.

Highlights

SUMMARY OF RESULTS

Year ended December 31

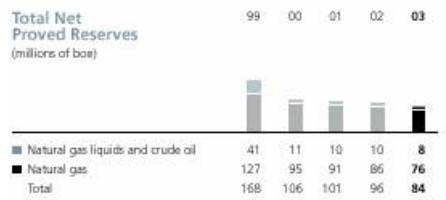
($ millions unless otherwise noted)	**2003**	**2002**	**2001**
Revenue	**512**	339	481
Production (thousands of barrels of oil equivalent per day (boe/d))	**34.9**	33.7	33.4
Natural gas (mmcf/day)	**187**	179	177
Natural gas liquids (thousands bpd)	**2.3**	2.4	2.4
Crude oil (thousands bpd)	**1.4**	1.5	1.5
Average sales price			

Natural gas ($/mcf)	**6.42**	3.91	6.09
Natural gas liquids ($/barrel)	**36.08**	29.35	34.38
Crude oil ($/barrel)	**40.29**	31.72	33.92
Net earnings before tax adjustments	**85**	33	97
Tax adjustments	**44**	2	20
Net earnings	**129**	35	117
Cash flow from operations	**300**	164	280
Total assets	**784**	765	722
Cash used in investing activities	**166**	158	113
Net cash surplus	**143**	28	211
ROCE (%) (1)	**29.2**	9.2	32.1

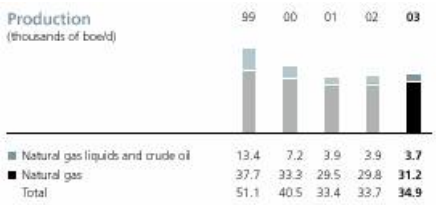
(1) ROCE for Suncor operating segments is calculated in a manner consistent with consolidated ROCE as reconciled in Non-GAAP Financial Measures. See page 50.

SIGNIFICANT DEVELOPMENTS DURING 2003

- Higher commodity prices and the impact of favourable tax adjustments drove strong financial results.
- Production increased 4% to 187 mmcf/d in 2003 compared with 179 mmcf/d in 2002. Favourable drilling results in the Foothills operating area were a major factor in delivering volume additions.
- Divestment of non-core assets yielded proceeds of $12 million ($7 million after tax).



NG activities have continued to be directed towards developing properties.



NG production increased 4% in 2003.

Offsetting increasing internal natural gas consumption continues to be a key long-term strategy in NG. In 2003, Suncor produced 187 mmcf/d of natural gas. With the acquisition of the Denver refinery, natural gas purchases in the fourth quarter of 2003 were approximately 120 mmcf/d. Oil Sands consumed an additional 40 mmcf/d of non-purchased gas received, as available, under an existing third party agreement in exchange for coker gases produced as a byproduct of upgrading operations.

Analysis of Net Earnings

NG's net earnings increased to $129 million in 2003 from $35 million in 2002 due to the favourable impact of commodity prices and decreased non-cash income tax expense, combined with increased production volumes and increased divestment gains. These factors were partially offset by higher royalty expenses, increased exploration expenses due to dry hole costs, higher DD&A and operating costs.

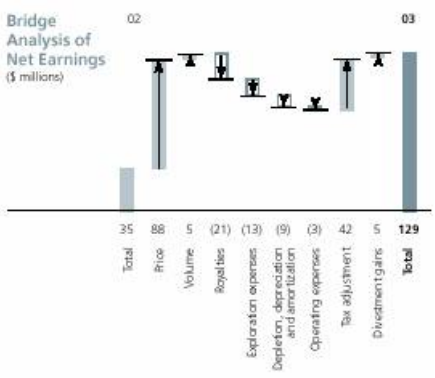
NG's average natural gas production increased to 187 mmcf/d in 2003 from 179 mmcf/d in 2002. Including liquids, total production in 2003 was 34,900 boe/d compared with 33,700 boe/d in 2002. Volume additions were partially offset by natural reservoir declines in existing wells. The higher volumes increased earnings by $5 million in 2003.

In 2003, NG's average realized price for natural gas was $6.42 per mcf, 64% higher than the average $3.91 per mcf realized in 2002. The higher WTI benchmark crude oil price in 2003 resulted in higher price realizations for NG's crude oil and natural gas liquids production.

The combined impact of the above pricing factors increased earnings in 2003 by $88 million compared with 2002.



The 2003 industry average reference price is an estimate.



Expenses

Royalties on NG production increased to $106 million ($8.32 per boe) in 2003, up from $65 million ($5.27 per boe) in 2002. The higher royalties reflect higher average commodity prices and increased production, which reduced after-tax earnings by $21 million.

Exploration expenses increased to $40 million in 2003 compared with $17 million in 2002, which reduced after-tax earnings by $13 million. The increase was due to higher dry hole costs and seismic expenditures. DD&A expenses increased to $91 million in 2003 from $75 million in 2002. The increase of $9 million after-tax was due to a higher depletable cost base and higher production, along with increased amortization of unproved coal bed methane lands. Suncor plans to continue to acquire land and explore for coal bed methane in the United States.

Operating costs increased to $77 million from $69 million in 2002 due primarily to higher electricity and site reclamation costs. The increase reduced earnings by $3 million after-tax.

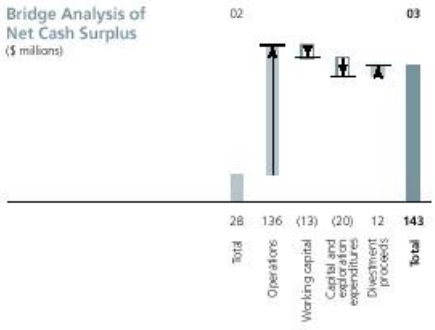
The positive tax adjustment in 2003 compared to 2002 of $42 million primarily related to changes in the federal government's taxation policies for the resource sector.



Lifting costs increased in 2003 due to increased electricity costs and employee benefit costs.

NET CASH SURPLUS ANALYSIS

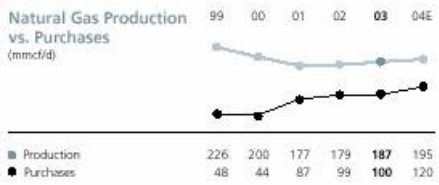
NG's net cash surplus was $143 million in 2003 compared with $28 million in 2002. Cash flow from operations increased to $300 million compared with $164 million a year earlier, largely due to higher commodity prices, partially offset by higher royalties. Working capital changed by $9 million in 2003 compared with a change of $22 million in 2002, due primarily to a reduction in accounts payable of $13 million. Cash used in investing activities increased to $166 million compared with $158 million in 2002 as a result of higher capital and exploration costs partially offset by divestment proceeds of $12 million from the sale of Mackenzie Delta non-core assets. There was no production, nor did Suncor have exploration or development plans for these assets.



OUTLOOK

NG's long-term financial goal is to achieve a sustainable ROCE of 12% at mid-cycle natural gas prices (US$3.50 to US$4.00/mcf). To meet this goal, management plans to continue improving base business efficiency, with a focus on reducing operating costs and capturing benefits from strategic partnerships and supply chain management.

At the same time, NG continues to work towards an operational target of increasing production by 3% to 5% per year to keep pace with the company's growing internal natural gas demands. In 2004, with continued development of the Firebag in-situ oil sands operation and full-year demands from the R&M refinery, Suncor's purchased consumption of gas is expected to be approximately 120 mmcf/d.



To support these goals, the company has budgeted $195 million in capital spending for exploration and development in 2004. NG's production goal for 2004 is 190 to 195 mmcf/d of natural gas production and approximately 3,300 bpd of crude oil and natural gas liquids.

NG will continue to leverage its expertise and existing assets to bring reserves into production in Western Canada. However, increasing production will likely require expansion through farm-ins,(1) joint-ventures or property acquisitions, which could expand the size and number of operating areas.

RISK/SUCCESS FACTORS AFFECTING PERFORMANCE

Certain issues Suncor must manage that may affect performance of the NG business include, but are not limited to, the following:

- Consistently and competitively finding and developing reserves that can be brought on stream economically. Positive or negative reserve revisions arising from technical and economic factors can have a corresponding positive or negative impact on asset valuation and depletion rates.
- The impact of market demand for land and services on capital and operating costs. Market demand and the availability of opportunities also influences the cost of acquisitions and the willingness of competitors to allow farm-ins on prospects.
- Risks and uncertainties associated with obtaining regulatory approval for exploration and development activities. These risks could add to costs or cause delays to projects.

These factors and estimates are subject to certain risks, assumptions and uncertainties discussed on page 51 under Forward-looking Statements. Refer to the Suncor Overview, Risk/Success Factors Affecting Performance on page 24.

(1) Acquisitions of all or part of the operating rights from the working interest owner. The acquirer assumes all or some of the burden of development in return for an interest in the property. The assignor usually retains an overriding royalty but may retain any type of interest.

Energy Marketing and Refining – Canada

Energy Marketing and Refining – Canada (EM&R) operates a 70,000 bpd (approximately 11,100 cubic metres per day) capacity refinery in Sarnia, Ontario, and markets refined products to industrial, wholesale and commercial customers primarily in Ontario and Quebec. Through its Sunoco-branded and joint venture operated service networks, the business markets products to retail customers in Ontario. The business also encompasses third party energy marketing activities and energy trading activities as well as providing marketing services for the sale of crude oil and natural gas on behalf of the Oil Sands and NG operations.

EM&R's strategy is focused on:

- Enhancing the profitability of refining operations by improving reliability and product yields and enhancing operational flexibility to process a variety of feedstock.
- Increasing the profitability and efficiency of retail networks by improving average site throughput and growing non-fuel ancillary retail revenue.
- Creating downstream market opportunities to capture greater long-term value from Oil Sands production.

As a marketing channel for Suncor's refined products, EM&R's Ontario retail networks generated approximately 58% of EM&R's total 2003 sales volumes of 94,400 bpd. EM&R's retail networks comprise 279 Sunoco-branded retail service stations, 18 Sunoco-branded Fleet Fuel Cardlock sites, and two 50% retail joint venture(1) businesses that operate 147 Pioneer-branded retail service stations, 53 UPI-branded retail service stations and 14 UPI bulk distribution facilities for rural and farm fuels. Wholesale and industrial sales were responsible for approximately 37% of

EM&R's refined product sales in 2003. Sun Petrochemicals Company (SPC), a 50% joint venture between a Suncor subsidiary and a Toledo, Ohio based refiner, generated the remaining 5% of sales.

Highlights

SUMMARY OF RESULTS

Year ended December 31

($ millions unless otherwise noted)	2003	2002	2001
Revenue	**2 671**	2 508	2 673
Refined product sales (millions of litres)			
Sunoco retail gasoline	**1 599**	1 642	1 575
Total	**5 477**	5 286	5 419
Net earnings (loss) breakdown:			
Rack Back	**48**	10	47
Rack Forward	**19**	16	23
Energy marketing and trading activities	**(2)**	3	—
Gain on sale of retail natural gas marketing business	**—**	35	—
Tax adjustments	**(12)**	—	10
Total net earnings	**53**	64	80
Cash flow from operations	**164**	112	165
Cash used in investing activities	**135**	34	71
Net cash surplus	**29**	63	111
ROCE (%) (1)	**10.2**	12.5	18.4

(1) ROCE for Suncor operating segments is calculated in a manner consistent with consolidated ROCE as reconciled in Non-GAAP Financial Measures. See page 50.

SIGNIFICANT DEVELOPMENTS DURING 2003

- In October 2003, Suncor and Shell Canada Products entered into a long-term agreement under which EM&R's Sarnia refinery will process high sulphur diesel from Shell's Sarnia refinery into low sulphur diesel to meet federal regulations that take effect in 2006. The agreement with Shell is expected to result in cost efficiencies for both parties.

- In 2003, 53 Sunoco convenience stores were renovated to enhance their appearance and align with new Sunoco sites. Merchandise sales in these locations increased 13% within six months of completion of the renovations.

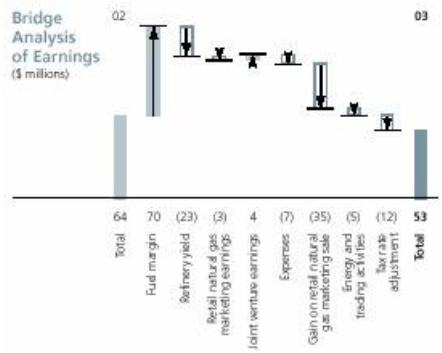
- EM&R's refined product market share in its primary market of Ontario increased to 19% in 2003, compared to 17% in 2002. Approximately 93% of EM&R's refined products were sold to the Ontario market in 2003.

(1) Pioneer Group Inc. is an independent company with which Suncor has a 50% joint venture partnership. UPI Inc. is a 50% joint venture company with GROWMARK Inc., a Midwest U.S. retail farm supply and grain marketing cooperative.

ANALYSIS OF NET EARNINGS

EM&R's net earnings decreased to $53 million in 2003 from $64 million in 2002. Net earnings in 2002 included a $35 million after-tax gain on the sale of EM&R's retail natural gas marketing business. Excluding the gain, net earnings increased by $24 million, or 83%, from 2002. This increase was primarily due to higher refining margins in 2003.

EM&R reports results based on an internal organizational structure. The Rack Back division includes Ontario refining operations, as well as sales and distribution to the Sarnia refinery's largest industrial and reseller customers and the SPC joint venture. Rack Forward includes retail operations, cardlock and industrial/commercial sales, as well as the UPI and Pioneer joint ventures. EM&R results also include the impact of Suncor's third party energy marketing and energy trading activities, that are reported separately in this analysis.



RACK BACK: REFINING AND INDUSTRIAL CUSTOMER DIVISION

Rack Back recorded improved net earnings of $48 million in 2003 compared with $10 million in 2002. The increase was due primarily to higher refining margins, partially offset by higher refinery expenses.

Refining margins averaged 6.5 cpl during 2003, up 35% from 4.8 cpl in 2002. The margin increase was largely a result of strong refined product demand and increased net earnings by $67 million. Increases in jet fuel, diesel fuel, petrochemical and heavy fuel oil sales volumes were partially offset by decreases in gasoline sales volumes.

Refinery utilization averaged 95% in 2003, unchanged from 2002. Utilization was less than capacity in 2003 primarily due to impacts of a widespread power outage that struck the northeastern United States and southern Ontario in August. Utilization was also affected by a planned 32-day maintenance shutdown on a portion of the refinery completed in the fourth quarter of 2003. Utilization capacity in 2002 was affected by a planned 34-day maintenance shutdown on a portion of the refinery's operations, and a number of smaller, unplanned outages.

The favourable impact of improved margins and higher volumes was partially offset by higher product purchase costs associated with meeting customer needs during the power outage noted above. These factors, including the impact of higher commodity prices in 2003 compared with 2002, reduced earnings by $23 million.

Expenses for the Rack Back division increased by $11 million in 2003 compared with 2002 resulting in a $7 million reduction in net earnings. The increase reflects higher natural gas costs, employee future benefits expense, and unplanned refinery maintenance expenses primarily as a result of the power outage. The early settlement of certain natural gas contracts, prompted by an unfavourable change in the credit rating of a counterparty, resulted in an expense reduction of $12 million. These contracts were replaced at current market prices for the supply of natural gas in 2004.

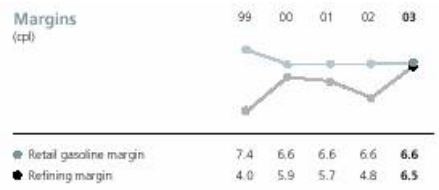
Net earnings from the SPC joint venture increased by $2 million due to a combination of inventory draws and lower freight expenses.

RACK FORWARD: RETAIL AND COMMERCIAL CUSTOMER DIVISION

Rack Forward net earnings in 2003 decreased to $19 million from $51 million in 2002. Net earnings in 2002 included a $35 million after-tax gain on the sale of EM&R's retail natural gas marketing business. Earnings excluding the retail natural gas sale increased $3 million year over year primarily due to higher diesel fuel, commercial and reseller gasoline margins, which increased earnings by $3 million, and higher UPI and Pioneer joint venture earnings of $2 million. This was partially offset by the absence of earnings in 2003 from the retail natural gas business, which had earnings of $3 million in 2002.

Average Sunoco-branded service station site throughput was 5.9 million litres per site in 2003 compared to 5.8 million litres per site in 2002. Site throughput is an important indicator of network efficiency. Total gasoline sales volumes in the Sunoco-branded retail network decreased to 1,599 million litres from 1,642 million litres in 2002. This volume decrease was attributed to local economic factors in the Ontario market, as well as site divestments and construction downtime related to network development. Sunoco-branded retail gasoline margins averaged 6.6 cpl, equal to the prior year.

EM&R's Ontario retail gasoline market share, including all Sunoco and joint venture operated retail sites, was 19% compared to 20% in 2002.



RELATED PARTY TRANSACTIONS

In accordance with GAAP, the Pioneer, UPI and SPC joint ventures are considered to be related parties to Suncor. EM&R supplies refined petroleum products to the Pioneer and UPI joint ventures. In addition, EM&R supplies petrochemical products to SPC. Suncor has a separate supply agreement with each of Pioneer, UPI and SPC. These supply agreements are evergreen, subject to termination only in accordance with the various agreements between the parties.

The following table summarizes the company's related party transactions with Pioneer, UPI and SPC, after eliminations, for the year. These transactions are in the normal course of operations and have been conducted on the same terms as would apply with unrelated parties.

($ millions)	2003	2002	2001
Operating revenues			
Sales to Energy Marketing and Refining – Canada segment joint ventures:			
Refined products	**301**	321	300
Petrochemicals	**187**	142	131

At December 31, 2003, amounts due from EM&R joint ventures were $36 million (2002 – $30 million).

ENERGY MARKETING AND TRADING ACTIVITIES

Third party energy marketing and energy trading activities, comprising both third party crude oil marketing, as well as financial and physical derivatives trading activities, resulted in a net loss of $2 million in 2003 compared to net earnings of $3 million in 2002. After-tax losses in energy trading activities during 2003 more than offset after-tax earnings from marketing activities. As energy trading activities commenced in late 2002, they did not have a significant impact on 2002's financial results.

Energy trading activities by their nature can result in volatile and large fluctuations in earnings, both positive and negative. Prior to commencing the energy trading activities, a separate risk management function was set up to review and monitor practices and policies and provide independent verification and valuation of these activities.

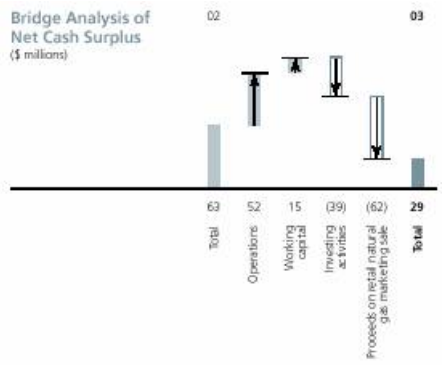
TAX ADJUSTMENTS

EM&R 2003 net earnings included a $12 million future income tax charge, due to the repeal of previously announced reductions in income tax rates by the Ontario provincial government.

NET CASH SURPLUS ANALYSIS

EM&R's net cash surplus decreased to $29 million in 2003 from $63 million in 2002. Cash flow from operations increased to $164 million in 2003 from $112 million in 2002. Working capital was unchanged in 2003, compared to an increase of $15 million in 2002, resulting in a year-over-year working capital improvement of $15 million.

The favourable impacts of the increased cash flow from operations and working capital were more than offset by an increase in cash used in investing activities, which increased to $135 million compared to $34 million in 2002. The increase primarily reflects capital expenditures associated with gasoline and diesel desulphurization projects at the Sarnia refinery, and the impact in 2002 of $62 million in proceeds received from the sale of the retail natural gas marketing business.



OUTLOOK

In October 2003, Suncor and Shell Canada Products entered into an agreement under which EM&R's Sarnia refinery will process high sulphur diesel from Shell's Sarnia refinery into low sulphur diesel, on a fee-for-service basis. The 20-year agreement is expected to enable both companies to meet federal regulations for on-road ultra low sulphur diesel fuel that take effect June 1, 2006. Operating a single hydrotreating unit, instead of two separate units, is expected to result in cost synergies to Suncor and Shell and environmental benefits for the Sarnia-Lambton community as one larger unit is expected to consume comparatively less energy and have lower greenhouse gas emissions. Engineering and construction details of the new facilities are in development. Construction of the facility is still subject to regulatory approval.

The project is expected to be completed in early 2006. Currently estimated to cost $300 million, the project is subject to change as detailed engineering is completed. In Suncor's 2002 Annual Report, the company originally estimated it would cost $225 million to meet diesel desulphurization regulations. The estimate increased after Suncor reached an agreement with Shell and the project scope was expanded to accommodate the higher capacity.

In combination with the diesel desulphurization project, Suncor is currently assessing plans to modify the Sarnia refinery to permit the processing of additional Oil Sands crude oil. These modifications, as currently envisioned, are expected to increase refinery production capacity by about 10%, and make the refinery more competitive through lower feedstock costs over the long term. This cost estimate is based on preliminary scope and engineering, actual amounts may differ and the difference may be material.

Suncor is continuing to review the feasibility of a proposed ethanol plant in the Sarnia region. The proposed plant would produce approximately 200 million litres of ethanol annually for blending in Suncor's Sunoco-branded fuels and fuels sold through its joint venture operated networks. The cost of constructing the facility is currently estimated to be $120 million. In February 2004, Suncor announced its proposal for funding was approved by the federal government's Ethanol Expansion Program. Subject to final approvals, Suncor will receive a $22 million contribution towards the construction of an ethanol production facility. There are certain performance requirements that will determine if any of these funds need to be repaid.

Cost estimates are, by their nature, uncertain and can be subject to wide variances as engineering is developed and as construction progresses. Estimates are subject to revisions, which may be material.

RISK/SUCCESS FACTORS AFFECTING PERFORMANCE

Certain issues Suncor must manage that may affect performance of the EM&R business include, but are not limited to, the following:

- Management expects that fluctuations in demand for refined products, margin and price volatility, and market competition, including potential new market entrants, will continue to impact the business environment.

- There are certain risks associated with the execution of capital projects, including the risk of cost overruns. The diesel desulphurization project must be completed prior to June 1, 2006, to ensure compliance with the legislative requirements. Numerous risks and uncertainties can affect construction schedules, including the availability of labour and other impacts of competing projects drawing on the same resources during the same time period.

- Environment Canada is expected to finalize regulations reducing sulphur in off-road diesel fuel and light fuel oil to take effect later in the decade. Suncor believes that if the regulations are finalized as currently proposed, the new facilities for reducing sulphur in on-road diesel fuel should also allow the company to meet the requirements for reducing sulphur in off-road diesel and light fuel oil.

For a discussion of other risks, assumptions and uncertainties, refer to Suncor Overview, Risk/Success Factors Affecting Performance on page 24.

Refining and Marketing – U.S.A.

In August 2003, Suncor acquired its first U.S. refining and marketing business. This acquisition is part of an integration strategy aimed at improving access to the North American energy markets through acquisitions, long-term contracts and possible joint ventures.

R&M's strategy is focused on:

- Enhancing the profitability of refining operations by improving reliability, product yields and operational flexibility to process a variety of feedstocks, including crude oil streams from Oil Sands operations.

- Creating additional downstream integration opportunities in the United States to capture greater long-term value from Oil Sands production.

Highlights

SUMMARY OF RESULTS

Five-month period ended December 31

(Cdn$ millions unless otherwise noted)	2003
Revenue	**515**
Refined product sales (millions of litres)	
Gasoline	**636**
Total	**1 384**
Net earnings	**18**
Cash flow from operations	**34**
Investing activities	**300**
Net cash surplus (deficiency)	**(220)**

Assets include:

- A 60,000 bpd (approximately 9,500 cubic metres per day) capacity refinery located in the Denver, Colorado area.

- A 100% interest in the 480-kilometre Rocky Mountain pipeline system.

- A 65% interest in the 140-kilometre Centennial pipeline system.

- 43 Phillips 66-branded retail stations, primarily in the Denver, Colorado area.

ANALYSIS OF NET EARNINGS

Net earnings for the period from August 1, 2003, through December 31, 2003, were $18 million, including after-tax transition and start-up costs of approximately $4 million. Net earnings reflect average refining margins of 5.9 cpl, retail margins of 5.6 cpl and a refinery utilization rate of 98%. Net earnings in 2003 reflect the five-month period since the acquisition and are not necessarily indicative of the expected results of operations for a full year. The profitability of R&M is expected to vary throughout the year due to the seasonal nature of vehicle fuel and asphalt sales and the logistics of moving product into and out of Colorado. As a result, summer months are typically expected to be more profitable than winter months.

EXPENSES

Expenses of $484 million for 2003 were primarily driven by crude oil purchases of $342 million. The refinery relies on a mixture of heavy high sulphur and light low sulphur crude oil feedstocks from both Canadian and U.S. sources. Currently, only a small portion of R&M's crude slate comes from Suncor's Oil Sands operation. Other expenses included excise taxes, DD&A and selling, general and administrative costs.

NET CASH DEFICIENCY ANALYSIS

Cash flow from operations was $34 million, reflecting earnings generated in five months of operation, which are not necessarily indicative of the cash flow from operations to be expected for a full year. Working capital was $46 million reflecting R&M's net liabilities balance at year-end, driven primarily by accrued liabilities for crude oil purchases and other accounts payable, partially offset by accounts receivable and inventory balances. Future working capital requirements will be assessed as R&M's business strategy is more fully developed.

Cash used in investing activities was $300 million, primarily relating to costs associated with the acquisition of the business. This total includes $28 million of

expenditures reflecting transitional infrastructure costs and sustaining capital outlays, including expenditures related to meeting legislated limits for sulphur content in gasoline and diesel fuels.

Combined, the above factors resulted in a net cash deficiency of $220 million.

OUTLOOK

Based on preliminary engineering, R&M estimates it will spend approximately $250 million to $325 million (US$175 million to US$225 million) between 2003 and 2006 to meet fuels desulphurization legislation and to enable the refinery to integrate about 20,000 bpd of Oil Sands crude oil blends, with up to 15,000 bpd of Oil Sands sour crude. This cost estimate is based on preliminary scope and engineering. Actual amounts will differ and the differences may be material.

Suncor is currently assessing its plans for potential additional refinery modifications post-2006 in order to have the potential to integrate up to an additional 30,000 bpd of Oil Sands crude oil, including additional barrels of Oil Sands sour crude oil. Cost estimates for this project are not yet available.

In early March 2004, scheduled maintenance is planned for pipeline and refinery equipment. During this estimated 10-day maintenance period there will be minimal production. Customer requirements are expected to be met from inventory and third party purchases and exchanges.

R&M expects to spend an additional $35 million to $45 million (US$25 million to US$30 million) by 2006 to meet existing obligations between the refinery and the United States Environmental Protection Agency and the State of Colorado. The expenditures, intended to improve environmental performance, are currently expected to be primarily capital.

With the R&M acquisition, Suncor assumed a work force of approximately 585 employees, including about 300 retail employees. Suncor also assumed the existing contract with the local Paper, Allied-Industrial Chemical and Energy Workers International Union, which applies to hourly wage employees at the refinery. This four-year contract will expire in January 2006.

As part of its transition to operations in Colorado, Suncor has initiated a strategic marketing review to develop an integrated marketing plan for R&M. This work is expected to be completed in 2004.

RISK/SUCCESS FACTORS AFFECTING PERFORMANCE

Certain issues Suncor must manage that may affect performance of the R&M business include, but are not limited to, the following:

- Management expects continuing fluctuations in demand for refined products, margin and price volatility and market competitiveness, including potential new market entrants, will continue to impact the business.

- There are certain risks associated with the execution of the fuels desulphurization project, including ensuring construction and commissioning is completed in time to comply with the June 1, 2006 legislative requirements. Numerous risks and uncertainties can affect construction schedules, including the availability of labour and other impacts of competing projects drawing on the same resources during the same time period. As well, Suncor's U.S. capital projects are expected to be partially funded from Canadian operations. A weaker Canadian dollar would result in a higher funding requirement for U.S. capital programs.

For a discussion of other risks, assumptions and uncertainties, refer to Suncor Overview, Risk/Success Factors Affecting Performance on page 24.

Non-GAAP Financial Measures

Certain financial measures referred to in this MD&A are not prescribed by GAAP. These non-GAAP financial measures do not have any standardized meaning and therefore are unlikely to be comparable to similar measures presented by other companies. Suncor includes cash flow from operations (dollars and per share amounts), ROCE, and operating costs per barrel data because investors may use this information to analyze operating performance, leverage and liquidity. The additional information should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP.

CASH FLOW FROM OPERATIONS PER COMMON SHARE

Cash flow from operations is expressed before changes in non-cash working capital. A reconciliation of net earnings to cash flow from operations

is provided in the schedules of segmented data, which are an integral part of Suncor's consolidated financial statements.

For the year ended December 31		2003	2002	2001
Cash flow from operations ($ millions)	A	**2 081**	1 440	831
Dividends paid on Preferred Securities ($ millions, pretax)	B	**45**	48	48
Weighted average number of common shares outstanding (millions of shares)	C	**449.8**	447.8	445.0
Cash flow from operations (per share)	A/C	**4.63**	3.22	1.87
Dividends paid on Preferred Securities (pretax, per share)	B/C	**0.10**	0.11	0.11
Cash flow from operations after deducting dividends paid on Preferred Securities (per share)	(A-B)/C	**4.53**	3.11	1.76

ROCE

For the year ended December 31 ($ millions, except ROCE)		2003	2002	2001
Adjusted net earnings				
Net earnings		**1 084**	761	388
Add: after-tax financing expenses (income)		**(75)**	72	9
	D	**1 009**	833	397
Capital employed – beginning of year				
Short-term and long-term debt, less cash and cash equivalents		**2 671**	3 143	2 235
Shareholders' equity		**3 458**	2 780	2 472
		6 129	5 923	4 707
Less capitalized costs related to major projects in progress (1)		**(511)**	(178)	(2 497)
	E	**5 618**	5 745	2 210
Capital employed – end of year				
Short-term and long-term debt, less cash and cash equivalents		**2 091**	2 671	3 143
Shareholders' equity		**4 425**	3 458	2 780
		6 516	6 129	5 923
Less capitalized costs related to major projects in progress		**(1 122)**	(511)	(3 691)
	F	**5 394**	5 618	2.232
Average capital employed	G=(E+F)/2	**5 506**	5 682	2 221
ROCE (%)	D/G	**18.3**	14.6	17.8

(1) During 2001, Millennium was a significant major project in progress throughout the year that was commissioned late in December. As such, Millennium work in progress was included as a reduction of the capital employed at the end of the year for 2001, but excluded as a reduction of the 2002 capital employed at the beginning of the year.

OIL SANDS OPERATING COSTS

	2003		2002		2001	
For the year ended December 31	$ millions	$/barrel	$ millions	$/barrel	$ millions	$/barrel
Operating, selling and general expenses	**890**		806		481	
Less: natural gas costs and inventory changes	**(176)**		(116)		(94)	
Taxes other than income taxes	**24**		23		12	
Cash costs	**738**	**9.30**	713	9.50	399	8.80
Natural gas	**169**	**2.15**	119	1.55	101	2.25
Imported bitumen (net of other reported product purchases)	**4**	**0.05**	3	0.05	3	0.05
Cash operating costs	**911**	**11.50**	835	11.10	503	11.10
Depreciation, depletion and amortization	**451**	**5.70**	450	6.00	233	5.15
Total operating costs	**1 362**	**17.20**	1 285	17.10	736	16.25
Production (thousands of barrels per day)	**216.6**		205.8		123.2	

FORWARD-LOOKING STATEMENTS

This Management's Discussion and Analysis contains certain forward-looking statements that are based on Suncor's current expectations, estimates, projections and assumptions that were made by the company in light of its experience and its perception of historical trends.

All statements that address expectations or projections about the future, including statements about Suncor's strategy for growth, expected and future expenditures, commodity prices, costs, schedules, production volumes, operating and financial results and expected impact of future commitments, are forward-looking statements. Some of the forward-looking statements may be identified by words like "expects," "anticipates," "plans," "intends," "believes," "projects," "indicates," "could," "vision," "goal," "target," "objective" and similar expressions. These statements are not guarantees of future performance and involve a number of risks and uncertainties, some that are similar to other oil and gas companies and some that are unique to Suncor. Suncor's actual results may differ materially from those expressed or implied by its forward-looking statements

and readers are cautioned not to place undue reliance on them.

The risks, uncertainties and other factors that could influence actual results include but are not limited to: changes in the general economic, market and business conditions; fluctuations in supply and demand for Suncor's products, commodity prices and currency exchange rates; Suncor's ability to respond to changing markets and to receive timely regulatory approvals; the successful and timely implementation of capital projects including growth projects (for example the Firebag in-situ development and Voyageur) and regulatory projects (for example, the clean fuels refinery modifications projects in Suncor's downstream businesses); the accuracy of cost estimates, some of which are provided at the conceptual or other preliminary stage of projects and prior to commencement or conception of the detailed engineering needed to reduce the margin of error or level of accuracy; the integrity and reliability of Suncor's capital assets; the cumulative impact of other resource development; future environmental laws; the accuracy of Suncor's reserve, resource and future production estimates and its success at exploration and development drilling and related activities; the maintenance of satisfactory relationships with unions, employee associations and joint venture partners; competitive actions of other companies, including increased competition from other oil and gas companies or from companies that provide alternative sources of energy; the uncertainties resulting from potential delays or changes in plans with respect to projects or capital expenditures; actions by governmental authorities including the imposition of taxes or changes to fees and royalties, changes in environmental and other regulations; the ability and willingness of parties with whom Suncor has material relationships to perform their obligations to Suncor; and the occurrence of unexpected events such as fires, blowouts, freeze-ups, equipment failures and other similar events affecting Suncor or other parties whose operations or assets directly or indirectly affect Suncor. The foregoing important factors are not exhaustive. Many of these risk factors are discussed in further detail throughout this Management's Discussion and Analysis and in the company's Annual Information Form/Form 40-F on file with Canadian Securities Commissions and the SEC. Readers are also referred to the risk factors described in other documents that Suncor files from time to time with securities regulatory authorities. Copies of these documents are available without charge from the company.

below be elected directors. The term of office of each director is from the date of the meeting at which he or she is elected or appointed until the next annual meeting of shareholders or until a successor is elected or appointed.

The Board of Directors is required to have an Audit Committee. The Board of Directors also has a Board Policy, Strategy Review and Governance Committee, a Human Resources and Compensation Committee, and an Environment, Health and Safety Committee. The following table summarizes the current membership of each committee.

Committee	Committee Members as of March 8, 2004
Audit Committee (all members independent)	John T. Ferguson (Chair) Bryan P. Davies Brian A. Felesky Robert W. Korthals
Board Policy, Strategy Review and Governance Committee (all members independent)	John R. Huff (Chair) Brian A. Canfield Susan E. Crocker John T. Ferguson JR Shaw
Environment, Health and Safety Committee (all members independent, except Mr. O'Brien, who is a former officer of Suncor)	M. Ann McCaig (Chair) Mel E. Benson Bryan P. Davies Brian A. Felesky Michael W. O'Brien
Human Resources and Compensation Committee (all members independent)	Brian A. Canfield (Chair) Mel E. Benson Susan E. Crocker John R. Huff M. Ann McCaig JR Shaw

For details of the mandates of these committees, see "Report on Executive Compensation" and "Statement of Corporate Governance Practices".

Unless it is specified in a proxy that the Common Shares it represents shall be withheld from voting in the election of directors, the persons named in the accompanying form of proxy intend to vote for the election of the nominees whose names appear in the table below.

Management does not expect that any of the nominees will be unable to serve as a director but, if that should occur for any reason prior to the Meeting, the persons named in the accompanying proxy reserve the right to vote for another nominee at their discretion unless the proxy specifies that the Common Shares are to be withheld from voting in the election of directors.

Information for each person proposed to be nominated for election as a director is as follows:

requirements. In addition, at least one member of the Audit Committee must be determined by the Board to be an "audit committee financial expert". The Board has determined Mr. Ferguson, the Chair of the Audit Committee, and an independent (unrelated) director, to be such an expert (See Appendix A for a description of the Board's independence criteria and determinations).

The following is a brief summary of the key functions, roles and responsibilities of Suncor's Board committees.

Policy, Strategy Review and Governance Committee. The Board Policy Committee assists the Board in two areas: corporate governance and corporate strategy. In its governance role, the committee is mandated to determine Suncor's overall approach to governance issues and key corporate governance principles. The Board Policy Committee also reviews key matters pertaining to Suncor's values, beliefs and standards of ethical conduct.

The committee annually assesses and evaluates the overall performance and effectiveness of the Board of Directors, its committees, and individual directors, both as directors and as chairs of the Board or a particular Board committee. Each year, directors complete a confidential questionnaire that includes both a self-assessment and peer review to assess individual performance. The resulting data is analyzed and presented to the Board Policy Committee, who then report to the full Board of Directors, with any recommendations for enhancing or strengthening effectiveness. The Chairman of the Board Policy Committee reviews data relating to individual performance and conducts one-on-one meetings with each director focused on individual effectiveness.

In its strategy role, the committee reviews and provides advice with respect to the preliminary stages of key strategic initiatives and projects, and reviews and assesses processes relating to long range and strategic planning and budgeting.

Audit Committee. The Audit Committee assists the Board in matters relating to Suncor's internal controls, internal and external auditors and the external audit process, oil and natural gas reserves reporting, financial reporting and public communication, and certain other key financial matters. The committee is also mandated to provide an open avenue of communication between management, the internal and external auditors,

and the Board of Directors.

In fulfilling its role, the Audit Committee monitors the effectiveness and integrity of the Company's financial reporting, management information and internal control systems. The Audit Committee exercises general oversight over the internal audit function, by reviewing the plans, activities, organizational structure, qualifications and performance of the internal auditors. The appointment or termination of Suncor's chief officer in charge of internal audit is reviewed and approved by the Audit Committee. This officer has a direct reporting relationship with the committee and meets with them, in the absence of other members of management, at least quarterly. The committee also monitors compliance with Suncor's business conduct code, by conducting an annual review of the code and the related annual compliance program, and monitoring the status and resolution of any complaints relating to code violations. The business conduct code applies to all employees and officers, including its chief executive officer and chief financial officer.

The Audit Committee plays a key role in relation to Suncor's external auditors. It initiates and approves their engagement or termination, subject to shareholder approval, and monitors and reviews their independence, effectiveness, performance and quality control processes and procedures. The Audit Committee reviews, with management and external auditors, significant financial reporting issues, the conduct and results of the annual audit, and significant finance, accounting and disclosure policies and other financial matters. The Audit Committee also plays a key role in financial reporting, by reviewing Suncor's core disclosure documents, being its annual and interim financial statements, Management's Discussion and Analysis (MD&A) and annual information form (Form 40-F in the United States). The committee approves interim financial

statements and interim MD&A and makes recommendations to the Board with respect to approval of the annual disclosure documents.

The Audit Committee also plays a key oversight role in the evaluation and reporting of Suncor's oil and natural gas reserves. This role includes review Suncor's procedures relating to reporting and disclosure, as well as those for providing information to Suncor's independent reserves evaluators (the "Evaluator"). The Committee annually approves the appointment and terms of engagement of the Evaluator, including their qualifications and independence, and any changes in their appointment. Suncor's annual reserves data and report of the Evaluator is annually reviewed by the committee prior to approval by the full Board of Directors.

The committee reviews the key policies and practices of the Company with respect to cash management, financial derivatives, financing, credit, insurance, taxation, commodities trading and related matters. It also reviews the assets, financial performance, funding and investment strategy of the Company's registered pension plan, as well as the terms of engagement of the plan's actuary and fund manager, and any significant actuarial reports.

Environment, Health and Safety Committee. The Environment, Health and Safety Committee reviews the effectiveness with which the Company meets its obligations and achieves its objectives pertaining to the environment, health and safety (EH&S). This includes the effectiveness with which management establishes and maintains appropriate EH&S policies. This committee also monitors management's performance and emerging trends and issues in these areas. In fulfilling its role, the Committee monitors the adequacy of the Company's system of EH&S internal controls, and reviews quarterly management stewardship reports as well as the findings of significant external and internal EH&S investigations, assessments, reviews and audits. Suncor's periodic sustainability report, a detailed public disclosure document that includes reporting on Suncor's EH&S progress, plans and performance objectives, is also reviewed by the Committee.

Human Resources & Compensation Committee. For more information regarding the nature, scope, roles and responsibilities of the Human Resources & Compensation Committee, see "Report on Executive Compensation", commencing on page 8 of this Circular.

Availability of Additional Information. The following materials referred to above, are available on Suncor's website at www.suncor.com:

- the complete text of the terms of reference of Suncor's Board and the mandates of the Board Committees
- Suncor's most recent sustainability report
- Suncor's Standards of Business Conduct Code

Our Governance Commitment. The current environment of change in corporate governance practices is expected to continue in 2004. Suncor's Board of Directors is committed to regular reviews of Suncor's governance against changing legal and regulatory requirements and emerging best practices, and continually enhancing its system of corporate governance.

SPECIAL BUSINESS OF THE MEETING - SHAREHOLDER PROPOSAL

The Company has received a shareholder proposal (the "Proposal"). Details of the Proposal, including the text of the resolution proposed by the Carpenters' Fund and the statement of the Carpenters' Fund in support of the Proposal, and the response and recommendation of Suncor's Board of Directors to vote **against** the Proposal, are in Appendix B to this Circular.

APPOINTMENT OF AUDITORS

The persons named in the accompanying form of proxy intend to vote in favour of the reappointment of PricewaterhouseCoopers LLP as auditors of Suncor, to hold office until the close of the next annual meeting. PricewaterhouseCoopers LLP have been auditors of Suncor for more than five years.

Fees payable to Pricewaterhouse Coopers LLP in 2003 and 2002 are detailed below.

	2002	2003

Audit Fees	1,347,700	918,014
Audit Related Fees	448,291	135,500
Tax Fees	149,097	34,678
All Other Fees	1,338,238	16,070
Total	3,283,326	1,104,262

The nature of each category of fees is described below.

Audit Fees

Audit fees were paid for professional services rendered by the auditors for the audit of Suncor's annual financial statements or services provided in connection with statutory and regulatory filings or engagements.

Audit-Related Fees

Audit-related fees were paid for professional services rendered by the auditors for preparation of reports on specified procedures as they relate to joint venture audits, audits of employee pension plans, attest services not required by statute or regulation, data center reviews, internal control reviews, audits of subsidiaries incremental to the audit of the consolidated financial statements, general assistance with implementation of the Sarbanes-Oxley legislation, translation of annual reports into the French language, due diligence services related to the acquisition of the ConocoPhillips' Denver refinery, associated pipelines and 43 retail stations, system conversion reviews as a part of the annual audit and research in connection with certain accounting issues.

Tax Fees

Tax fees were paid for international tax planning and advice, international tax compliance, assistance with tax audits and expatriate tax assistance and compliance.

All Other Fees

Fees disclosed under "All Other Fees" were paid for services consisting of, subscriptions to auditor provided and supported tools, services related to Suncor's sustainability reports, risk management advisory services and assistance with the divestiture of a portion of Suncor's retail business.

GENERAL

The information contained herein is given as of March 8, 2004, except as otherwise indicated. A copy of the documents set out below may be obtained on our website at www.suncor.com, or, without charge, by any person upon request from the Company at 112 - 4th Avenue S.W., Calgary, Alberta, T2P 2V5, by calling 1-800-558-9071, or by email request to info@suncor.com:

APPENDIX A

The following chart compares Suncor's corporate governance practices with the TSX corporate governance guidelines (TSX Guidelines).

In November 2003, the NYSE published final listing requirements incorporating its new corporate governance standards (the NYSE Requirements). While these requirements are generally not applicable to non-U.S. companies, Suncor has undertaken a review of its practices against the NYSE Requirements. Based on that review, as of March 8, 2004, Suncor's corporate governance practices do not differ from the NYSE Requirements in any significant respect.

	Corporate Governance Guideline	Suncor Alignment	Commentary
1.	The Board of Directors should explicitly assume responsibility for stewardship of the Company, and specifically for:	Yes	The Board of Directors ("Board") has adopted terms of reference, which includes guidelines for the Board and its committees, as well as a formal mandate setting out the Board's major goals, responsibilities and duties. The overarching duty of the Board is to oversee development of the overall strategic direction and policy framework for the Company.

a.	Adoption of a strategic planning process	Yes	One of the Board's major duties is to review with management the Company's mission, objectives and goals, and the strategies whereby it proposes to achieve them. The Board is responsible for ensuring the Company has an effective strategic planning process, and for annually approving the strategies reflected in the Company's long range plan, which takes into account, among other things, the opportunities and risks of the Company's business. The Board Policy, Strategy Review and Governance ("Board Policy") Committee assists the Board of Directors and management by, among other things, reviewing and assessing the effectiveness of processes relating to long range planning and budgeting. A Board meeting principally devoted to strategic planning is held annually.
b.	Identification of principal risks, and implementing risk management systems	Yes	One of the major responsibilities of the Board is to identify the principal risks of the Company's business and ensure there are systems in place to effectively monitor and manage them. The Board discharges these responsibilities by, among other things, its participation in the long range and strategic planning processes, which involves consideration of the principal risks inherent in Suncor's businesses. Specific risks and risk management are also addressed by committees of the Board. For example, the Board Policy Committee's mandate includes providing advice with respect to the early stages of key strategic initiatives and projects and assessing the planning and budgeting processes, all of which involve consideration of risks and related management systems. The Environment, Health and Safety Committee plays a role in reviewing environmental, health and safety issues and reporting to the Board of Directors on these matters. The Audit Committee reviews financial risk management issues, programs and policies, including cash management, insurance and the use of financial derivatives.

	Corporate Governance Guideline	**Suncor Alignment**	**Commentary**
c.	Succession planning and monitoring senior management	Yes	The Board is responsible for monitoring and reviewing the performance of the Chief Executive Officer ("CEO") and other senior officers and for ensuring adequate succession for their positions. The Human Resources and Compensation Committee ("HR&CC") is specifically mandated to ensure that appropriate executive succession planning and performance evaluation programs are in place and that they are operating effectively. The committee conducts an annual review of the performance of the CEO against predetermined goals and criteria, and recommends to the Board the total compensation of the CEO. Senior management performance evaluations are undertaken annually, under the aegis of the CEO, and the results are reviewed by the committee. The committee also reviews and reports to the Board of Directors on the succession plan for senior management positions, including the position of the CEO. In addition, succession planning is included in the job descriptions for senior management.
d.	Communications policy	Yes	The Board of Directors is specifically mandated to ensure systems are in place for communications with Suncor's shareholders and other stakeholders. Through Company policies, procedures and processes, Suncor seeks to interpret its operations for its shareholders and other stakeholders, through a variety of channels, including its periodic financial reports, securities filings, news releases, environmental reports, webcasts, an external website, briefing sessions and group meetings. The Company encourages and seeks stakeholder feedback through corporate communications and investor relations programs. The Board, either directly or through the activities of the Audit Committee, reviews and approves all quarterly and annual financial statements and related management's discussion and analysis, management proxy circulars and annual information forms, among others. The Company has a communication policy that addresses the Company's interaction with shareholders, investment analysts, other stakeholders and the public. The policy includes measures to avoid selective disclosure of material information. Suncor's business conduct code addresses the Company's obligations for continuous and timely disclosure of material information. These policies are reviewed at least annually by the Company. The Audit Committee reviews and approves the Company's communication policy, and oversees an annual review of compliance with the Company's business conduct code.

e.	Integrity of internal control and management information systems	Yes	The Board of Directors is specifically mandated to ensure processes are in place to monitor and maintain the integrity of Suncor's internal control and management information systems. The Audit Committee is specifically mandated to assist the Board of Directors by reviewing the effectiveness of financial reporting, management information and internal control systems. This includes a review of the evaluation of these systems by internal and external auditors, as well as the activities, organizational structure and qualifications of internal auditors, and the independence and effectiveness of external auditors.
2.	Majority of directors should be "unrelated" (independent)	Yes	The Board reviews the independence of its members annually and has determined based on its most recent annual review conducted in February 2004 that all but two (Richard L. George, Suncor's President and CEO, and Michael W. O'Brien, who retired as Suncor's CFO and Vice President, Corporate Development, in 2002) of the thirteen director nominees are unrelated and independent.

	Corporate Governance Guideline	**Suncor Alignment**	**Commentary**
3.	Disclose analysis of independence determinations by the Board	Yes	Under the TSX guidelines, an "unrelated" director is a director who is independent of management and free from any business or other relationship which could, or could reasonably be perceived to, materially interfere with the director's ability to act with a view to the best interests of the Company. The NYSE Requirements state that an independent director has no material relationship with the company, either as partner, shareholder or officer of an organization that has a relationship with the company. The NYSE Requirements include additional criteria that should be considered in determining whether directors are "independent" and identify certain relationships that operate as a complete bar to a finding of independence. Suncor's Board has adopted these independence bars as part of their criteria for determining whether its members are unrelated and independent. When assessing against the criteria, the board determines whether any independence bars exist, as they do in the case of two directors: Mr. George is deemed to be related and non-independent because he is Suncor's CEO, and Mr. O'Brien is deemed to be related and non-independent because he is a recently retired executive of Suncor. Pursuant to the Board's criteria, the Chairman of the Board, Mr. Shaw, is not considered to be a "related" director by virtue of his position as chair, as he holds the position in a non-executive and non full-time capacity. In addition to a review of any independence bars, the Board also reviews and analyzes the existence, materiality and affect of any relationships between the Company and each of its directors, either directly, through immediate family members or as partners, significant shareholders or officers of another organization that has a relationship with Suncor, and determines in each case whether the relationships could, or could reasonably be perceived to, materially interfere with the director's ability to act with a view to the best interests of the Company.
4.	Appoint a Committee:		
a.	responsible for the appointment and assessment of directors	Yes	Suncor's Board Policy Committee is charged with the duty of assisting the Board in matters pertaining to, among other things, the Board's organization and composition. Suncor's Board of Directors supports the principle that its membership should represent a diversity of backgrounds, experience and skills. The Board Policy Committee annually reviews the appropriate characteristics of Board members in the context of the current composition of the Board and the objectives and needs of the Company. This Committee works with the Board, with input from outside advisors and management, to establish criteria for selecting new director candidates, maintains a list of potential candidates, and recommends Board nominees to the full Board of Directors. The Board Policy Committee has the authority on behalf of the Board to engage outside advisors to assist in the identification and assessment of director candidates. This Committee also conducts an annual assessment of the effectiveness of the Board and its committees, which includes an evaluation of the performance and contribution of individual directors. See item 5 below.
b.	composed exclusively of outside (non-management) directors, the majority of whom are unrelated	Yes	The Board Policy Committee consists entirely of outside, independent (unrelated) directors.

	Corporate Governance Guideline	Suncor Alignment	Commentary
5.	Implement a process for assessing the effectiveness of the Board of Directors, its committees and individual directors	Yes	The Board Policy Committee annually assesses and evaluates the overall performance and effectiveness of the Board of Directors, its committees, and individual directors, both as directors and as chairs of the board or a particular board committee, if applicable. Each year, directors complete a confidential questionnaire that includes both a self-assessment and peer review to assess individual performance. The resulting data is analyzed by the Board and presented to the Board Policy Committee, who then report to the full Board of Directors, with any recommendations for enhancing or strengthening effectiveness. The Chairman of the Board Policy Committee reviews data relating to individual performance and conducts one-on-one meetings with each director focused on individual effectiveness.
6.	Provide orientation and education programs for new directors	Yes	Suncor provides orientation and education materials to new members of the Board of Directors, and conducts a formal orientation program involving meetings with senior management on key legal, environmental, business, financial and operational issues. A Directors' Manual, containing pertinent information relating to the Board and the Company, is provided to each director. Presentations and tours at the sites of Suncor's principal operations are provided to directors on a periodic basis, often in conjunction with Board meetings, for the purpose of acquainting directors with Suncor's operations and the communities in which they are located. In 2003, Suncor's Board approved a Directors' Continuing Education Policy, which encourages directors to enroll in courses and programs that enhance and supplement their knowledge and skills in areas relevant to their role on Suncor's Board, with the approval of the Chairman of the Board or Board Policy Committee.
7.	Consider size of Board of Directors, and impact of the number on Board effectiveness	Yes	The Board of Directors is specifically mandated to fix its size, subject to shareholder approval, where required. The Board has determined that its size is conducive to effective decision making while ensuring a sufficient number to resource the Board's four standing committees. See item 4(a).
8.	Review compensation of directors in light of risks and responsibilities	Yes	The HR&CC reviews and reports to the Board on directors' compensation issues. The committee has developed, in consultation with outside advisors, guidelines for director compensation based on, among other factors, directors' roles and responsibilities and an analysis of the competitive position of Suncor's director compensation program. The Board has set director compensation based upon recommendations from this committee.
9.	Committees should generally be composed of outside directors, a majority of whom are unrelated	Yes	Three of Suncor's standing committees (Audit, Board Policy and HR&CC) are comprised solely of unrelated (independent) directors. Suncor's fourth standing committee (Environment Health and Safety) is comprised of a majority of unrelated (independent) directors. Mr. O'Brien, a "related" director, is a member of the Environment, Health and Safety Committee. The composition of Suncor's Board committees is consistent with the NYSE Requirements.

	Corporate Governance Guideline	Suncor Alignment	Commentary
10.	Appoint a committee responsible for Suncor's approach to corporate governance issues	Yes	The Board Policy Committee assists the Board of Directors in matters pertaining to the Company's approach to governance issues. In fulfilling its governance role, this committee monitors developments relating to governance issues and makes recommendations to the full Board relating to the Company's corporate governance system. Among other things, this committee has reviewed Suncor's response to the TSX guidelines as well as the NYSE Requirements, and continues to monitor, review and recommend to the full Board changes to Suncor's governance system as practices, guidelines and requirements evolve.
11.			
a.	Define limits to management's responsibilities by developing mandates for:		

	i. the Board of Directors	Yes	The Board of Directors has approved and regularly reviews its terms of reference. The Board terms of reference, as the charter of the Board, includes a general overview of the Board's role in Suncor's governance, a statement of key guidelines and policies applicable to the Board and its committees, and a mandate that describes its major responsibilities, goals and duties. The Board's statutory duty to supervise the management of Suncor's business and affairs, is embodied in the scope of the Board's role in overseeing strategic planning, management succession plans, risk identification and management, succession planning, internal controls and other key aspects of governance. The Board of Directors delegates day-to-day management to Suncor's CEO and other members of management. A management control process policy, adopted by the Board, sets limits on the specific authority delegated to management.
	ii. the Chief Executive Officer	Yes	There is an accountability statement for the office of CEO which defines the main role of the position and identifies its key accountabilities, described in more detail in the "Report on Executive Compensation".
b.	Board of Directors should approve the Chief Executive Officer's corporate objectives and assess CEO against these objectives.	Yes	The corporate objectives for which the CEO is responsible represent a combination of corporate goals and personal goals, set annually by the Board of Directors in consultation with the HR&CC and Chairman of the Board, respectively. In addition, the HR&CC annually reviews the CEO's performance against these objectives and against the key accountabilities of his position, in conjunction with compensation reviews. The Committee reports its assessment to the full Board which ultimately approves CEO compensation.

	Corporate Governance Guideline	Suncor Alignment	Commentary
12.	Establish structures and procedures to enable the Board of Directors to function independently of management.	Yes	The Board Terms of Reference state that the Chairman of the Board must be an unrelated (independent) director. Mr. Shaw, Suncor's Chairman of the Board, has been determined by the Board to be unrelated (independent) (See item 2). The Board of Directors and its committees meet independently of management when warranted. In addition, in camera sessions, chaired by the Chairman of the Board or of the applicable committee, are held at each Board and Board committee meeting in the absence of inside directors and other members of management. At least once annually, the Board meets in the absence of any director who is deemed non-independent (related) by the Board. The Audit Committee meets with the external auditors and independent reserves evaluators without management present, and Suncor's Director of Internal Audit, a Suncor employee with direct reporting channels to the Audit Committee, also meets with the Audit Committee in the absence of other members of management.
13.			
a.	Ensure an Audit Committee has a specifically defined mandate.	Yes	The Audit Committee has a specifically defined mandate. A summary of that mandate is included in the "Statement of Corporate Governance Practices" in this Circular.
	The Audit Committee should have direct communication channels with internal and external auditors.		The Audit Committee has direct communication channels with Suncor's internal and external auditors and independent reserves evaluators and meets regularly with them without presence of management. Suncor's Director of Internal Audit reports directly to the Audit Committee on a regular basis.
	The Audit Committee's duties should include oversight of management's design and implementation of effective internal controls.		The Audit Committee is mandated to enquire as to the adequacy of Suncor's system of internal controls, and review the evaluation of internal and financial controls by internal and external auditors, respectively.

Corporate Governance Guideline	Suncor Alignment	Commentary

b.	All members should be non-management directors.	Yes	All members are outside, unrelated (independent) directors. NYSE Requirements state that audit committee members should be financially literate and at least one member (the “Audit Committee Financial Expert”) should have “financial expertise”. The Board has defined financial literacy generally as the ability to read and understand financial statements, and has defined an Audit Committee Financial Expert as a director who has an understanding of generally accepted accounting principles and financial statements; the ability to assess the general application of such principles in connection with the accounting for estimates, accruals and reserves; experience preparing, auditing, analyzing or evaluating financial statements that present a breadth and complexity of accounting issues that are generally comparable to Suncor’s, or experience actively supervising one or more persons engaged in such activities; an understanding of internal control over financial reporting; and an understanding of audit committee functions. The Board has also established criteria to assist the Board in evaluating each director’s education and experience against the financial literacy and expertise requirements. The Board has affirmatively determined that all members of the Audit Committee are financially literate and has designated John Ferguson, an independent (unrelated) director, as “Audit Committee Financial Expert” pursuant to the foregoing criteria. Pursuant to the Board Terms of Reference, Audit Committee members must not be members of the audit committees of more than two other public companies, unless the Board determines that simultaneous service on a greater number of audit committees would not impair the member’s ability to effectively serve on Suncor’s Audit Committee. Mr. Korthals is currently on the audit committee of five public companies. The Board has determined that this fact does not impair Mr. Korthals’ ability to effectively serve on Suncor’s Audit Committee based on an analysis of Mr. Korthals time commitments in general, the demands of those other committees, and the time commitment required of members of Suncor’s Audit Committee.
14.	Implement a system to enable individual directors to engage outside advisors at the Company’s expense.	Yes	The Board of Directors, its committees, and individual directors may engage outside advisors at Suncor’s expense with the approval of the Chairman of the Board of Directors, Chairman of the Board Policy Committee or Chairman of the applicable committee.

EXHIBIT 4

Consent of PricewaterhouseCoopers LLP



PricewaterhouseCoopers LLP
Chartered Accountants
111 5th Avenue SW, Suite 3100
Calgary, Alberta
Canada T2P 5L3
Telephone +1 (403) 509 7500
Facsimile +1 (403) 781 1825

Consent of Independent Accountants

We hereby consent to the inclusion in this Annual Report on Form 40-F and the incorporation by reference in the registration statements on Form F-3 (File No. 333-7450), Form F-10 (File No. 333-14242), Form S-8 (File No. 333-87604) and on Form S-8 (File No. 333-112234), of Suncor Energy Inc. of our report dated January 27, 2004 relating to the consolidated financial statements, which appears in the Annual Report to Shareholders.

“PRICEWATERHOUSECOOPERS LLP”

Chartered Accountants
Calgary, Alberta
April 13, 2004

PricewaterhouseCoopers refers to the Canadian firm of PricewaterhouseCoopers LLP and the other member firms of PricewaterhouseCoopers International Limited, each of which is a separate and independent legal entity.

Exhibit 5

Gilbert Laustsen Jung
Associates Ltd. Petroleum Consultants
4100, 400 — 3rd Avenue S.W., Calgary, Alberta, Canada T2P 4H2 (403) 266-9500 Fax (403) 262-1855

LETTER OF CONSENT

TO: Suncor Energy Inc.
The Securities and Exchange Commission
The Securities Regulatory Authorities of Each of the Provinces of Canada

Dear Sirs

Re: Suncor Energy Inc.

We refer to the following reports dated February 20, 2004 (collectively the "Reports"), prepared by Gilbert Laustsen Jung Associates Ltd.:

- the letter report, as to the synthetic crude oil reserves effective December 31, 2003 associated with the Suncor Energy Inc. oil sands operations located near Fort McMurray, Alberta;
- the Reserves Assessment and Evaluation of Firebag effective December 31, 2003;
- the Reserves Assessment and Evaluation of Canadian Oil and Gas Properties of Suncor Energy Inc. Natural Gas effective December 31, 2003;

We hereby consent to the use of our name, reference to and excerpts from the said reports by Suncor Energy Inc. in its Annual Information Form for the 2003 fiscal year (AIF) and its annual report on Form 40-F (Form 40-F), including Exhibit 1, Proved Oil and Gas Reserves Quantities, thereto, and the registration statements of Suncor Energy Inc. on Form F-3 (File No. 333-7450), Form F-10 (File No. 333-14242), Form S-8 (File No. 333-87604), and Form S-8 (File No. 333-112234).

We have read the AIF and the Form 40-F and have no reason to believe that there are any misrepresentations in the information contained therein that is derived from our Reports or that are within our knowledge as a result of the services which we performed in connection with the preparation of the Reports.

Yours very truly,

GILBERT LAUSTSEN JUNG
ASSOCIATES LTD.

ORIGINALLY SIGNED BY

Wayne W. Chow, P. Eng.
Vice-President

Dated: April 13, 2004
Calgary, Alberta
CANADA

EXHIBIT 6

Certificate of President and Chief Executive Officer Pursuant to Exchange Act Rules 13a-15(e) and 15d-15(e)

I, RICHARD L. GEORGE, President and Chief Executive Officer of Suncor Energy Inc. ("Issuer"), certify that:

1. I have reviewed this annual report on Form 40-F of the Issuer;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the Issuer as of, and for, the periods presented in this annual report;

4. The Issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the Issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision to ensure that material information relating to the Issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   (b) Evaluated the effectiveness of the Issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (c) Disclosed in this report any change in the Issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The Issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Issuer's auditors and the audit committee of Issuer's board of directors (or persons performing the equivalent function):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably

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likely to adversely affect the Issuer's ability to record, process, summarize and report financial information; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the Issuer's internal control over financial reporting.

SUNCOR ENERGY INC.

DATE: April 13, 2004

PER: "RICHARD L. GEORGE"
RICHARD L. GEORGE
President and Chief Executive Officer

EXHIBIT 7

Certificate of Senior Vice President and Chief Financial Officer Pursuant to Exchange Act Rules 13a-15(e) and 15d-15(e)

I, J. KENNETH ALLEY, Senior Vice President and Chief Financial Officer of Suncor Energy Inc. ("Issuer"), certify that:

1. I have reviewed this annual report on Form 40-F of the Issuer;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the Issuer as of, and for, the periods presented in this annual report;

4. The Issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the Issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision to ensure that material information relating to the Issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   (b) Evaluated the effectiveness of the Issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (c) Disclosed in this report any change in the Issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The Issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Issuer's auditors and the audit committee of Issuer's board of directors (or persons performing the equivalent function):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably

---

likely to adversely affect the Issuer's ability to record, process, summarize and report financial information; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the Issuer's internal control over financial reporting.

SUNCOR ENERGY INC.

DATE: April 13, 2004

PER: "J. KENNETH ALLEY"
J. KENNETH ALLEY
Senior Vice President and
Chief Financial Officer

EXHIBIT 8

Certificate of the President and Chief Executive Officer Pursuant to 18 U.S.C.Section 1350, as Enacted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

The following certifications accompany the annual report on Form 40-F pursuant to 18 U.S.C. Section 1350, as enacted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, and shall not, except to the extent required by 18 U.S.C. Section 1350, as enacted pursuant to the Sarbanes-Oxley Act of 2002, be deemed filed by Suncor Energy Inc. for the purposes of Section 18 of the Securities Exchange Act of 1934.

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ENACTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the annual report of Suncor Energy Inc. (the "Company") on Form 40-F for the fiscal year ending December 31, 2003 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, RICHARD L. GEORGE, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of the operations of the Company.

"RICHARD L. GEORGE"
RICHARD L. GEORGE
President and Chief Executive Officer
Suncor Energy Inc.

DATE: April 13, 2004

EXHIBIT 9

Certificate of the Senior Vice President and Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as Enacted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

The following certifications accompany the annual report on Form 40-F pursuant to 18 U.S.C. Section 1350, as enacted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, and shall not, except to the extent required by 18 U.S.C. Section 1350, as enacted pursuant to the Sarbanes-Oxley Act of 2002, be deemed filed by Suncor Energy Inc. for the purposes of Section 18 of the Securities Exchange Act of 1934.

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ENACTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the annual report of Suncor Energy Inc. (the "Company") on Form 40-F for the fiscal year ending December 31, 2003 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, J. KENNETH ALLEY, Senior Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of the operations of the Company.

"J. KENNETH ALLEY"
J. KENNETH ALLEY
Senior Vice President and Chief Financial Officer
Suncor Energy Inc.

DATE: April 13, 2004