SUNCOR ENERGY INC
Form 40-F
March 08, 2007

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

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

For fiscal year ended	**December 31, 2006**
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:

x Annual Information Form x 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	**As of December 31, 2006 there were 459,943,827 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 x

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 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 x No o

SUNCOR ENERGY INC. ANNUAL INFORMATION FORM

February 28, 2007

ANNUAL INFORMATION FORM

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GLOSSARY OF TERMS

In this Annual Information Form (AIF), references to we , our , us , Suncor or the company include Suncor Energy Inc., its subsidiaries, partnerships and joint venture investments unless the context otherwise requires.

Barrel of Oil Equivalent (BOE)

Suncor converts natural gas to barrels of oil equivalent (BOE) at a 6 mcf:1 bbl ratio. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6:1 is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Bitumen/Heavy Crude Oil

A naturally occurring viscous tar-like mixture, mainly containing hydrocarbons heavier than pentane, which 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 crude 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.

Conventional Crude Oil

Crude oil produced through wells by standard industry recovery methods.

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.

Development Costs

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

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.

Feedstock

Purchases of components required in the production of refined product other than crude oil.

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.

Gross Production/Reserves

Suncor s working interest in production/reserves, as the case may be, 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. This product traditionally sells at less than the cost of crude oil.

In-situ Oil

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

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.

MD&A

Suncor s Management s Discussion and Analysis dated February 28, 2007, accompanying its audited consolidated financial statements, notes thereto and auditor s report thereon, as at and for the three years in the period ended December 31, 2006, which 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, 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.

Oil Sands

Oil sands are a naturally occurring mixture of water, sand, clay and bitumen, a very heavy crude oil.

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.

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 assumed economic and operating conditions.

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

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(1) We are subject to Canadian disclosure rules in connection with the reporting of reserves. However, we have received exemptive relief from Canadian securities administrators permitting us to report our reserves in accordance with U.S. disclosure practices. Although U.S. companies do not disclose probable reserves for non-mining properties, we voluntarily disclose probable reserves for our Firebag in-situ leases as we believe this information is useful to investors. See RESERVES ESTIMATES on page 20 for a description of how our voluntary reserves disclosure differs from our U.S. required disclosure.

(2) In estimating our proved and probable reserves, our independent reserves evaluators, GLJ Petroleum Consultants Ltd. (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 our reserves have been prepared using deterministic, rather than probabilistic methods, consistent with industry practice, GLJ s estimates do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

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.

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.

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.

For a discussion of pricing assumptions see the tables under the headings REQUIRED U.S. OIL AND GAS AND MINING DISCLOSURE Proved Conventional Oil and Gas Reserves and under VOLUNTARY OIL SANDS RESERVES DISCLOSURE Oil Sands Mining and In-Situ Firebag Reserves Reconciliation .

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 anticipated date of resumption of production must be known.

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 purification of bitumen.

Synthetic Crude Oil

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

Undeveloped Oil and Natural Gas Lands

Undeveloped lands are 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.

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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 as well as production using conventional methods.

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, or adjacent to, 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 a territory without existing proved reserves, with the intention to discover commercial reservoirs or deposits of crude oil and/or natural gas.

CONVERSION TABLE

1 cubic metre m^3 = 6.29 barrels
1 cubic metre m^3 (natural gas) = 35.49 cubic feet
1 cubic metre m^3 (overburden) = 1.31 cubic yards

1 tonne = 0.984 tons (long)
1 tonne = 1.102 tons (short)
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 our current expectations, estimates, projections and assumptions that we ve made in light of our experience.

All statements that address expectations or projections about the future, including statements about our strategy for growth, expected 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, estimate , plans, believes, indicates, could, goal, t objective, will continue, schedule, foreseeable, proposed, potential, may, and similar expressions. These statements are not guarantees 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 our experience. Our actual results may differ materially from those expressed or implied by our 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 our products; commodity prices and currency exchange rates; our 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 continued investment in our Firebag in-situ development project) and regulatory projects (for example, the clean fuels refinery modifications projects in our 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 our capital assets; the cumulative impact of other resource development; future environmental laws; the accuracy of our reserve, resource and future production estimates and our 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 and from companies that provide alternative sources of energy; labour and material shortages; and other facilities 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 (for example, the Government of Alberta s current review of the Crown Royalty regime, and the Government of Canada s current review of greenhouse gas emission regulations); the ability and willingness of parties with whom we have material relationships to perform their obligations to us; and the occurrence of unexpected events such as fires, blowouts, freeze-ups, equipment failures and other similar events affecting us or other parties whose operations or assets directly or indirectly affect us. These 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 our MD&A, incorporated by reference herein. Readers are also referred to the risk factors described in other documents we file from time to time with securities regulatory authorities. Copies of these documents are available without charge from Suncor at 112 4th Avenue S.W., Calgary, Alberta, T2P 2V5, by calling 1-800-558-9071, or by email request to info@suncor.com or by referring to SEDAR at www.sedar.com or by referring to EDGAR at www.sec.gov. Information contained in or otherwise accessible through our website does not form a part of this AIF. All such references are inactive textual references only.

References herein to our 2006 Consolidated Financial Statements mean Suncor s audited consolidated financial statements prepared in accordance with Canadian generally accepted accounting principles (GAAP), notes thereto and auditor s report thereon, as at and for the three years in the period ended December 31, 2006.

NON GAAP FINANCIAL MEASURES

Certain financial measures referred to in this AIF that are not prescribed by GAAP, namely, cash flow from operations and Oil Sands cash and total operating costs per barrel, are described and reconciled in the Non GAAP Financial Measures , section of our 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, we amalgamated with a wholly-owned subsidiary under the *Canada Business Corporations Act*. We amended our articles in 1995 to move our registered office from Toronto, Ontario, to Calgary, Alberta, and again in April 1997, to adopt our current name, Suncor Energy Inc. . In April 1997, May 2000, and May 2002, we amended our articles to divide our issued and outstanding shares on a two-for-one basis.

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

Intercorporate Relationships

We have four principal subsidiaries and partnerships.

Suncor Energy Oil Sands Limited Partnership, is an Alberta limited partnership that is indirectly wholly owned by Suncor Energy Inc. Effective February 1, 2005, Suncor Energy Inc., as general partner, and one of its wholly-owned subsidiaries, as a limited partner, formed the Suncor Energy Oil Sands Limited Partnership. At this time the partnership held certain net profits interests related to our oil sands business and natural gas business. Effective January 1, 2006, Suncor Energy Inc. contributed, subject to certain exceptions, its oil sands assets to the partnership. This internal reorganization had no effect on operations or on our consolidated net earnings.

Suncor Energy Products Inc. (formerly Sunoco Inc.) is an Ontario corporation that is wholly-owned by Suncor Energy Inc. This company refines and markets petroleum products and petrochemicals directly and indirectly through subsidiaries and joint ventures. We operate a retail business in Canada under the Sunoco brand through this subsidiary. We are unrelated to Sunoco, Inc. (formerly known as Sun Company, Inc.), headquartered in Philadelphia, Pennsylvania.

Suncor Energy Marketing Inc. (SEMI), wholly-owned by Suncor Energy Products Inc., is incorporated under the laws of Alberta. This company markets, mainly to customers in Canada and the United States, the crude oil, diesel fuel, bitumen and byproducts such as petroleum coke, sulphur and gypsum, produced by our Oil Sands business. Through this subsidiary we also administer Suncor s energy trading activities, market certain third party products, and procure crude oil feedstocks and natural gas for our downstream businesses. This subsidiary markets certain natural gas volumes produced by, and purchased from, our Natural Gas business unit. Suncor Energy Marketing Inc. also has a petrochemical marketing division that holds a 50% interest in Sun Petrochemicals Company (SPC), a petrochemical products joint venture.

Suncor Energy (U.S.A.) Inc., indirectly wholly-owned by Suncor Energy Inc., is incorporated under the laws of Delaware. Through this U.S. subsidiary, headquartered in Denver, Colorado, we refine crude oil at our refinery in Commerce City, Colorado, near Denver, into a broad range of petroleum products, and market our refined products to industrial, wholesale and commercial customers principally in Colorado and to retail customers in Colorado through Phillips 66 ® - branded sites. We also transport crude oil on our wholly or partly owned pipelines in Wyoming and Colorado.

We also have a number of other subsidiary companies. However, the total assets of such subsidiaries and partnerships 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 corporate headquarters in Calgary, Alberta, Canada. We are strategically focused on developing one of the world s largest petroleum resource basins Canada s Athabasca oil sands. In addition, we explore for, acquire, develop, produce and market crude oil and natural gas, transport and refine crude oil and market petroleum and petrochemical products. Periodically, we also market third party petroleum products. We also carry on energy trading activities focused principally on buying and selling futures contracts and other derivative instruments based on the commodities we produce.

We have four principal operating businesses:

Our Oil Sands business, based near Fort McMurray, Alberta, recovers bitumen, primarily through oil sands mining and in-situ development, and upgrades it into refinery feedstock, diesel fuel and by-products. Bitumen feedstock is also occasionally supplemented by third party suppliers.

Our Natural Gas business, based in Calgary, Alberta, explores for, acquires, develops and produces natural gas and natural gas liquids from reserves in Western Alberta and Northeastern British Columbia. The sale of natural gas production provides a natural price hedge for natural gas purchased for consumption at our Oil Sands facility and our refineries in Sarnia, Ontario and near Denver, Colorado. In addition, our indirectly wholly-owned U.S. subsidiary, Suncor Energy (Natural Gas) America Inc., acquires land and explores for coal bed methane in the United States.

Our third business, Energy Marketing and Refining Canada, headquartered in Toronto, Ontario, refines crude oil at Suncor s refinery in Sarnia, Ontario, into a broad range of petroleum, petrochemical and biofuel products. These products are then marketed 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. We also engage in third party energy marketing and trading activities through this business.

Our fourth business, Refining and Marketing U.S.A., headquartered in Denver, Colorado, refines crude oil at our refinery in Commerce City, Colorado, near Denver, into a broad range of petroleum products, and markets our refined products to industrial, wholesale and commercial customers principally in Colorado and to retail customers in Colorado through Phillips 66 ® - branded sites. We also transport crude oil on our wholly or partly owned pipelines in Wyoming and Colorado.

For financial reporting purposes, we also report financial data for activities not directly attributable to an operating business under the results of Suncor s Corporate segment. This includes the activity of our self-insurance entity, as well as activities to pursue the development of low-emission and no-emission energy sources that have a reduced environmental impact outside our hydrocarbon-based businesses.

In 2006, we produced approximately 294,800 boe per day, comprised of 263,000 barrels per day (bpd) of crude oil and natural gas liquids and 191 million cubic feet per day (mmcf/d) of natural gas. In 2005, the most recent period with published results, we were the fourth largest crude oil and natural gas liquids producer in Canada (approximately 7%[3] of Canada s crude oil production in 2005) and the 18th largest natural gas producer in Canada.[4]

In 2006, our Energy Marketing and Refining business sold approximately 95,000 bpd (2005 96,000 bpd) or 15,100 m^3 per day (2005 15,200 m^3 per day) of refined products, mainly in Ontario but also in the United States and Europe. Our refined product sales in Ontario represented approximately 18% (2005

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(3) CAPP Crude Oil Report Table 1 Canadian Crude Oil Production Forecast

(4) Oilweek July 2006, Top 100 Oil and Gas Producers

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19%) of Ontario s total refined product sales in 2006[5]. In 2006, our Refining & Marketing business sold approximately 90,600 bpd or 14,400 m^3 of refined products in Colorado, including approximately 76,100 bpd or 12,100 m^3 per day of light oils (gasoline and distillates) (2005 86,200 bpd or 13,700 m^3 per day, including approximately 69,200 bpd or 11,000 m^3 per day of light oils).

Three-Year History

Cost estimates for major projects involve uncertainties and evolve in stages. For a discussion of this process, an update on the status of our significant capital projects in progress and an explanation of on time and on budget , see page 27 of our MD&A, incorporated by reference herein.

Oil Sands (OS)

OS growth We continue to advance our multi-phased growth strategy to increase production capacity to 500,000 to 550,000 bpd in 2010 to 2012. Key components of this strategy include the following milestones:

During the fourth quarter of 2005, we increased our production capacity to 260,000 bpd through the completion of a new vacuum unit. In addition, we also completed a debottleneck of our Steepbank mine operation.

We plan to increase production capacity to 350,000 bpd in 2008. We anticipate capital spending of approximately $2.1 billion for an additional coker unit to expand Upgrader 2. The project is currently on schedule and on budget. We currently estimate an additional $1.5 billion in costs to increase bitumen supply. (The $2.1 billion estimated cost for the coker unit has a range of uncertainty of +/- 10%. The $1.5 billion estimated cost for increased bitumen supply in connection with reaching our target of 350,000 bpd, has a range of uncertainty of +/- 10%.)

For expansion beyond 2008, toward our goal of 500,000 to 550,000 bpd in 2010 to 2012, OS filed a regulatory application in March 2005, and received regulatory approval in November 2006, to construct a third upgrader. The company expects to advance project development plans and cost estimates to a level appropriate to seek Board of Directors approval in 2007. Pending Board approval, we plan to begin construction in 2007.

In support of our plans to increase production capacity, we remain focused on increasing bitumen supply from:

i) the development of our Firebag in-situ oil sands reserves. Firebag Stage 1 began producing bitumen in 2004, and Firebag Stage 2 commenced commercial operations during the first quarter of 2006. A capital project expanding Firebag Stages 1 and 2 in conjunction with the addition of a cogeneration facility is on schedule and on budget for completion in 2007. Also planned for 2007 is the submission for approval to our Board of Directors for Firebag Stage 3;

ii) continued development of our mining leases, including our North Steepbank Mine extension, and the regulatory, consultation and engineering work supporting potential development of Lease 23; and

iii) procurement of bitumen from third parties.

Petro-Canada Agreement - Incremental bitumen to feed the expanded OS operation is also expected to be provided under a processing agreement between Suncor and Petro-Canada, expected to take effect in 2008. Under the agreement, we will process a minimum of 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, we will sell an additional 26,000 bpd of our proprietary sour

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(5) Statistics Canada Modified Monthly Report For Refined Petrochemical Production Development Sales

crude oil production to Petro-Canada. Both the processing and sales components of the agreement will be for a minimum 10-year term.

Kyoto Protocol   On December 17, 2002, the Government of Canada announced its ratification of the Kyoto Protocol. On October 19, 2006, the Government of Canada announced their plan to address clean air that focuses on the regulation of indoor and outdoor air quality and greenhouse gases (GHG). The announced Clean Air Act, followed by the Notice of Intent to Regulate Criteria Air Contaminants (CACs) and GHGs has been referred to a special committee for review and revision. Consultation with key sectors is underway however, the ultimate regulatory outcome is unknown. We plan to continue to actively manage our air emissions and greenhouse gas emissions to improve performance. We also plan to advance opportunities such as carbon capture, geological sequestration and renewable and alternate forms of energy, such as wind power and biofuels.

Oil Sands Fire   A fire on January 4, 2005, caused significant damage to one of our two upgraders, reducing upgraded crude oil production capacity of 225,000 bpd from base operations to about 122,000 bpd for the first nine months of 2005. Repair and maintenance work to restore the facility was completed in September 2005. Our property loss and business interruption insurance policies substantially mitigated the financial impact of the fire, and were fully settled in 2006. For additional information on our insurance policies and recoveries refer to note 10(b) to our 2006 consolidated financial statements, and page 26 of our MD&A.

Bitumen Royalty Option Agreement   In September 2005, an agreement was reached with the Alberta Government on the terms and conditions of Suncor s option to transition to the generic bitumen-based royalty regime in 2009. During the fourth quarter of 2006, we elected to exercise our option to move our base operations to the bitumen-based royalty effective January 1, 2009. Under this regime we will pay a royalty based on 25% of bitumen revenues, minus allowable costs. During 2006, the government of Alberta began deliberations to establish a prescribed method of determining the fair market value of heavy oil/bitumen for the purposes of determining bitumen-based royalty. Royalty payments under this new bitumen pricing methodology may change significantly. The methodology is not likely to be finalized until 2008, and as a result, the potential future impacts are not currently known, but may be material. Any retroactive adjustment is not anticipated to be material. For additional information on our Oil Sands Crown Royalties see page 29 of our MD&A.

Natural Gas (NG)

South Rosevear Gas Plant   In January 2006, we disposed of 15% of the total interest in the South Rosevear gas plant for proceeds of $12 million. We currently retain a 60.4% interest and continue to operate the gas plant.

Divestment of non-core properties   In 2005, we disposed of non-core properties for proceeds of $21 million.

Simonette Gas Plant   In December 2005, we, along with our partner, completed a plant capacity expansion and a new pipeline to connect the Simonette plant with volumes produced from the Cabin Creek and Solomon fields in the Alberta Foothills. In November 2004, Natural Gas divested 62.5% of its interest in the Simonette gas plant for proceeds of $19 million. We retain a 37.5% ownership and continue to operate the gas plant.

Land Acquisition   In December 2004, we acquired assets in eastern British Columbia for $33 million. These assets consist of developed and undeveloped land.

Settlement Also in December 2004, we paid $18 million as a final arbitrated settlement relating to the termination of gas marketing contracts related to Enron Corporation s bankruptcy in December 2001.

Energy Marketing & Refining - Canada (EM&R)

Desulphurization Projects 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 parts per million (ppm), by June 1, 2006. The previous maximum was 500 ppm. To meet these requirements, in October 2003, we and Shell Canada Products Inc. (Shell) entered into a 20-year agreement under which we built hydrotreating facilities at our Sarnia refinery to process high-sulphur diesel from both Shell s and our Sarnia refineries, to produce low sulphur diesel in compliance with the new on-road diesel limits. Under the agreement Shell pays us a processing fee. Construction of the diesel desulphurization facilities was completed in July 2006, enabling the production of ultra low sulphur diesel sufficient to meet the regulatory requirements.

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

In combination with the diesel desulphurization project, we are in the process of modifying the refinery s processing capacity, enabling it to process up to 40,000 bpd of Oil Sands sour crude blends. The project is expected to be completed in 2007. The original cost estimate for the combined project of $800 million has been revised upward to $960 million.

Ethanol Plant In July 2006, we completed our ethanol facility on time and on budget, for a final cost of $112 million, and with a production capacity of 200 million litres per year. The ethanol produced is available for blending into our Sunoco-branded fuels and fuels sold through our joint venture operated networks. Natural Resources Canada contributed $22 million towards this project through their Ethanol Expansion Program.

Refining & Marketing U.S.A. (R & M)

As part of the agreement to acquire assets from ConocoPhillips Company (ConocoPhillips) in August 2003, we 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 capital obligations were met during a planned maintenance shutdown in 2006. The total cost was approximately $60 million (approximately US$50 million). These expenditures reduce air emissions at our refinery, and were primarily capital in nature. There are other continuing non-capital obligations under the Consent Decree that will continue for several more years.

On May 31, 2005 we acquired a second refinery from Valero Energy Corporation (Valero) in the Denver area adjacent to our existing refinery. The 30,000 bpd Valero refinery was purchased for $37 million (US$30 million) plus working capital and associated oil and product inventory adjustments, for a total acquisition cost of $62 million (US$50 million). The refinery was acquired by purchasing all of the issued and outstanding stock of Valero s indirect wholly-owned subsidiary, Colorado Refining Company (CRC). CRC was subsequently merged into Suncor Energy (USA) Inc. effective August 1, 2005. We continue efforts to fully integrate the two operations, providing combined refining capacity of approximately 90,000 bpd in the U.S.

Along with the purchase of the Valero assets, we assumed environmental regulatory and contractual obligations of CRC at the refinery, including CRC s obligation under a Consent Decree with the United States Environmental Protection Agency, the United States Department of Justice and the State of Colorado for alleged violations of air regulations prior to our purchase, as well as a Compliance Order on Consent with the State of Colorado, relating to groundwater and soil contamination. The Consent Decree obligations are expected to require expenditures of approximately $25 million (US$20 million) through 2011.

Desulphurization Projects In July 2006, R&M completed its diesel desulphurization and oil sands integration project at a total cost of approximately $530 million (US$435 million). The completion of the project allows us to produce ultra low sulphur diesel to meet requirements for fuels desulphurization legislation, and enable the refinery to process up to 15,000 bpd of Oil Sands sour crude oil, while also increasing the refinery s ability to process a broader slate of bitumen based crude oil. The clean fuels legislation required production of lower diesel sulphur levels (15 ppm) by June 2006, and requires lower gasoline sulphur levels (30 ppm average, 80 ppm cap) by 2009.

We are currently assessing plans for additional refinery modifications in 2007 and beyond in order to have the potential to integrate additional volumes of Oil Sands crude oil.

Other

Financing Activities

Our available credit facilities at December 31, 2006 totaled approximately $2.3 billion, of which $1.8 billion was undrawn. Available credit facilities include a $2.0 billion agreement expiring in 2011, and a $300 million agreement expiring in 2008. Our current long-term debt ratings are A(low) by Dominion Bond Rating Service, A3 by Moody s Investors Service and A- by Standard & Poor s. All debt ratings have a stable outlook.

In 2004, we repurchased an undivided interest in our Oil Sands energy service assets previously held under a lease financing arrangement with a third party for $101 million.

In 1999, we completed an offering of preferred securities the proceeds of which totaled Canadian $507 million after issue. We redeemed these securities on March 15, 2004, for the original principal amount plus accrued and unpaid interest as at March 15, 2004. See Note 1(a) to our Consolidated Financial Statements, which is incorporated by reference herein.

Renewable Energy

In November 2006, we, along with our joint venture partners, Enbridge Income Fund and Acciona Wind Energy Canada Inc., officially opened a 30-megawatt wind power project near Taber, Alberta called the Chin Chute Wind Power Project. The project includes 20 wind turbines with the capacity to produce enough zero-emission electricity to offset the equivalent of approximately 102,000 tonnes of carbon dioxide per year.

In November 2005, we, along with our joint venture partner Acciona Wind Energy Canada Inc., were selected by the Ontario government to build a 76-megawatt wind power project near Ripley, Ontario. The Ripley Wind Power project is expected to include 38 wind turbines and offset approximately 66,000 tonnes of carbon dioxide annually. Commissioning is targeted for late 2007.

Other Transactions

In 2004, we repurchased approximately 2.1 million barrels of crude oil originally sold to a Variable Interest Entity (VIE) in 1999 for net consideration of $49 million. As we economically hedged the repurchase of the inventory the net consideration paid was equal to the original proceeds we received in 1999 when the inventory was sold to the VIE.

In 2004, we received $40 million for the sale of certain proprietary technology. Throughout 2005, $40 million was received for the provision of associated training services. Amounts are being recognized into income over the term of the sale agreement.

In September 2004, we, along with our joint venture partners, Enbridge Income Fund and Acciona Wind Energy Canada Inc., officially opened the 30-megawatt Magrath Wind Power Project (Magrath) in southern Alberta. Magrath s zero-emissions electricity production is expected to offset the equivalent of approximately 82,000 tonnes of carbon dioxide per year. The project has benefited from the support of the Federal Government s Wind Power Production Incentive.

For further information on developments and issues referred to above and other highlights of 2006, and a discussion of other trends known to us that could reasonably be expected to have a material effect on the company, refer to the Outlook and other sections of Suncor s MD&A, and to Risk Factors in this Annual Information Form.

NARRATIVE DESCRIPTION OF THE BUSINESS

OIL SANDS (OS)

Suncor produces a variety of refinery feedstock, diesel fuel and by-products by developing the Athabasca oil sands in northeastern Alberta and upgrading the bitumen extracted at our plant near Fort McMurray, Alberta. Our Oil Sands operations, accounting for virtually all of our conventional and synthetic crude oil production in 2006, represent a significant portion of our 2006 capital employed (65%)[(6)], cash flow from operations (83%)[(6)] and net earnings (89%). These percentages have been determined excluding the corporate and eliminations segment information.

Operations

Our integrated Oil Sands business involves four operations located north of Fort McMurray, Alberta off Highway 63.

1) Bitumen is supplied from a combination of a mining operation using trucks and shovels, an in-situ operation and third party bitumen supply. Commencing in 2004, the Firebag in-situ operation began producing bitumen which was initially sold into the market as diluted bitumen. Since late 2005, bitumen from Firebag is being upgraded, with only a small portion of production being strategically sold directly into the market.

2) Extraction facilities recover the bitumen from the oil sands ore that is mined.

3) Heavy oil upgrading converts bitumen into crude oil products.

4) Currently, our energy service needs are primarily met through facilities operated by TransAlta that provide steam and electricity to the operations. In an effort to reduce our future external steam and electricity needs, we are constructing our own cogeneration facility to assist in meeting growth project steam and electricity needs. It is currently on schedule to be completed in 2007.

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.

We continue to explore and develop improved and alternative technologies to facilitate increased efficiency and processing within our mining operation. Based on the results of testing performed during 2006, we plan to utilize certain mobile mining and extraction equipment and processes in our future mine development plans.

Our in-situ operation uses an extraction technology called Steam Assisted Gravity Drainage (SAGD) to extract bitumen from oil sands deposits that are too deep to be mined economically. The first step of the SAGD process is to drill a pair of horizontal wells with one well located above the other. Steam produced by our steam generation facilities is injected through the top well into the oil sands. Heated bitumen and condensed steam drain into the bottom well and flow up the well to the surface. The bitumen is pumped to our oil/water separation facilities where the water is removed from the bitumen, treated, and recycled into the steam generation facilities. Naphtha is added to the bitumen to facilitate transportation and the blended bitumen is transported by pipeline to our upgrading facilities.

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 synthetic crude oil, is either sold directly to customers as sour synthetic crude

(6) Refer to Non GAAP Financial Measures on page ix of this AIF.

oil or is further upgraded into sweet synthetic 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.

While there is virtually no finding cost associated with synthetic crude oil, the delineation of the resource and development and expansion of production can entail significant capital outlays. For the same reason, the costs associated with synthetic crude oil production are largely fixed, 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 in SAGD production at our Firebag operations, and accordingly natural gas prices are a key variable component of synthetic crude oil production costs.

In the normal course of our operations we regularly complete planned maintenance shutdowns of our oil sands facilities. These shutdowns are scheduled, and provide both preventative maintenance and capital replacement which are expected to improve our operational efficiency. The next major scheduled shutdown is a planned 50 day shutdown in 2007 to enable key tie-ins for capital expansion projects expected to come online in 2008.

Principal Products

Sales of light sweet synthetic crude oil and diesel represented 58% of Oil Sands consolidated operating revenues in 2006, compared to 54% in 2005. The balance of our revenues were comprised of light sour synthetic crude oil and bitumen sales of 42% (2005 46%). Set forth below is information on daily sales volumes and the corresponding percentage of Oil Sands consolidated operating revenues by product for each of the last two years.

	2006		**2005**	
Product:	**(thousands of barrels per day)**	**(% of Oil Sands consolidated revenues)**	**(thousands of barrels per day)**	**(% of Oil Sands consolidated revenues)**
Light sweet crude oil/diesel	138.7	58	88.9	54
Light sour crude oil/bitumen	124.4	42	76.4	46
Total	263.1	100	165.3	100

In 2005, sales volumes and sales mix were adversely impacted by the fire at our Oil Sands operation that occurred January 2005. We anticipate that approximately 52% of Oil Sands sales in 2007 will be light sweet synthetic crude and diesel products.

Principal Markets

We market our crude oil product blends principally to customers in Canada and the United States, and periodically to offshore markets.

Transportation

We own and operate a pipeline that transports synthetic crude oil from Fort McMurray, Alberta to Edmonton, Alberta. The pipeline has a capacity of approximately 110,000 bpd.

Our Oil Sands business unit entered into a transportation service agreement with a subsidiary of Enbridge Inc. for a term that commenced in 1999 and extends to 2028. Under the agreement, our current pipeline capacity for the transport of synthetic crude oil and diluted bitumen from Fort McMurray, Alberta to Hardisty, Alberta is 170,000 bpd. This pipeline, together with our proprietary pipeline, is expected to meet our anticipated crude oil shipping requirements for expected future production levels until 2008.

In 2005, Suncor entered into a binding memorandum of understanding with Enbridge Pipelines (Athabasca) Inc, Petro-Canada, Total E&P Canada Limited, and ConocoPhillips Surmont Partnership for the transportation of crude oil, on a proposed new pipeline running from Cheecham, Alberta to Edmonton, Alberta. The expected in-service date of the line is targeted for July 1, 2008, with a 25 year term. Initial line capacity is expected to be 350,000 bpd with potential expansion of capacity to 600,000 bpd with the construction of additional pumping facilities. Our initial line commitment is 30,000 bpd. It is expected that the pipeline will provide an enhanced ability to access new markets on the West coast and offshore. We, along with other industry shippers, are assessing additional Athabasca-region pipeline options beyond 2008.

Periodically, we also enter into strategic short term cargo transport agreements to ship synthetic crude oil to the United States Gulf Coast. These agreements have a term of less than one year, and are specific to individual shipments.

We have a 20 year agreement with TransCanada Pipeline Ventures Limited Partnership to provide us with firm capacity on a natural gas pipeline that came into service in 1999. The natural gas pipeline ships natural gas to our Oil Sands facility.

We also transport natural gas to our Oil Sands operations on the company-owned and operated Albersun pipeline, constructed in 1968. It extends approximately 300 kilometres south of the plant and connects with TransCanada Pipeline s Alberta intra-provincial pipeline system. The Albersun pipeline has the capacity to move in excess of 100 mmcf/day of natural gas. We arrange for natural gas supply and control most of the natural gas on the system under delivery based contracts. The pipeline moves natural gas both north and south for us and other shippers.

Our Oil Sands mining facilities are readily accessible by public road. Our Firebag in-situ facilities are currently accessible by private road. We anticipate termination of such access in 2009, and are currently evaluating alternative means of access.

Competitive Conditions

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

Seasonal Impacts

Severe climatic conditions at Oil Sands can cause reduced production 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, we entered into a long-term agreement with Koch Industries Inc. (Koch) to supply Koch with up to 30,000 bpd (approximately 11% of our average 2006 total production (2005 18%)) of sour crude from the Oil Sands operation. We began shipping the crude to Koch at Hardisty, Alberta (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 on twenty-four months notice by either party. Neither party has provided notice of termination at this time.

Under a long term sales agreement with Consumers Co-operative Refineries Limited (CCRL) we supply 20,000 bpd of sour crude oil production. In 2005, we signed another contract with CCRL for an additional 12,000 bpd of sour crude oil. Prices for sour crude oil under both of these agreements are set at agreed differentials to market benchmarks. Both CCRL agreements extend through to 2011, with renewal options that could extend out to 2018 and beyond.

In 2001, we announced an agreement with Petro-Canada to supply up to 30,000 bpd of diluent to dilute bitumen produced by Petro-Canada. Deliveries under the contract are expected to end when the bitumen processing and sour crude oil supply agreement with Petro-Canada, described below, takes effect in 2008. Under the agreement, we will process a minimum of 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, we will sell an additional 26,000 bpd of our 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.

There were no customers that represented 10% or more of our consolidated revenues in 2006, 2005, or 2004.

A portion of our Oil Sands production is used in connection with our Sarnia and Commerce city refining operations. During 2006, the Sarnia refinery processed approximately 8% (2005 - 4%) of Oil Sands crude oil production and the Commerce City refinery processed approximately 3% (2005 3%) of Oil Sands crude oil production.

Environmental Compliance

For a discussion of environmental risks at our Oil Sands operations, refer to the Legal and Regulatory Risks outlined in the Risk Factors section of this Annual Information Form, as well as the Asset Retirement Obligations section under Critical Accounting Estimates in the Suncor Overview and Strategic Priorities section of our MD&A.

NATURAL GAS (NG)

Our Natural Gas business, based in Calgary, Alberta, explores for, develops and produces conventional natural gas and natural gas liquids in western Canada, supplying it to markets throughout North America. The sale of NG s production provides a natural price hedge for natural gas purchased for consumption at our Oil Sands facility and our refineries in Sarnia, Ontario and near Denver, Colorado.

In addition, our U.S. subsidiary, Suncor Energy (Natural Gas) America Inc., continues to acquire land and explore for coal bed methane in the United States.

In 2006, natural gas and natural gas liquids accounted for approximately 97% of the NG business unit s production (2005 98%).

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. We drill primarily medium to high-risk wells focusing on prospects that are in proximity to existing infrastructure. Production in 2006 was below expectations due to shut-in production as a result of pipeline and processing facility constraints, as well as delayed production.

Marketing, Pipeline and Other Operations

We operate natural gas processing plants at South Rosevear, Pine Creek, Boundary Lake South, Progress and Simonette with a total design capacity of approximately 315 mmcf/d. Our capacity interest in these gas processing plants is approximately 135 mmcf/d. We also have varying undivided percentage interests in natural gas processing plants operated by other companies and processing agreements in facilities where we do not hold an ownership interest.

Approximately 83% of our natural gas production is sold to SEMI and then 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, we are responsible

for transportation arrangements to the point of sale.

Approximately 17% of our 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 our system sales volumes are contracted to Cargill Gas Marketing Ltd. (formerly TransCanada Gas Services) and Pan-Alberta Gas. 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, we have a long-term gas pipeline transportation contract on the National Energy Group Transmission Pipeline (formerly Pacific Gas Transmission).

We do not typically enter long-term supply arrangements for our conventional crude oil production. Instead, our conventional crude oil production is generally sold under spot contracts or under contracts that can be terminated on relatively short notice. Our 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.

Principal Products

Sales of natural gas represented 90% (2005 91%) of NG s consolidated operating revenues in 2006, with the remaining 10% (2005 9%) comprised of sales of natural gas liquids and crude oil. Set forth below is information on daily sales volumes and the corresponding percentage of Natural Gas consolidated operating revenues by product for the last two years.

	2006		**2005**	
Product:	**(thousands of barrels of oil equivalent per day)**	**(% of NG consolidated revenues)**	**(thousands of barrels of oil equivalent per day)**	**(% of NG consolidated revenues)**
Natural gas	31.8	90	31.6	91
Natural gas liquids	2.3	7	2.4	7
Crude oil	0.7	3	0.8	2
Total	34.8	100	34.8	100

Competitive Conditions

Competitive conditions affecting NG are described under Competition in the Risk Factors section of this Annual Information Form.

Seasonal Impacts

Risk and uncertainties associated with weather conditions can shorten the winter drilling season and impact the spring and summer drilling programs, with increased costs or reduced production.

Environmental Compliance

For a discussion of environmental risks at our NG operations, refer to the Legal and Regulatory Risks outlined in the Risk Factors section of this Annual Information Form, as well as the Asset Retirement Obligations section under Critical Accounting Estimates in the Suncor Overview and Strategic Priorities section of our MD&A.

ENERGY MARKETING & REFINING   CANADA (EM&R)

Our EM&R business unit operates a refining and marketing business in Central Canada, and an energy marketing and trading business. Our refinery in Sarnia, Ontario, refines petroleum feedstock from Oil Sands and other sources into gasoline, distillates, biofuels and petrochemicals with the majority of these refined products being distributed in Ontario. Our ethanol facility in St. Clair, Ontario, produces ethanol from corn, which is used for blending into our fuels and sold to third parties. For information about EM&R s energy marketing and trading business, refer to Energy Marketing and Refining Canada (EM&R) under the Three-Year Highlights , Energy Marketing & Trading heading.

As a marketing channel for our refined products, EM&R s Ontario retail network generated approximately 58% of EM&R s total 2006 sales volume of 95,000 bpd. The retail networks are comprised of Sunoco-branded retail service stations, Sunoco-branded Fleet Fuel Cardlock sites, and two 50% retail joint venture[7] businesses that operate Pioneer-branded retail service stations, UPI-branded retail service stations and UPI bulk distribution facilities for rural and farm fuels. Approximately 36% of EM&R s refined product sales in 2006 were wholesale and industrial sales. Sun Petrochemicals Company (SPC), a 50% joint venture between a Suncor subsidiary and a Toledo, Ohio-based refinery, generated the remaining 6% of sales.

Procurement of Feedstocks

The Sarnia refinery uses both synthetic and conventional crude oil. In 2006, the Sarnia refinery procured approximately 55% (2005 16%) of its synthetic crude oil feedstock from our Oil Sands production. In 2006, 60% (2005 62%) 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.

We procure conventional crude oil feedstock for our Sarnia 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. We have not made any firm capacity commitments on these pipeline systems. Crude oil is procured from the market on a spot basis or under contracts which can be terminated on short notice.

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

In July 2006, with the completion of our ethanol facility we produce ethanol for use in our blended gasoline products, and for sales to third parties.

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. Upgrading units include a 23,300 bpd hydrocracker, and a 5,400 bpd alkylation unit. The petrochemical facilities have a capacity of 13,100 bpd,

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(7) Pioneer Group Inc. is an independent company with which Suncor has a 50% joint venture partnership. UPI Inc. is a 50% joint venture company Suncor has with GROWMARK Inc., a Midwest U.S. retail farm supply and grain marketing cooperative.

the aromatic solvents unit has a capacity of approximately 1,000 bpd, and our gasoline desulphurization unit has a capacity to process 10,250 bpd. The distillate hydrotreater that became operational in July 2006 has a processing capacity of 43,600 bpd

The refinery has a cracking capacity of 40,200 bpd 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 2004, a sustainability study to assess the catcracker concluded that, with planned improvements and upgrades, it can continue to be operated economically and safely for up to 10 years. A range of replacement options for the catcracker was identified during a review in 2005. Continued analysis of these and other options will occur through 2007, as we work to identify the preferred option for the catcracker.

Overall, crude utilization averaged 78% for the year, compared to 95% in 2005. 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. The comparatively low utilization rates in 2006 were a result of a major maintenance shutdown during 2006.

Sarnia Refinery Capacity	2006	2005
Average daily crude input (barrels per day)	57,400	66,700
Average crude utilization rate (%)(1)	78	95
Average cracking capacity utilization (%)(2)	82	95

Notes:

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

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

The refinery s external steam and electricity needs are currently being met by supply from the Sarnia Regional Co-generation Project.

In the normal course of our operations we regularly complete planned maintenance shutdowns of our EM&R refinery facilities. These shutdowns are scheduled, and provide both preventative maintenance and capital replacement which is expected to improve our operational efficiency. During 2006, a significant maintenance shutdown was successfully completed.

Principal Products

Sales of gasoline and other transportation fuels represented 58% of EM&R s consolidated operating revenues in 2006, compared to 68% in 2005. 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:	2006 (thousands of cubic meters per day)	2006 (% of EM&R s consolidated revenues)	2005 (thousands of cubic meters per day)	2005 (% of EM&R s consolidated revenues)
Transportation Fuels				
Gasoline				
Retail	4.6	24	4.5	27
Joint Ventures	3.0	10	2.8	15
Other	0.9	9	1.1	7
Jet Fuel	0.7	2	0.9	4
Diesel	3.3	13	3.3	15
Sub-total Transportation Fuels	12.5	58	12.6	68
Petrochemicals	0.9	5	0.7	4
Heating Fuels	0.5	2	0.4	3
Heavy Fuel Oils	0.8	1	1.0	2
Other	0.6	2	0.5	2
Total Refined Products	15.3	68	15.2	79
Other Non-Refined Products(1)		3		3
Energy Marketing & Trading		29		18
Total %		100		100

Note:

(1) Includes ancillary revenues

Principal Markets

Approximately 58% (2005 57%) of EM&R s total sales volumes are marketed through retail networks, including the Sunoco-branded retail network, joint venture operated retail stations and cardlock operations. In 2006, this network was comprised of:

272 (2005 275) Sunoco-branded retail service stations

151 (2005 149) Pioneer-operated retail service stations

53 (2005 50) UPI-operated retail service stations and a network of 14 bulk distribution facilities for rural and farm fuels

36 (2005 28) Sunoco branded Fleet Fuel Cardlock sites

UPI Inc. 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.

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

Approximately 36% (2005 39%) 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.

EM&R markets toluene, mixed xylenes, orthoxylene and other petrochemicals, primarily in Canada and the U.S., through Sun Petrochemicals Company (SPC). EM&R has a 50% interest in SPC, a petrochemical marketing joint venture that markets products from our Sarnia, Ontario refinery and from a Toledo, Ohio, refinery owned by the joint venture partner. SPC 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, Ontario.

EM&R s share of total refined product sales in its primary market of Ontario was approximately 18% in 2006 (2005 19%). Transportation fuels accounted for 82% of EM&R s total sales volumes in 2006 (2005 82%); and petrochemicals accounted for 6% (2005 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. We have a separate supply agreement with each of UPI and Pioneer. These supply agreements are evergreen, subject to termination only in accordance with the terms of 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 us and 45% owned by another refiner. The pipeline operates as a private facility for its owners, serving terminal facilities in Toronto, Hamilton and London, with a capacity of 130,800 bpd (20,800 cubic metres). EM&R utilized 50% of this capacity in 2006 (2005 54%). Total utilization of the pipeline was 77% in 2006 (2005 - 84%).

EM&R also has pipeline access, subject to availability, to petroleum markets in the Great Lakes region of the United States by way of 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.

We believe our own storage facilities, and those under long-term contractual arrangements with other parties, are sufficient to meet our current and foreseeable storage needs.

Competitive Conditions

Competitive conditions affecting our EM&R business are described under Competition in the Risk Factors section of this Annual Information Form.

Environmental Compliance

For a discussion of environmental risks at our EM&R operations, refer to the Legal and Regulatory Risks outlined in the Risk Factors section of this Annual Information Form, as well as the Asset Retirement Obligations section under Critical Accounting Estimates in the Suncor Overview and Strategic Priorities section of our MD&A.

REFINING & MARKETING U.S.A. (R & M)

Our R&M business unit operates a refining and marketing, and pipeline transportation business primarily in Colorado and Wyoming. The Denver area refining facility, located in Commerce City, Colorado, has a combined crude distillation capacity of 90,000 bpd. The majority of the refined products from the Denver refinery are distributed in Colorado.

Approximately 18% of R&M s petroleum products sales in 2006 (2005 18%) were sold through a distribution network in Colorado that sells gasoline and diesel fuel to retail customers. In 2006, approximately 74% (2005 70%) of R&M s petroleum product sales volumes were to industrial, commercial, wholesale and refining customers in Colorado, representing primarily jet fuels, diesel and gasoline. Asphalt sales comprised the remaining 8% of R&M s refined product sales volumes for 2006 (2005 12%).

Procurement of Feedstocks

The Denver refining operation uses both conventional and synthetic crude oil. Approximately one-quarter of the 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. With the completion of our diesel desulphurization and oil sands integration project in July 2006, the refinery facility commenced processing up to 15,000 bpd of Oil Sands sour crude oil.

The refinery s crude oil purchase contracts have terms ranging from month-to-month to multi-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.

Refining Operations

Upgrading units at the refining operation include two fluidized catalytic crackers with a 29,500 bpd combined capacity, a 19,000 bpd distillate hydrotreater and a 26,000 bpd gas oil hydrotreater. The refined gasoline products from the Denver refinery supply R&M s marketing operations in Colorado. Refining sales in 2006 averaged approximately 90,600 bpd (14,400 m^3 per day) compared to 86,200 bpd (13,700 m^3) in 2005.

The Denver area refining operation is a high conversion operation 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 approximately one-third heavy, high sulphur crude. Overall, crude utilization averaged 92% in 2006 (2005 98%). The following chart sets out daily crude input, average refinery utilization rates and cracking capacity utilization for 2006 and 2005.

Denver Refining Capacity	**2006**	**2005**
Average daily crude input (barrels per day)(1)	82,600	76,300
Average crude utilization rate (%)(2)	92	98
Average fluidized catalytic cracker capacity utilization rate (%)(3)	76	89

Notes:

(1) 30,000 bpd Valero refinery capacity acquired May 31, 2005.

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

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

In the normal course of our operations we regularly complete planned maintenance shutdowns of our R&M refinery facilities. These shutdowns are scheduled, and provide both preventative maintenance and capital replacement which is expected to improve our operational efficiency. During 2006, a significant maintenance and capital tie-in shutdown was successfully completed.

Principal Products

Sales of gasoline and other transportation fuels represented 93% of R&M s consolidated operating revenues in 2006 (2005 90%). Set forth below is information on daily sales volumes and percentage of R&M s consolidated operating revenues contributed by product group for 2006 and 2005.

	2006		2005	
Product:	**(Thousands of cubic meters per day)**	**(% of R&M s consolidated revenues)**	**(Thousands of cubic meters per day)**	**(% of R&M s consolidated revenues)**
Transportation Fuels				
Gasoline				
Retail	0.7	11	0.7	11
Other	6.8	48	6.2	46
Jet Fuel	1.0	7	0.8	6
Diesel	3.6	27	3.3	27
Total Transportation Fuels	12.1	93	11.0	90
Asphalt	1.2	4	1.6	4
Other	1.1	2	1.1	4
Total Refined Product Sales	14.4	99	13.7	98
Other Non-Refined Product(1)		1		2
		100		100

Note:

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

Principal Markets

Approximately 18% 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 5% of R&M s sales volumes; and

Supply agreements with 167 Phillips 66 ® branded marketer outlets throughout the state of Colorado, which account for approximately 13% 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.

We have an exclusive license from ConocoPhillips to use the Phillips 66 ® and related trademarks and brand names in Colorado until December 31, 2012.

The Denver refining operation also supplies all of its asphalt production to SemMaterials, L.P. Asphalt sales made up about 8% of R&M s total 2006 sales volumes (2005 12%).

Approximately 74% of R&M s total sales volumes are sold to industrial, commercial, wholesale, and refining customers, primarily in Colorado, of which approximately 13% was sold under a long-term supply agreement with ConocoPhillips (expiring in 2013) and 24% under a supply agreement with Valero (expiring in 2008).

R&M estimates its sales of total light fuels refined product in 2006 represented a market share, in its primary market of Colorado, of approximately 40% (2005 35%). Within this market, R&M s Phillips 66 ® - branded sites represent a 15% market share (2005 18%).

Transportation and Distribution

Approximately three-quarters of crude oil processed at the Denver refining operation is transported via pipeline, with the remainder supplied via truck. R&M owns and operates the Rocky Mountain Crude system which runs from Guernsey, Wyoming to Denver, Colorado. This pipeline is a common carrier pipeline that transports crude for the Denver refinery as well as for other shippers. We also operate a joint venture crude pipeline, the Centennial pipeline, from Guernsey, Wyoming to Cheyenne, Wyoming. We own approximately 65% of the Centennial pipeline. The other 35% is owned by another area refiner. The Rocky Mountain crude system had a capacity of 38,000 bpd in 2006 for the Guernsey to Cheyenne leg of the pipeline and 73,500 bpd for the Cheyenne to Denver leg of the pipeline. In 2006, the Rocky Mountain Crude system utilized approximately 81% (2005 115%) of its capacity with average throughput of 28,200 bpd (2005 35,400 bpd) in the Guernsey to Cheyenne leg of the pipeline, and 62,400 bpd (2005 - 70,150 bpd) in the higher capacity Cheyenne to Denver leg. During the same period, the Centennial pipeline utilized approximately 85% (2005 102%) of capacity, with an average throughput of approximately 54,400 bpd (2005 62,500 bpd).

R&M has both truck and rail loading racks at the Denver area refining facility with product loading capacity in excess of 30,000 bpd, 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.

We believe our own storage facilities, and those under long-term contractual arrangements with other parties, are sufficient to meet our current and foreseeable storage needs.

Competitive Conditions

Competitive conditions affecting our R&M business are described under the heading Competition in the Risk Factors section of this Annual Information Form.

Environmental Compliance

Due to increasingly stringent regulations regarding water discharges, we need to improve water treatment capability at our Denver refining operation which will require additional water treating equipment for the discharge of process waste water. It is estimated that this will cost approximately $19 to $23 million (US$16 to $20 million) and be completed in the 2007 to 2010 timeframe.

For a discussion of environmental risks at our R&M operations, refer to the Legal and Regulatory Risks outlined in the Risk Factors section of this Annual Information Form, as well as the Asset Retirement Obligations section under Critical Accounting Estimates in the Suncor Overview and Strategic Priorities section of our MD&A.

MATERIAL CONTRACTS

During the year ended December 31, 2006, we have not entered into any contracts, nor are there any contracts still in effect, that are material to our business, other than contracts entered into in the ordinary course of business and the Shareholder Rights Plan dated April 28, 2005.

RESERVES ESTIMATES

We are a Canadian issuer subject to Canadian reporting requirements, including rules in connection with the reporting of our reserves. However, we have received an exemption from Canadian securities administrators permitting us to report our reserves in accordance with U.S. disclosure requirements. Pursuant to U.S. disclosure requirements, we disclose net proved conventional oil and gas reserves, including natural gas reserves and bitumen reserves from our Firebag in-situ leases, using constant dollar cost and pricing assumptions. As there is no recognized posted bitumen price, these assumptions are based on a posted benchmark oil price, adjusted for transportation, gravity and other factors that create the difference (differential) in price between the posted benchmark price and Suncor s bitumen. Both the posted benchmark price and the differential are generally determined as of a point in time, namely December 31 (Constant Cost and Pricing). Reserves from our Firebag in-situ leases are reported as barrels of bitumen, using these Constant Cost and Pricing assumptions (see REQUIRED U.S. OIL AND GAS AND MINING DISCLOSURE Proved Conventional Oil and Gas Reserves for net proved conventional oil and gas reserves).

Pursuant to U.S. disclosure requirements, we also disclose gross and net proved and probable mining reserves. The estimates of our gross and net mining reserves are based in part on the current mine plan and estimates of extraction recovery and upgrading yields. We report mining reserves as barrels of synthetic crude oil based on a net coker, or synthetic crude oil yield from bitumen of 80%. During 2005, we reached an agreement with the Government of Alberta finalizing the terms of our option to transition to the generic bitumen based royalty regime commencing in 2009, allowing us to prepare an estimate of our net mining reserves. The estimate of our net mining reserves reflects the value of Alberta Crown and freehold royalty burdens under constant December 31st bitumen pricing and our exercise of the option electing to transfer to a bitumen based Crown royalty effective at the beginning of 2009 (See REQUIRED U.S. OIL AND GAS AND MINING DISCLOSURE Proved and Probable Oil Sands Mining Reserves for both gross and net, proved and probable mining reserves). Our Firebag in-situ leases are subject to Crown royalty based on bitumen, rather than synthetic crude oil. As there is currently no legislated methodology for determining bitumen value for Alberta Crown royalty purposes, bitumen value for determining royalties has been assumed to equal the bitumen value used to determine reserve quantities. However, determination of bitumen value for royalty purposes is currently under review by the Government of Alberta. For a full discussion of our oil sands Crown royalties, see Oil Sands Crown Royalties and Cash Income Taxes in the Suncor Overview and Strategic Priorities section of our MD&A.

In addition to required disclosure, our exemption issued by Canadian securities administrators permits us to provide further disclosure voluntarily. We provide this additional voluntary disclosure to show aggregate proved and probable oil sands reserves, including both mining reserves and reserves from our Firebag in-situ leases. In our voluntary disclosure we report our aggregate reserves on the following basis:

Gross and net proved and probable mining reserves, on the same basis as disclosed pursuant to U.S. disclosure requirements (reported as barrels of synthetic crude oil based upon a net coker, or synthetic crude oil yield from bitumen of 80%); and

Gross and net proved and probable bitumen reserves from Firebag in-situ leases, evaluated based on constant dollar cost and pricing assumptions. Bitumen reserves estimated on this basis are subsequently converted, for aggregation purposes only, to barrels of synthetic crude oil based on a net coker or synthetic crude oil yield from bitumen of 80%.

Accordingly, our voluntary disclosures of reserves from our Firebag in-situ leases will differ from our required U.S. disclosure in three ways. Reserves from our Firebag in-situ leases under our voluntary disclosure:

(a) are disclosed on a gross basis as well as the required net basis under U.S. disclosure requirements;

(b) are converted from barrels of bitumen under U.S. disclosure requirements to barrels of synthetic crude oil for aggregation purposes only;

(c) include proved plus probable reserves, rather than proved reserves only under U.S. disclosure requirements.

Under the U.S. disclosure requirements described above, our Firebag in-situ reserves were determined to be entirely uneconomic at December 31, 2004. In 2005, Constant Cost and Pricing assumptions were again applied to assess economic viability of our in-situ reserves. This assessment resulted in the rebooking of proved reserves at December 31, 2005. At December 31, 2006, pricing assumptions were again considered economically viable and our proved reserves disclosures reflect this. (See REQUIRED U.S. OIL AND GAS AND MINING DISCLOSURE - Proved Conventional Oil and Gas Reserves).

Under our voluntary disclosure, the year end 2006 bitumen price determined pursuant to SEC pricing methodology was not materially different than the price determined pursuant to CSA Staff Notice 51-315. Consequently for 2006 only one constant price scenario was used for year end disclosures. Refer to VOLUNTARY OIL SANDS RESERVES DISCLOSURE - Estimated Gross and Net Proved and Probable Oil Sands Reserves Reconciliations .

Comparisons of reserve estimates under Required U.S. Oil and Gas Mining Disclosure and Voluntary Oil Sands Reserve Disclosure may show material differences based on the pricing assumptions used, whether the reserves are reported as barrels of bitumen or barrels of synthetic crude oil, whether probable reserves are included, and whether the reserves are reported on a gross or net basis. These differences were more significant during 2004 and 2005 with considerably lower constant price assumptions. At December 31, 2006, there was no difference arising from pricing.

All of our reserves have been evaluated as at December 31, 2006, by independent petroleum consultants, GLJ Petroleum Consultants Ltd. (GLJ). In reports dated February 9, 2007 (GLJ Oil Sands Reports), GLJ evaluated our proved and probable reserves on our oil sands mining and Firebag in-situ leases pursuant to both U.S. disclosure requirements using Constant Cost and Pricing assumptions.

Estimates in the GLJ Oil Sands Reports consider recovery from leases for which regulatory applications have been submitted and no impediment to the receipt of regulatory approval is expected. The mining reserve estimates are based on 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 in-situ reserve estimates, GLJ considered similar factors such as our regulatory approval or likely impediments to the receipt of pending regulatory approval, project implementation commitments, detailed design estimates, detailed reservoir studies, demonstrated commercial success of analogous commercial projects and drill density. Our proved reserves are delineated to within 80 acre spacing with 3D seismic control (or 40 acre spacing without 3D seismic control) while our probable reserves are delineated to within 160 acre spacing without 3D seismic control. The major facility expenditures to develop our proved undeveloped reserves have been approved by our Board. Plans to develop our probable undeveloped reserves in subsequent phases are under way but have not yet received final approval from our Board.

In a report dated February 9, 2007 (GLJ NG Report), GLJ also evaluated our proved reserves of natural gas, natural gas liquids and crude oil (other than reserves from our mining leases and the Firebag in-situ reserves) as at December 31, 2006.

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

Net reserves represent Suncor s undivided percentage interest in total reserves after deducting Crown Royalties, freehold and overriding royalty interests. Reserve estimates are based on assumptions about future prices, production levels, operating costs, capital expenditures, and the current Government of

Alberta royalty regime. These assumptions reflect market and regulatory conditions, as required, at December 31, 2006, which could differ significantly from other points in time throughout the year, or future periods. Changes in market and regulatory conditions and assumptions can materially impact the estimation of net reserves.

REQUIRED U.S. OIL AND GAS AND MINING DISCLOSURE

Proved and Probable Oil Sands Mining Reserves

	Proved		**Probable**		**Proved & Probable**	
Millions of barrels of synthetic crude oil (1)	**Gross(2)**	**Net(3)**	**Gross(2)**	**Net(3)**	**Gross(2)**	**Net(3)**
December 31, 2005	1,528	1,440	896	862	2,424	2,302
Revisions of previous estimates	266	140	(262)	(298)	4	(158)
Extensions and discoveries						
Production	(85)	(73)			(85)	(73)
December 31, 2006	**1,709**	**1,507**	**634**	**564**	**2,343**	**2,071**

Notes:

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

(2) Our gross mining reserves are based in part on our current mine plan and estimates of extraction recovery and upgrading yields, rather than an analysis based on constant dollar or forecast pricing and cost assumptions.

(3) Net mining reserves reflect the value of Crown, freehold and overriding royalty burdens under constant December 31st pricing and incorporates our exercised option to elect to transfer to a bitumen based Crown royalty effective at the beginning of 2009. Refer to the Alberta Crown Bitumen-Based Royalty Regime risk, as outlined in the Risk Factors section of this AIF.

Significant Mining Leases

Interest Held	Description	Gross Acres	Expiry Date[3]	Retention Conditions
Leases:	7279080T19	18,541	n/a	(1)
	7597030T11	2,454	n/a	(1)
	7280100T25	49,365	n/a	(1)
	7387060T04	4,469	n/a	(1)
	7279120092	1,600	n/a	(1)
	7280060T23	36,526	n/a	(1)
	7498050014	240	May 27, 2019	(2)
	7405080347	5,693	Aug. 24, 2020	(2)
	7405030690	633	Mar. 23, 2020	(2)
	7405010854	22,773	Jan. 26, 2020	(2)
	7405010853	22,773	Jan. 26, 2020	(2)
	7400120007	22,773	Dec. 13, 2015	(2)
	7405080346	5,060	Aug. 24, 2020	(2)
	7401100029	10,120	Oct. 17, 2016	(2)
Permits:	7006060389	8,853	May 31, 2011	(2)
	7006060390	1,897	May 31, 2011	(2)
	7006060391	3,162	May 31, 2011	(2)
Fee Lots:	1	1,894	n/a	n/a
	2	1,972	n/a	n/a
	3	1,967	n/a	n/a
	4	1,886	n/a	n/a
	5	1,881	n/a	n/a
	6	1,483	n/a	n/a
Total		228,015		

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(1) These producing leases can be retained indefinitely so long as agreed minimum levels of production are maintained.

(2) Annual lease rentals are required to maintain these leases until the indicated expiry dates for the primary term of the lease. Leases can be retained after these dates if:

a. they are in production and sustain agreed minimum levels of production; or

b. retained indefinitely if escalating rents are paid. Depending on area, such rents range from $3/hectare/year in in-situ areas to $7/hectare/year in surface mining zones and double every three years to a maximum of $96/hectare/year in in-situ zones and $224/hectare/year in surface mining areas.

(3) There is no undeveloped acreage subject to expiration in each of the next three years.

Oil Sands Mining Operating Statistics

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

	2006	2005	2004
Total mined volume (1)			
millions of tonnes	356.2	313.7	371.2
Mined volume to tar sands ratio(1)	41.8%	32.0%	41.6%
Tar sands mined			
millions of tonnes	149.0	100.5	154.3
Average bitumen grade (weight %)	12.8%	12.2%	11.2%
Crude bitumen in mined tar sands			
millions of tonnes	19.1	12.3	17.3
Average extraction recovery %	93.1%	92.6%	91.9%
Crude bitumen production			
millions of cubic meters(2)	17.6	11.4	15.7
Gross synthetic crude oil produced			
Thousands of barrels per day(3)	231.9	152.2	215.6

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. Note, in 2004 production equaled our base operations production statistics as included in the operating summaries filed with our annual financial statements. In 2005 and subsequent years, bitumen production from Firebag is upgraded and included in the base operations production. Therefore the mining production reported above will no longer agree to the operating statistics.

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 our Oil Sands mining reserves are excluded, while in-situ Firebag reserves are included.

The following data is provided on a net basis in accordance with the provisions of the Financial Accounting Standar

NET PROVED RESERVES(1)

Crude Oil, Natural Gas Liquids and Natural Gas

Constant Cost and Pricing as at December 31	**Oil Sands business: Firebag Crude Oil (millions of barrels of bitumen) (2),(3),(4)**	**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, 2003	424	8	432	456
Revisions of previous estimates	(420)	1	(419)(5)	
Purchases of minerals in place				14
Extensions and discoveries				30
Production	(4)	(1)	(5)	(54)
Sales of minerals in place				
December 31, 2004	(3)	8	8	446
Revisions of previous estimates	639		639(5)	14
Purchases of minerals in place				
Extensions and discoveries				40
Production	(7)	(1)	(8)	(50)
Sales of minerals in place				(1)
December 31, 2005	632	7	639	449
Revisions of previous estimates	(57)		(57)(5)	5
Improved Recovery	340(6)		340	
Purchases of minerals in place				
Extensions and discoveries		1	1	26
Production	(12)	(1)	(13)	(53)
Sales of minerals in place				(1)
December 31, 2006	903	7	910	426
Proved Developed				
December 31, 2003	92	6	98	403
December 31, 2004		7	7	385
December 31, 2005	137	7	144	387
December 31, 2006	188	6	194	365

Notes:

(1) Our undivided percentage interest in reserves, after deducting Crown royalties, freehold royalties and overriding royalty interests. Our Firebag leases are only subject to Crown royalties.

(2) Although we are subject to Canadian disclosure rules in connection with the reporting of our reserves, we have received exemptive relief from Canadian securities administrators permitting us to report our proved reserves in accordance with U.S. disclosure practices. See Reliance on Exemptive Relief on pg 46.

The following data is provided on a net basis in accordance with the provisions of the Financial Accounting Standar

(3) Estimates of proved reserves from our Firebag in-situ leases are based on Constant Cost and Pricing assumptions as at December 31. In 2004, due to unusually low year-end posted benchmark oil prices, and unusually high year-end diluent prices, our proved reserves were determined to be uneconomic. Under 2005 Constant Cost and Pricing we have rebooked our proved reserves, and these continued to be economically viable in 2006.

(4) We have the option of selling the bitumen production from these leases or upgrading the bitumen to synthetic crude oil. With the completion of upgrading expansion projects during 2005, substantially all bitumen is expected to be processed into synthetic crude oil in the future, unless strategic market conditions exist.

(5) Natural gas infill drilling included in total revisions for 2006 was 11 billion cubic feet (bcf), (2005 23 bcf; 2004 20 bcf).

(6) Improved recovery recognizes a portion of our Firebag Stage 3 expansion project.

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, 2006. We do not have

The following data is provided on a net basis in accordance with the provisions of the Financial Accounting Standar

long-term supply agreements or contracts with governments in which we act as producer nor do we have any interest in oil and gas operations accounted for by the equity method.

Capitalized Costs Relating to Oil and Gas Activities (1)

($ millions)	For the years ended December 31, 2006	2005
Proved properties	3,869	3,268
Unproved properties	224	159
Other support facilities and equipment	22	15
Total cost	4,115	3,442
Accumulated depreciation and depletion	(1,041)	(852)
Net capitalized costs	3,074	2,590

Note:

(1) Capitalized costs do not include costs related to the associated upgrading expansion projects.

Costs Incurred in Oil and Gas Acquisition, Exploration and Developmental Activities (1)

	For the years ended December 31,		
($ millions)	2006	2005	2004
Property acquisition costs			
Proved properties		1	32
Unproved properties	29	9	10
Exploration costs	247	148	78
Development costs	688	552	545
Asset retirement obligations	35	4	27
Total capital and exploration expenditures	999	714	692

Note:

(1) Costs incurred do not include costs related to associated upgrading expansion projects.

Results of Operations for Oil and Gas Production

	For the years ended December 31,		
($ millions)	2006	2005	2004
Revenues			
Sales to unaffiliated customers	516	670	469
Transfers to other operations	387	52	64
	903	722	533

Expenses			
Production costs	291	213	122
Depreciation, depletion and amortization	215	145	130
Exploration	87	66	57
Gain on disposal of assets	(4)	(12)	(19)
Other related costs	40	39	73
	629	451	363
Operating profit before income taxes	274	271	170
Related income taxes	(38)	(98)	(48)
Results of operations	236	173	122

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. We caution against viewing this information as a forecast of future economic conditions or revenues, and do not consider it to represent the fair market value of our Firebag in-situ and Natural Gas properties. Figures are based on our 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:

	2006	2005	2004
Year end natural gas price (AECO- $/GJ)	7.52	10.22	7.17
Year end crude oil price (WTI US$/bbl)	62.09	59.45	43.26
Year end light/heavy crude oil differential, WTI at Cushing less LLB at Hardisty (US$/bbl)	17.99	26.35	22.71

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;

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, bitumen valuation methodology, and the impact of future expenditures on unproved properties; and

Our exercised election to move to the generic bitumen based Crown royalty effective 2009.

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. 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, we have 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 estimated cash flows related to asset retirement obligations. Deducting future income tax expenses then further reduces the estimated pre-tax future net cash flows. 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 our 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, reflects that Firebag is classified as a separate operation for royalty purposes, as described in our MD&A (see Oil Sands Crown Royalties and Cash Income Taxes in the Suncor Overview and Strategic Priorities Section of our 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)	2006	2005	2004
Future cash flows	32,882	16,444	3,355
Future production costs	(12,264)	(10,181)	(640)
Future development costs	(5,648)	(1,705)	(64)
Other related future costs	(612)	(464)	(367)
Future income tax expenses	(4,221)	(1,216)	(460)
Subtotal	10,137	2,878	1,824
*Discount at 10%	(6,768)	(1,214)	(750)
Standardized measure of discounted future net cash flows from estimated production of proved oil and gas reserves after income taxes	3,369	1,664	1,074

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

($ millions)	2006	2005	2004
Balance, beginning of year	1,664	1,074	1,851
Sales and transfers of oil and gas produced, net of production costs	(559)	(456)	(359)
Net changes in prices and production costs	1,907	737	(1,786)
Changes in estimated future development costs	(1,141)	(573)	14
Extensions, discoveries and improved recovery, less related costs	59	162	131
Development costs incurred during the period	772	557	524
Revisions of previous quantity estimates	1,051	440	(47)
Purchases of reserves in place			32
Sale of reserves in place	(2)	(4)	
Accretion of discount	231	125	245
Net changes in income taxes	(714)	(470)	426
Other related costs	101	72	43
Balance, end of year	3,369	1,664	1,074

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

The following tables set out additional information on our conventional oil and gas producing activities, including our Firebag in-situ operation. Information with respect to our Oil Sands mining operations is not covered by the information below but is addressed in the preceding information under Oil Sands Mining Operations .

Sales Prices(1), (2)

For the year ended December 31,	2006	2005	2004
Crude Oil and Bitumen ($/bbl)	38.94	45.86	37.71
NGL ($/bbl)	44.96	50.70	42.82
Natural Gas ($/mcf)	7.15	8.57	6.70

Notes:

(1) Production is based in Western Canada.

(2) Prices are calculated using our undivided percentage interest production before royalties.

Production Costs

For the year ended December 31, ($ per BOE of gross production)	2006	2005	2004
Average production (lifting) cost of conventional crude oil and gas(1)	11.92	10.86	7.08

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, and Firebag central facilities. It does not include an estimate for future asset retirement costs. These costs represent a blended average of our Firebag and Natural Gas lifting costs.

Producing Oil and Gas Wells

	Crude Oil(3)		Natural Gas		Total	
As at December 31, 2006 number of wells	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
Alberta	70	54	364	220	434	274
British Columbia	24	11	136	59	160	70
Total	94	65	500	279	594	344

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) Well information includes Firebag.

Oil and Gas Acreage

	Developed		Undeveloped(1)		Total	
As at December 31, 2006	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)

(thousands of acres)						
Canada						
Natural Gas	714	412	1,207	664	1,921	1,076
Firebag	2	2	287	287	289	289
Total Canada	716	414	1,494	951	2,210	1,365
USA						
Natural Gas			63	28	63	28
Total	716	414	1,557	979	2,273	1,393

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 mean all the acres in which we have either an entire or undivided percentage interest.

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

Drilling Activity

For the year ended December 31, 2006 (number of net wells)	Productive	Net Exploratory Dry Holes	Total	Productive	Net Development Dry Holes	Total
Canada						
Natural Gas	3	6	9	14	4	18
Firebag				8		8
United States				31		31
Total	3	6	9	53	4	57

For the year ended December 31, 2005 (number of net wells)	Productive	Net Exploratory Dry Holes	Total	Productive	Net Development Dry Holes	Total
Canada						
Natural Gas	8	3	11	18	4	22
Firebag				10		10
United States		1	1			
Total	8	4	12	28	4	32

For the year ended December 31, 2004 (number of net wells)	Productive	Net Exploratory Dry Holes	Total	Productive	Net Development Dry Holes	Total
Canada						
Natural Gas	5	5	10	15		15
Firebag				11		11
Total	5	5	10	26		26

At December 31, 2006, we were participating in the drilling of 42 gross (25 net) exploratory and development wells.

Future Commitments to Sell or Deliver Crude Oil and Natural Gas

We have entered into a number of natural gas sale commitments aggregating approximately 92 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 our reserves. All pricing under these agreements is based upon both a combination of variable, fixed and index-based terms.

As at March 1, 2007 crude oil hedges totaling 60,000 bpd of production were outstanding for the remainder of 2007 and 10,000 bpd in 2008. Prices for these barrels are fixed within a range of US$51.64 to US$93.26 per barrel in 2007 and US$59.85 to US$101.06 per barrel in 2008. We intend to consider additional costless collars of up to approximately 30% of our crude oil production if strategic opportunities are available. For further particulars of these hedging arrangements, see the information under the heading Derivative Financial Instruments , under Risk Factors Affecting Performance in the Suncor Corporate Overview and Strategic Priorities section of our MD&A, and Note 6 to our 2006 Consolidated Financial Statements, which note is incorporated by reference herein.

VOLUNTARY OIL SANDS RESERVES DISCLOSURE

Oil Sands Mining and Firebag In-Situ Reserves Reconciliation

The following tables set out, on a gross[(8)] and net basis, a reconciliation of our proved and probable reserves of synthetic crude oil from our Oil Sands mining leases and bitumen, converted to synthetic crude oil for comparison purposes only, from our in-situ Firebag leases, from December 31, 2005, to December 31, 2006, based on the GLJ Oil Sands Reports.

(8) Suncor s working interest in reserves, before deducting Crown royalties, freehold and overriding royalty interests.

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Estimated Gross Proved and Probable Oil Sands Reserves Reconciliation

(millions of barrels of synthetic crude oil)(1)	Oil Sands Mining Leases(1)(2) Proved	Probable	Proved & Probable	Firebag In-situ Leases(1)(3) Proved(3)	Probable(3)	Proved & Probable	Total Mining and In-situ(3) Proved & Probable
December 31, 2005	1,528	896	2,424	561	2,137	2,698	5,122
Revisions of previous estimates	266	(262)	4		22	22	26
Improved recovery				252	(252)		
Extensions and discoveries							
Production	(85)		(85)	(10)		(10)	(95)
December 31, 2006	1,709	634	2,343	803	1,907	2,710	5,053

Estimated Net Proved and Probable Oil Sands Reserves Reconciliation

(millions of barrels of synthetic crude oil)(1)	Oil Sands Mining Leases(1)(2) Proved	Probable	Proved & Probable	Firebag In-situ Leases(1)(3) Proved(3)	Probable(3)	Proved & Probable	Total Mining and In-situ(3) Proved & Probable
December 31, 2005	1,440	862	2,302	556	2,029	2,585	4,887
Revisions of previous estimates	140	(298)	(158)	(50)	(164)	(214)	(372)
Improved recovery				226	(226)		
Extensions and discoveries							
Production	(73)		(73)	(10)		(10)	(83)
December 31, 2006	1,507	564	2,071	722	1,639	2,361	4,432

Notes:

(1) Synthetic crude oil reserves are based upon a net coker, or synthetic crude oil yield from bitumen of 80% for reserves under Oil Sands mining and Firebag in-situ leases. Although virtually all of our bitumen from the Oil Sands mining leases is upgraded into synthetic crude oil, we have the option of selling the bitumen produced from our Firebag in-situ leases directly to the market where strategic opportunities exist. Accordingly, these bitumen reserves are converted to synthetic crude oil for aggregation purposes.

(2) Our gross mining reserves are evaluated in part, based on the current mine plan and estimates of extraction recovery and upgrading yields, rather than an analysis based on constant dollar or forecast pricing assumptions. Net mining reserves reflect the relative value of Crown, freehold and overriding royalty burdens under constant December 31st pricing and reflects our exercised option to elect to transfer to a bitumen-based Crown royalty effective at the beginning of 2009.

(3) Under Required U.S. OIL AND GAS AND MINING DISCLOSURE , we reported proved reserves from our Firebag in-situ leases. The disclosure in the table above reports proved reserves from these leases and differs in the following three ways. Reserves from our Firebag in-situ leases under our voluntary disclosure:

(a) are disclosed on a gross basis as well as the required net basis under U.S. disclosure requirements;

(b) are converted from barrels of bitumen to barrels of synthetic crude oil in this table for aggregation purposes only;

(c) include proved plus probable reserves, rather than proved reserves only under U.S. disclosure requirements. U.S. companies do not disclose probable reserves for non-mining properties. We voluntarily disclose our probable reserves for Firebag in-situ leases as we believe this information is useful to investors, and allows us to aggregate our mining and our in-situ reserves into a consolidated total for our Oil Sands business. As a result, our Firebag in-situ estimates in the above tables are not comparable to those made by U.S. companies.

SUNCOR EMPLOYEES

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

	as at December 31, 2006	2005
Oil Sands	3,182	2,787
Natural Gas	170	214
Energy Marketing & Refining Canada	605	638
Marketing & Refining U.S.A	463	662
Corporate(2)	1,346	851
Total (1)	5,766	5,152

Notes:

(1) In addition to our employees, we also use independent contractors to supply a range of services.

(2) Corporate employees includes employees from our Major Projects group, which supports all four of our business units.

The Communications, Energy and Paperworkers Union Local 707 represent approximately 1,500 Oil Sands employees. A collective agreement with the union was entered effective May 1, 2004. The terms of the agreement include a 9.5% 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. During 2005, a three year agreement was signed with the Sarnia employee association that will be renegotiated in 2008. 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 United Steel Workers (USW) union represents approximately 218 employees at R&M s refining facilities. In February 2006, the union voted to merge all workers into a single collective bargaining agreement. The merged contract became effective in March 2006 and will expire in January 2009.

RISK FACTORS

As a company we identify risks in four principal categories: 1) Operational; 2) Financial; 3) Legal and Regulatory; and 4) Strategic. These categories are defined below, and identified risks have been classified accordingly. Please note, identified risks could relate to multiple risk categories; we have classified risks based on the primary category to which they apply to Suncor.

We are continually working to mitigate the impact of potential risks to our stakeholders. This process includes an entity wide risk review. The internal review is completed annually to help ensure that all significant risks are identified and appropriately managed. Identified risks are outlined in no particular order below:

1) Operational Risks Risks that *directly* affect our ability to continue normal operations within our identified businesses.

Confidentiality. Breach of confidentiality could place us at competitive risk if confidential operational information or proprietary intellectual property was improperly disclosed.

Operating Hazards and Other Uncertainties. Each of our four principal operating businesses, Oil Sands, NG, EM&R, and R&M require high levels of investment and have particular economic risks and opportunities. Generally, our 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, IT systems and related data and control systems, equipment and the environment, as well as interrupt operations. In addition, all of our operations are subject to all of the risks normally incident to transporting, processing and storing crude oil, natural gas and other related products. Risks associated with access to skilled labour to support our operations in a safe and effective manner are also discussed in Labour and Materials Supply , below.

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 our ability to produce higher value products due to the interdependence of its component systems. For information on the 2005 Oil Sands fire, refer to page 4 of this AIF**.** 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, fires, 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.

Our downstream business units, EM&R and R&M, are subject to all of the risks normally inherent with the operation of a refinery, terminals, pipelines and other distribution facilities as well as service stations, including loss of product, slowdowns due to equipment failures, unavailability of feedstock, price and quality of feedstock or other accidents.

We are also subject to operational risks such as sabotage, terrorism, trespass, related damage to remote facilities, theft and malicious software or network attacks.

Major Projects. There are certain risks associated with the execution of our major projects, including without limitation, the new coker unit, each of the Firebag stages, the Voyageur growth strategy, and the oil sands integration capital project in EM&R. These risks include: our 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; our ability to finance growth if commodity prices were to decline and stay at low levels for an extended period; 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. Our 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 us. 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 these differences can be material.

Cost estimates for major projects involve uncertainties and evolve in stages. For a discussion of this process, an update on the status of our significant capital projects in progress and an explanation of on time and on budget , see page 27 of our MD&A, incorporated by reference herein.

Insurance. Although we maintain a risk management program, which includes an insurance component, such insurance may not provide adequate coverage in all circumstances, nor are all such risks insurable. Losses beyond the scope of insurance could have a material adverse impact on the company. In late 2005, a self-insurance entity was formed to provide additional business interruption coverage for potential losses. In 2006, one of our external business interruption service providers discontinued operations. We continue to evaluate options to replace this coverage. Refer to note 10(b) to our 2006 Consolidated Financial Statements, which is incorporated by reference herein, for further description of our insurance coverage.

In December 2006, insurers impacted by the January 4, 2005, fire at Oil Sands have filed a statement of claim to recover settlement costs. Due to the terms of our insurance contract, we are named as Plaintiff. However, the action will not have an impact on the insurance settlements we have already reached with our insurers or on our future revenues.

2) Financial Risks Risks that affect the compilation, reporting and accuracy of financial results.

Uncertainty of Reserve Estimates. The reserves estimates for our Oil Sands and Natural Gas (NG) business units included in this AIF, 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 our control.

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, pricing assumptions, 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. Our actual production, revenues, royalties, taxes and development and operating expenditures with respect to our reserves will vary from such estimates, and such variances could be material. Production 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 classification of such reserves based on risk of recovery, prepared by different engineers or by the same engineers at different times, may vary substantially.

Volatility of Crude Oil and Natural Gas Prices. Our future financial performance is closely linked to crude 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 us are affected primarily by North American supply and demand and by prices of alternate sources of energy. All of these factors are beyond our 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 and bitumen. Oil and natural gas prices have fluctuated widely in recent years and we expect 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 our crude oil and gas properties and the level of spending on growth projects, and could result in curtailment of production on some properties. Accordingly, low crude oil prices in particular could have an adverse impact on our financial condition and liquidity and results of operations. A key component of our business strategy is to produce sufficient natural gas to meet or exceed internal demands for natural gas purchased for consumption in our operations, creating a price hedge which reduces our exposure to gas price volatility. However, there are no assurances that we will be able to continue to increase production to keep pace with growing internal natural gas demands.

Under our strategic crude oil hedging program, management has approval to fix a price or range of prices for approximately 30% of our total crude oil production for specified periods of time. As at March 1, 2007, crude oil hedges totaling 60,000 bpd of crude oil production in 2007, and 10,000 bpd of production in

2008. Prices for these barrels are fixed within a range from an average of US$51.64/bbl up to an average of US$101.06/bbl. We intend to consider additional strategic hedging opportunities as they become available.

We conduct an assessment of the carrying value of our assets to the extent required by Canadian generally accepted accounting principles. If crude oil and natural gas prices decline, the carrying value of our assets could be subject to downward revisions, and our 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, and in the case of R&M, asphalt. 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. We 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 and may be adversely affected.

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 below noted expansion plans of our competitors could result in an increase in the supply of diesel fuel and weaken margins.

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

Exchange Rate Fluctuations. Our 2006 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 our revenue is received by reference to U.S. dollar denominated prices and a significant portion of our debt is denominated in U.S. dollars. Crude oil and natural gas prices are generally based in U.S. dollars, while a portion of our sales of refined products are in Canadian dollars. In addition, we have subsidiary operations that are denominated in U.S. dollars, translated to Canadian dollars using the current rate approach, whereby revenues and expenses are recorded at the exchange rate at the time the transaction occurs, and assets and liabilities are translated at the exchange rate at the balance sheet date. Therefore, fluctuations in exchange rates between the U.S. and Canadian dollar may give rise to foreign currency exposure, either favorable or unfavorable, creating another element of uncertainty.

Interest Rate Risk. **We are exposed to fluctuations in short-term Canadian interest rates as a result of the use of floating rate debt. We maintain a substantial portion of our debt capacity in revolving, floating rate bank facilities and commercial paper, with the remainder issued in fixed rate borrowings. To minimize our exposure to interest rate fluctuations, we occasionally enter 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 our MD&A.**

3) Legal and Regulatory Risks Risks that affect our ability to comply with regulatory and statutory requirements under applicable law.

Environmental Regulation and Risk. Environmental regulation affects nearly all aspects of our operations. These regulatory regimes are laws of general application that apply to us in the same

Interest Rate Risk. We are exposed to fluctuations in short-term Canadian interest rates as a result of the use of flo

manner as they apply to other companies and enterprises in the energy industry. The regulatory regimes require us 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, we expect future changes to environmental legislation, including anticipated legislation for air pollution (Criteria Air Contaminants) and greenhouse gases that 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 withdrawals and discharges to water;
- issues relating to global climate change, land reclamation and restoration;
- reformulated gasoline to support lower vehicle emissions.

Changes in environmental regulation could have an adverse effect on us from the standpoint of product demand, product reformulation and quality, methods of production and distribution and costs, and financial results. 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 us. 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 will result in the imposition of fines and penalties, liability for clean up costs and damages and the loss of important permits.

For Suncor s Oil Sands Mining Leases 86 and 17, we are required to and have posted annually with Alberta Environment an irrevocable letter of credit equal to $0.03 per bbl of crude oil produced as of December 31, 2005 ($14 million as at December 31, 2005) as security for the estimated cost of our reclamation activity. Since there has been no production from Leases 86/17 in 2006, the amount of security remains unchanged.

For the Millennium and Steepbank mines, we have posted irrevocable letters of credit equal to approximately $163 million, representing security for the maximum reclamation liability in the period March 31, 2006 through March 31, 2007. For more information about our reclamation and environmental remediation obligations, refer to Asset Retirement Obligations under Critical Accounting Estimates in the Suncor Overview and Strategic Priorities section of our MD&A.

A new Mine Liability Management Program (MLMP) is under review by the Province of Alberta, and is currently planned for implementation on June 30, 2007. The MLMP would involve increased reporting of progressive reclamation, measurement of MLMP assets against MLMP liabilities and measurement of reserve life. As currently proposed, initial security deposits for oil sands mining would be reduced. Partial security could be required if reclamation targets are not met and full security may eventually be required.

Interest Rate Risk. We are exposed to fluctuations in short-term Canadian interest rates as a result of the use of flo

Over the past few years legislation has been passed in Canada and the United States to reduce allowable levels of sulphur in transportation fuels. For a discussion of projects completed at our EM&R and R&M operations, see the information under the EM&R and R&M sections of Narrative Description of the Business , in this AIF. Projects to retrofit existing facilities to comply with these standards are subject to all risks inherent in large capital 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, or subject the Company to fines and penalties potentially having a material impact on revenues and earnings.

Interest Rate Risk. We are exposed to fluctuations in short-term Canadian interest rates as a result of the use of flo

The R&M business is subject to Consent Decrees with the United States Environmental Protection Agency, the United States Department of Justice and the State of Colorado. For a discussion of these consent decrees and the related obligations, see the information under the R&M section of Narrative Description of the Business in this AIF. The Company is subject to the risk that failure to meet its obligations or the deadlines under these Consent Decrees could have a material impact on the Company s ability to market its products, potentially having a material impact on revenues and earnings.

Governmental Regulation. The oil and gas industry in Canada and the United States, including the oil sands industry and our downstream segments, 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, taxes including income taxes, 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, 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, we 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 on satisfactory terms, 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 our costs and have a material adverse effect on our financial condition.

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 our Natural Gas business. We are unable to assess the effect, if any, these claims would have on our Oil Sands or other operations. Other than these claims, to our knowledge the First Nations peoples have asserted no other land claims against us.

Alberta Crown Bitumen-Based Royalty Regime. During the fourth quarter of 2006, we elected to exercise our option to move our base operations to the bitumen based royalty effective January 1, 2009. Also in 2006, the government of Alberta began deliberations to establish a prescribed method of determining the fair market value of heavy oil/bitumen for the purposes of determining bitumen-based royalty. This new bitumen pricing methodology may significantly change the nature, extent and timing of our royalty obligations, and as a result impact cash flows, earnings and net reserve estimates. The methodology is not likely to be finalized until 2008, and as a result, the potential future impacts are not currently known but may be material.

In early 2007, the Alberta Government also announced a review of its Crown royalty regime. The outcome of this review is uncertain and future royalties payable, as well as the determination of net reserves may be affected.

4) Strategic Risks Risks that affect our ability to meet long term goals and planning initiatives.

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, we expect to further mitigate adverse impacts of interdependent systems and to reduce the production and cash flow impacts of complete plant-wide shutdowns. For example, we added a second upgrader which provides us with the

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Interest Rate Risk. We are exposed to fluctuations in short-term Canadian interest rates as a result of the use of flo

flexibility to conduct periodic plant maintenance on one operation while continuing production and cash flow generation from the other.

Dependence on Oil Sands business. The Company s significant capital commitment to further our growth projects at Oil Sands, including Firebag and Voyageur, may require us to forego investment opportunities in other segments of our operations. The completion of future projects to increase production at Oil Sands will further increase our dependence on the Oil Sands segment of our business. For example, in 2006, the Oil Sands business accounted for approximately 88% (83% in 2005) of our upstream production, 89% (76% in 2005) of our net earnings and 83% (70% in 2005) of our cash flow from operations. These percentages have been determined excluding the corporate and eliminations segment information.

Need to Replace Conventional Natural Gas Reserves. Future natural gas reserves and production of the Company s NG business unit are highly dependent on our success in discovering or acquiring additional reserves and exploiting our current reserve base. This impacts our ability to maintain a price hedge against the growing consumption of natural gas in our operations. Without natural gas reserve additions through exploration and development or acquisition activities, our conventional natural gas reserves and production will decline over time as reserves are depleted. For example, in 2006, our average natural gas reservoir decline rate was approximately 24% (2005 24%). Decline rates will vary with the nature of the reservoir, life-cycle of the well and other factors. Therefore, historical 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[9] is insufficient to generate sufficient capital and external sources of capital become limited or unavailable, our ability to make the necessary capital investments to maintain and expand our conventional natural gas reserves could be impaired. In addition, the long term performance of the NG business is dependent on our 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 we will be able to find and develop or acquire additional reserves to replace production at acceptable costs.

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. We compete in virtually every aspect of our business with other energy companies. The petroleum industry also competes with other industries in supplying energy, fuel and related products to consumers. We believe the competition for our crude oil production is other North American conventional and synthetic sweet and sour crude oil producers. With current expansion plans there are risks associated with the delivery of our products to market.

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 their 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 one million bpd in 2004 to approximately two million bpd by 2010[10]. Increasing industry consolidation, a global focus on oil sands and additional competitors with financial capacity has: i) materially increased the supply of bitumen and synthetic crude oil and other competing crude oil products in the marketplace; ii) exponentially increased land values and availability of new leases; and iii) placed stress on availability of all resources required to run the Oil Sands operation. If we are unable to transport our produced crude oil products, production levels may be adversely affected.

Historically, the industry-wide oversupply of refined petroleum products and the overabundance of retail outlets have kept downward pressure on downstream refining and retail margins. Management expects that fluctuations in demand for refined products, margin volatility and overall marketplace competitiveness

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Interest Rate Risk. We are exposed to fluctuations in short-term Canadian interest rates as a result of the use of flo

(9) Refer to Non GAAP Financial Measures on page ix of this AIF.

(10) Alberta Government Talk About Oil Sands

will continue. In addition, to the extent that our 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.

Labour and Materials Supply. With the expansion of the industry and the impact of new entrants to the business, risks in the form of availability/competition for skilled labour and materials supply continue to build. Although these risks are not exclusive to our Oil Sands operation, the increased demands on the Fort McMurray, Alberta infrastructure (for example, housing, roads and schools) and a commuting workforce have heightened concerns. Our ability to operate safely and effectively and complete major projects on time and on budget is significantly impacted by these risks. Risks associated with completion of significant capital projects are discussed in Major Projects above.

Pipeline Capacity Constraints. With our current expansion plans, combined with several other major capital initiatives scheduled by others in the industry, there are increasing risks associated with pipeline capacity and infrastructure which may negatively affect our sales mix and production levels. This is already evident in the timing and method of delivery of our crude oil products to market, as well as our ability to produce at capacity levels in our Natural Gas business.

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.

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. 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.

Reclamation. There are risks associated with our ability to complete reclamation work, specifically reclaiming tailings ponds which contain water, clay and residual bitumen produced through the extraction process. To reclaim tailings ponds, we are using a process referred to as consolidated tailings (CT) technology. At this time, no ponds have been fully reclaimed using this technology. The success of the CT technology and time to reclaim the tailings ponds could increase or decrease the current asset retirement cost estimates. We continue to monitor and assess other possible technologies and/or modifications to the consolidated tailings process now being used. Regulatory approval of our North Steepbank mine extension, planned for operation in 2010, is subject to certain conditions related to the performance of CT technology.

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

Interest Rate Risk. We are exposed to fluctuations in short-term Canadian interest rates as a result of the use of flo

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, 2006, is derived from our 2006 Consolidated Financial Statements. Our consolidated financial statements for each of the years in the three-year period ended December 31, 2006, have been audited by PricewaterhouseCoopers LLP, Chartered Accountants. The information set forth below should be read in conjunction with our MD&A and our 2006 Consolidated Financial Statements.

	Year ended December 31,		
($ millions except per share amounts)	**2006**	**2005**	**2004**
Revenues	15,829	11,129	8,705
Net earnings	2,971	1,158	1,076
Per common share (undiluted)	6.47	2.54	2.38
Per common share (diluted)	6.32	2.48	2.33
Cash flow from operations	4,533	2,476	2,013
Capital and exploration expenditures	3,613	3,153	1,847

	Year ended December 31,		
($ millions)	**2006**	**2005**	**2004**
Total assets	18,781	15,149	11,774
Long-term debt	2,385	3,007	2,217
Accrued liabilities and other(1)	1,214	1,005	749
Shareholders equity	8,952	5,996	4,874

Note:

(1) See Note 7 to our 2006 Consolidated Financial Statements, which is incorporated by reference herein.

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

Revenues from:

($ millions)	2006	%	2005	%
Transportation fuel sales	7,016	44	5,502	49
Crude oil sales	6,781	43	3,203	29
Other (2)	2,019	13	2,422	22
Total	15,816(1)	100	11,127(1)	100

Note:

(1) Excludes interest income.

(2) Includes net insurance proceeds of $436 million (2005 - $572 million)

Dividend Policy and Record

Our Board of Directors has established a policy of paying dividends on a quarterly basis. We review our policy from time to time in light of our financial position, financing requirements for growth, cash flow and other factors which our Board of Directors considers relevant. Our Board of Directors approved an increase in the quarterly dividend to $0.08 per share from $0.06 per share in the second quarter of 2006, and an increase to $0.06 per share from $0.05 per share during the second quarter of 2004.

The following table sets forth the per share amount of dividends we paid to shareholders during the last three years.

	Year Ended December 31, 2006	2005	2004
Common Shares cash dividends	$ 0.30	$ 0.24	$ 0.23
Dividends paid in common shares			

MANAGEMENT S DISCUSSION AND ANALYSIS

Our MD&A, dated February 28, 2007, is incorporated by reference herein and forms an integral part of this AIF, and should be read in conjunction with our 2006 Consolidated Financial Statements and the notes thereto.

DESCRIPTION OF CAPITAL STRUCTURE

General Description of Capital Structure

Our authorized capital consists of an unlimited number of common shares without nominal or par value and an unlimited number of preferred shares without nominal or par value, issuable in series. As at December 31, 2006, a total of 459,943,827 common shares were issued and outstanding and no preferred shares had been issued.

Each common share entitles the holder to receive notice of and to attend all meetings of our shareholders, other than meetings at which only the holders of another class or series are entitled to vote. Each common share entitles the holder to one vote. The holders of common shares, in the discretion of the Board of Directors, are entitled to receive out of any monies properly applicable to the payment of dividends, and after the payment of any dividends payable on preferred shares (if any), of any series or any other series ranking prior to the common shares as to the payment of dividends, any dividends declared and payable on the common shares. Upon any liquidation, dissolution or winding-up of Suncor, or other distribution of our assets among our shareholders for the purposes of winding-up our affairs, the holders of the common shares are entitled to share on a share-for-share basis in the distribution, except for the prior rights of the holders of the preferred shares of any series, or any other class ranking prior to the common shares. There are no pre-emptive or conversion rights, and the common shares are not subject to redemption. All common shares currently outstanding and to be outstanding upon exercise of outstanding options are, or will be, fully paid and non-assessable.

Ratings

At December 31, 2006, our current long-term senior debt ratings are A(low) by Dominion Bond Rating Service, A3 by Moody s Investor Service and A- by Standard & Poor s and our current commercial paper debt rating is R-1(low) by Dominion Bond Rating Service. All debt ratings have a stable outlook.

Dominion Bond Rating Service s (DBRS) credit ratings are on a long-term debt rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. A rating of A (low) by DBRS is the third highest of nine categories and is assigned to debt securities considered to be of satisfactory credit quality. Protection of interest and principal is still substantial, but the degree of strength is less than with AA rated entities. Entities in the A category may be more susceptible to adverse economic conditions and have greater cyclical tendencies than higher rated companies. The assignment of a (high) or (low) modifier within each rating category indicates relative standing within such category. The high and low grades are not used for the AAA category.

Moody s credit ratings are on a long-term debt rating scale that ranges from AAA to C, which represents the range from highest to lowest quality of such securities rated. A rating of A3 by Moody s is the third highest of nine categories and is assigned to debt securities which are considered upper-medium grade obligations and are subject to low credit risk. Moody s appends numerical modifiers 1, 2 or 3 to each generic rating classification. The modifier 1 indicates that the issue ranks in the higher end of its generic rating category, the modifier 2 indicates a mid-range ranking and the modifier 3 indicates that the issue ranks in the lower end of its generic rating category.

Standard and Poor s (S&P) credit ratings are on a long-term debt rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. A rating of A- by S&P is the third highest of eleven categories and indicates that the obligor is somewhat more susceptible to adverse effects of changes in circumstances and economic conditions than obligors in the higher-rated categories. However, the obligor s capacity to meet its financial commitment on the obligation is still strong. The addition of a plus (+) or minus (-) designation after a rating indicates the relative standing within a particular rating category.

DBRS s commercial paper credit ratings are on a short-term debt rating scale that ranges from R-1(high) to D, which represent the range from highest to lowest quality of such securities rated. A rating of R-1(low) by DBRS is the third highest of ten categories and is assigned to debt securities considered to be of satisfactory credit quality. The overall strength and outlook for key liquidity, debt, and profitability ratios is not normally as favourable as with higher rating categories, but these considerations are still respectable, and any qualifying negative factors that exist are considered manageable, and the entity is normally of sufficient size to have some influence in its industry.

The credit ratings accorded to the notes by the rating agencies are not recommendations to purchase, hold or sell the notes inasmuch as such ratings do not comment as to the market price or suitability for a particular investor. Any rating may not remain in effect for any given period of time or may be revised or withdrawn entirely by a rating agency in the future if in its judgment circumstances so warrant.

MARKET FOR OUR SECURITIES

Our common shares are listed on the Toronto Stock Exchange in Canada, and on the New York Stock Exchange in the United States.

Price Range and Trading Volume of Common Shares

Toronto Stock Exchange	**Price Range ($Cdn)**		**Trading Volume**
2006	**High**	**Low**	**(000 s)**
January	91.70	73.58	39,965
February	93.85	80.06	36,389
March	91.66	80.68	31,443
April	102.18	90.53	26,010
May	99.13	83.40	33,894
June	92.40	75.00	41,722

July	94.85	86.33	26,464
August	97.12	85.55	28,816
September	87.75	71.18	51,069
October	89.75	72.26	47,728
November	92.38	83.25	29,849
December	95.00	88.24	22,127

New York Stock Exchange 2006	Price Range ($US) High	Low	Trading Volume (000 s)
January	80.41	64.00	38,549
February	82.15	69.20	37,791
March	78.83	69.70	33,070
April	89.96	77.75	28,726
May	89.53	72.21	40,808
June	83.83	67.36	46,959
July	85.37	75.89	30,052
August	86.78	77.21	26,670
September	78.89	63.77	43,991
October	79.59	64.06	44,606
November	81.80	73.44	29,420
December	82.08	76.39	20,650

DIRECTORS AND EXECUTIVE OFFICERS

Directors

Reference is made to the information under the heading, Election of Directors on pages 5-8 inclusive of Suncor s Management Proxy Circular dated March 1, 2007 for information regarding our directors, which information is incorporated by reference into this AIF.

Executive Officers

The following individuals are the executive officers of Suncor. Except where otherwise indicated, these individuals held the offices set out opposite their respective names as at December 31, 2006, 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. ASHA Denver, Colorado	Executive Vice President, Refining and Marketing U.S.A.
DAVID W. BYLER Cochrane, Alberta	Executive Vice President, Natural Gas and Renewable Energy
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	Executive Vice President, Major Projects
THOMAS L. RYLEY Toronto, Ontario	Executive Vice President, Energy, Marketing and Refining Canada
JAY THORNTON Calgary, Alberta	Senior Vice President, Business Integration
STEVEN W. WILLIAMS Fort McMurray, Alberta	Executive Vice President, Oil Sands

Note:

(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 Canadian based downstream subsidiaries, Suncor Energy Marketing Inc. and Suncor Energy Products Inc., respectively, and Mr. Nabholz, Ms. Lee and Mr. Thornton are Executive Vice-Presidents of Suncor Energy Services Inc., in respect of major projects, human resources and communications, and business services, respectively, which are shared services provided 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 Mobile Corporation.

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, we confirm that, as at the date hereof:

(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 relevant issuer access to any exemption under Canadian securities legislation for a period of more than 30 consecutive days;

(b) was subject to an event that resulted, after the director or executive officer ceased to be a director or executive officer, in the company being the subject of a cease trade or similar order or an order that denied the relevant company access to any exemption under securities legislation, for a period of more than 30 consecutive days; or

(c) became bankrupt or 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 its assets, other than Mr. Ford, a director of Suncor who is currently a director of USG Corporation, which was in bankruptcy protection until June, 2006, and who was also a director of United Airlines (until February 2006) which was in Chapter 11 bankruptcy protection until February, 2006.

(ii) no director or executive officer of Suncor has:

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

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

No director, executive officer, or principal holder of Suncor securities or any associate or affiliate of these persons has, or has had, any material interest in any transaction or any proposed transaction that has materially affected or will materially affect us or any of our affiliates, within the three most recently completed financial years or during the current financial year.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for our common shares is Computershare Trust Company of Canada at its principal offices in Calgary, Montreal, Toronto and Vancouver and Computershare Trust Company Inc. in Denver, Colorado.

INTERESTS OF EXPERTS

As at the date hereof the designated professionals of GLJ Petroleum Consultants Ltd., as a group, beneficially owned, directly or indirectly, less than 1% of our outstanding securities, including the securities of our associates and affiliates.

FEES PAID TO AUDITORS

Fees Paid to Auditors

Reference is made to the information under the heading, Appointment of Auditors on page 9 of Suncor s Management Proxy Circular dated March 1, 2007, 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 AIF.

Audit Committee Pre-Approval Policies for Non Audit Services

Our 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. A copy of our policy relating to Audit Committee approval of fees paid to our auditors, in compliance with the *Sarbanes Oxley Act of 2002,* is attached as Schedule A to this AIF.

Additional Audit Committee Information

Additional information about the members of the Audit Committee and their financial literacy is contained on pages 32 and 47-48 inclusive of our management proxy circular dated March 1, 2007, and incorporated by reference herein. The Audit Committee Charter is attached as Schedule B to this AIF.

RELIANCE ON EXEMPTIVE RELIEF

We are reporting our reserves data in accordance with, and are 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).

Our 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, 2006, using constant dollar cost and pricing assumptions as of a point in time, namely December 31, 2006, and the related standardized measure;

gross and net proved and probable working interest oil reserve quantities relating to surface mineable oil sands operations estimated as at December 31, 2006; and

gross and net proved and probable working interest oil and gas reserve quantities relating to Firebag in-situ leases, estimated as at December 31, 2006, using constant dollar cost and pricing assumptions, generally intended to represent a normalized annual average for the year in accordance with CSA Staff Notice 51-315.

Our 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.

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If we had been reporting our reserves data in accordance with National Instrument 51-101 and had not been relying on the terms of the Decision Document, we 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%.

LEGAL PROCEEDINGS

There are no legal proceedings to which we are a party or of which any of our property is the subject, nor are there any proceedings known by us to be contemplated that involves a claim for damages exceeding ten percent of our current assets.

ADDITIONAL INFORMATION

Additional information, including directors and officers remuneration and indebtedness, principal holders of our securities, options to purchase securities and interests of insiders in material transactions, where applicable, is contained in our most recent management proxy circular for our most recent annual meeting of our shareholders that involved the election of directors. Additional financial information is provided in our 2006 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 Form (AIF/40-F) is available online at www.sedar.com and www.sec.gov. In addition, our Standards of Business Conduct Code is available online at www.suncor.com. Information contained in or otherwise accessible through our website does not form part of this AIF. All such references are inactive textual references only.

SCHEDULE A

*****Approved and Accepted April 28, 2004*****

SUNCOR ENERGY INC.

POLICY AND PROCEDURES FOR PRE-APPROVAL OF AUDIT

AND NON-AUDIT SERVICES

Pursuant to the Sarbanes-Oxley Act of 2002 and Multilateral Instrument 52-110, the Securities and Exchange Commission and the Ontario Securities Commission respectively has adopted final rules relating to audit committees and auditor independence. These rules require the Audit Committee of Suncor Energy Inc (Suncor) to be responsible for the appointment, compensation, retention and oversight of the work of its independent auditor. The Audit Committee must also pre-approve any audit and non-audit services performed by the independent auditor or such services must be entered into pursuant to pre-approval policies and procedures established by the Audit Committee pursuant to this policy.

I. STATEMENT OF POLICY

The Audit Committee has adopted this Policy and Procedures for Pre-Approval of Audit and Non-Audit Services (the Policy), which sets forth the procedures and the conditions pursuant to which services proposed to be performed by the independent auditor will be pre-approved. The procedures outlined in this Policy are applicable to all Audit, Audit-Related, Tax Services and All Other Services provided by the independent auditor.

II. RESPONSIBILITY

Responsibility for the implementation of this Policy rests with the Audit Committee. The Audit Committee delegates its responsibility for administration of this policy to management. The Audit Committee shall not delegate its responsibilities to pre-approve services performed by the independent auditor to management.

III. DEFINITIONS

For the purpose of these policies and procedures and any pre-approvals:

a) Audit services include services that are a necessary part of the annual audit process and any activity that is a necessary procedure used by the auditor in reaching an opinion on the financial statements as is required under generally accepted auditing standards (GAAS), including technical reviews to reach audit judgment on accounting standards;

The term audit services is broader than those services strictly required to perform an audit pursuant to GAAS and include such services as:

i) the issuance of comfort letters and consents in connections with offerings of securities;

ii) the performance of domestic and foreign statutory audits;

iii) Attest services required by statute or regulation;

iv) Internal control reviews; and

v) Assistance with and review of documents filed with the Canadian Securities administrators, the Securities and Exchange Commission and other regulators

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having jurisdiction over Suncor and its subsidiaries, and responding to comments from such regulators;

b) Audit-related services are assurance (e.g. due diligence services) and related services traditionally performed by the external auditors and that are reasonably related to the performance of the audit or review of financial statements and not categorized under audit fees for disclosure purposes.

Audit-related services include:

i) employee benefit plan audits, including audits of employee pension plans;

ii) due diligence related to mergers and acquisitions;

iii) consultations and audits in connection with acquisitions, including evaluating the accounting treatment for proposed transactions;

iv) internal control reviews;

v) attest services not required by statute or regulation; and

vi) consultations regarding financial accounting and reporting standards;

Non-financial operational audits are not audit-related services;

c) Tax services include but are not limited to services related to the preparation of corporate and/or personal tax filings, tax due diligence as it pertains to mergers, acquisitions and/or divestitures and tax planning;

d) All other services consist of any other work that is neither an Audit service, nor an Audit-Related service nor a Tax service, the provision of which by the independent auditor is not expressly prohibited by Rule 2-01(c)(7) of Regulation S-X under the Securities and Exchange Act of 1934, as amended. (See Appendix A for a summary of the prohibited services.)

IV. GENERAL POLICY

The following general policy applies to all services provided by the independent auditor:

All services to be provided by the independent auditor will require specific pre-approval by the Audit Committee. The Audit Committee will not approve engaging the independent auditor for services which can reasonably be classified as tax services or all other services unless a compelling business case can be made for retaining the independent auditor instead of another service provider.

The Audit Committee will not provide pre-approval for services to be provided in excess of twelve months from the date of the pre-approval, unless the Audit Committee specifically provides for a different period.

The Audit Committee has delegated authority to pre-approve services with an estimated cost not exceeding $100,000 in accordance with this Policy to the Chairman of the Audit Committee. The delegate member of the Audit Committee must report any pre-approval decision to the Audit Committee at its next meeting.

The Chairman of the Audit Committee may delegate his authority to pre-approve services to another sitting member of the Audit Committee provided that the recipient has also

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been delegated the authority to act as Chairman of the Audit Committee in the Chairman s absence. A resolution of the Audit Committee is required to evidence the Chairman s delegation of authority to another Audit Committee member under this policy.

The Audit Committee will, from time to time, but no less than annually, review and pre-approve the services that may be provided by the independent auditor.

The Audit Committee must establish pre-approval fee levels for services provided by the independent auditor on an annual basis. On at least a quarterly basis, the Audit Committee will be provided with a detailed summary of fees paid to the independent auditor and the nature of the services provided and a forecast of fees and services that are expected to be provided during the remainder of the fiscal year.

The Audit Committee will not approve engaging the independent auditor to provide any prohibited non-audit services as set forth in Appendix A.

The Audit Committee shall evidence their pre-approval for services to be provided by the independent auditor as follows:

a) In situations where the Chairman of the Audit Committee pre-approves work under his delegation of authority, the Chairman will evidence his pre-approval by signing and dating the pre-approval request form, attached as Appendix B. If it is not practicable for the Chairman to complete the form and transmit it to the Company prior to engagement of the independent audit, the Chairman may provide verbal or email approval of the engagement, followed up by completion of the request form at the first practical opportunity.

b) In all other situations, a resolution of the Audit Committee is required.

All audit and non-audit services to be provided by the independent auditors shall be provided pursuant to an engagement letter that shall:

a) be in writing and signed by the auditors

b) specify the particular services to be provided

c) specify the period in which the services will be performed

d) specify the estimated total fees to be paid, which shall not exceed the estimated total fees approved by the Audit Committee pursuant to these procedures, prior to application of the 10% overrun.

e) include a confirmation by the auditors that the services are not within a category of services the provision of which would impair their independence under applicable law and Canadian and U.S. generally accepted accounting standards.

The Audit Committee pre-approval permits an overrun of fees pertaining to a particular engagement of no greater than 10% of the estimate identified in the associated engagement letter. The intent of the overrun authorization is to ensure on an interim basis only, that services can continue pending a review of the fee estimate and if required, further Audit Committee approval of the overrun. If an overrun is expected to exceed the 10% threshold, as soon as the overrun is identified, the Audit Committee or its designate must be notified and an additional pre-approval obtained prior to the engagement continuing.

V. RESPONSIBILITIES OF EXTERNAL AUDITORS

To support the independence process, the independent auditors will:

a) Confirm in each engagement letter that performance of the work will not impair independence;

b) Satisfy the Audit Committee that they have in place comprehensive internal policies and processes to ensure adherence, world-wide, to independence requirements, including robust monitoring and communications;

c) Provide communication and confirmation to the Audit Committee regarding independence on at least a quarterly basis;

d) Maintain registration by the Canadian Public Accountability Board and the U.S. Public Company Accounting Oversight Board;

e) Review their partner rotation plan and advise the Audit Committee on an annual basis.

In addition, the external auditors will:

a) Provide regular, detailed fee reporting including balances in the Work in Progress account;

b) Monitor fees and notify the Audit Committee as soon as a potential overrun is identified.

VI. DISCLOSURES

Suncor will, as required by applicable law, annually disclose its pre-approval policies and procedures, and will provide the required disclosure concerning the amounts of audit fees, audit-related fees, tax fees and all other fees paid to its outside auditors in its filings with the SEC.

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Appendix A

Prohibited Non-Audit Services

An external auditor is not independent if, at any point during the audit and professional engagement period, the auditor provides the following non-audit services to an audit client.

Bookkeeping or other services related to the accounting records or financial statements of the audit client. Any service, unless it is reasonable to conclude that the results of these services will not be subject to audit procedures during an audit of Suncor s financial statements, including:

Maintaining or preparing the audit client s accounting records;

Preparing Suncor s financial statements that are filed with the Securities and Exchange Commission (SEC) or that form the basis of financial statements filed with the SEC; or

Preparing or originating source data underlying Suncor s financial statements.

Financial information systems design and implementation. Any service, unless it is reasonable to conclude that the results of these services will not be subject to audit procedures during an audit of Suncor s financial statements, including:

Directly or indirectly operating, or supervising the operation of, Suncor s information system or managing Suncor s local area network; or

Designing or implementing a hardware or software system that aggregates source data underlying the financial statements or generates information that is significant to Suncor s financial statements or other financial information systems taken as a whole.

Appraisal or valuation services, fairness opinions or contribution-in-kind reports. Any appraisal service, valuation service or any service involving a fairness opinion or contribution-in-kind report for Suncor, unless it is reasonable to conclude that the results of these services will not be subject to audit procedures during an audit of Suncor s financial statements.

Actuarial services. Any actuarially-oriented advisory service involving the determination of amounts recorded in the financial statements and related accounts for Suncor other than assisting Suncor in understanding the methods, models, assumptions, and inputs used in computing an amount, unless it is reasonable to conclude that the results of these services will not be subject to audit procedures during an audit of Suncor s financial statements.

Internal audit outsourcing services. Any internal audit service that has been outsourced by Suncor that relates to Suncor s internal accounting controls, financial systems, or financial statements, unless it is reasonable to conclude that the result of these services will not be subject to audit procedures during an audit of Suncor s financial statements.

Management functions. Acting, temporarily or permanently, as a director, officer, or employee of Suncor, or performing any decision-making, supervisory, or ongoing monitoring function for Suncor.

Human resources.

Searching for or seeking out prospective candidates for managerial, executive, or director positions;

Engaging in psychological testing, or other formal testing or evaluation programs;

Undertaking reference checks of prospective candidates for an executive or director position;

Acting as a negotiator on Suncor s behalf, such as determining position, status or title, compensation, fringe benefits, or other conditions of employment; or

Recommending, or advising Suncor to hire a specific candidate for a specific job (except that an accounting firm may, upon request by Suncor, interview candidates and advise Suncor on the candidate s competence for financial accounting, administrative, or control positions.)

Broker-dealer, investment adviser or investment banking services. Acting as a broker-dealer (registered or unregistered), promoter, or underwriter, on behalf of Suncor, making investment decisions on behalf of

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Suncor or otherwise having discretionary authority over Suncor s investments, executing a transaction to buy or sell Suncor s investment, or having custody of Suncor s assets, such as taking temporary possession of securities purchased by Suncor.

Legal services. Providing any service to Suncor that, under circumstances in which the service is provided, could be provided only by someone licensed, admitted, or otherwise qualified to practice law in the jurisdiction in which the service is prohibited.

Expert services unrelated to the audit. Providing an expert opinion or other expert service for Suncor, or Suncor s legal representative, for the purpose of advocating Suncor s interest in litigation or in a regulatory or administrative proceeding or investigation. In any litigation or regulatory or administrative proceeding or investigation, an accountant s independence shall not be deemed to be impaired if the accountant provides factual accounts, including testimony, of work performed or explains the positions taken or conclusions reached during the performance of any service provided by the accountant for Suncor.

Appendix B

Pre-approval Request Form

NATURE OF WORK	**ESTIMATED FEES (Cdn $)**
Total	

Date

Signature

1

SCHEDULE B

AUDIT COMMITTEE CHARTER

The Audit Committee

The by-laws of Suncor Energy Inc. provide that the Board of Directors may establish Board committees to whom certain duties may be delegated by the Board. The Board has established, among others, the Audit Committee, and has approved this mandate, which sets out the objectives, functions and responsibilities of the Audit Committee.

Objectives

The Audit Committee assists the Board of Directors by:

monitoring the effectiveness and integrity of the Corporation's financial reporting systems, management information systems and internal control systems, and by monitoring financial reports and other financial matters.

selecting, monitoring and reviewing the independence and effectiveness of, and where appropriate replacing, subject to shareholder approval as required by law, external auditors, and ensuring that external auditors are ultimately accountable to the Board of Directors and to the shareholders of the Corporation.

Reviewing the effectiveness of the internal auditors; and

approving on behalf of the Board of Directors certain financial matters as delegated by the Board, include the matters outlined in this mandate.

The Committee does not have decision-making authority, except in the very limited circumstances described herein or where and to the extent that such authority is expressly delegated by the Board of Directors. The Committee conveys its findings and recommendations to the Board of Directors for consideration and, where required, decision by the Board of Directors.

Constitution

The Terms of Reference of Suncor s Board of Directors set out requirements for the composition of Board Committees and the qualifications for Committee membership, and specify that the chair and membership of the Committees are determined annually by the Board. As required by Suncor s by-laws, unless otherwise determined by resolution of the board of directors, a majority of the members of a committee constitute a quorum for meetings of committees, and in all other respects, each committee determines its own rules of procedure.

Functions and Responsibilities

The Committee has the following functions and responsibilities:

Internal Controls

1. Enquire as to the adequacy of the Corporation s system of internal controls, and review the evaluation of internal controls by internal auditors, and the evaluation of financial and internal controls by external auditors.

2. Review management s monitoring of compliance with the Corporation s Code of Business Conduct.

3. Establish procedures for the confidential submission by employees of complaints relating to any concerns with accounting, internal control, auditing or Standards of Business Conduct Code matters, and periodically review a summary of complaints and their related resolution.

4. Review the findings of any significant examination by regulatory agencies concerning the Corporation s financial matters.

5. Periodically review management s governance processes for information technology resources,

to assess their effectiveness in addressing the integrity, the protection and the security of the Corporation s electronic information systems and records.

6. Review the management practices in effect over officers expenses and perquisites.

External and Internal Auditors

7. Evaluate the performance of the external auditors and initiate and approve the engagement or termination of the external auditors, subject to shareholder approval as required by applicable law.

8. Review the audit scope and approach of the external auditors, and approve their terms of engagement and fees.

9. Review any relationships or services that may impact the objectivity and independence of the external auditor, including annual review of the auditor s written statement of all relationships between the auditor (including its affiliates) and the Corporation; review and approve all engagements for non-audit services to be provided by external auditors or their affiliates.

10. Review the external auditor s quality control procedures including any material issues raised by the most recent quality control review or peer review and any issues raised by a government authority or professional authority investigation of the external auditor, providing details on actions taken by the firm to address such issues.

11. Review and approve the appointment or termination of the Director, Internal Audit, and annually review a summary of the remuneration and performance of the Director, Internal Audit.

12. Review the Internal Audit Department Charter, and the plans, activities, organisational structure and qualifications of the internal auditors, and monitor the department s performance and independence.

13. Provide an open avenue of communication between management, the internal auditors or the external auditors, and the Board of Directors.

Financial Reporting and other Public Disclosure

14. Review external auditor s management comment letter and management s responses thereto, and enquire as to any disagreements between management and external auditors or restrictions imposed by management on external auditors. Review any unadjusted differences brought to the attention of management by the external auditor and the resolution of same.

15. Review with management and external auditors the financial materials and other disclosure documents referred to in paragraph 16, including any significant financial reporting issues, the presentation and impact of significant risks and uncertainties, and key estimates and judgements of management that may be material to financial reporting including alternative treatments and their impacts.

16. Review and approve the Corporation s interim consolidated financial statements and accompanying management s discussion and analysis (MD&A). Review and make recommendations to the Board of Directors on approval of the Corporation s annual audited financial statements and MD&A, Annual Information Form and Form 40-F. Review other material annual and quarterly disclosure documents or regulatory filings containing or accompanying audited or unaudited financial information.

17. Review and approve the Corporation s policy on external communication and disclosure of material information, including the form and generic content of any quarterly earnings guidance and of any financial disclosure provided to investment analysts and rating agencies.

18. Review any change in the Corporation s accounting policies.

19. Review with legal counsel any legal matters having a significant impact on the financial reports.

Oil and Gas Reserves

20. Review with reasonable frequency Suncor s procedures for:

(A) the disclosure in accordance with applicable law of information with respect to Suncor s oil and gas activities including procedures for complying with applicable disclosure requirements;

(B) providing information to the qualified reserves evaluators (Evaluators) engaged annually by Suncor to evaluate Suncor s reserves data for the purpose of public disclosure of such data in accordance with applicable law.

21. Annually approve the appointment and terms of engagement of the company s Evaluator, including the qualifications and independence of the Evaluator; Review and approve any proposed change in the appointment of the Evaluator, and the reasons for such proposed change including whether there have been disputes between the Evaluator and the Company s management.

22. Annually review Suncor s reserves data and the report of the Evaluator thereon; Annually review and make recommendations to the Board of Directors on the approval of (i) the content and filing by the Company of a statement of reserves data (Statement) and report of management and the directors thereon to be included in or filed with the Statement, and (ii) the filing of the report of the Evaluator to be included in or filed with the Statement, all in accordance with applicable law.

Risk Management

23. Periodically review the policies and practices of the Corporation respecting cash management, financial derivatives, financing, credit, insurance, taxation, commodities trading and related matters. Oversee the Board s risk management governance model by conducting periodic reviews with the objective of appropriately reflecting the principal risks of the Corporation s business in the mandate of the Board and its committees.

Pension Plan

24. Review the assets, financial performance, funding status, investment strategy and actuarial reports of the Corporation s pension plan including the terms of engagement of the plan s actuary and fund manager.

Security

25. Review on a summary basis any significant physical security management, IT security or business recovery risks and strategies to address such risks.

Other Matters

26. Conduct any independent investigations into any matters which come under its scope of responsibilities.

27. Review any recommended appointees to the office of Chief Financial Officer.

Review and/or approve other financial matters delegated specifically to it by the Board of Directors.

Reporting to the Board

28. Report to the Board of Directors on the activities of the Committee with respect to the foregoing matters as required at each Board meeting and at any other time deemed appropriate by the Committee or upon request of the Board of Directors.

As adopted by resolution of the Board of Directors.

Revision Dated January 26, 2006

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, 2006 using constant dollar cost and pricing assumptions as of a point in time, namely December 31, 2006, and the related standardized measure;

(b) proved and probable working interest oil reserve quantities relating to surface mineable oil sands operations estimated as at December 31, 2006; and

(c) proved and probable working interest oil and gas reserve quantities relating to Firebag in-situ leases, estimated as at December 31, 2006 using constant dollar cost and pricing assumptions, generally intended to represent a normalized annual average for the year in accordance with CSA Staff Notice 51-315.

GLJ Petroleum Consultants 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 judgments 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

March 8, 2007

REPORT ON RESERVES DATA

BY INDEPENDENT QUALIFIED RESERVES

EVALUATOR

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, 2006. The reserves data consist of the following:

Proved working interest oil and gas reserve quantities relating to oil and gas operations, other than mining, estimated as at December 31, 2006 using constant dollar cost and pricing assumptions as of a point in time, namely December 31, 2006, and the related standardized measure; proved and probable working interest oil reserve quantities relating to surface mineable oil sands operations estimated as at December 31, 2006; and proved and probable working interest oil reserves quantities relating to Firebag in-situ leases, estimated as at December 31, 2006 using constant dollar cost and pricing assumptions.

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, 2006:

		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 9, 2007	Canada	$4,861 million (99%)	$54 million (1%)	$4,915 million (100%)

In addition, all proved plus probable company gross and net reserves have been evaluated for Suncor s oil sands 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, 2006 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 judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

GLJ PETROLEUM CONSULTANTS LTD.

ORIGINALLY SIGNED BY

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

Calgary, Alberta, Canada

February 9, 2007

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-X in connection with the Common Shares.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

See page 41 of Exhibit 99-2.

AUDIT COMMITTEE FINANCIAL EXPERT

See pages 47 and 48 of Appendix B of Exhibit 99-3.

CODE OF ETHICS

See page 38 of Exhibit 99-3 and page 48 of our Annual Information Form.

FEES PAID TO PRINCIPAL ACCOUNTANT

See page 9 of Exhibit 99-3.

AUDIT COMMITTEE PRE-APPROVAL POLICIES

See Schedule A of Annual Information Form.

APPROVAL OF NON-AUDIT SERVICES

See page 9 of Exhibit 99-3.

OFF-BALANCE SHEET ARRANGEMENTS

See page 26 of Exhibit 99-2.

TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS

See page 26 of Exhibit 99-2.

IDENTIFICATION OF THE AUDIT COMMITTEE

See page 32 of Exhibit 99-3.

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:	March 8, 2007	PER:	Richard L. George RICHARD L. GEORGE President and Chief Executive Officer

EXHIBIT INDEX

Exhibit No.	Description
99-1	Audited Consolidated Financial Statements of Suncor Energy Inc. for the fiscal year ended December 31, 2006, including reconciliation to U.S. GAAP (Note 18)
99-2	Management s Discussion and Analysis for the fiscal year ended December 31, 2006, dated February 28, 2007
99-3	Excerpts from pages 9, 32, 38, 47 and 48 inclusive of Suncor Energy Inc. s Management Proxy Circular dated March 1, 2007
99-4	Consent of PricewaterhouseCoopers LLP
99-5	Consent of GLJ Petroleum Consultants Ltd.
99-6	Certificate of President and Chief Executive Officer Pursuant to Exchange Act Rules 13a-14(a) or 15d-14(a)
99-7	Certificate of Senior Vice President and Chief Financial Officer Pursuant to Exchange Act Rules 13a-14(a) or 15d-14(a)
99-8	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
99-9	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