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SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 40-F

(Check One)

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

or

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

For fiscal year ended: December 31, 2010
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)

150 - 6th Avenue S.W.
Box 2844
Calgary, Alberta, Canada T2P 3E3
(403) 296-8000

(Address and telephone number of registrant's principal executive office)

CT Corporation System
111 Eighth Avenue
New York, New York, U.S.A. 10011
(212) 894-8940

(Name, address and telephone number of agent for service in the United States)

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

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

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

None

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

None

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

ý Annual Information Form ý Annual Audited Financial Statements

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

Common Shares	**As of December 31, 2010 there were 1,565,489,162 Common Shares issued and outstanding**
Preferred Shares, Series A	**None**

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

Yes ý No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes o No o

ANNUAL INFORMATION FORM DATED MARCH 3, 2011



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GLOSSARY OF TERMS

In this Annual Information Form (AIF), references to "we", "our", "us", "Suncor" or "the company" mean Suncor Energy Inc., its subsidiaries, partnerships and joint venture investments unless the context otherwise requires. References to "legacy Suncor" and "legacy Petro-Canada" refer to the applicable entity prior to the August 1, 2009 effective date of the merger between legacy Suncor and legacy Petro-Canada.

Barrel of oil equivalent (boe)

Suncor converts certain natural gas volumes to barrels (bbls) of oil equivalent (boe), thousands of barrels of oil equivalent (mboe), mboe per day (mboe/d) or millions of barrels of oil equivalent (mmboe) on the basis of one barrel (bbl) to six thousand cubic feet and daily production is presented as barrels of oil equivalent per day (boe/d). Boe, mboe and mmboe may be misleading, particularly if used in isolation. A conversion ratio of one barrel of crude oil or natural gas liquids to six thousand cubic feet of natural gas is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent value equivalency at the wellhead.

Bcf

Billions of cubic feet.

Bitumen/heavy crude oil

A naturally occurring viscous mixture, consisting mainly of pentanes and heavier hydrocarbons, 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 may be upgraded into crude oil and other petroleum products.

Bpd

Barrels per day.

Capacity

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

Conventional crude oil

Crude oil produced through wells by standard industry recovery methods.

Conventional natural gas

Natural gas produced from all geological strata, including associated, non-associated and solution gas, but excluding coal bed methane and shale gas.

Crude oil

Unrefined liquid hydrocarbons, excluding natural gas liquids.

Development costs

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

Exploration and Production Sharing Agreements (EPSAs)

See production sharing contracts.

Feedstock

In the oil sands business, feedstock generally refers to raw bitumen required in the production of synthetic crude oil. In the downstream business, feedstock refers to crude oil and/or other components required in the production of refined products.

Field

A defined geographical area consisting of one or more pools containing hydrocarbons.

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.

GBP

The pound sterling, commonly called the pound (£), is the official currency of the United Kingdom.

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

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.

Mbbls/d

Thousands of barrels per day.

MMbbls

Millions of barrels.

MMbtu

Millions of british thermal units.

Mcf

Thousands of cubic feet.

MMcf/d

Millions of cubic feet per day.

Mcfe or MMcfe

Suncor converts certain crude oil and natural gas liquids volumes to thousands of cubic feet equivalent of natural gas (Mcfe) and millions of cubic feet equivalent of natural gas (MMcfe) on the basis of one barrel to six thousand cubic feet, and daily production is presented as millions of cubic feet equivalent per day (MMcfe/d). Mcfe and MMcfe may be misleading, particularly if used in isolation. A conversion ratio of one barrel of crude oil or natural gas liquids to six thousand cubic feet of natural gas is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent value equivalency at the wellhead.

Natural gas

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

Natural gas liquids (NGLs)

Those hydrocarbon components that can be recovered from natural gas as liquids, including, but not limited to, ethane, propane, butanes, pentanes, plus condensate and small quantities of non-hydrocarbons.

Overburden

Material overlying oil sands that must be removed before mining, and that 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.

Production Sharing Contracts (PSCs)

A common type of contract signed between a government and a resource extraction company that states how much of the resource extracted from the country each party will receive and which parties are responsible for the development and operation of the resources. The company conducts its operations in Syria pursuant to PSCs.

An Exploration Production and Sharing Agreement (EPSA) is a form of PSC, which also states which parties are responsible for exploration activities. The company conducts its operations in Libya pursuant to EPSAs.

Reservoir

A porous and permeable subsurface rock formation that contains a separate accumulation of petroleum that is confined by impermeable rock or water barriers and is characterized by a single pressure system.

Steam Assisted Gravity Drainage (SAGD)

An enhanced oil recovery technology for producing heavy crude oil and bitumen. It is an advanced form of steam stimulation in which a pair of horizontal wells are drilled into the oil reservoir, one a few metres above the other. Low pressure steam is continuously injected into the upper wellbore to heat the oil and reduce its viscosity, causing the heated oil to drain into the lower wellbore, where it is pumped out.

Synthetic crude oil (SCO)

A mixture of hydrocarbons derived by upgrading (thermal cracking and purification) of crude bitumen from oil sands that may contain sulphur or other non-hydrocarbon compounds and has many similarities to crude oil. SCO with lower sulphur content is referred to as "sweet" while SCO with higher sulphur content is referred to as "sour".

Utilization

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

Wells

Appraisal well

A well drilled to measure the commercial potential (i.e. size and quality) of a hydrocarbon discovery. Before development, a discovery is likely to need several such wells.

Development or developmental well

A well drilled inside the established limits of an oil or gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

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 or exploration 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.

West Texas Intermediate (WTI)

A type of crude oil used as a benchmark in oil pricing, WTI is the underlying commodity of futures contracts on the New York Mercantile Exchange (NYMEX).

CONVERSION TABLE (1)(2)

1 cubic metre m^3 = 6.29 barrels	1 tonne = 0.984 tons (long)
1 cubic metre m^3 (natural gas) = 35.49 cubic feet	1 tonne = 1.102 tons (short)
1 cubic metre m^3 (overburden) = 1.31 cubic yards	1 kilometre = 0.62 miles
	1 hectare = 2.5 acres

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

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

PRESENTATION OF INFORMATION

All references in this AIF to dollar amounts are in Canadian (Cdn) dollars unless otherwise indicated.

FORWARD-LOOKING STATEMENTS

Certain statements contained in this AIF constitute "forward-looking statements" within the meaning of the *United States Private Securities Litigation Reform Act of 1995* and "forward-looking information" within the meaning of applicable Canadian securities legislation (collectively, "forward-looking statements"). All forward-looking statements are based on the company's current expectations, estimates, projections, beliefs and assumptions based on information available at the time the statement was made and in light of the company's experience and its perception of historical trends, including expectations and assumptions concerning the accuracy of reserve and resource estimates; commodity prices and interest and foreign exchange rates; capital efficiencies and cost-savings; applicable royalty rates and tax laws; future production rates; the sufficiency of budgeted capital expenditures in carrying out planned activities; the availability and cost of labour and services; and the receipt, in a timely manner, of regulatory and third-party approvals.

Some of the forward-looking statements may be identified by words like "expects", "anticipates", "estimates", "plans", "scheduled", "intends", "may", "believes", "projects", "indicates", "could", "focus", "vision", "goal", "proposed", "target", "objective", "continue" and similar expressions. Forward-looking statements in this AIF include references to:

- business strategies and goals;
- future investment decisions;
- future capital, exploration and other expenditures;
- future cash flows;
- future resource purchases and sales;
- anticipated construction and repair activities;
- anticipated turnarounds at upgraders, refineries and other facilities;
- anticipated refining margins;
- future oil and natural gas production levels, including anticipated field lives, and the sources of their growth;
- project development and expansion schedules and results;
- future exploration activities and results, and dates by which certain areas may be developed or come on-stream;
- anticipated retail throughputs;
- anticipated pre-production and operating costs;
- reserves and resources estimates;
- future royalties and taxes payable;
- anticipated cost savings, and other synergies, realized from the merger with Petro-Canada;
- production life-of-field estimates;
- natural gas export capacity;
- future financing and capital activities;

- contingent liabilities;
- the impact and cost of compliance with existing and potential environmental regulations;
- future regulatory approvals;
- expected rates of return.

In addition, all other statements that address expectations or projections about the future, including statements about our strategy for growth, commodity prices, costs, schedules, production volumes, operating and financial results, and expected impact of future commitments, are forward-looking statements.

Forward-looking statements are not guarantees of future performance and involve a number of risks and uncertainties, some that are similar to other oil and gas companies and some that are unique to Suncor. Our actual results may differ materially from those expressed or implied by our forward-looking statements, and readers are cautioned not to place undue reliance on them.

The risks, uncertainties and other factors, many of which are beyond our control, that could influence actual results include, but are not limited to, market instability affecting Suncor's ability to borrow in the capital debt markets at acceptable rates; consistently and competitively finding and developing reserves that can be brought on-stream economically; success of hedging strategies; maintaining a desirable debt to cash flow ratio; changes in the general economic, market and business conditions; our ability to finance capital investment to replace reserves or increase processing capacity in a volatile commodity pricing and credit environment; fluctuations in supply and demand for Suncor's products; commodity prices, interest rates and currency exchange; volatility in natural gas and liquids prices; Suncor's ability to respond to changing markets and to receive timely regulatory approvals; the successful and timely implementation of capital projects including growth projects and regulatory projects; risks and uncertainties associated with consulting with stakeholders and obtaining regulatory approval for exploration and development activities in Suncor's operating areas (these risks could increase costs and/or cause delays to or cancellation of projects); effective execution of planned turnarounds; the accuracy of cost estimates, some of which are provided at the conceptual or other preliminary stage of projects and prior to commencement or conception of the detailed engineering needed to reduce the margin of error and increase the level of accuracy; the integrity and reliability of Suncor's capital assets; the cumulative impact of other resource development; the cost of compliance with current and future environmental laws; the accuracy of Suncor's reserve, resource and future production estimates and its success at exploration and development drilling and related activities; the maintenance of satisfactory relationships with unions, employee associations and joint venture partners; competitive actions of other companies, including increased competition from other oil and gas companies or from companies that provide alternative sources of energy; labour and material shortages; 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, our negotiations with the Alberta Department of Energy in respect of the Bitumen Valuation Methodology Regulation; 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 (including in respect of any planned divestitures); risks and uncertainties associated with the ability to meet closing conditions with respect to the sale of any of Suncor's assets, the timing of closing and the consideration to be received with respect to the planned sale of any of Suncor's assets, including the ability of counterparties to comply with their obligations in a timely manner and the receipt of any required regulatory or other third party approvals outside of Suncor's control; the occurrence of unexpected events such as fires, blowouts, freeze-ups, equipment failures and other similar events affecting Suncor or other parties whose operations or assets directly or indirectly affect Suncor; failure to realize anticipated synergies or cost savings; risks regarding the integration of the Suncor and Petro-Canada after the merger; and incorrect assessments of the values of Petro-Canada. The foregoing important factors are not exhaustive.

Many of these risk factors and other specific risks and uncertainties are discussed in further detail in "Risk Factors", and throughout this AIF and in our MD&A. 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 150-6th Avenue S.W., Calgary, Alberta, T2P 3E3, 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, and is not incorporated into this AIF by reference.

ACCOUNTING MATTERS

References to our "2010 Consolidated Financial Statements" mean Suncor's audited consolidated financial statements prepared in accordance with Generally Accepted Accounting Principles (GAAP), the notes and the auditors' report, as at and for the three-year period ended December 31, 2010. References to our MD&A mean Suncor's Management's Discussion and Analysis, dated February 24, 2011, accompanying the 2010 Consolidated Financial Statements.

On August 1, 2009, Suncor completed its merger with Petro-Canada. As such, the 2009 results reflect those of the post-merger Suncor from August 1, 2009 together with results of legacy Suncor only from January 1, 2009 through July 31,

2009. The comparative figures from 2008 reflect solely the results of legacy Suncor. Additional information about Suncor and legacy Petro-Canada filed with Canadian securities commissions and the United States (U.S.) Securities and Exchange Commission (SEC), including periodic quarterly and annual reports, are available online at www.sedar.gov and our website www.suncor.com.

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

The Canadian Institute of Chartered Accountants Accounting Standards Board confirmed in February 2008 that Canadian publicly accountable enterprises must adopt International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board, effective January 1, 2011. For more information with respect to the company's adoption of IFRS, see the "Changes in Accounting Policies" section of our MD&A.

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, May 2002, and May 2008, we amended our articles to divide our issued and outstanding shares on a two-for-one basis.

Pursuant to an arrangement (the Arrangement), which was completed effective August 1, 2009, legacy Suncor and legacy Petro-Canada amalgamated to form a single corporation continuing under the name "Suncor Energy Inc.". The Arrangement was effected pursuant to section 192 of the *Canada Business Corporations Act* through an arrangement agreement dated March 22, 2009 and accompanying plan of arrangement, as amended. Under the terms of the Arrangement, Petro-Canada shareholders received 1.28 Suncor common shares for each Petro-Canada common share held.

Our registered and head office is located at 150-6 th Avenue, S.W., Calgary, Alberta, T2P 3E3.

Inter-Corporate Relationships

Material subsidiaries, each of which was owned 100%, directly or indirectly, by the company as at December 31, 2010 are as follows:

Name	Jurisdiction	Purpose
Suncor Energy Oil Sands Limited Partnership	Canada	A partnership in which Suncor Energy Inc. and certain of its wholly-owned subsidiares are partners. The partnership holds certain oil sands assets.
Suncor Energy Products Inc. (1)	Canada	An Ontario corporation that is wholly-owned by Suncor Energy Inc. through which some of Suncor's Canadian refining and marketing operations are conducted.
Suncor Energy Marketing Inc.	Canada	A subsidiary of Suncor Energy Products Inc. through which the products produced by our North American businesses are marketed. 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 business.
Suncor Energy (U.S.A.) Inc.	U.S.	A subsidiary of Suncor Energy Inc. through which our U.S. refining and marketing operations are conducted.
Suncor Energy Oil & Gas Partnership	Canada	A partnership in which Suncor Energy Inc. and one of its wholly-owned subsidiaries are partners. The partnership holds certain of our upstream Canadian oil and gas operations and our 12% interest in the Syncrude joint venture.
3908968 Canada Inc.	Canada	A subsidiary of Suncor Energy Inc. that holds certain of our international interests.
Petro-Canada Cooperative Holding UA	Netherlands	A subsidiary of 3908968 Canada Inc. that holds certain of our international interests.
Petro-Canada (International) Holdings BV	Netherlands	A subsidiary of Petro-Canada Cooperative Holding UA that holds certain of our international interests.
Petro-Canada Germany GmbH	Germany	A subsidiary of Petro-Canada (International) Holdings BV that holds the majority of our Libya interests.
Petro-Canada Oil (North Africa) GmbH	Germany	A subsidiary of Petro-Canada Germany GmbH through which the majority of our Libya operations are conducted.
Petro-Canada U.K. Holdings Ltd.	United Kingdom (U.K.)	A subsidiary of 3908968 Canada Inc. that holds certain of our U.K. interests.
Petro-Canada U.K. Ltd.	U.K.	A subsidiary of Petro-Canada U.K. Holdings Ltd. through which certain of our operations are conducted in the U.K.

(1) Effective January 1, 2011, Suncor Energy Products Inc. transferred substantially all of its assets and liabilities relating to Suncor's Canadian refining and marketing operations to Suncor Energy Products Partnership. Suncor Energy Products Inc. is a general partner of Suncor Energy Products Partnership.

Individually, the company's remaining subsidiaries accounted for (i) less than 10% of the company's consolidated assets as at December 31, 2010, and (ii) less than 10% of the company's consolidated sales and operating revenues for the fiscal year ended December 31, 2010. In aggregate, the remaining subsidiaries accounted for less than 20% of each of (i) and (ii) described above.

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 in Canada and internationally, and we transport and refine crude oil, and market petroleum and petrochemical products primarily in Canada. Periodically, we also market third-party petroleum products. We also carry on energy trading activities focused principally on marketing and trading of crude oil, natural gas, refined products and byproducts, and the use of financial derivatives.

Our operating segments are composed of Oil Sands, Natural Gas, International and Offshore, and Refining and Marketing. For financial reporting purposes, we also report financial data for activities not directly attributable to an operating business under "Corporate, Energy Trading and Eliminations". This includes our energy trading activities and our investments in renewable energy opportunities.

The table below outlines various Suncor investments as at December 31, 2010:

Oil Sands

- Mining
  - *Millennium and Steepbank Mining Operations*
  - *Syncrude (12% Interest)*
  - *Fort Hills (60% Interest)* (1)
  - *Other Mining Developments*
- In Situ
  - *Firebag*
  - *MacKay River*
  - *Other In Situ Developments*
- Upgrading Facilities

Natural Gas

- Western Canada
  - *Shale (northeast British Columbia (B.C.))*
  - *Shallow (southeast Alberta)*
  - *Foothills (western Alberta, northeast B.C.)*
  - *Plains (western Alberta)*
- Northwest Territories (NWT)/Nunavut
- Alaska/Arctic Islands

Refining and Marketing

- Refineries
  - *Edmonton Refinery*
  - *Montreal Refinery*
  - *Sarnia Refinery*
  - *Commerce City (Colorado) Refinery*
  - *ParaChem Chemicals Joint Venture (51% Interest)*
- Sales and Marketing
  - *Retail Operations*
  - *Wholesale Operations*
- Mississauga Lubricants Plant

International and Offshore

- East Coast Canada
  - *Terra Nova* (2) *(37.675% Interest)*
  - *Hibernia (20% Interest)*
  - *Hibernia South Extension* (3) *(19.5% Interest)*
  - *White Rose (27.5% Interest)*
  - *White Rose Extensions* (4) *(26.125% Interest)*
  - *Hebron (22.7% Interest)*
- North Sea
  - *Buzzard (29.9% Interest)*
  - *Golden Eagle Area Development (26.7% Interest)*
  - *Other Exploration Acreage*
- Syria PSCs
- Libya EPSAs

Corporate, Energy Trading and Eliminations

- Energy Trading activities
- St. Clair Ethanol Plant
- Wind Farms
  - *Ripley (50% Interest)*
  - *Chin Chute (33.3% Interest)*
  - *Magrath (33.3% Interest)*
  - *SunBridge (50% Interest)*
  - *Wintering Hills (70% Interest)*
  - *Kent Breeze*

(1) On December 17, 2010, Suncor announced that it had entered into a strategic partnership with Total E&P Canada Ltd. (Total). Assuming the transaction closes, Total will acquire a portion of Suncor's interest in Fort Hills, resulting in Suncor holding a 40.8% interest. See the "Three-Year History by Segment" section for further details about this transaction.

(2) In the fourth quarter of 2010, the joint owners of the Terra Nova oilfield finalized the redetermination of working interests required under the Terra Nova Development and Operating Agreement following field payout on February 1, 2005. Suncor's working interest increased to 37.675% from 33.990%.

(3) Suncor's working interest in the Hibernia South Extension agreement is 19.5% after Nalcor Energy Oil and Gas Inc. (NALCOR) acquired its 10% unit interest effective with the signing of the related agreement on February 16, 2010.

(4) The White Rose Extensions are the White Rose North Amethyst, West White Rose and South White Rose Extensions. Suncor's working interest in the White Rose Extensions is 26.125% after NALCOR acquired its 5% working interest effective with the signing of the final project agreements in February 2009.

Three-Year History by Segment

Pursuant to a statutory plan of arrangement completed effective August 1, 2009, Suncor and Petro-Canada, and certain of their respective subsidiaries, amalgamated to form a single corporation continuing under the name "Suncor Energy Inc.". The Arrangement was effected pursuant to section 192 of the *Canada Business Corporations Act* through an arrangement agreement dated March 22, 2009 (Arrangement Agreement) and accompanying plan of arrangement, as amended (the Plan of Arrangement). Under the Arrangement Agreement and Plan of Arrangement, each holder of common shares of legacy Suncor received one common share of Suncor and each holder of common shares of legacy Petro-Canada received 1.28 common shares of Suncor for each share of Petro-Canada held. Upon completion of the Arrangement, approximately 60% of the outstanding common shares of Suncor were held by legacy Suncor shareholders and approximately 40% of the outstanding common shares of Suncor were held by legacy Petro-Canada shareholders.

Oil Sands

Our Oil Sands business, located near Fort McMurray, Alberta, produces bitumen recovered from oil sands through mining and in situ technology and upgrades it into refinery feedstock, diesel fuel and byproducts. Bitumen feedstock is also occasionally supplemented by third-party suppliers. The company also has a 12% ownership interest in the Syncrude oil sands mining and upgrading joint venture, also located near Fort McMurray, Alberta.

Key milestones and significant events that have affected our Oil Sands business during this time period include the following:

2010

- Production Overview – In the fourth quarter, our operations reached a record production of 325,900 bpd (excluding Syncrude) due to improved upgrader performance and strong bitumen supply from all of Suncor's oil sands assets. Earlier in the year, production was negatively impacted by two fires. In December 2009, there was a fire at our Upgrader 2 facility, which was repaired and returned to normal operations in February 2010. In February 2010, there was a fire at our Upgrader 1 facility, which was repaired and returned to full operations by April 2010.

- Hydrotreater Outage – Oil Sands experienced an unplanned outage at one of its hydrogen reformer units at the end of August 2010, which was repaired and returned to normal operations in October 2010. This outage impacted production mix, increasing the percentage of lower value sour crude produced, but did not impact overall production volumes.

- Reclamation of Tailings Pond – During the year, Suncor became the first oil sands company to complete surface reclamation of a tailings pond. The 220-hectare site was the company's first storage pond for oil sands tailings when commercial production began in 1967. Suncor has renamed the area Wapisiw Lookout.

- Tailings Reduction Operations (TRO_{TM}) – Suncor received regulatory approval from Alberta regulators to convert from its current Consolidated Tailings (CT) management process to TRO_{TM}, in which mature fine tails are dried, rather than mixed with sand and other materials to form CT. The processing rate for TRO_{TM} is expected to be more efficient and effective than CT. We believe that TRO_{TM} will allow Suncor to meet the requirements of the new Tailings Directive issued by Alberta's Energy Resources Conservation Board (ERCB) in 2008. Suncor plans to spend $670 million during 2011 to continue development of the TRO_{TM} initiative.

- Royalties – In the fourth quarter of 2010, Suncor received a notice from the Alberta government modifying the bitumen valuation methodology (BVM) calculation for the interim period from January 1, 2009 to December 31, 2010. As a result, Suncor recognized a pre-tax gain of $140 million for a reduction in its royalty provision. The company continues to negotiate final adjustments to the bitumen valuation calculation for the interim period and for the term of the Suncor Royalty Amending Agreement (the Suncor RAA), which expires December 31, 2015. Also, MacKay River moved to post-payout in November 2010, thereby increasing the percentage of royalties paid.

- Turnaround and Maintenance – Oil Sands completed planned turnarounds at Upgrader 1 and Upgrader 2 in 2010 and unplanned maintenance on the hydrogen reformer unit. We expect that the maintenance performed will allow for improved reliability at these plants.

- Safe Mode – In 2010, Firebag Stage 3, Firebag Stage 4 and the Millennium Naphtha Unit (MNU) projects were all taken out of safe mode. Safe mode is the deferral of projects and maintenance of equipment and facilities in a safe manner in order to expedite remobilization when appropriate.

- Powerhouse Operations – In December 2010, Suncor assumed operation of certain power and steam generation assets previously operated on our behalf by TransAlta Corporation (TransAlta). Approximately 200 employees from TransAlta joined Suncor as a result.

- Slurry at Face – Oil Sands discontinued use of certain assets involved in an alternative extraction process to crush and slurry oil sands at the mine face, resulting in a pre-tax write-off of $189 million.

2009

- Merger – On August 1, 2009, Suncor merged with Petro-Canada, resulting in the acquisition of a 12% ownership in the Syncrude joint venture (an oil sands mining operation and upgrading facility), 100% ownership of the MacKay River in situ bitumen project, a 60% ownership in, and operatorship of, the proposed Fort Hills oil sands mining project, and extensive oil sands acreage considered prospective for in situ development of bitumen resources. The merger did not result in increased Oil Sands production (excluding Syncrude) as production from MacKay River was already included in Suncor's reported production from January 1, 2009 to July 31, 2009 as volumes processed by Suncor under a processing fee arrangement.

- Steepbank Extraction Plant – This project was completed during the third quarter of 2009, resulting in improved reliability and bitumen recovery.

- Firebag Sulphur Plant – This project was also completed during the third quarter of 2009. The plant is currently operating to support sulphur emissions reductions for existing and planned in situ development at Firebag, including Stage 3.

- Safe Mode – In the first quarter of 2009, Suncor placed a number of Oil Sands projects into safe mode as a result of economic conditions at the time. As a result of placing Oil Sands projects into safe mode, Suncor incurred pre-tax costs of $380 million in 2009.

2008

- Royalties – In January 2008, we entered into the Suncor RAA with the Government of Alberta, which modified the rates under the Government of Alberta's New Royalty Framework (New Royalty Framework) that apply to our in situ operations and would otherwise apply to our base mining operations. For more information on Oil Sands royalties, please see "Industry Conditions – Royalties and Incentives – Alberta" in this AIF.

- Coker Unit – Suncor completed a $2.3 billion expansion to one of its two oil sands upgraders. This new set of cokers increased our design capacity by 90,000 bpd to a total design capacity of 350,000 bpd at our Oil Sands facilities.

The following changes to our Oil Sands business have occurred, or are expected to occur, in 2011:

- Strategic partnership with Total – In December 2010, Suncor announced that it had entered into a strategic partnership with Total E&P Canada Ltd. (previously defined as Total), setting forth the terms for the two companies to develop the Fort Hills and Joslyn oil sands mines projects jointly and restart the construction of the Voyageur Upgrader at Suncor's Oil Sands operations in Fort McMurray, Alberta. The transaction is subject to certain regulatory and other approvals, with closing targeted late in the first quarter of 2011. Key terms of the agreement between Suncor and Total include:

    - Total will acquire a 49% interest in Suncor's planned third upgrader. Upon completion, the planned 200,000 barrel per day facility will be operated by Suncor;

    - Total will also acquire a portion of Suncor's interest in the Fort Hills oil sands project, resulting in Suncor holding a 40.8% interest, Total holding 39.2%, and Teck Resources Limited (Teck) holding 20%. Currently, Suncor holds a 60% interest, with Total and Teck each holding 20%;

    - Suncor will acquire a 36.75% working interest in the Total-operated Joslyn joint venture with Total holding a 38.25%, Occidental Petroleum holding 15% and Inpex Canada Ltd. holding 10%. Currently, Total holds a 75% interest, Occidental Petroleum a 15% interest and Inpex Canada Ltd. a 10% interest; and

    - Suncor will receive cash consideration totaling approximately $1.75 billion from the transaction.

  Suncor and Total have agreed to develop the Fort Hills mine and Voyageur Upgrader in parallel, with a target of having both come on-stream in 2016. Execution of the Fort Hills and Joslyn projects, as well as the continued construction of the Voyageur Upgrader, is subject to approval by the partners in these ventures and by Suncor's Board of Directors.

- Firebag Expansion – Suncor plans to direct approximately $1.28 billion in growth spending in 2011 toward the Firebag Stages 3 and 4 in situ oil sands expansion. Suncor expects the Firebag Stage 3 project to begin production late in the second quarter of 2011, with volumes ramping up over an estimated 24-month period toward planned production capacity of approximately 62,500 bpd of bitumen.

- North Steepbank Extension (NSE) – We expect this extension will improve the productivity of mining equipment by opening up a new mine face. Suncor expects to develop the mine face in 2011 and commence mining ore from the NSE in 2012.

- By the end of 2011, Suncor expects to complete the construction of the MNU to complement its upgrading assets. This new unit is expected to add 30,000 bpd of naphtha hydrotreating capacity to further upgrade sour SCO into sweet SCO.

- Suncor expects to complete a six-week turnaround of one of its upgraders, resulting in a decrease in production of approximately 215,000 bpd during that period.

Natural Gas

Our Natural Gas business explores for, acquires, develops and produces natural gas, NGLs, oil and byproducts from reserves in Western Canada. This business also has assets in NWT, Alaska, and the Arctic Islands.

Key milestones and significant events that have affected our Natural Gas business during the past three years include the following:

2010

- Canadian Dispositions – Throughout the year, the company completed several sales of non-core natural gas properties in Canada, including:

- On September 30, 2010, the company completed the sale of its properties located in southern Alberta, known as Wildcat Hills, for net proceeds of $351 million.

- On August 31, 2010, the company completed the sale of its properties located in west central Alberta, known as Bearberry and Ricinius, for net proceeds of $275 million.

- On May 31, 2010, the company completed the sale of properties located in central Alberta, known as Rosevear and Pine Creek, for net proceeds of $229 million.

- On March 31, 2010, the company completed the sale of certain properties located in northeast B.C. known as Blueberry and Jedney, for net proceeds of $383 million.

- U.S. Dispositions – On March 1, 2010, the company completed the sale of substantially all of its U.S. Rockies upstream assets for net proceeds of US$481 million. Remaining U.S. Rockies upstream assets were sold shortly thereafter.

- Shallow Gas – Suncor's key shallow gas producing properties near Medicine Hat, in southeast Alberta, continued with drilling and tie-in activity. In total, 324 wells were drilled in 2010.

- Other Drilling Programs – In the fourth quarter of 2010, we began two new drilling programs: one in the Ferrier area located in central Alberta and another at Pouce Coupe in western Alberta. Both programs are expected to start being tied-in during the first quarter of 2011.

2009

- Merger – On August 1, 2009, Suncor merged with Petro-Canada, adding significant natural gas assets in Western Canada and the U.S. Rockies, as well as assets in Alaska, the NWT and the Arctic Islands.

The following changes to our Natural Gas business have occurred, or are expected to occur, in 2011:

- Organizational Change – In January 2011, Suncor announced organizational changes that included the International and Offshore and Natural Gas business divisions merging into a single conventional production-focused organization, including both onshore and offshore operations.

- Additional Planned Divestitures – As part of its strategic business alignment, Suncor is targeting further divestments of non-core natural gas assets of approximately 220 MMcfe/d.

International and Offshore

International and Offshore consists of conventional oil and gas exploration, development and production offshore Newfoundland and Labrador, in the North Sea, and in Libya and Syria. Suncor acquired the International and Offshore assets in the merger with Petro-Canada in 2009.

Our East Coast Canada business comprises production and exploration activity offshore Newfoundland and Labrador. The company has a position in every major producing oil development in the region and is the operator of the Terra Nova oilfield. The company also holds a number of exploration licences and significant discovery licences in the region.

Our International business focuses on countries and regions where material positions of long-life assets may be built. This includes the exploration for, and production of, crude oil and natural gas primarily in the North Sea (offshore U.K. and Norway), Libya and Syria.

Key milestones and significant events that have affected our International and Offshore business during the past three years include the following:

East Coast Canada

2010

- Terra Nova Redetermination – On December 1, 2010, the joint owners of the Terra Nova oilfield finalized the redetermination of working interests required under the Terra Nova Development and Operating Agreement following field payout on February 1, 2005. Suncor's working interest increased to 37.675% from 33.990%, and the other owners have agreed to reimburse the company for its increased working interest from February 1, 2005 to December 31, 2010. As a result, the company recognized a pre-tax gain of $295 million.
- Terra Nova Production – In the fourth quarter of 2010, during regular well testing, we encountered hydrogen sulphide (H_2S) in part of the Terra Nova oilfield. We have safely shut-in affected wells and facilities while we develop a mitigation plan.
- Hibernia South – Final fiscal agreements were made between co-venturers and the Government of Newfoundland and Labrador in February 2010 for the Hibernia South Extension. The development plan for the extension has been approved and sanction is expected in the first quarter of 2011. First oil from platform development wells is expected in the first half of 2011.
- White Rose Extensions – On May 31, 2010, first oil was achieved at the North Amethyst portion of the White Rose Extensions, and development drilling continues.

2009

- Hibernia Production – Production from the AA Block began in the fourth quarter of 2009.

North Sea

2010

- U.K. Dispositions – On September 8, 2010, the company reached agreements to sell non-core U.K. offshore assets (Scott/Telford and Triton) for gross proceeds of £240 million, effective July 1, 2010. Divestment of a portion of these assets was completed in 2010 for net proceeds of £55 million. The sales of the remaining assets are expected to close during the first half of 2011. The remaining divestments are subject to closing conditions, closing adjustments to the purchase price and regulatory and other approvals customary for transactions of this nature.
- Netherlands Disposition – On August 13, 2010, the company completed the sale of its shares in Petro-Canada Netherlands BV for net proceeds of €316 million, with an effective date of January 1, 2010.
- Buzzard Production – In October 2010, a shutdown and tie-in of the fourth platform at Buzzard was completed and staged commissioning began on the sulphur handling platform. Production disruptions during ramp-up have been minimal to date. Commissioning of the new platform will continue in the first quarter of 2011.
- Norway Exploration – The company completed its first operated exploration well in January 2010 and encountered hydrocarbons. An appraisal well was drilled and tested in the fourth quarter of 2010 with positive results. Further evaluation is required to determine the potential size of this discovery. Suncor submitted bids for further acreage in Norway in the fourth quarter of 2010.

2009

- Buzzard Production – Production was shut-in for four weeks for the installation of the jacket for the fourth platform at Buzzard, which will handle sulphur.
- U.K. Exploration – There was a non-operated oil discovery called Hobby. This discovery will allow the Golden Eagle area to move forward to a pre-development stage.

2008

- U.K. Exploration – There was a non-operated oil discovery called Pink. The Pink Block is located in the Golden Eagle Area Development.

Libya

2010

- Exploration – Suncor progressed with its seismic acquisition program, with completion planned for March 2011. Starting in April, Suncor drilled two exploration wells and four appraisal wells.
- Development Drilling – Suncor completed 26 development wells in the producing fields in Libya, with an additional four development wells drilling at year end. Suncor completed eight development wells in 2009 and twelve development wells in 2008.
- Signature Bonus Payments – Suncor made a payment of US$200 million to the Libya National Oil Corporation (NOC) related to its EPSAs. Additionally, in return for the NOC providing consent in writing to the merger of Suncor and Petro-Canada, and to Suncor being accepted as the guarantor to the NOC of our legal entities in Libya as set out in the EPSAs, Suncor agreed to make a payment of US$94 million.

2008

- Libya EPSAs – In June 2008, six new EPSAs with the NOC were signed to replace existing concession agreements and one EPSA. The agreements will expire in 2033.

Syria

2010

- Operations – Suncor achieved commercial production from the Ebla natural gas project on April 19, 2010. First oil was achieved from Ebla on December 10, 2010. The company also submitted bids for additional acreage in Syria in December 2010.

Trinidad and Tobago

2010

- Disposition – On August 5, 2010, the company completed the sale of its Trinidad and Tobago assets for net proceeds of US$378 million with an effective date of January 1, 2010.

The following changes to our International and Offshore business have occurred, or are expected to occur, in 2011:

- Libya – In late February, civil unrest swept Libya, where Suncor has both oil production and exploration activities. At the time of filing this report, the degree and duration of impact on our business is not known. Suncor's immediate focus has been the safety of expatriate and Libyan national staff, and the contractors and service providers supporting Suncor's operations.
- Organizational Change – In January 2011, Suncor announced organizational changes that included the International and Offshore and Natural Gas business divisions merging into a single conventional production-focused organization, including both onshore and offshore operations.
- White Rose Extension – First oil for the West White Rose Phase 1 extension is expected in the second quarter of 2011. Results of Stage 1, combined with ongoing evaluation, will help define the scope of Stage 2.
- Hebron – The development plan approval submission is expected to be made in the second quarter of 2011, with first oil expected in 2017.
- In January 2011, Suncor was awarded two new production licences in Norway.

Refining and Marketing

Our Refining and Marketing business refines crude oil at Suncor's refineries in Edmonton, Alberta, Montreal, Quebec and Sarnia, Ontario in Canada, and in Commerce City, Colorado, U.S., into a broad range of petroleum and petrochemical products for sale to retail, commercial and industrial customers. In 2010, our Refining and Marketing business averaged sales of 87,800 cubic metres per day (m^3/d) of refined products nationwide in Canada and in Colorado, as well as into other parts of the

United States and Europe. Refining and Marketing transports crude oil through pipelines in Eastern and Western Canada, and through wholly-owned pipelines in Wyoming and Colorado.

Our Refining and Marketing business also includes a lubricants plant in Mississauga, Ontario that produces specialty lubricants and waxes.

In Canada, our retail business is managed primarily through Petro-Canada$_{TM}$-branded retail sites. In Colorado, our retail business is primarily managed through Phillips 66® and Shell®-branded sites.

Key milestones and significant events that have affected our Refining and Marketing business during the past three years include the following:

2010

- Retail Site Rebranding – Suncor rebranded 158 Sunoco$_{TM}$ retail sites to substantially complete the consolidation of our post-merger Canadian offering under the Petro-Canada$_{TM}$ brand.
- Retail Site Disposition – Suncor divested 104 retail sites in Ontario to comply with Canadian Competition Bureau requirements relating to the merger with Petro-Canada.
- Edmonton Refining Capacity – Following improvements completed in previous years, the observed performance of the Edmonton refinery enabled us to upwardly revise our crude oil capacity to 135,000 bpd from the previously disclosed 125,000 bpd, effective January 1, 2010.
- Oil Sands Diesel Marketing – Responsibility for marketing diesel production from Suncor's Oil Sands upgraders was transferred to Refining and Marketing from Suncor's Energy Trading division in mid-2010.
- St. Clair Ethanol Plant – Responsibility for operation and ownership of the St. Clair Ethanol Plant in Ontario was transferred from Refining and Marketing to Suncor's Renewable Energy division in early 2010.

2009

- Merger – On August 1, 2009, Suncor merged with Petro-Canada and acquired the Edmonton and Montreal refineries (with a total daily crude oil capacity of 255,000 bpd), a lubricants plant that is the largest producer of lubricant base stocks in Canada, a network of retail service stations, a national commercial road transport system and a bulk fuel sales channel.
- Terminal Storage and Distribution Capacity – In conjunction with Canadian Competition Bureau requirements relating to the merger, Suncor entered into terminalling agreements for 10 years with Ultramar Ltd. to provide 1.1 billion litres of terminal and distribution capacity in the Greater Toronto Area.
- Commerce City Refinery Capacity – The Commerce City refinery revised its crude oil capacity to 93,000 bpd from 90,000 bpd on January 1, 2009 to more accurately reflect the combined capability of its multiple crude processing trains.

2008

- Edmonton Refinery Conversion – The Edmonton refinery completed its refinery conversion project to process 100% oil sands-based feedstock.
- Sarnia Refining Capacity – The Sarnia refinery revised its crude oil capacity to 85,000 bpd from 70,000 bpd, based on observed performance after the completion of the diesel desulphurization and oil sands integration projects in 2007.

The following changes to our Refining and Marketing business have occurred, or are expected to occur, in 2011:

- The Sun Petrochemicals Company joint venture partnership agreement between Suncor and a Toledo, Ohio-based refinery was terminated on December 31, 2010. Starting in 2011, petrochemical sales out of our Sarnia refinery will be marketed solely by Suncor's Refining and Marketing division.

Other Suncor Businesses

Renewable Energy

Key milestones and significant events that have affected our renewable energy interests during the past three years include the following:

2010

- Wintering Hills – After receiving approval from the Alberta Utilities Commission, the company began construction on an 88 megawatt (MW), 55 turbine wind power project, located in southern Alberta. The company has signed a joint venture agreement with Teck Resources Limited (Teck) to develop the project. Under the terms of the agreement, Suncor will own a 70% interest and operate the project and Teck will own the remaining 30%. The project is expected to be completed by the end of 2011.

- Kent Breeze – Suncor also received regulatory approval for and began construction on a 20 MW, eight turbine wind power project located in southwest Ontario. The project is expected to be completed by the second quarter of 2011.

The following changes to our Renewable Energy business have occurred, or are expected to occur, in 2011:

- St. Clair Ethanol Expansion Project – Suncor completed a $120 million expansion of its ethanol plant in Ontario on January 22, 2011. The project expanded existing plant capacity from 200 million litres per year to 400 million litres per year.

Forward-Looking Information

The preceding paragraphs describing the general development of our business contain forward-looking statements, including those related to: cost estimates; the Total transaction (and the anticipated terms of same); our TRO_{TM} process, and the expectation that we will spend $670 million during 2011 to continue development of the initiative; the planned expansion of Firebag Stages 3 and 4, NSE and MNU assets (and expected production and capacity relating to the foregoing assets); expected turnarounds; planned divestitures of our natural gas assets and U.K. assets; anticipated first oil from some of Suncor's International and Offshore assets; and project completion dates. The material factors and assumptions used to develop the foregoing forward-looking statements include those related to the following: current capital spending plans; the current status of procurement, design and engineering phases of projects; updates from third-parties on delivery of services and goods associated with the projects; and estimates from major project teams on completion of future phases of the project. We have assumed that commitments from third parties will be honoured and that material delays and increased costs related to projects will not be encountered. Assumptions for production outlook include implementing reliability and operational efficiency initiatives, which we expect to minimize further unplanned maintenance. We have also provided forward-looking statements concerning the timing of the proposed transaction with Total and the development of the Fort Hills mine and Voyageur upgrader. Suncor has provided these anticipated times in reliance on certain assumptions that Suncor believes are reasonable at this time, including assumptions as to the timing of receipt of the necessary regulatory, court and other third party approvals; and the time necessary to satisfy the conditions to the closing of the transaction. These dates may change for a number of reasons, including unforeseen delays in the inability to secure necessary regulatory or other third-party approvals in the time assumed or the need for additional time to satisfy the conditions to the completion of the transaction. There is no assurance that the transaction will close as scheduled or at all, or if it does close, that any of the key terms of the agreement will come to fruition. For additional information on risks, uncertainties and other factors that could cause actual results to differ, please see the "Forward-Looking Statements" section above and the our Risk Factors section of this AIF.

NARRATIVE DESCRIPTION OF SUNCOR'S BUSINESSES

Oil Sands

Operations

Our integrated Oil Sands business involves five operations located near Fort McMurray, Alberta:

- Oil sands ore is supplied from open pit mining operations.

Open pit mining operations extract the overburden with trucks and shovels to provide access to the oil sands, which are excavated and delivered via hydrotransport pipeline to ore preparation plants, where crushers and sizers prepare the ore for primary extraction.

- Primary extraction facilities recover the bitumen from the mined oil sands ore.

In the primary extraction process, raw bitumen is separated from sand using a hot water process in giant separation cells. After the final removal of impurities and minerals during secondary extraction, naphtha is added to dilute the bitumen to facilitate transportation to upgrading facilities.

- In situ operations provide additional bitumen to upgrading facilities.

Our in situ operations, Firebag and MacKay River, use SAGD to separate 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 located above the other. Steam produced by on-site 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 and water mixture is pumped to our oil/water separation facilities where the water is removed from the bitumen, treated and recycled back to the steam generation facilities. At our Firebag operation, naphtha is added to dilute the bitumen to facilitate transportation to our upgraders. At our MacKay River operation, a heated pipeline is used instead of naphtha dilution for transport. The bitumen is transported to our upgrading facilities or sold directly to market.

- Upgrading facilities convert bitumen into crude oil products.

After the diluted bitumen is transferred to the upgrading plant, the naphtha is removed and recycled to be used again as diluent. The bitumen recovered from both in situ and mining is upgraded through a coking and distillation process. The upgraded product, referred to as sour SCO, is either sold directly to customers or upgraded further into sweet SCO by removing the sulphur and nitrogen using a hydrogen treating process. In addition to sweet and sour SCO, our upgrading also produces diesel, naphtha, kerosene and gas oil.

- Utilities – water, steam and electricity – are generated through facilities on site, some owned and operated by Suncor and others owned and operated by third parties. Process water is used in extraction processes. Steam generation is critical to SAGD processes and also assists in the production of energy in Suncor's plants. Excess energy produced is sold back to the power grid.

There are virtually no finding costs associated with oil sands resources; however, the delineation and development (mining and in situ drilling) of the resources, and the upgrading of bitumen into SCO involve significant capital outlays. As a result, our production costs are largely fixed in the short term such that operating costs per unit are largely dependent on levels of production. Natural gas is used in the production of SCO, particularly in our SAGD operations, and, accordingly, natural gas prices are a key variable component of SCO production costs.

We continue to explore and develop improved and alternative technologies to facilitate increased efficiency within our operations. In the normal course of our operations, we regularly conduct planned maintenance shutdowns of our facilities. These shutdowns provide opportunities for both preventive maintenance and capital replacement, which are expected to improve operational efficiency.

Suncor also holds a 12% interest in Syncrude, which operates the North and Aurora oil sands mines, a utilities plant, bitumen extraction plant and upgrading facility that processes bitumen and produces SCO. Mine operations use truck, shovel and hydrotransport systems. Suncor's share of SCO production is processed primarily at our refinery in Edmonton, Alberta, with the balance periodically processed in Eastern Canada and in the United States.

In 2010, production at Suncor's Oil Sands facilities averaged 283,000 bpd, and Suncor's share of production from Syncrude averaged 35,200 bpd.

Transportation

Suncor owns a pipeline that transports SCO from our facilities in Fort McMurray, Alberta to Edmonton, Alberta. The pipeline has a capacity of approximately 110,000 bpd and is operated by Suncor's Refining and Marketing business.

We have a transportation service agreement on the Enbridge Athabasca Pipeline for a term that commenced in 1999 and extends to 2028. Total line design capacity is 600,000 bpd, and the current configuration capacity is 350,000 bpd. Under this agreement, our current pipeline commitment is 182,000 bpd for the transportation of SCO and diluted bitumen from Fort McMurray, Alberta to Hardisty, Alberta.

We are a founding member of the Waupisoo Pipeline, owned and operated by Enbridge Inc. (Enbridge) that went into service on June 1, 2008. Under the agreement, our founding member status is for a minimum term of 25 years with options to extend. Total line capacity is 350,000 bpd with potential expansion to 535,000 bpd. Our pipeline commitment under this agreement is 75,000 bpd for the transportation of SCO and diluted bitumen from Cheecham, Alberta to Edmonton, Alberta.

Following the Petro-Canada merger, we additionally assumed i) a short-haul commitment from Fort McMurray to Cheecham for 58,000 bpd on the Enbridge Athabasca Pipeline; ii) a lateral transportation agreement for 40,000 bpd from MacKay River to the Athabasca Tank Terminal that also includes contracted storage facilities of 250,000 bbls, which expires June 30, 2017; and iii) contracted storage facilities at Edmonton for 500,000 bbls, which expires March 31, 2028.

In 2009, Suncor entered into long-term service agreements with affiliates of TransCanada Corporation to transport crude oil on the Keystone Pipeline. The agreements will provide for pipeline transportation of our crude oil from Hardisty, Alberta to both Patoka, Illinois and Cushing, Oklahoma. Our capacity from Hardisty, Alberta to Patoka, Illinois is 25,000 bpd. In 2011, our contracted capacity from Patoka, Illinois to Cushing, Oklahoma is 50,000 bpd. In 2008, Suncor contracted additional storage facilities at both Patoka and Cushing, in order to provide further flexibility for trading strategies. Both contracts are for 1.1 MMbbls of storage and for fixed five-year terms. On January 1, 2009, Suncor contracted storage facilities for an additional 1.2 MMbbls at Nederland, Texas for a fixed five-year term. Until the company completes its Oil Sands growth projects, Suncor's Energy Trading business expects to optimize the capacities associated with these arrangements.

In 2008, we entered into commitments for the transportation of crude oil on the Express New Pipeline (30,000 bpd starting in 2008) and the Wamsutter Pipeline (10,000 bpd starting in 2009). The Express New Pipeline runs from Hardisty, Alberta to Wood River, Illinois, and helps enable delivery of sour SCO production to our Commerce City refinery or to the Gulf Coast. The Wamsutter Pipeline in Wyoming runs from Wamsutter to Fort Laramie and also primarily helps deliver crude oil feedstock to the Commerce City refinery. We continue to evaluate additional pipeline agreements to support planned increases in production capacity.

Periodically, we also enter into strategic short-term cargo transportation agreements to ship SCO internationally. 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. This pipeline extends approximately 300 kilometres south of the Oil Sands plant and is connected to TransCanada PipeLine Limited's (TCPL) Alberta intra-provincial pipeline system. The Albersun Pipeline had the capacity to move in excess of 100 MMcf/d of natural gas in both north and south directions until we closed our Atmore receipt terminal in November 2009. Following this closure, our capacity became 46 MMcf/d in the north direction only. We arrange for natural gas supply and purchase most of the natural gas on the system under delivery-based contracts.

Our Oil Sands mining facilities are readily accessible by public road. Our Firebag in situ facilities are currently accessible by air and private road, while our MacKay River in situ facilities are accessible by a combination of public and private roads. We anticipate termination of the current road access to Firebag in 2011. The East Athabasca Highway was completed in the fourth quarter of 2010 to provide access to the Firebag site. This highway is owned by Suncor, Husky Energy Inc. and Imperial Oil Ltd. to provide each company with access to its oil sands operations in the area.

Principal Products

Sales of light sweet SCO and diesel represented 45% (2009 – 48%) and sales of light sour SCO and bitumen represented 49% (2009 – 49%) of Oil Sands consolidated operating revenues in 2010. Information on daily sales volumes and the corresponding percentage of Oil Sands operating revenues by product for each of the last two years are as follows:

Product:	2010		2009	
	Mbbls/d	% of operating revenues	Mbbls/d	% of operating revenues
Sweet synthetic crude oil [(1)] / diesel	137.9	45	144.9	48
Sour synthetic crude oil / bitumen	176.6	49	147.5	49
Total	314.5		292.4	

(1) Includes sales of Syncrude production, effective August 1, 2009.

Sales of Synthetic Crude Oil, Bitumen and Diesel

SCO and bitumen production from our Oil Sands operations is sold to and subsequently marketed by Suncor's Energy Trading business. Primary markets for our synthetic crude oil and bitumen products include refining operations in Alberta, Ontario, the U.S. Midwest and the U.S. Rocky Mountain regions. Diesel products are sold primarily in Western Canada, marketed by Suncor's Refining and Marketing business.

For production of bitumen from our in situ assets, Oil Sands operating strategy allows Suncor to take advantage of changes in market and operating conditions by either: a) upgrading the bitumen directly at our Oil Sands facilities; b) upgrading the bitumen at Suncor's refineries, by transporting diluted bitumen to those facilities; or c) selling diluted bitumen directly to third parties.

In 1997, we entered into a long-term agreement with Flint Hills Resources LLC (Flint Hills) to supply Flint Hills with up to 30,000 bpd of sour crude from our Oil Sands operations. We began shipping the crude to Flint Hills at Hardisty, Alberta on January 1, 1999. The term of the initial agreement expires on June 30, 2011. A new agreement was negotiated to supply Flint Hills with 20,000 bpd beginning July 1, 2011. The initial term of that agreement extends to June 30, 2014 and will continue thereafter until termination upon a minimum of 24 months notice by either party.

Under a long-term sales agreement from August 2001 with Consumers Co-operative Refineries Limited (CCRL), we supply CCRL with 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. The initial term of both CCRL agreements is 15 years with five-year evergreen terms thereafter subject to termination by either party on 24 months notice. Neither party has provided notice of termination at this time.

A portion of our Oil Sands production is used in our refining operations. Our refineries processed the following portion of our total Oil Sands crude sales in the past two years:

Refinery	Year Ended December 31, 2010		Year Ended December 31, 2009	
	Mbbls/d	% total Oil Sands sales [1]	Mbbls/d	% total Oil Sands sales [1]
Edmonton [2]	55	24	58	25
Sarnia	60	27	44	18
Commerce City	9	4	9	4
Total	124		111	

(1) Calculated based on Oil Sands sales, excluding diesel and bitumen sales.

(2) For 2009, reflects operations subsequent to the Petro-Canada merger on August 1, 2009.

There were no customers that represented 10% or more of our consolidated revenues in 2010 or 2009.

Competitive Conditions

For a discussion of the competitive conditions affecting our Oil Sands operations, refer to "Competition" in the Risk Factors section of this AIF.

Seasonal Impacts

Severe winter climatic conditions at our Oil Sands operations can cause reduced production and, in some situations, can result in higher costs.

Environmental Compliance

For a discussion of environmental risks at our Oil Sands operations, refer to "Government Regulation" in the Risk Factors section of this AIF.

As part of Suncor's strong focus on operational excellence, Suncor has set four key environmental performance goals it intends to reach by 2015 (the base year for planned improvements is 2007): reduce total water intake by 12%, increase land area reclaimed by 100%, improve energy efficiency by 10% and reduce air emissions by 10%. In addition, Suncor has advanced strategies focused on operational excellence aimed at further improving process safety and reliability, which in turn will impact our environmental impact. Suncor has adopted a clear set of process safety management standards and has implemented the same at all of our facilities.

In 2010, Suncor reclaimed the industry's first tailings pond to a trafficable surface. As well, Suncor received approval and started implementation of a new tailings technology, TRO_{TM}, which Suncor expects will significantly reduce tailings reclamation time. The technology has already enabled Suncor to cancel plans to build five additional tailings ponds at its existing operations. Suncor will continue to pursue the implementation of TRO_{TM} across its existing operations and continue to take a

leadership position in collaborative efforts with industry counterparts on the development of environmental technologies. Suncor expects to spend significant amounts of capital over 2010 and 2011 to implement TRO_{TM}. This represents a significant step forward in addressing one of the biggest environmental challenges facing the oil sands industry.

Suncor will also work closely with the Oil Sands Leadership Initiative (OSLI). Comprised of Suncor, Total and three other like-minded oil sands companies, this organization is squarely focused on innovations that lead to continuous improvement in environmental, social and economic performance.

Suncor has implemented a regulatory compliance assurance process applicable to its ongoing operations and proposed future projects. A major component of the regulatory assurance work is carried out through the implementation of a software system that sets out applicable legal requirements and generates tasks to meet these requirements. To date, the scope of the regulatory compliance assurance process has included environmental regulatory compliance, mainly associated with Suncor's Oil Sands and In Situ operations

Suncor has also implemented a comprehensive roles and responsibilities matrix as part of our greenhouse gas (GHG) management program. For details refer to "Suncor's Governance Process" in the Risk Factors section of this AIF.

Natural Gas

Our Natural Gas business explores for, develops and produces natural gas, NGLs, crude oil and byproducts in Western Canada, supplying markets throughout North America. After the merger with Petro-Canada, we implemented a new strategy with greater emphasis on unconventional gas. To focus on this goal, and to help reduce the company's debt, we decided to sell a number of non-core natural gas assets.

Our exploration program is primarily focused on multiple geological zones throughout Western Canada. The business is structured with the following core asset areas:

- Shale (northeast B.C.);
- Shallow (southeast Alberta);
- Foothills (western Alberta and portions of northeast B.C.); and
- Plains (western Alberta).

Marketing, Pipeline and Other Operations

In Western Canada, Suncor operates 10 natural gas processing plants, with total licensed capacity of 793 MMcf/d, of which the company's share is 481 MMcf/d. The following table shows Suncor's working interest ownership and the licensed capacity of operated processing plants as at December 31, 2010.

Suncor Operated Plants	Working Interest Ownership %	Gross Licensed Capacity MMcf/d	Net Licensed Capacity MMcf/d
Hanlan Sweet	40.73	44.2	18.0
Hanlan Sour	49.86	382.0	190.5
Wilson Creek	52.17	34.6	18.1
Boundary Lake Sweet	100.00	20.0	20.0
Boundary Lake Sour	50.00	66.0	33.0
Parkland 1	43.98	18.1	8.0
Parkland 2	34.75	11.7	4.1
Ferrier	99.99	120.0	120.0
Gilby East	100.00	52.4	52.4
Progress	38.46	44.0	16.9
Total		**793.0**	**481.0**

Suncor also has varying working interests in other natural gas processing plants and field gathering facilities operated by other oil and natural gas companies. The company's aggregate share from such interests is 91.5 MMcf/d of licensed capacity.

In 2010, Suncor's share of production from its Natural Gas properties was 575 MMcfe/d, with 432 MMcfe/d produced from continuing operations.

Substantially all of our natural gas production is sold to our Energy Trading business, which then markets the product to our customers under direct sales arrangements. Contracts for these direct sales arrangements are of varied terms, with a majority having terms of one year or less, and incorporate pricing that 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.

To provide price diversity for natural gas marketing Suncor holds 85,000 MMcf/d of firm capacity on the Alliance Pipeline system and 68,000 MMbtu per day on the TCPL Gas Transmission Northwest Pipeline (GTN). The Alliance pipeline capacity, which expires in December 2015, enables Suncor to transport high-energy, rich natural gas from northeast B.C. and northwest Alberta to the Alliance pipeline terminus in Illinois. The GTN capacity, which expires in 2023, enables Suncor to deliver natural gas to the Pacific Northwest and California markets.

Suncor does not typically enter into long-term supply arrangements to sell its conventional crude oil and NGL production. Instead, our conventional crude oil and NGL 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. We currently have no pipeline commitments related to the shipment of conventional crude oil.

Principal Products

Sales of natural gas represented 77% of the Natural Gas business segment's consolidated operating revenues in 2010, with 22% comprised of sales of NGLs and crude oil. The remaining 1% is related mainly to sales of sulphur byproduct. Average daily sales volumes and the corresponding percentage of Natural Gas's operating revenues by product for the last two years are as follows:

Product:	2010		2009	
	MMcfe/d	% of operating revenues	MMcfe/d	% of operating revenues
Natural gas	522	77	397	76
Crude oil and NGLs	53	22	49	23
Total	575		446	

Competitive Conditions

For a discussion of the competitive conditions affecting the Natural Gas business, refer to "Competition" in the Risk Factors section of this AIF.

Seasonal Impacts

Risks and uncertainties associated with weather conditions and wildlife restrictions can shorten the winter drilling season and can impact the spring and summer drilling programs, potentially resulting in increased costs or reduced production.

Environmental Compliance

For a discussion of environmental risks at our Natural Gas operations, refer to "Government Regulation" in the Risk Factors section of this AIF.

International and Offshore

The International and Offshore business explores for, develops and produces crude oil and natural gas offshore Newfoundland and Labrador and in the North Sea, primarily in the U.K. and Norway, and conventionally in Libya and Syria. International and Offshore's business interests include:

East Coast Canada

- Suncor is the operator of Terra Nova oilfield, holding a 37.675% interest.
- A 20% interest in the Hibernia oilfield (including the AA Blocks) and a 19.5% interest in the Hibernia South Extension.
- A 27.5% interest in the White Rose oilfield and a 26.125% interest in the North Amethyst, West White Rose and South White Rose Extensions (collectively the White Rose Extensions).
- A 22.7% interest in the Hebron oilfield.
- Interests in 47 significant other discovery licences and seven other exploration licences offshore Newfoundland and Labrador.

North Sea

- A 29.9% interest in the Buzzard oilfield.
- A 26.69% interest in the Golden Eagle Area Development.

Libya

- Six EPSAs to extend development of energy resources in Libya's oil fields. The EPSAs provide exploration opportunities in the Sirte Basin.

Syria

- Two PSCs in Syria to develop and produce natural gas and other hydrocarbons from Syrian fields. One PSC relates to the Ebla gas project and the other relates to another onshore exploration block.

As part of its strategic business alignment, during 2010, Suncor divested all of its Trinidad and Tobago assets and certain non-core North Sea assets, including all assets in The Netherlands.

Exploration and Production

East Coast Canada

Terra Nova

The Terra Nova oilfield, which is approximately 350 kilometres southeast of St. John's, Newfoundland, was discovered by Petro-Canada in 1984. Terra Nova is the second oilfield to be developed offshore Newfoundland and Labrador. This Suncor-operated production system uses a Floating Production, Storage and Offloading (FPSO) vessel that is moored on location, with a gross production capacity of 180,000 bpd and storage capacity of 960,000 bbls. Terra Nova was the first harsh environment development in North America to use a FPSO vessel. Actual production levels are lower than production capacity, reflecting current reservoir capability. Production from the Terra Nova oilfield began in January 2002. The field is estimated to have a remaining production life of approximately 13 to 20 years at current rates.

On December 1, 2010, the joint owners of the Terra Nova oilfield finalized the redetermination of working interests required under the Terra Nova Development and Operating Agreement following field payout on February 1, 2005. As a result, Suncor's working interest increased to 37.675% from 33.990% effective January 1, 2011.

At December 31, 2010, there were 15 producing oil wells, nine water injection wells and three gas injection wells in operation. Field production is transported by shuttle tanker from the FPSO to either a transshipment terminal on Placentia Bay or, if tanker schedules permit, directly to market. Crude oil delivered to the transshipment facility is transferred to storage tanks and loaded onto tankers for transport to markets in Eastern Canada and the U.S. Suncor has a 14% ownership interest in the transshipment facility.

In 2010, Suncor's share of Terra Nova production averaged 23,200 bpd. H_2S was detected in several production wells in the fourth quarter of 2010. The affected wells and facilities have been safely shut-in while the company develops a mitigation plan to safely address the situation.

Hibernia and Hibernia South

The Hibernia oilfield, encompassing the Hibernia and Ben Nevis Avalon reservoirs, is approximately 315 kilometres southeast of St. John's and was the first field to be developed in the Jeanne d'Arc Basin. Operated by Hibernia Management and Development Company Ltd., the production system is a fixed Gravity Base Structure (GBS), which sits on the ocean floor. The GBS has gross production capacity of 230,000 bpd and storage capacity of 1.3 MMbbls. Actual production levels are lower reflecting current reservoir capability and natural decline. Hibernia commenced production in November 1997. The Hibernia oilfield is estimated to have a remaining production life of 25 to 30 years at current rates.

Final fiscal agreements were signed between co-venturers and the Government of Newfoundland and Labrador in February 2010 that established the key fiscal, equity and operational principles for the development of the Hibernia South Extension. The Hibernia South Unit Development Plan Amendment (DPA) was approved by the Canada Newfoundland and Labrador Offshore Petroleum Board (CNLOPB) on September 3, 2010. The federal and provincial governments approved the CNLOPB decision on October 8, 2010. Subject to completion of certain agreements with the federal government, production from Hibernia South is expected in mid-2011, with the completion of the first oil producer/water injector well pair.

At December 31, 2010, there were 34 producing oil wells, 24 water injection wells and six gas injection wells in operation. Hibernia uses the same transshipment terminal and the same system of shuttle tankers that are used for Terra Nova, and also transports its crude oil to markets in Eastern Canada and the U.S.

In 2010, Suncor's share of Hibernia production averaged 30,900 bpd.

White Rose and the White Rose Extensions

White Rose, the third oilfield development offshore Newfoundland, is about 350 kilometres southeast of St. John's. Operated by Husky Oil Operations Limited, White Rose uses a FPSO vessel (similar to Terra Nova) that has a gross production capacity of

140,000 bpd and a storage capacity of 940,000 bbls. Production from the White Rose oilfield began in November 2005. The field is estimated to have a remaining production life of approximately 15 to 18 years at current rates.

In December 2007, the White Rose joint venture participants signed a formal agreement with the Province of Newfoundland and Labrador for the development of the White Rose Extensions, incorporating the South White Rose Extension, North Amethyst and West White Rose satellite fields. In May 2010, first oil was achieved in the North Amethyst portion of the White Rose Extensions and development drilling is ongoing. Development of the West White Rose Extension will be divided into two stages. Stage 1 was approved in the second quarter of 2009. First oil from the West White Rose Extension is expected by mid-2011 following completion of the first production well. Results of Stage 1, combined with other ongoing evaluation, will help define the scope of Stage 2.

At December 31, 2010, there were 10 producing oil wells and 12 water injection wells in operation. White Rose uses the same transshipment terminal and the same system of shuttle tankers that are used for Hibernia and Terra Nova, and also transports its crude oil directly to markets in Eastern Canada and the U.S.

In 2010, Suncor's share of White Rose production averaged 14,500 bpd.

Hebron

Hebron is an oilfield discovery located 340 kilometres southeast of St. John's. In August 2008, the Hebron joint venture participants reached an agreement with the Government of Newfoundland and Labrador on commercial terms that will allow development activities to proceed for Hebron. The project will be operated by ExxonMobil Canada Ltd. The contract for front end engineering and design for topsides, procurement and construction was awarded in September 2010. The development plan application is expected to be submitted for approval in the second quarter of 2011, with first oil expected in 2017.

Other Exploration Offshore Newfoundland

In addition to existing East Coast Canada developments, Suncor also holds interests in a number of other discoveries and continues to pursue opportunities offshore Newfoundland and Labrador.

North Sea

The Buzzard oilfield is located in the Outer Moray Firth, 95 kilometres northeast of Aberdeen, Scotland. Operated by Nexen Petroleum U.K. Limited, the Buzzard system has production capacity of 200,000 bpd of oil and 60 mmcf/d of natural gas. Buzzard achieved first oil in January 2007 and reached peak production in the middle of 2007. Buzzard is supported by four bridge-linked platforms supporting wellhead facilities, production facilities, sulphur handling, and living quarters and utilities. Crude oil is transported via the Forties pipeline system to the Kinneil terminal in Scotland, and natural gas is transported via the Frigg pipeline to the St. Fergus gas terminal in Scotland. Commissioning of the fourth platform, installed to remove H_2S in the oil production from some segments of the field, was initiated in 2010 and will continue into the first quarter of 2011. The field is expected to have a remaining production life of approximately 20 years at current rates.

An agreement has been reached to unitize the discoveries in Pink, Hobby and Golden Eagle into a pre-development project called the Golden Eagle Area Development. A development project is ongoing with first oil projected in 2014-2015.

In 2010, Suncor reached agreements to sell non-core offshore U.K. assets (Scott/Telford and Triton) and completed the sale of a portion of these assets. Suncor also sold its non-core offshore Netherlands assets.

In 2010, Suncor's share of North Sea production averaged 79,000 boe/d, including 55,500 boe/d from Buzzard.

In Norway, the company completed its first operated exploration well in January 2010 and encountered hydrocarbons. An appraisal well was drilled and tested in the fourth quarter of 2010 with positive results. Further evaluation is required to determine the potential size of this discovery.

Libya

Suncor conducts its Libya operations pursuant to EPSAs, under which the company pays 50% of the costs and recovers these costs from 12% of production. Excess production is then shared between Suncor and the Libyan government. The EPSAs, which expire in 2033, enable Suncor and the NOC to design and implement jointly the redevelopment of the existing fields in the Sirte Basin.

As a result of the merger, the company assumed the remaining US$500 million obligation for a signature bonus relating to Petro-Canada's ratification of the EPSAs in 2008. As at December 31, 2010, the undiscounted value of Suncor's remaining obligation is US$290 million, payable in several installments through 2013. Under the EPSAs, Suncor is the exploration operator and has committed to fully fund an exploration program, at an estimated remaining cost of US$335 million. Failure by Suncor to conduct its exploration commitment or make the signature bonus payments could result in the NOC terminating the EPSAs, which would result in Suncor losing all of its rights to production in Libya.

In 2010, Suncor's share of production in Libya averaged 35,200 boe/d.

Syria

The Ebla gas project is operated pursuant to a PSC, under which the company pays 100% of the costs and recovers these costs from a 40% share of production after deduction for royalties of 12.5%. The remaining profit is shared between Suncor and the Syria government. The Ebla PSC will expire in April 2035.

First commercial gas production from Ebla was achieved on April 10, 2010. First oil was achieved on December 10, 2010. The transfer of ownership of hydrocarbons to the Syria government is governed under the terms and conditions of the PSC and related sales agreements.

Located in the Central Syrian Gas Basin, Ebla includes the Ash Shaer and Cherrife development areas, which cover more than 300,000 acres (approximately 1,251 square kilometres) combined. The Ebla development comprises the gas producing wells, a gas gathering and compression station, approximately 80 kilometres of pipeline and a gas treatment plant. The facility is designed to produce 80 MMcf/d of natural gas, along with related liquefied petroleum gas (LPG) and condensate volumes. Natural gas is delivered into the Syrian national gas grid for domestic consumption. LPG volumes are delivered via truck to major Syrian cities. Condensate and oil are transported to the Banias refinery in Syria.

In 2010, Suncor's share of production in Syria averaged 11,600 boe/d.

Trinidad and Tobago

On August 5, 2010, the company completed the sale of its Trinidad and Tobago assets. Prior to the sale, Suncor's share of Trinidad and Tobago production averaged 11,300 boe/d.

Principal Products

Sales of crude oil and NGLs represented 92% and sales of natural gas represented 8% of International and Offshore's consolidated operating revenues. Information on daily sales volumes and the corresponding percentage of International and Offshore's operating revenues by product for 2010, 2009 and the final five months of 2009 are as follows:

Product:	Year ended December 31, 2010		Year ended December 31, 2009	
	Mboe/d	% of operating revenues	Mboe/d	% of operating revenues
Crude oil and NGLs	179.6	92	66.8	95
Natural gas	21.5	8	8.1	5
Total	201.1		74.9	

Product:	Five months ended December 31, 2009 (1)	
	Mboe/d	% of operating revenues
Crude oil and NGLs	159.5	95
Natural gas	19.3	5
Total	178.8	

(1) Reflects operations subsequent to the Petro-Canada merger on August 1, 2009.

Sales of Conventional Crude Oil and Natural Gas

We do not typically enter into long-term supply arrangements for our East Coast Canada or North Sea production. Instead, this production is generally sold under spot contracts or under contracts that can be terminated on relatively short notice.

Approximately 20,000 bpd of Suncor's share of Hibernia production was sold to our Montreal refinery.

Hydrocarbons produced in Libya are marketed by the Libya government on behalf of Suncor.

The transfer of ownership of hydrocarbons to the Syria government is governed under the terms and conditions of the PSC and related sales agreements.

Competitive Conditions

For a discussion of the competitive conditions affecting the International and Offshore business unit, refer to "Competition" in the Risk Factors section of this AIF.

Seasonal Impacts

The primary seasonal International and Offshore impacts are caused by winter storms, pack ice, icebergs and fog offshore Newfoundland and Labrador. During the winter storm season (October to March), we may have to reduce production rates at our offshore facilities as a result of limited storage capacity and the inability to offload to shuttle tankers due to wave height restrictions. We also experience seasonal impacts in the spring period, due to pack ice and icebergs drifting in the area of our offshore facilities. We have had precautionary shut-in of FPSO production and drilling delays due to pack ice and icebergs. In late spring and early summer, fog also impacts our ability to transfer personnel to the offshore facilities by helicopter.

Environmental Compliance

For a discussion of environmental risks for our International and Offshore operations, refer to "Government Regulation" in the Risk Factors section of this AIF.

Refining and Marketing

The Refining and Marketing business:

- Owns and operates refineries in Edmonton, Alberta, Montreal, Quebec, Sarnia, Ontario and Commerce City, Colorado, with a total crude oil capacity of 443,000 bpd.
- Owns and operates a lubricants plant in Mississauga, Ontario.
- Owns a joint venture interest in a petrochemical plant in Montreal, Quebec.
- Owns and operates and has equity interests in pipeline systems in Canada and the U.S.
- Owns and operates a network of distribution terminals across Canada and in Colorado.
- Markets refined products to retail, commercial and industrial customers, primarily in Canada and Colorado, through a combination of company-owned, branded-dealer and joint venture-operated retail stations, a large Canadian national commercial road transportation network and a bulk sales channel.

Refining and Product Supply Operations

Eastern North America

Our Montreal refinery has a current crude oil capacity of 130,000 bpd and produces gasoline, distillates, asphalts, heavy fuel oil, petrochemicals and solvents, which are distributed primarily across Quebec and Ontario. The Montreal refinery also produces feedstock for our lubricants plant.

The Montreal refinery processes primarily foreign conventional crude oil and has a flexible configuration that allows processing of a variety of crude oils, including heavy grades and intermediate feedstocks. Crude oil is procured from the market on a spot basis or under contracts that can be terminated on short notice.

Suncor holds a 51% interest in ParaChem Chemicals L.P. (ParaChem), which owns and operates a petrochemicals plant located adjacent to the Montreal refinery. The plant primarily produces up to 350,000 metric tons per year of paraxylene, which is used to manufacture polyester textiles and plastic bottles. ParaChem also produces benzene, hydrogen and heavy aromatics.

Our Sarnia refinery has a current crude oil capacity of 85,000 bpd and produces gasoline, distillates, and petrochemicals, which are primarily distributed in Ontario. On December 31, 2010, the company terminated its joint venture partnership with Sun Petrochemicals Company, a Toledo, Ohio-based refinery, which managed the sale of petrochemicals from Sarnia. These petrochemical sales will now be marketed solely by Refining and Marketing.

The Sarnia refinery processes both SCO and conventional crude oil. In 2010, we refined 68,000 bpd of SCO, of which 31,300 bpd was supplied from our Oil Sands operations. In the event of a significant disruption in the supply of SCO, the Sarnia refinery has the flexibility to substitute other sources of sweet or sour conventional crude oil. The balance of the refinery's feedstocks are purchased from third parties on a spot basis or under contracts that can be terminated on short notice.

To maintain supply and demand balance, Suncor imports and exports feedstocks and finished products from the East Coast. Suncor also enters into reciprocal exchange arrangements with other refining companies in Eastern North America as a means of minimizing transportation costs, balancing product availability and leveraging our assets.

Our lubricants plant produces specialty lubricants and waxes that are marketed in Canada and internationally. Suncor's lubricants plant is the largest producer of lubricant base stocks in Canada, with annual base oil production capacity in excess of 900 million litres. Feedstock for our lubricants facility comes from our Montreal refinery and other purchase contracts.

Western North America

Our Edmonton refinery has a current crude oil capacity of 135,000 bpd and primarily produces gasoline and distillates, the majority of which are distributed in Western Canada.

The Edmonton refinery has the potential to run entirely on feedstocks sourced from Alberta's oil sands and heavy crude oil production. Feedstock is supplied from Suncor's Oil Sands operations, Syncrude operations (including volumes purchased by Suncor from other joint owners' share of production) and other producers from the Athabasca and Cold Lake regions of Alberta. The refinery can upgrade directly 35,000 bpd of blended feedstock (comprised of 25,000 bpd of bitumen and 10,000 bpd of diluent) and process 45,000 bpd of sour SCO. The refinery can also process 55,000 bpd of sweet SCO through its synthetic train.

Our Commerce City refinery has a current combined crude distillation capacity of 93,000 bpd and produces primarily gasoline, diesel and asphalt. The majority of the refined products from the refinery are distributed to industrial, commercial, wholesale, and refining customers in Colorado. The remaining production is sold through a retail distribution network in Colorado.

The Commerce City refinery processes conventional crude oil and after the completion of our diesel desulphurization and oil sands integration projects, the refinery is now capable of processing up to 15,000 bpd of sour SCO from Suncor's Oil Sands operations. 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. A majority of crude feedstock is supplied from sources in the U.S., primarily the Rocky Mountain region, while the remainder is purchased from Canadian sources. The crude oil purchase contracts have terms ranging from month-to-month to multi-year.

To maintain supply and demand balance, Suncor imports and exports feedstocks and finished products from the West Coast. Suncor also enters into reciprocal exchange arrangements with other refining companies in western North America as a means of minimizing transportation costs, balancing product availability and leveraging our assets.

The following table summarizes the crude feedstock and utilizations for Suncor's refineries for the year ended December 31, 2010.

Refinery	2010 Average Daily Crude Input				
	Average Daily Crude Input Mbbls/d	Conventional Mbbls/d	Synthetic Mbbls/d	Oil Sands Synthetic Mbbls/d	Utilization %
Montreal	121.5	121.5	—	—	94
Sarnia	70.5	2.3	36.9	31.3	83
Edmonton	118.6	25.9	39.6	53.1	88
Commerce City	99.0	89.3	—	9.7	106

Transportation and Distribution

Eastern North America

Crude oil for the Montreal refinery is largely supplied by the Portland-Montreal Pipeline, in which Suncor has a 24% ownership interest. Refined products are distributed via the Trans-Northern Pipeline (33% ownership interest) and also by truck, rail and marine vessel.

Crude oil is supplied to the Sarnia refinery primarily via the Enbridge system. We procure conventional crude oil feedstock primarily from Western Canada, but periodically supplement supply with purchases from the U.S. and other countries. Foreign crude oil is delivered to Sarnia via the Enbridge Pipeline system from Montreal. We have not made any firm capacity commitments on these pipeline systems. Refined products are distributed via the Sun-Canadian Pipeline (55% ownership interest), delivering to core markets in Ontario via terminal facilities in Toronto, Hamilton and London, and also via marine vessel and rail. The Sarnia refinery also has limited access to pipelines delivering refined product into the U.S.

Western North America

Crude oil is supplied to the Edmonton refinery via third-party pipelines. Refined products are distributed via the Alberta Products Pipeline (35% ownership interest), the TransMountain Pipeline, and the Enbridge Pipeline system. Refined product also moves to distribution terminals via truck and rail.

Approximately 60% of crude oil supplied to the Commerce City refinery is transported via pipeline, with the remainder transported via truck. Refined products are distributed by truck and rail, a jet fuel pipeline to the Denver International Airport and a diesel pipeline to the Union Pacific railroad yard in Denver.

In the U.S., Suncor owns and operates the Rocky Mountain Crude Pipeline system, which runs from Guernsey, Wyoming to Denver, Colorado. This is a common carrier pipeline that transports crude for our refinery as well as for other shippers. We also own and operate the Centennial Pipeline, which transports crude from Guernsey, Wyoming to Cheyenne, Wyoming.

Refining and Marketing owns and operates 13 major refined products terminals across Canada and two product terminals in Colorado. Combined with access to facilities under long-term contractual arrangements with other parties, Suncor's North American assets are sufficient to meet Refining and Marketing's current storage and distribution needs.

Marketing Operations

Suncor's retail service station network operates nationally under the Petro-Canada $_{TM}$ brand. Most of Suncor's owned and operated Sunoco $_{TM}$-branded retail and cardlock sites were re-branded to the Petro-Canada$_{TM}$ brand in 2010. In addition to marketing through our proprietary retail outlets, petroleum product is marketed through independent dealers and joint venture facilities. In conjunction with the merger with Petro-Canada, the Canadian Competition Bureau required Suncor to divest 104 retail sites in Ontario, which was successfully completed during 2010.

As at December 31, 2010, Suncor's branded retail service station network consisted of 1,457 outlets across Canada. Our network had annual sales of gasoline motor fuels averaging approximately 5.1 million litres per site in 2010, and attracted a 19% share of the national retail market (based on data available from Statistics Canada for the period from January to October 2010). Our Colorado retail network consisted of 44 outlets owned by Suncor.

	As at December 31,	
Retail Sites:		
Canada	2010	2009
Petro-Canada$_{TM}$-branded retail service stations	1,447	1,318
Sunoco$_{TM}$-branded retail service stations	10	280
Total branded retail service stations	1,457	1,598
Colorado		
Shell®-branded retail service stations	37	37
Phillips 66®-branded retail service stations	7	7
Total retail service stations	44	44

Suncor has product supply agreements with an additional 178 Shell®-branded sites and 73 Phillips 66®-branded sites in Colorado. We also generate non-petroleum revenues from convenience stores, car washes, and automotive repair and maintenance services.

Suncor's wholesale operations sell petroleum products into farm, home heating, paving, small industrial, commercial and truck markets. Through our Petro-Pass network, we are the leading national marketer to the commercial road transport segment in Canada. We also sell large volumes of petroleum products directly to large industrial and commercial customers and independent marketers.

	As at December 31,	
Wholesale Sites:		
Canada	2010	2009
Petro-Canada$_{TM}$-branded cardlock sites (Petro-Pass)	249	235
Sunoco$_{TM}$-branded cardlock sites	—	49
	249	284

Principal Products

Daily sales volumes and corresponding percentages of Refining and Marketing's operating revenues for the last two years are as follows:

Product:	2010		2009	
	thousands of m^3/d	% of operating revenues	thousands of m^3/d	% of operating revenues
Gasoline [1]				
Eastern North America	22.2		14.6	
Western North America	18.9		13.0	
	41.1	48	27.6	52
Distillates [2]				
Eastern North America	12.4		8.8	
Western North America	18.5		9.5	
	30.9	36	18.3	33
Other [3]				
Eastern North America	10.7		4.3	
Western North America	5.1		4.7	
	15.8	16	9.0	15
Total	87.8		54.9	

(1) Includes motor and aviation gasoline.

(2) Includes diesel oils, heating oils and aviation jet fuels.

(3) Includes heavy fuel oil, asphalts, lubricants, LPG, petrochemical feedstock and other petroleum and non-petroleum products.

Product:	Five months ended December 31, 2009 [1]	
	thousands of m^3/d	% of operating revenues
Gasoline [2]		
Eastern North America	23.0	
Western North America	18.9	
	41.9	51
Distillates [3]		
Eastern North America	13.4	
Western North America	15.4	
	28.8	34
Other [4]		
Eastern North America	6.9	
Western North America	7.2	
	14.1	15
Total	84.8	

(1) Reflects operations subsequent to the Petro-Canada merger on August 1, 2009.

(2) Includes motor and aviation gasoline.

(3) Includes diesel oils, heating oils and aviation jet fuels.

(4) Includes heavy fuel oil, asphalts, lubricants, LPG, petrochemical feedstock and other petroleum and non-petroleum products.

Competitive Conditions

For a discussion of the competitive conditions affecting our Refining and Marketing business, refer to "Competition" in the Risk Factors section of this AIF.

Environmental Compliance

For a discussion of environmental risks at our Refining and Marketing business operations, refer to "Government Regulation" in the Risk Factors section of this AIF.

Other Suncor Businesses

Renewable Energy

Suncor's renewable energy interests include four wind power projects, with two more projects currently under construction, and Canada's largest ethanol plant by production volume.

Wind power is one of the most economically recognized forms of green power. Suncor is a Canadian pioneer in wind power with investments in four wind farms in operation, which have a gross generating capacity of 147 MW and reduce carbon dioxide (CO_2) emissions by approximately 284,000 tonnes each year. Suncor does not operate any of these wind farms. Two additional wind farm projects, Wintering Hills and Kent Breeze are under construction and will be operated by Suncor.

Wind Farm	Location	Ownership Interest	Size (MW)	Turbines	Commissioned
Ripley	Ripley, Ontario	50.0%	76	38	2007
Chin Chute	Taber, Alberta	33.3%	30	20	2006
Magrath	Magrath, Alberta	33.3%	30	20	2004
SunBridge	Gull Lake, Saskatchewan	50.0%	11	17	2002

Biofuels

Since 2006, Suncor has invested in Canada's emerging biofuels industry. Suncor operates Canada's largest ethanol facility, the St. Clair Ethanol Plant in the Sarnia-Lambton region of Ontario. Our ethanol plant had an original production capacity of 200 million litres per year, which has since doubled with the completion of the plant expansion on January 22, 2011. Feedstock for the plant will consist of approximately 40 million bushels of corn annually following the expansion. In 2010, the plant produced 206 million litres of ethanol.

Energy Trading

Our Energy Trading business is organized around four main commodity groups – crude oil, natural gas, sulphur and petroleum coke. Each commodity group provides value to customers through innovative commodity supply, transportation and pricing solutions. Our customers include mid- to large-sized commercial and industrial consumers, utility companies and energy producers, all of which demand specialized solutions to meet unique energy requirements.

Significant Policies

Suncor has adopted a Stakeholder Relations Policy which reflects Suncor's values and beliefs. The policy provides that Suncor is committed to developing and maintaining positive, meaningful relationships with stakeholders in all of its operating areas and provides Suncor's principles for guiding the development of stakeholder relations (respect, responsibility, transparency, timeliness and mutual benefit). The policy makes it clear that successful stakeholder engagement fosters informed decision making, resolving issues with timely, cost-effective and mutually beneficial solutions and supporting shared learning.

Suncor has adopted an Aboriginal Affairs Policy, which affirms Suncor's desire to work in collaboration with Canada's Aboriginal peoples to develop a thriving energy industry that allows Aboriginal communities to be vibrant, diversified and sustainable. The policy provides a consistent approach to the company's relationships with Canada's Aboriginal peoples and outlines Suncor's responsibilities and commitments, and is intended to guide Suncor's business decisions on a day-to-day basis. Suncor is committed to work closely with Canada's Aboriginal peoples and communities to build and maintain effective, long-term and mutually beneficial relationships. The policy makes it clear that responsible development takes into account Aboriginal issues and concerns about the effects, positive and negative, of energy development on communities and their traditional and current uses of lands and resources.

Suncor is in the process of finalizing specific guidelines for each of the Stakeholder Relations Policy and the Aboriginal Affairs Policy. During 2011, Suncor plans to hold training and awareness events which are expected to assist in continuing to affect the policies across the company.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Date of Statement

The statement of reserves data and other oil and gas information outlined below is dated March 3, 2011, with an effective date of December 31, 2010. The preparation date of the information is February 16, 2011.

Disclosure of Reserves Data

As a Canadian issuer, Suncor is subject to the reporting requirements of Canadian securities regulatory authorities, including the reporting of our reserves in accordance with National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* (NI 51-101). For the year ended December 31, 2009, Suncor applied for, and received, an exemption from Canadian securities regulatory authorities permitting Suncor to report its reserves as at December 31, 2009 in accordance with the rules and regulations of the United States Securities and Exchange Commission. Suncor did not apply for a similar exemption order for the year ended December 31, 2010. As a result, closing balances presented in 2009 have been restated (compared to those presented in our December 31, 2009 statement of reserves data and other information) to comply with NI 51-101.

The reserves data set forth below for Suncor's Canadian mining and in situ operations is based upon an evaluation conducted by GLJ Petroleum Consultants Ltd. (GLJ) with an effective date of December 31, 2010, contained in their reports (the GLJ Reports). The reserves data set forth below for all other reserves, which includes Suncor's interests in its Canadian onshore conventional (Natural Gas) and offshore conventional (East Coast Canada) assets, the North Sea of the United Kingdom (the North Sea), and Syria and Libya (collectively, Other International) is based upon evaluations or reviews conducted by Sproule Associates Limited or Sproule International Limited (collectively, Sproule) with an effective date of December 31, 2010 contained in their reports (the Sproule Reports). The reserves data reviewed by Sproule was evaluated by Suncor's internal qualified reserves evaluators. All factual data supplied to GLJ and Sproule (the Evaluators) was accepted as presented. No field inspections were conducted.

The reserves data summarizes Suncor's oil, liquids and natural gas reserves and the net present values of future net revenue for these reserves using forecast prices and costs (unless otherwise indicated) prior to provision for interest, general and administrative expenses, costs associated with environmental regulations, the impact of any hedging activities or the liabilities associated with certain abandonment and all well, pipeline, facilities and mine reclamation costs. Future net revenues have been presented on a before and after-tax basis. The reserves data conforms with the requirements of NI 51-101. See also the "Notes to Reserves Data Tables" and the "Definitions for Reserves Data Tables"

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserves estimates of oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual oil, natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein. Readers should review the definitions and information contained in "Notes to Reserves Data Tables", "Definitions for Reserves Data Tables" and "Notes to Future Net Revenues Tables" in conjunction with the following tables and notes. For more information as to the risks involved, see "Risk Factors – Uncertainty of Reserves and Resources Estimates" in this AIF.

Summary of Oil and Gas Reserves [1][2][3]

as at December 31, 2010
(forecast prices and costs)

	SCO		Bitumen		Light & Medium Oil		Natural Gas		Natural Gas Liquids	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	MMbbls	MMbbls	MMbbls	MMbbls	MMbbls	MMbbls	Bcf	Bcf	MMbbls	MMbbls
Proved Developed Producing										
Mining	2 084	1 779	—	—	—	—	—	—	—	—
In Situ	121	113	37	30	—	—	—	—	—	—
East Coast Canada	—	—	—	—	53	39	—	—	—	—
Natural Gas	—	—	—	—	10	9	953	806	8	5
Total Canada	2 205	1 892	37	30	63	48	953	806	8	5
North Sea [4]	—	—	—	—	86	86	10	10	1	1
Other International [5]	—	—	—	—	102	37	251	166	8	5
Total Proved Developed Producing	**2 205**	**1 892**	**37**	**30**	**251**	**172**	**1 214**	**982**	**16**	**11**
Proved Developed Non-Producing										
Mining	—	—	—	—	—	—	—	—	—	—
In Situ	50	47	—	—	—	—	—	—	—	—
East Coast Canada	—	—	—	—	—	—	—	—	—	—
Natural Gas	—	—	—	—	—	—	41	31	—	—
Total Canada	50	47	—	—	—	—	41	31	—	—
North Sea [4]	—	—	—	—	13	13	—	—	—	—
Other International [5]	—	—	—	—	32	12	—	—	—	—
Total Proved Developed Non-Producing	**50**	**47**	**—**	**—**	**45**	**25**	**42**	**32**	**—**	**—**
Proved Undeveloped										
Mining	—	—	—	—	—	—	—	—	—	—
In Situ	651	561	360	307	—	—	—	—	—	—
East Coast Canada	—	—	—	—	28	22	—	—	—	—
Natural Gas	—	—	—	—	—	—	118	109	—	—
Total Canada	651	561	360	307	28	22	118	109	—	—
North Sea [4]	—	—	—	—	19	19	1	1	—	—
Other International [5]	—	—	—	—	7	3	—	—	—	—
Total Proved Undeveloped	**651**	**561**	**360**	**307**	**54**	**44**	**120**	**110**	**—**	**—**
Proved										
Mining	2 084	1 779	—	—	—	—	—	—	—	—
In Situ	822	722	397	337	—	—	—	—	—	—
East Coast Canada	—	—	—	—	81	61	—	—	—	—
Natural Gas	—	—	—	—	10	9	1 113	946	8	5
Total Canada	2 906	2 500	397	337	91	70	1 113	946	8	5
North Sea [4]	—	—	—	—	118	118	12	12	1	1
Other International [5]	—	—	—	—	141	52	251	166	8	5
Total Proved	**2 906**	**2 500**	**397**	**337**	**350**	**241**	**1 376**	**1 124**	**17**	**11**
Probable										
Mining	542	462	37	30	—	—	—	—	—	—
In Situ	462	360	1 850	1 493	—	—	—	—	—	—
East Coast Canada	—	—	—	—	149	96	—	—	—	—
Natural Gas	—	—	—	—	7	5	374	307	3	3
Total Canada	1 003	821	1 887	1 523	155	102	374	307	3	3
North Sea [4]	—	—	—	—	57	57	4	4	—	—
Other International [5]	—	—	—	—	101	39	281	157	9	5
Total Probable	**1 003**	**821**	**1 887**	**1 523**	**313**	**198**	**660**	**468**	**13**	**8**
Proved Plus Probable										
Mining	2 626	2 240	37	30	—	—	—	—	—	—
In Situ	1 283	1 081	2 247	1 830	—	—	—	—	—	—
East Coast Canada	—	—	—	—	230	158	—	—	—	—
Natural Gas	—	—	—	—	17	14	1 488	1 253	11	7
Total Canada	3 909	3 321	2 284	1 860	247	172	1 488	1 253	11	7
North Sea [4]	—	—	—	—	175	175	16	16	1	1
Other International [5]	—	—	—	—	241	91	532	323	17	10
Total Proved Plus Probable	**3 909**	**3 321**	**2 284**	**1 860**	**663**	**439**	**2 036**	**1 592**	**29**	**19**

Please see Notes (1) through (5) at the end of the reserves data section for important information about volumes in this table.

Summary of Oil and Gas Reserves [1][2][3]

as at December 31, 2010
(constant prices and costs)

	SCO		Bitumen		Light & Medium Oil		Natural Gas		Natural Gas Liquids	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	MMbbls	MMbbls	MMbbls	MMbbls	MMbbls	MMbbls	Bcf	Bcf	MMbbls	MMbbls
Proved Developed Producing										
Mining	2 084	1 792	—	—	—	—	—	—	—	—
In Situ	121	115	37	30	—	—	—	—	—	—
East Coast Canada	—	—	—	—	53	40	—	—	—	—
Natural Gas	—	—	—	—	10	10	874	756	7	5
Total Canada	2 205	1 907	37	30	63	50	874	756	7	5
North Sea [4]	—	—	—	—	86	87	10	10	1	1
Other International [5]	—	—	—	—	102	37	246	166	8	5
Total Proved Developed Producing	**2 205**	**1 907**	**37**	**30**	**251**	**173**	**1 130**	**933**	**16**	**11**
Proved Developed Non-Producing										
Mining	—	—	—	—	—	—	—	—	—	—
In Situ	50	48	—	—	—	—	—	—	—	—
East Coast Canada	—	—	—	—	—	—	—	—	—	—
Natural Gas	—	—	—	—	—	—	25	20	—	—
Total Canada	50	48	—	—	—	—	25	20	—	—
North Sea [4]	—	—	—	—	13	13	—	—	—	—
Other International [5]	—	—	—	—	32	12	—	—	—	—
Total Proved Developed Non-Producing	**50**	**48**	**—**	**—**	**45**	**25**	**25**	**20**	**—**	**—**
Proved Undeveloped										
Mining	—	—	—	—	—	—	—	—	—	—
In Situ	652	577	360	318	—	—	—	—	—	—
East Coast Canada	—	—	—	—	27	21	—	—	—	—
Natural Gas	—	—	—	—	—	—	79	74	—	—
Total Canada	652	577	360	318	27	21	79	74	—	—
North Sea [4]	—	—	—	—	19	19	1	1	—	—
Other International [5]	—	—	—	—	7	3	—	—	—	—
Total Proved Undeveloped	**652**	**577**	**360**	**318**	**52**	**43**	**80**	**75**	**—**	**—**
Proved										
Mining	2 084	1 792	—	—	—	—	—	—	—	—
In Situ	822	739	397	348	—	—	—	—	—	—
East Coast Canada	—	—	—	—	79	61	—	—	—	—
Natural Gas	—	—	—	—	10	10	978	850	8	5
Total Canada	2 906	2 531	397	348	90	70	978	850	8	5
North Sea [4]	—	—	—	—	118	118	12	12	1	1
Other International [5]	—	—	—	—	140	52	246	166	8	5
Total Proved	**2 906**	**2 531**	**397**	**348**	**348**	**240**	**1 235**	**1 028**	**17**	**11**
Probable										
Mining	542	472	37	31	—	—	—	—	—	—
In Situ	462	384	1 850	1 580	—	—	—	—	—	—
East Coast Canada	—	—	—	—	150	99	—	—	—	—
Natural Gas	—	—	—	—	3	3	259	221	2	2
Total Canada	1 003	856	1 887	1 612	153	102	259	221	2	2
North Sea [4]	—	—	—	—	58	58	4	4	—	—
Other International [5]	—	—	—	—	101	41	277	157	9	5
Total Probable	**1 003**	**856**	**1 887**	**1 612**	**312**	**200**	**540**	**382**	**12**	**7**
Proved Plus Probable										
Mining	2 626	2 264	37	31	—	—	—	—	—	—
In Situ	1 283	1 124	2 247	1 928	—	—	—	—	—	—
East Coast Canada	—	—	—	—	230	160	—	—	—	—
Natural Gas	—	—	—	—	14	12	1 237	1 071	10	7
Total Canada	3 909	3 387	2 284	1 959	243	172	1 237	1 071	10	7
North Sea [4]	—	—	—	—	176	176	16	16	1	1
Other International [5]	—	—	—	—	241	92	523	323	17	10
Total Proved Plus Probable	**3 909**	**3 387**	**2 284**	**1 959**	**660**	**440**	**1 776**	**1 410**	**28**	**18**

Please see Notes (1) through (5) at the end of the reserves data section for important information about volumes in this table.

Please see "Notes to Future Net Revenue Tables" section for important information about constant prices and costs.

Reconciliation of Gross Oil Reserves [1][2][3]

as at December 31, 2010
(forecast prices and costs)

	SCO			Bitumen			Light & Medium Oil		
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	MMbbls	MMbbls	MMbbls	MMbbls	MMbbls	MMbbls	MMbbls	MMbbls	MMbbls
December 31, 2009 [6]									
Mining	2 202	591	2 794	—	—	—	—	—	—
In Situ	734	665	1 398	450	1 560	2 010	—	—	—
East Coast Canada	—	—	—	—	—	—	89	137	226
Natural Gas	—	—	—	—	—	—	15	6	21
Total Canada	2 936	1 256	4 192	450	1 560	2 010	104	143	247
North Sea [4]	—	—	—	—	—	—	141	70	210
United States	—	—	—	—	—	—	23	4	28
Other International [5]	—	—	—	—	—	—	125	133	258
Total	**2 936**	**1 256**	**4 192**	**450**	**1 560**	**2 010**	**393**	**350**	**743**
Extensions & Improved Recovery [7]									
Mining	—	—	—	—	—	—	—	—	—
In Situ	14	(8)	6	2	6	8	—	—	—
East Coast Canada	—	—	—	—	—	—	6	2	9
Natural Gas	—	—	—	—	—	—	—	—	—
Total Canada	14	(8)	6	2	6	8	6	3	9
North Sea [4]	—	—	—	—	—	—	—	—	—
United States	—	—	—	—	—	—	—	—	—
Other International [5]	—	—	—	—	—	—	6	8	13
Total	**14**	**(8)**	**6**	**2**	**6**	**8**	**12**	**11**	**22**
Technical Revisions [8]									
Mining	(29)	(50)	(79)	—	37	37	—	—	—
In Situ	91	(195)	(105)	(45)	284	239	—	—	—
East Coast Canada	—	—	—	—	—	—	12	8	20
Natural Gas	—	—	—	—	—	—	—	(2)	(2)
Total Canada	62	(245)	(184)	(45)	321	276	12	6	18
North Sea [4]	—	—	—	—	—	—	8	(6)	2
United States	—	—	—	—	—	—	—	—	—
Other International [5]	—	—	—	—	—	—	22	(40)	(18)
Total	**62**	**(245)**	**(184)**	**(45)**	**321**	**276**	**42**	**(40)**	**2**
Discoveries [9]									
Mining	—	—	—	—	—	—	—	—	—
In Situ	—	—	—	—	—	—	—	—	—
East Coast Canada	—	—	—	—	—	—	—	2	2
Natural Gas	—	—	—	—	—	—	—	—	—
Total Canada	—	—	—	—	—	—	—	2	2
North Sea [4]	—	—	—	—	—	—	—	—	—
United States	—	—	—	—	—	—	—	—	—
Other International [5]	—	—	—	—	—	—	—	—	—
Total	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**2**	**2**

Please see Notes (1) through (11) at the end of the reserves data section for important information about volumes in this table.

Reconciliation of Gross Oil Reserves [1][2][3] *(continued)*
as at December 31, 2010
(forecast prices and costs)

	SCO			Bitumen			Light & Medium Oil		
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	MMbbls	MMbbls	MMbbls	MMbbls	MMbbls	MMbbls	MMbbls	MMbbls	MMbbls
Acquisitions									
Mining	—	—	—	—	—	—	—	—	—
In Situ	—	—	—	—	—	—	—	—	—
East Coast Canada	—	—	—	—	—	—	—	—	—
Natural Gas	—	—	—	—	—	—	—	—	—
Total Canada	—	—	—	—	—	—	—	—	—
North Sea [4]	—	—	—	—	—	—	—	—	—
United States	—	—	—	—	—	—	—	—	—
Other International [5]	—	—	—	—	—	—	—	—	—
Total	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Dispositions [10]									
Mining	—	—	—	—	—	—	—	—	—
In Situ	—	—	—	—	—	—	—	—	—
East Coast Canada	—	—	—	—	—	—	—	—	—
Natural Gas	—	—	—	—	—	—	(2)	(1)	(2)
Total Canada	—	—	—	—	—	—	(2)	(1)	(2)
North Sea [4]	—	—	—	—	—	—	(4)	(6)	(10)
United States	—	—	—	—	—	—	(23)	(4)	(27)
Other International [5]	—	—	—	—	—	—	—	—	—
Total	**—**	**—**	**—**	**—**	**—**	**—**	**(29)**	**(11)**	**(39)**
Economic Factors [11]									
Mining	—	—	—	—	—	—	—	—	—
In Situ	—	—	—	—	—	—	—	—	—
East Coast Canada	—	—	—	—	—	—	—	—	—
Natural Gas	—	—	—	—	—	—	(3)	3	—
Total Canada	—	—	—	—	—	—	(3)	3	—
North Sea [4]	—	—	—	—	—	—	—	—	—
United States	—	—	—	—	—	—	—	—	—
Other International [5]	—	—	—	—	—	—	—	—	—
Total							**(3)**	**3**	**—**
Production									
Mining	(89)	—	(89)	—	—	—	—	—	—
In Situ	(17)	—	(17)	(10)	—	(10)	—	—	—
East Coast Canada	—	—	—	—	—	—	(26)	—	(26)
Natural Gas	—	—	—	—	—	—	(1)	—	(1)
Total Canada	(106)	—	(106)	(10)	—	(10)	(27)	—	(27)
North Sea [4]	—	—	—	—	—	—	(27)	—	(27)
United States	—	—	—	—	—	—	—	—	—
Other International [5]	—	—	—	—	—	—	(13)	—	(13)
Total	**(106)**	**—**	**(106)**	**(10)**	**—**	**(10)**	**(67)**	**—**	**(67)**
December 31, 2010									
Mining	2 084	542	2 626	—	37	37	—	—	—
In Situ	822	462	1 283	397	1 850	2 247	—	—	—
East Coast Canada	—	—	—	—	—	—	81	149	230
Natural Gas	—	—	—	—	—	—	10	7	17
Total Canada	2 906	1 003	3 909	397	1 887	2 284	91	155	247
North Sea [4]	—	—	—	—	—	—	118	57	175
United States	—	—	—	—	—	—	—	—	—
Other International [5]	—	—	—	—	—	—	141	101	241
Total	**2 906**	**1 003**	**3 909**	**397**	**1 887**	**2 284**	**350**	**313**	**663**

Please see Notes (1) through (11) at the end of the reserves data section for important information about volumes in this table.

Reconciliation of Gross Natural Gas and NGL Reserves [1][2][3]

as at December 31, 2010
(forecast prices and costs)

	Natural Gas			Natural Gas Liquids		
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	Bcf	Bcf	Bcf	MMbbls	MMbbls	MMbbls
December 31, 2009 [6]						
Natural Gas and Total Canada	1 547	712	2 259	18	6	24
North Sea [4]	29	74	102	2	1	3
United States	154	26	180	—	—	—
Trinidad and Tobago	172	90	263	—	—	—
Other International [5]	341	613	953	9	19	28
Total	**2 243**	**1 515**	**3 757**	**29**	**26**	**55**
Extensions & Improved Recovery [7]						
Natural Gas and Total Canada	39	78	116	—	—	—
North Sea [4]	—	—	—	—	—	—
United States	—	—	—	—	—	—
Trinidad and Tobago	—	—	—	—	—	—
Other International [5]	—	—	—	—	—	—
Total	**39**	**78**	**116**	**—**	**—**	**—**
Technical Revisions [8]						
Natural Gas and Total Canada	161	(191)	(29)	(1)	—	(1)
North Sea [4]	6	(5)	1	(1)	(1)	(1)
United States	—	—	—	—	—	—
Trinidad and Tobago	—	1	1	—	—	—
Other International [5]	(68)	(331)	(400)	—	(9)	(10)
Total	**99**	**(526)**	**(427)**	**(2)**	**(10)**	**(12)**
Discoveries [9]						
Natural Gas and Total Canada	1	—	2	—	—	—
North Sea [4]	—	—	—	—	—	—
United States	—	—	—	—	—	—
Trinidad and Tobago	—	—	—	—	—	—
Other International [5]	—	—	—	—	—	—
Total	**1**	**—**	**2**	**—**	**—**	**—**

Please see Notes (1) through (11) at the end of the reserves data section for important information about volumes in this table.

Reconciliation of Gross Natural Gas and NGL Reserves [1][2][3] *(continued)*
as at December 31, 2010
(forecast prices and costs)

	Natural Gas			Natural Gas Liquids		
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	Bcf	Bcf	Bcf	MMbbls	MMbbls	MMbbls
Acquisitions						
Natural Gas and Total Canada	—	—	—	—	—	—
North Sea [4]	—	—	—	—	—	—
United States	—	—	—	—	—	—
Trinidad and Tobago	—	—	—	—	—	—
Other International [5]	—	—	—	—	—	—
Total	**—**	**—**	**—**	**—**	**—**	**—**
Dispositions [10]						
Natural Gas and Total Canada	(402)	(133)	(535)	(7)	(2)	(10)
North Sea [4]	(11)	(64)	(75)	—	—	—
United States	(151)	(26)	(177)	—	—	—
Trinidad and Tobago	(158)	(92)	(249)	—	—	—
Other International [5]	—	—	—	—	—	—
Total	**(722)**	**(315)**	**(1 036)**	**(7)**	**(2)**	**(10)**
Economic Factors [11]	—	—	—	—	—	—
Natural Gas and Total Canada	(45)	(92)	(137)	—	—	—
North Sea [4]	—	—	—	—	—	—
United States	—	—	—	—	—	—
Trinidad and Tobago	—	—	—	—	—	—
Other International [5]	1	—	1	—	—	—
Total	**(44)**	**(92)**	**(136)**	**—**	**—**	**—**
Production						
Natural Gas and Total Canada	(189)	—	(189)	(2)	—	(2)
North Sea [4]	(12)	—	(12)	—	—	—
United States	(3)	—	(3)	—	—	—
Trinidad and Tobago	(15)	—	(15)	—	—	—
Other International [5]	(22)	—	(22)	(1)	—	(1)
Total	**(241)**	**—**	**(241)**	**(3)**		**(3)**
December 31, 2010						
Natural Gas and Total Canada	1 113	374	1 488	8	3	11
North Sea [4]	12	4	16	1	—	1
United States	—	—	—	—	—	—
Trinidad and Tobago	—	—	—	—	—	—
Other International [5]	251	281	532	8	9	17
Total	**1 376**	**659**	**2 036**	**17**	**12**	**29**

Please see Notes (1) through (11) at the end of the reserves data section for important information about volumes in this table.

Notes to Reserves Data Tables
as at December 31, 2010

(1) Numbers in the above tables are rounded to the nearest MMbbl or Bcf, as the case may be, and may not add due to rounding.

(2) The reserves data are based upon evaluations by GLJ and Sproule with an effective date of December 31, 2010, except for certain North Sea reserves (approximately 15% of total North Sea reserves) which were evaluated by Suncor's internal qualified reserves evaluators and reviewed by Sproule. The reserves data does not account for any planned divestitures after the effective date.

(3) See "Notes to Future Net Revenues Tables" for information on forecast and constant prices and costs.

(4) No royalty is payable on reserves in the U.K. The "Reconciliation of Gross Oil Reserves" and "Reconciliation of Gross Natural Gas and NGL Reserves" tables include Suncor's Netherlands operations, which were sold effective August 13, 2010.

(5) "Other International" reserves, which include Libya and Syria, include quantities of crude oil and natural gas, which will be produced under PSCs, which involve the company in upstream risks and rewards, but which do not transfer title of the product to the company. Under these PSCs, net proved and probable reserves have been determined using the economic interest method. See "Definitions for Reserves Data Tables" section.

(6) For the year ended December 31, 2009, Suncor presented disclosures in accordance with U.S. disclosure requirements under an exemption from Canadian securities requirements. As a result, closing balances presented in the 2009 disclosure have been restated to comply with NI 51-101, consistent with the presentation format for December 31, 2010 reserve disclosures.

(7) Extensions and Improved Recovery are additions to the reserves resulting from step-out drilling, infill drilling and installation of improved recovery schemes.

(8) Technical Revisions include changes in previous estimates, upward or downward, resulting from new technical data or revised interpretations.

(9) Discoveries are additions to reserves in reservoirs where no reserves were previously booked.

(10) Suncor sold its U.S. natural gas assets effective March 1, 2010. Suncor sold its Trinidad and Tobago assets effective August 5, 2010. Suncor sold its Netherland operations, included in "North Sea" reserves in the "Reconciliation of Gross Oil Reserves" and "Reconciliation of Gross Natural Gas and NGL Reserves" tables, effective August 13, 2010.

(11) Economic Factors are changes due to product pricing.

Definitions for Reserves Data Tables

In the tables set forth above and elsewhere in this AIF, the following definitions and other notes are applicable:

"**Gross"** means:

(a) in relation to Suncor's interest in production, reserves and contingent resources, Suncor's working interest (operating and non-operating) share before deduction of royalties and without including any royalty interests of Suncor;

(b) in relation to wells, the total number of wells in which Suncor has an interest; and

(c) in relation to properties, the total area of properties in which Suncor has an interest.

"**Net**" means:

(a) in relation to Suncor's interest in production, reserves and contingent resources, Suncor's working interest (operating and non-operating) share after deduction of royalty obligations, plus the company's royalty interests in production, reserves or contingent resources;

(b) in relation to wells, the number of wells obtained by aggregating Suncor's working interest in each of the company's gross wells; and

(c) in relation to Suncor's interest in a property, the total area in which Suncor has an interest multiplied by the working interest owned by Suncor.

Reserves Categories

The oil, natural gas liquids and natural gas reserves estimates presented are based on the definitions and guidelines contained in the Canadian Oil and Gas Evaluation Handbook (COGE Handbook). A summary of those definitions are set forth below. The synthetic crude oil reserves include Suncor's diesel sales volumes.

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on analysis of drilling, geological, geophysical and engineering data; the use of established technology; and specified economic conditions which are generally accepted as being reasonable.

Reserves are classified according to the degree of certainty associated with the estimates.

Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

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

Other criteria that must also be met for the categorization of reserves are provided in the COGE Handbook.

Each of the reserves categories (proved and probable) may be divided into developed and undeveloped categories:

Developed reserves are those 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 (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

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

(ii) **Developed non-producing reserves** are those reserves that either have not been on production, or have previously been on production but are shut-in, and the date of resumption of production is unknown.

Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves category (proved or probable) to which they are assigned.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

In the **economic interest method** used for PSCs, the contractor's (i.e. Suncor's) share of profit revenue plus cost recovery revenue is divided by the associated oil or gas price forecast to determine the contractor's net volume entitlement, or **entitlement reserves**. The entitlement reserves are then adjusted to include reserves relating to income taxes payable. Under this method, reported reserves will increase as commodity prices decrease (and vice versa), since the production barrels necessary to achieve cost recovery change with the prevailing commodity prices.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserves entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

(a) at least a 90 per cent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

(b) at least a 50 per cent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates are prepared using deterministic methods that 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. Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

Net Present Value of Future Net Revenues
as at December 31, 2010
(forecast prices and costs)

	Net Present Values of Future Net Revenue Before Income Taxes Discounted at %/year ($ millions) [1]					Unit Value [2]
	0%	5%	10%	15%	20%	$/boe
Proved Developed Producing						
Mining	66 666	39 429	25 893	18 474	14 043	14.56
In Situ	4 315	3 691	3 215	2 844	2 547	22.48
East Coast Canada	1 988	1 828	1 687	1 564	1 458	42.94
Natural Gas	4 071	2 791	2 146	1 755	1 492	14.45
Total Canada	77 041	47 740	32 941	24 636	19 540	15.62
North Sea	6 491	5 681	5 056	4 563	4 166	56.38
Other International	4 861	3 640	2 895	2 399	2 046	41.39
Total Proved Developed Producing	88 393	57 061	40 892	31 598	25 751	18.02
Proved Developed Non-Producing						
Mining	—	—	—	—	—	—
In Situ	1 896	1 472	1 168	945	779	24.80
East Coast Canada	—	—	—	—	—	—
Natural Gas	80	55	40	30	23	7.45
Total Canada	1 976	1 527	1 209	976	802	23.01
North Sea	991	756	599	490	411	46.58
Other International	1 109	620	374	239	158	31.33
Total Proved Developed Non-Producing	4 076	2 903	2 182	1 705	1 371	28.22
Proved Undeveloped						
Mining	—	—	—	—	—	—
In Situ	27 109	12 318	6 152	3 272	1 781	7.09
East Coast Canada	973	810	685	588	511	31.07
Natural Gas	308	186	113	68	38	6.19
Total Canada	28 390	13 314	6 950	3 928	2 330	7.65
North Sea	1 404	1 141	951	810	702	49.88
Other International	197	137	99	72	52	31.57
Total Proved Undeveloped	29 991	14 592	8 001	4 810	3 084	8.59
Proved						
Mining	66 666	39 429	25 893	18 474	14 043	14.56
In Situ	33 320	17 481	10 536	7 061	5 107	9.95
East Coast Canada	2 961	2 638	2 371	2 151	1 968	38.67
Natural Gas	4 459	3 032	2 300	1 853	1 554	13.35
Total Canada	107 406	62 580	41 100	29 540	22 672	13.38
North Sea	8 886	7 578	6 607	5 863	5 278	54.32
Other International	6 167	4 396	3 368	2 710	2 257	39.61
Total Proved	122 460	74 554	51 075	38 113	30 208	15.58
Probable						
Mining	24 854	8 447	3 272	1 402	653	6.65
In Situ	77 617	22 472	7 940	3 065	1 065	4.29
East Coast Canada	7 033	5 204	4 028	3 232	2 672	41.75
Natural Gas	1 835	836	461	280	176	7.83
Total Canada	111 339	36 959	15 701	7 979	4 566	6.28
North Sea	5 041	3 436	2 501	1 912	1 515	43.35
Other International	5 775	3 415	2 221	1 554	1 149	31.73
Total Probable	122 155	43 810	20 424	11 445	7 230	7.77
Proved Plus Probable						
Mining	91 520	47 876	29 165	19 876	14 696	12.84
In Situ	110 937	39 954	18 477	10 126	6 172	6.35
East Coast Canada	9 994	7 842	6 399	5 384	4 640	40.56
Natural Gas	6 294	3 869	2 761	2 133	1 730	11.94
Total Canada	218 745	99 541	56 802	37 519	27 238	10.20
North Sea	13 927	11 014	9 108	7 775	6 794	50.79
Other International	11 942	7 813	5 590	4 264	3 406	36.06
Total Proved Plus Probable	244 614	118 368	71 500	49 558	37 438	12.11

(1) Numbers in the above table are rounded to the nearest $1MM and may not add due to rounding.

(2) Unit values are before income taxes, discounted at 10%, using net reserves.

Net Present Value of Future Net Revenues
as at December 31, 2010
(forecast prices and costs)

	Net Present Values of Future Net Revenue After Income Taxes Discounted at %/year ($ millions) [1]				
	0%	5%	10%	15%	20%
Proved Developed Producing					
Mining	50 377	29 410	19 145	13 580	10 281
In Situ	4 121	3 515	3 054	2 694	2 408
East Coast Canada	1 363	1 246	1 141	1 049	969
Natural Gas	3 239	2 229	1 718	1 408	1 199
Total Canada	59 100	36 401	25 058	18 731	14 857
North Sea	3 037	2 675	2 393	2 169	1 988
Other International	2 458	1 915	1 567	1 326	1 150
Total Proved Developed Producing	64 594	40 990	29 018	22 226	17 995
Proved Developed Non-Producing					
Mining	—	—	—	—	—
In Situ	1 468	1 149	921	752	625
East Coast Canada	—	—	—	—	—
Natural Gas	59	39	28	20	15
Total Canada	1 527	1 189	948	772	640
North Sea	496	388	317	268	233
Other International	399	230	144	95	65
Total Proved Developed Non-Producing	2 421	1 807	1 409	1 135	938
Proved Undeveloped					
Mining	—	—	—	—	—
In Situ	20 029	8 766	4 132	1 998	910
East Coast Canada	667	552	463	394	339
Natural Gas	228	130	73	37	14
Total Canada	20 925	9 448	4 668	2 429	1 264
North Sea	702	578	488	420	368
Other International	70	49	35	25	19
Total Proved Undeveloped	21 697	10 075	5 191	2 875	1 650
Proved					
Mining	50 377	29 410	19 145	13 580	10 281
In Situ	25 618	13 430	8 107	5 444	3 944
East Coast Canada	2 031	1 799	1 604	1 443	1 308
Natural Gas	3 526	2 399	1 819	1 466	1 228
Total Canada	81 552	47 037	30 675	21 932	16 761
North Sea	4 234	3 641	3 198	2 857	2 589
Other International	2 927	2 194	1 746	1 446	1 233
Total Proved	88 713	52 873	35 619	26 236	20 583
Probable					
Mining	19 242	6 289	2 291	884	339
In Situ	57 629	16 228	5 407	1 808	350
East Coast Canada	5 476	4 078	3 180	2 572	2 142
Natural Gas	1 367	616	332	193	114
Total Canada	83 714	27 211	11 209	5 457	2 946
North Sea	2 523	1 742	1 283	991	793
Other International	2 693	1 632	1 078	762	568
Total Probable	88 930	30 585	13 570	7 210	4 307
Proved Plus Probable					
Mining	69 619	35 699	21 436	14 464	10 620
In Situ	83 247	29 658	13 513	7 252	4 294
East Coast Canada	7 506	5 877	4 784	4 014	3 451
Natural Gas	4 893	3 015	2 151	1 659	1 342
Total Canada	165 265	74 248	41 883	27 389	19 707
North Sea	6 758	5 383	4 481	3 848	3 381
Other International	5 621	3 827	2 824	2 208	1 801
Total Proved Plus Probable	177 644	83 459	49 188	33 445	24 889

(1) Numbers in the above table are rounded to the nearest $1MM and may not add due to rounding.

Total Future Net Revenues
as at December 31, 2010
(forecast prices and costs)

(undiscounted in $ millions) [1]	Revenue	Royalties	Operating Costs	Capital Development Costs	Abandonment Costs	Future Net Revenue Before Deducting Future Income Tax Expenses	Future Income Tax Expenses	Future Net Revenue After Deducting Future Income Tax Expenses
Proved Developed Producing								
Mining	226 272	33 812	81 027	44 767	—	66 666	16 290	50 377
In Situ	13 339	1 103	6 605	1 268	48	4 315	195	4 121
East Coast Canada	4 763	1 192	1 107	220	256	1 988	625	1 363
Natural Gas	8 186	1 105	2 856	22	131	4 071	832	3 239
Total Canada	252 561	37 212	91 596	46 277	435	77 041	17 942	59 100
North Sea	8 268	—	1 439	60	278	6 491	3 455	3 037
Other International	6 844	493	1 302	170	15	4 861	2 403	2 458
Total Proved Developed Producing	267 672	37 705	94 336	46 507	728	88 393	23 800	64 594
Proved Developed Non-Producing								
Mining	—	—	—	—	—	—	—	—
In Situ	4 959	290	2 272	488	13	1 896	428	1 468
East Coast Canada	—	—	—	—	—	—	—	—
Natural Gas	267	53	113	20	1	80	21	59
Total Canada	5 226	343	2 385	508	15	1 976	449	1 527
North Sea	1 274	—	283	—	—	991	496	496
Other International	1 341	11	142	71	9	1 109	709	399
Total Proved Developed Non-Producing	7 840	353	2 809	579	24	4 076	1 654	2 421
Proved Undeveloped								
Mining	—	—	—	—	—	—	—	—
In Situ	105 768	15 301	38 693	24 198	466	27 109	7 079	20 029
East Coast Canada	2 658	609	579	466	31	973	306	667
Natural Gas	819	60	201	231	19	308	80	228
Total Canada	109 245	15 970	39 473	24 895	516	28 390	7 464	20 925
North Sea	1 803	—	291	86	24	1 404	702	702
Other International	311	7	20	85	1	197	127	70
Total Proved Undeveloped	111 359	15 976	39 783	25 066	541	29 991	8 294	21 697
Proved								
Mining	226 272	33 812	81 027	44 767	—	66 666	16 290	50 377
In Situ	124 067	16 695	47 570	25 954	527	33 320	7 703	25 618
East Coast Canada	7 421	1 801	1 686	686	287	2 961	931	2 031
Natural Gas	9 272	1 217	3 170	274	152	4 459	933	3 526
Total Canada	367 032	53 525	133 453	71 681	967	107 406	25 857	81 552
North Sea	11 345	—	2 011	146	302	8 886	4 653	4 234
Other International	8 494	510	1 464	326	26	6 167	3 239	2 927
Total Proved	386 870	54 035	136 927	72 153	1 294	122 460	33 748	88 713
Probable								
Mining	77 180	11 786	26 915	13 625	0	24 854	5 610	19 242
In Situ	240 597	48 189	72 795	41 259	736	77 617	19 988	57 629
East Coast Canada	14 773	5 172	1 166	1 307	95	7 033	1 557	5 476
Natural Gas	4 193	673	1 396	268	21	1 835	468	1 367
Total Canada	336 743	65 820	102 272	56 459	852	111 339	27 623	83 714
North Sea	6 046	—	796	180	29	5 041	2 518	2 523
Other International	7 852	695	969	410	3	5 775	3 082	2 693
Total Probable	350 641	66 515	104 037	57 049	884	122 155	33 223	88 930
Proved Plus Probable								
Mining	303 452	45 598	107 942	58 392	—	91 520	21 900	69 619
In Situ	364 663	64 884	120 365	67 213	1 263	110 937	27 690	83 247
East Coast Canada	22 194	6 973	2 852	1 993	382	9 994	2 488	7 506
Natural Gas	13 464	1 891	4 565	542	173	6 294	1 401	4 893
Total Canada	703 773	119 346	235 724	128 140	1 818	218 745	53 479	165 265
North Sea	17 391	—	2 807	326	331	13 927	7 170	6 758
Other International	16 347	1 205	2 433	735	29	11 942	6 321	5 621
Total Proved Plus Probable	737 511	120 551	240 964	129 201	2 178	244 614	66 969	177 644

(1) Numbers in the above table are rounded to the nearest $1MM and may not add due to rounding.

Future Net Revenues by Production Group
as at December 31, 2010
(forecast prices and costs)

Future Net Revenue Before Income Taxes
Discounted at 10%/year

	$ millions [1]	$/boe [2]
Proved		
Unconventional – Mining	25 893	14.56
Unconventional – In Situ	10 536	9.95
Total Unconventional [3]	36 429	12.84
Light and Medium Oil [4]	11 398	47.16
Natural Gas [5]	3 248	17.35
Total Proved	51 075	15.58
Proved Plus Probable		
Unconventional – Mining	29 165	12.84
Unconventional – In Situ	18 477	6.35
Total Unconventional [3]	47 642	9.19
Light and Medium Oil [4]	19 466	44.36
Natural Gas [5]	4 393	16.56
Total Proved Plus Probable	71 500	12.11

(1) Numbers in the above table are rounded to the nearest $1MM and may not add due to rounding.

(2) Per unit values use net reserves.

(3) Total Unconventional includes SCO and bitumen.

(4) Light and Medium Oil includes associated byproducts including solution gas and NGLs.

(5) Natural gas includes associated byproducts including oil and NGLs.

Notes to Future Net Revenues Tables

Prices

Forecast prices and costs

Crude oil, natural gas and other important benchmark reference pricing, as well as inflation and exchange rates utilized in the GLJ Reports and the Sproule Reports, are as per GLJ's price forecast dated January 1, 2011, as set out below. To the extent that there are fixed or presently determinable future prices or costs to which Suncor is legally bound by contractual or other obligations to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs have been incorporated into the forecast prices as applied to the pertinent properties. The forecast cost and price assumptions include increases in wellhead selling prices, take into account inflation with respect to future operating and capital costs and assume the continuance of current laws and regulations. Price adjustments relating to factors such as product quality and transportation were applied on an individual property basis in cash flow calculations.

Forecast prices also included a $Cdn/$US exchange rate of 1.02, a $Cdn/Euro exchange rate of 1.35 and a $Cdn/GBP exchange rate of 1.60. Forecast costs included a 2% inflation factor, except for costs for mining operations, which included 4% inflation for 2012-2014, 3% inflation for 2015 and 2% thereafter.

Constant Prices and costs

Benchmark prices utilized for the purpose of disclosing supplementary reserves estimates under constant pricing assumptions are also set out in the table below. Prices are based on the unweighted arithmetic average of the first-day-of-the-month price for the product for each month of 2010.

Prices used in Reserves Tables[1]

Year	NYMEX WTI [2] Crude Oil at Cushing, Oklahoma	Light Sweet [3] Crude Oil (40 API, 0.3%S) at Edmonton	WCS [4] Stream Quality at Hardisty	Edmonton [5] Pentanes Plus	Brent Blend [6] Crude Oil FOB North Sea	Natural Gas [7] at AECO	National [8] Balancing Point (U.K.)
Forecast	US$/bbl	Cdn$/bbl	Cdn$/bbl	Cdn$/bbl	US$/bbl	Cdn$/MMbtu	Cdn$/MMbtu
2011	88.00	86.22	74.98	90.54	88.50	4.16	9.03
2012	89.00	89.29	74.95	91.96	88.25	4.74	9.01
2013	90.00	90.92	74.13	92.74	88.50	5.31	9.03
2014	92.00	92.96	75.23	94.82	90.50	5.77	9.23
2015	95.17	96.19	77.84	98.12	93.67	6.22	9.56
2016	97.55	98.62	79.79	100.59	96.05	6.53	9.80
2017	100.26	101.39	82.02	103.42	98.76	6.76	10.08
2018	102.74	103.92	84.05	106.00	101.24	6.90	10.33
2019	105.45	106.68	86.28	108.82	103.95	7.06	10.61
2020	107.56	108.84	88.01	111.01	106.06	7.21	10.82
2021+	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr
Constant	US$/bbl	Cdn$/bbl	Cdn$/bbl	Cdn$/bbl	US$/bbl	Cdn$/MMbtu	Cdn$/MMbtu
All	79.43	79.46	68.07	84.10	79.22	4.03	6.66

(1) Each price from the GLJ forecast was adjusted for quality differentials and transportation costs applicable to the specific product group and country or area of production.

(2) Price used when determining SCO reserves presented as In Situ and Mining reserves.

(3) Price used when determining light and medium oil reserves presented as Natural Gas reserves.

(4) Price used when determining bitumen reserves presented as In Situ reserves.

(5) Price used when determining diluent costs associated with bitumen reserves presented as In Situ reserves. A bitumen/diluent ratio of 2:1 was assumed.

(6) Price used when determining light and medium oil reserves presented as East Coast Canada reserves, North Sea reserves and Other International reserves.

(7) Price used when determining natural gas reserves presented as Natural Gas reserves for Canada. Price also used when determining natural gas input costs for the production of SCO and bitumen reserves.

(8) Price used when determining natural gas reserves presented as North Sea reserves and Other International reserves.

Prices Realized

For prices realized by Suncor during 2010, please see the Production History section contained within this Statement of Reserves Data and Other Oil and Gas Information.

Future Development Costs
as at December 31, 2010
(forecast prices and costs)

The following table sets forth development costs deducted in the estimation of Suncor's future net revenue attributable to the reserves categories noted below as at December 31, 2010.

($ millions) [1]	2011	2012	2013	2014	2015	Remainder	Total	10% Discounted
Proved								
Mining	2 153	2 122	1 781	1 746	1 736	35 229	44 767	19 133
In Situ	1 338	667	745	711	984	21 509	25 954	9 608
East Coast Canada	198	140	114	53	47	136	689	538
Natural Gas	112	37	31	17	25	53	274	220
Total Canada	3 802	2 966	2 670	2 527	2 792	56 926	71 684	29 499
North Sea	131	9	2	2	1	2	146	137
Other International	192	78	31	9	9	5	326	291
Total Proved	4 124	3 053	2 704	2 538	2 802	56 934	72 155	29 927
Proved Plus Probable								
Mining	2 205	2 211	1 889	2 018	2 363	47 706	58 392	22 565
In Situ	1 793	1 780	1 535	2 997	1 654	57 455	67 213	18 925
East Coast Canada	329	196	432	278	75	685	1 995	1 327
Natural Gas	261	98	63	41	25	53	542	459
Total Canada	4 589	4 285	3 919	5 334	4 117	105 898	128 142	43 276
North Sea	179	141	2	2	1	2	326	301
Other International	207	167	33	9	9	310	735	535
Total Proved Plus Probable	4 975	4 593	3 954	5 345	4 127	106 210	129 203	44 112

(1) Numbers in the above table are rounded to the nearest $1MM and may not add due to rounding.

Management currently believes internally generated cash flows, proceeds from other planned asset divestitures, proceeds from the agreement with Total and existing credit facilities are sufficient to fund future development costs. There can be no guarantee that funds will be available or that Suncor will allocate funding to develop all of the reserves attributed in the GLJ Reports and the Sproule Reports. Failure to develop those reserves would have a negative impact on future cash flow from operating activities.

The interest or other costs of external funding are not included in the reserves and future net revenue estimates and would reduce reserves and future net revenue to some degree depending upon the funding sources utilized. Suncor does not anticipate that interest or other funding costs would make development of any property uneconomic.

Additional Information Relating to Reserves Data

Gross Proved Undeveloped Reserves
(forecast prices and costs)

The table below outlines the gross proved undeveloped reserves, by product type, attributed to the company over the three most recent years specifically, and in aggregate for those beyond three years.

	Prior		2008		2009		2010	
	First Attributed [1]	Total at [2] Dec. 31, 2007	First Attributed [1]	Total at [2] Dec. 31, 2008	First Attributed [1][3]	Total at [2] Dec. 31, 2009	First Attributed [1]	Total at [2] Dec. 31, 2010
SCO (MMbbls)								
Mining	—	—	—	—	—	—	—	—
In Situ	704	704	63	766	121	564	14	651
Total SCO	704	704	63	766	121	564	14	651
Bitumen (MMbbls)								
Mining	—	—	—	—	—	—	—	—
In Situ	—	—	—	—	—	427	2	360
Total Bitumen	—	—	—	—	—	427	2	360
Light & Medium Oil (MMbbls)								
East Coast Canada	—	—	—	—	36	36	3	28
Natural Gas	—	—	—	—	—	—	—	—
Total Canada	—	—	—	—	36	36	—	28
North Sea [4]	—	—	—	—	68	68	—	19
United States	—	—	—	—	8	8	—	—
Other International [5]	—	—	—	—	—	—	6	6
Total Light & Medium Oil	—	—	—	—	112	112	9	54
Natural Gas (Bcf)								
East Coast Canada	—	—	—	—	—	—	—	—
Natural Gas	24	24	8	31	29	16	32	118
Total Canada	24	24	8	31	29	16	32	118
North Sea [4]	—	—	—	—	—	—	—	1
United States	—	—	—	—	24	24	—	—
Other International [5]	—	—	—	—	413	413	—	—
Total Natural Gas	24	24	8	31	466	453	32	120
NGLs (MMbbls)								
East Coast Canada	—	—	—	—	—	—	—	—
Natural Gas	—	—	—	—	—	—	—	—
Total Canada	—	—	—	—	—	—	—	—
North Sea [4]	—	—	—	—	1	1	—	—
Other International [5]	—	—	—	—	9	9	—	—
Total NGLs	—	—	—	—	10	10	—	—
Total (mmboe)	708	708	64	771	321	1 189	31	1 085

(1) First Attributed reserves include acquisitions, discoveries and extensions pertaining to the year in which the events first occurred.

(2) Year end reserves may not reflect the summation of First Attributed reserves due to changes in reserves resulting from other factors such as economic factors, improved recovery and technical revisions, which are not reflected in this table.

(3) Undeveloped reserves first attributed in 2009 primarily include those that were acquired as a result of the merger with Petro-Canada effective August 1, 2009.

(4) In this table, "North Sea" includes properties offshore of the U.K. and properties previously held by Suncor in the Netherlands.

(5) In this table, "Other International" includes properties in Libya and Syria and properties previously held by Suncor in Trinidad and Tobago.

Gross Probable Undeveloped Reserves
(forecast prices and costs)

The table below outlines the gross probable undeveloped reserves, by product type, attributed to the company over the three most recent years specifically, and in aggregate for those beyond three years.

	Prior		2008		2009		2010	
	First Attributed [1]	Total at [2] Dec. 31, 2007	First Attributed [1]	Total at [2] Dec. 31, 2008	First Attributed [1][3]	Total at [2] Dec. 31, 2009	First Attributed [1]	Total at [2] Dec. 31, 2010
SCO (MMbbls)								
Mining	617	617	—	617	264	264	—	215
In Situ	1 792	1 792	—	1 746	174	595	6	400
Total SCO	2 409	2 409	—	2 363	438	859	6	615
Bitumen (MMbbls)								
Mining	—	—	—	—	—	—	—	37
In Situ	—	—	—	—	—	1 550	8	1 835
Total Bitumen	—	—	—	—	—	1 550	8	1 871
Light & Medium Oil (MMbbls)								
East Coast Canada	—	—	—	—	80	80	7	85
Natural Gas	—	—	—	—	5	5	—	4
Total Canada	—	—	—	—	85	85	7	89
North Sea [4]	—	—	—	—	35	35	—	15
United States	—	—	—	—	4	4	—	—
Other International [5]	—	—	—	—	62	62	8	11
Total Light & Medium Oil	—	—	—	—	186	186	15	114
Natural Gas (Bcf)								
East Coast Canada	—	—	—	—	—	—	—	—
Natural Gas	55	55	21	76	233	233	75	136
Total Canada	55	55	21	76	233	233	75	136
North Sea [4]	—	—	—	—	50	50	—	1
United States	—	—	—	—	12	12	—	—
Other International [5]	—	—	—	—	651	651	—	240
Total Natural Gas	55	55	21	76	946	946	75	377
NGLs (MMbbls)								
East Coast Canada	—	—	—	—	—	—	—	—
Natural Gas	—	—	—	—	1	1	—	1
Total Canada	—	—	—	—	1	1	—	1
North Sea [4]	—	—	—	—	1	1	—	—
Other International [5]	—	—	—	—	18	18	—	8
Total NGLs	—	—	—	—	20	20	—	9
Total (mmboe)	2 418	2 418	4	2 375	801	2 772	41	2 672

(1) First Attributed reserves include acquisitions, discoveries and extensions pertaining to the year in which the events first occurred.

(2) Year end reserves may not reflect the summation of First Attributed reserves due to changes in reserves resulting from other factors such as economic factors, improved recovery and technical revisions, which are not reflected in this table.

(3) Undeveloped reserves first attributed in 2009 primarily include those that were acquired as a result of the merger with Petro-Canada effective August 1, 2009.

(4) In this table, "North Sea" includes properties offshore of the U.K. and properties previously held by Suncor in the Netherlands.

(5) In this table, "Other International" includes properties in Libya and Syria and properties previously held by Suncor in Trinidad and Tobago.

Both proved and probable undeveloped reserves are attributed by the Evaluators in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that are expected to be recovered from known accumulations with a high degree of certainty and where a significant expenditure is required to render them capable of production. Probable undeveloped reserves are those reserves in known accumulations that are less certain to be recovered than proved reserves and where a significant expenditure is required to render them capable of production.

With respect to mining and in situ reserves, which collectively constitute approximately 93% of Suncor's gross proved undeveloped reserves and 93% of Suncor's gross probable undeveloped reserves, management uses integrated plans to forecast future development. The detailed plan aligns current production, processing and pipeline capacities, capital spending commitments and future development for the next 10 years, and is reviewed and updated continuously for internal and external factors affecting planned activity. Reserves are developed as required to keep

processing capacity full. It will take more than two years to develop the in situ proved undeveloped and probable undeveloped reserves. Suncor has delineated the reserves to a high degree of certainty through seismic data, corehole drilling and pilot well performance, thereby demonstrating a high certainty of sustaining full facility capacity for over 20 years.

With respect to conventional properties, as part of its active portfolio management process, Suncor continually reviews the economic viability of its conventional properties containing undeveloped reserves using industry standard economic evaluation techniques and our own pricing and economic environment assumptions. Through this active management process, Suncor selects some properties for further development activities, while others are held in abeyance, sold, or swapped. In developing the company's reserves, Suncor considers existing facility and gathering system capacity, capital allocation plans and remaining recoverable resources availability. Accordingly, in some cases it will take longer than two years to develop all of the currently assigned conventional reserves. With the exception of undeveloped reserves that Suncor may divest, Suncor plans to develop the majority of the conventional proved undeveloped reserves over the next five years and the majority of the conventional probable undeveloped reserves over the next seven years. Exceptions are development of some offshore properties which are limited by production facility capacity and development of some international properties constrained by daily contract quantities stipulated by PSCs.

Significant Factors or Uncertainties Affecting Reserves Data

The evaluation of reserves is a continuous process, one that can be significantly impacted by a variety of internal and external influences. Revisions are often required resulting from changes in technical data acquired, historical performance, pricing, economic conditions, market availability, regulatory changes, and future technology improvements. Additional technical information regarding geology, reservoir properties and reservoir fluid properties are obtained through seismic programs, drilling programs and production history and may result in upward or downward revisions to reserves. Pricing, market availability and economic conditions affect the profitability of reserves exploitation. Typically, higher prices will result in higher reserves by making more projects economically viable and extending their economic life, while lower prices will result in lower reserves. Regulatory changes, including royalty regimes and environmental regulations, cannot be predicted but may have positive or negative effects on reserves. Future technology improvements would be expected to have a favourable impact on the economics of reserves development and exploitation, and therefore result in an increase to reserves.

While the above factors, and many others, can be considered, certain judgments and assumptions are always required. As new information becomes available these areas are reviewed and revised accordingly.

For a summary of risks and uncertainties affecting Suncor please refer to "Industry Conditions" and "Risk Factors" in this AIF.

Other Oil and Gas Information

Oil and Gas Properties and Wells

For a description of our important properties, plants, facilities and installations, see "Narrative Description of Suncor's Businesses" in this AIF.

Suncor's oil sands business recovers bitumen through oil sands mining and in situ development in northern Alberta. Conventional activities are focused on the development and production of oil, natural gas, and natural gas liquids from onshore reserves in western Canada, Libya and Syria and from reserves offshore Newfoundland and in the North Sea.

The following table is a summary of oil and gas wells associated with the company's reserves as at December 31, 2010:

	Oil Wells [1]				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	256	253	115	108	3 864	2 786	133	82
British Columbia	5	5	4	4	115	85	72	51
Saskatchewan	—	—	—	—	254	132	29	14
Newfoundland	58	12	1	—	—	—	—	—
North Sea	81	29	21	5	1	1	—	—
Other International	162	81	186	94	6	6	—	—
Total	562	380	327	211	4 240	3 010	234	147

(1) SAGD well pairs are counted as one well.

There are no wells associated with mining properties. Suncor has no proved non-producing reserves or probable non-producing reserves in its mining reserves.

For in situ properties, proved non-producing reserves and probable non-producing reserves are associated with wells that have been drilled within the last two years and require only minor capital for facilities to bring them on-stream.

Conventional non-producing reserves are primarily associated with i) recently drilled wells to be brought on production in 2011; ii) secondary zones forecast to be brought on stream over the next two years; iii) wells shut in due to OPEC quotas to be returned to production when quotas allow; and iv) gas production being re-injected to maintain gas cap pressure on oil

producing zones until depletion of the oil zones. The majority of these reserves have been in their current non-producing state for between one and four years and are forecast to be brought on-stream within the next two years.

Properties with No Attributed Reserves

The following table is a summary of properties to which no reserves are attributed as at December 31, 2010.

Country	Gross Hectares [1]	Net Hectares
Canada	6 155 544	3 836 761
Libya	2 950 978	1 339 489
Morocco	1 995 097	1 047 426
U.S. – Alaska	1 090 949	378 783
Syria	345 194	345 194
Norway	280 931	104 380
United Kingdom	165 124	78 820
Australia [2]	113 027	—
Total Hectares	13 096 844	7 130 853

(1) For lands in which Suncor holds interests in different formations under the same surface area pursuant to separate leases, the area has been counted for each lease.

(2) Suncor has an overriding royalty interest only.

Suncor holds interests in a diverse portfolio of undeveloped petroleum assets in Canada and in several international areas (offshore Norway and the United Kingdom, onshore Alaska, Libya, Syria and Morocco). These assets range from exploration properties in a very preliminary phase of evaluation, to discovery areas where tenure to the property is held indefinitely on the basis of hydrocarbon test results, but where economic development is not currently possible or has not yet been sanctioned. In many cases where reserves are not attributed to lands containing one or more discovery wells, the key limiting factor is the lack of available production infrastructure. As part of its active portfolio management process, Suncor continually reviews the economic viability of its undeveloped properties using industry standard economic evaluation techniques and our own pricing and economic environment assumptions. Each year, as part of this active management process, some properties are selected for further development activities, while others are held in abeyance, sold, swapped or relinquished back to the mineral rights owner.

In 2011, Suncor's rights to explore, develop and exploit will expire for 322,000 net hectares in Canada. These lands are entirely attributed to our conventional properties. No land tenure expiries are scheduled to occur for either mining or in situ properties for 2011. Additionally, all of Suncor's rights to explore in Morocco will expire in 2011. Substantial portions of expiring lands may have their tenure continued beyond 2011 through the conduct of work programs and/or the payment of prescribed fees to the rights owner.

Work Commitments

The practice of governments requiring companies to pledge to carry out work commitments in exchange for the right to carry out exploration for and development of hydrocarbons is common, particularly in unexplored or lightly explored regions of the world. The following table shows the estimated values of work commitments Suncor has made in regard to the lands it holds as at December 31, 2010. These commitments run through 2013 and are primarily for conducting seismic programs and drilling exploration wells.

Country/Area	Total Work Commitments (in $ millions)	2011 Work Commitments (in $ millions)
Canada	24	—
North Sea	92	20
Other International	337	120

Forward Contracts

We may use financial derivatives to manage our exposure to fluctuations in commodity prices. A description of such instruments is provided in our annual audited consolidated financial statements and related MD&A for the year ended December 31, 2010.

As a result of the merger, Suncor holds a commitment of 85,000 Mcf/d of contract capacity on the Alliance Pipeline that expires in November 2015, which enables Suncor to transport high-energy, rich natural gas from northeastern B.C. and northwestern Alberta to the Alliance Pipeline terminus in Illinois. Subsequent to Suncor's 2010 divestitures, this commitment exceeds Suncor's production from the area. Suncor estimates its minimum commitment on the Alliance Pipeline to be approximately

US$50 million per year. Natural gas for the Alliance Pipeline commitment is expected to be supplemented by supply purchased from third parties. Deliveries to Illinois are expected to continue for the term of the contract provided the sales price in Illinois exceeds, at a minimum, the variable cost of the transportation.

Additional Information Concerning Abandonment and Reclamation Costs

The company completes an annual review of its abandonment and reclamation costs as they relate to our overall operations. The specific estimates established for forecasted abandonment and reclamation costs are based on available information, consistent with that assumed in our long range planning. These estimates consider the nature of all our forecasted abandonment and reclamation costs, where determinable, for our mining, in situ and conventional operations. Where assets have indeterminate lives or where no legal liability for reclamation exists, potential costs have been excluded from the company's abandonment and reclamation cost estimates.

At December 31, 2010, Suncor estimated its undiscounted abandonment and reclamation costs, net of estimated salvage value, for surface leases, wells, facilities and pipelines pertaining to its upstream assets to be approximately $7.3 billion (discounted at 10%, approximately $1.5 billion).

Approximately $2.2 billion has been deducted as abandonment costs in estimating the future net revenues from proved plus probable reserves. This $2.2 billion represents the abandonment obligation for approximately 8,750 net reserves wells, including a forecasted number of future wells for undeveloped reserves, for our in situ and conventional activities. Abandonment and reclamation costs included in Suncor's total that are excluded from the determination of future net revenues from proved plus probable reserves include, but are not limited to, costs related to the mining and processing of oil sands ore, the treatment of oil sands tailings, gas processing facilities, and wells to which no reserves have been assigned.

Suncor anticipates incurring approximately $426 million (2011 – $110 million, 2012 – $197 million, 2013 – $119 million) of its identified abandonment and reclamation costs during the next 3 years.

Cost estimates in this section do not include the company's estimated abandonment and reclamation costs for its Refining and Marketing assets ($100 million, undiscounted).

Tax Horizon

In 2010, Suncor was subject to cash tax in the local jurisdictions related to earnings from its North Sea and Other International production, but was not cash taxable in Canada on its Canadian earnings. Suncor's audited consolidated financial statements were prepared on the assumption that it would not be cash taxable in Canada until 2014. However, as a result of the recently announced transactions with Total, Suncor may become cash taxable in Canada by 2012.

Costs Incurred

The table below summarizes the company's capital expenditures related to its reserve activities for the year ended December 31, 2010.

(in $ millions)	Exploration Costs	Proved Property Acquisition Costs	Unproved Property Acquisition Costs	Development Costs	Total
Canada – Oil Sands	6	—	—	3 426	3 432
Canada – Conventional	63	—	38	337	438
North Sea [1]	191	—	—	319	510
United States	—	—	—	5	5
Trinidad and Tobago	3	—	—	14	17
Other International	153	—	—	364	517
Total	416	—	38	4 465	4 919

(1) In this table North Sea includes Suncor's Netherlands operations prior to their sale, effective August 13, 2010.

Exploration and Development Activities

The table below outlines the gross and net exploratory and development wells the company completed during the year ended December 31, 2010. These represent wells from both our in situ and conventional activities only, as no wells are drilled in mining activities.

Total number of wells completed [1]	Exploration Wells		Development Wells	
	Gross	Net	Gross	Net
Canada				
Oil	—	—	16	13
Natural Gas	2	2	338	172
Dry	1	1	—	—
Service	4	4	8	6
Stratigraphic Test	—	—	—	—
Total	7	7	362	191
North Sea				
Oil	2	1	7	3
Natural Gas	2	1	1	1
Dry	1	1	2	1
Service	—	—	—	—
Stratigraphic Test	—	—	—	—
Total	5	3	10	5
Other International				
Oil	—	—	19	10
Natural Gas	—	—	—	—
Dry	4	4	1	1
Service	—	—	8	4
Stratigraphic Test	—	—	—	—
Total	4	4	28	15

(1) Totals include wells completed for assets and operations that were sold during the year. "North Sea" includes Netherlands. There were no wells completed in Trinidad and Tobago prior to disposition. There were nine natural gas development wells completed in the United States prior to disposition.

Suncor's most important current and likely exploration and development activities include

- In situ – During 2011, Suncor will continue the development of its in situ Firebag Stage 3 and Stage 4 assets, as well as MacKay River Phase 2.
- Natural Gas – Two significant drilling programs began in the fourth quarter of 2010: one in the Ferrier area located in central Alberta and another at Pouce Coupe in western Alberta. Tie-in activities for both programs started in the first quarter of 2011.
- East Coast Canada – The development plan for the Hibernia South Extension has been approved by the joint owners and sanction is expected in the first quarter of 2011. First oil from platform development wells is expected by mid-2011. On May 31, 2010, first oil was achieved at the North Amethyst portion of the White Rose Extensions and development drilling continues.
- North Sea – In Norway, Suncor completed its first operated exploration well and encountered hydrocarbons. An appraisal well was drilled and tested in the fourth quarter of 2010 with positive results. Further evaluation is required to determine the potential size of this discovery.
- Libya – Suncor began its operated exploration drilling program in mid-2010. The company has commitments to drill an additional 42 remaining commitment wells under its EPSAs; 14 exploration wells are planned to be drilled in 2011. Field development plans were prepared for the redevelopment of part of the Ghani field, and for the further development of the En Naga field. Redevelopment plans for the company's other fields are expected to be defined in 2011.
- Syria – In 2011, Suncor will focus on the Ash Shaer oil development area with the drilling of one well and continued investment in our oil production facilities. Technical evaluation of an oil prospect is to be completed in the first quarter and may lead to drilling of a well towards the end of the year. Within the exploration acreage of Block II, seismic work will be performed during 2011 to support drilling activities in the coming year.

Production Estimates

The table below outline the volume of the company's production of gross proved and gross proved plus probable reserves estimated for the year ending December 31, 2011, as is reflected in the estimates of gross proved reserves and gross probable reserves previously disclosed in the "Summary of Oil and Gas Reserves" tables.

	SCO [1]		Bitumen		Light & Medium Oil		Natural Gas		Natural Gas Liquids	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	Mbbls/d	Mbbls/d	Mbbls/d	Mbbls/d	Mbbls/d	Mbbls/d	MMcf/d	MMcf/d	Mbbls/d	Mbbls/d
Canada										
Total Proved	327	293	13	11	52	38	381	319	3	2
Total Probable	9	8	6	6	28	18	21	18	—	—
Total Proved Plus Probable	336	300	19	17	80	57	401	336	3	2
North Sea										
Total Proved	—	—	—	—	63	63	9	9	1	1
Total Probable	—	—	—	—	2	2	—	—	—	—
Total Proved Plus Probable	—	—	—	—	65	65	9	9	1	1
Other International										
Total Proved	—	—	—	—	37	11	80	54	3	2
Total Probable	—	—	—	—	—	—	14	9	1	—
Total Proved Plus Probable	—	—	—	—	37	11	94	64	3	2

(1) Production estimates for 2011 from Suncor's mining operations (excluding Syncrude) are 83.5 MMbbls of synthetic crude oil, approximately 36% of estimated production for 2011.

Production History

The table below outlines the company's historical production information, by product type, for each of the four financial quarters, as an average daily measure, for Canada, North Sea, the United States, Trinidad and Tobago and Other International.

	2010			
	Three months ended			
	Mar 31	Jun 30	Sept 30	Dec 31
Canada				
Oil Sands [1]				
Average Total Production (Mbbls/d)	234.6	334.4	338.3	363.8
Average Production In Situ (Mbbls/d)	87.5	88.2	79.2	85.8
Average Price Received ($/bbl)	70.32	73.73	66.73	69.52
Royalties ($/bbl)	(3.29)	(5.99)	(9.30)	(4.19)
Total Cash Operating Costs ($/bbl)	(53.37)	(35.40)	(34.38)	(36.62)
In Situ Cash Operating Costs ($/bbl)	(19.35)	(18.70)	(22.40)	(21.30)
Light & Medium Oil				
Average Production (Mbbls/d)	74.6	70.6	66.3	62.9
Average Price Received ($/bbl)	80.79	78.99	81.06	89.35
Royalties ($/bbl)	(28.78)	(28.45)	(25.49)	(29.17)
Production Costs ($/bbl)	(8.48)	(8.19)	(9.08)	(9.80)
Netback ($/bbl)	43.53	42.35	46.49	50.38
Natural Gas [2]				
Average Production (MMcfe/d)	680	586	546	438
Average Price Received ($/Mcfe)	6.14	4.94	4.63	4.47
Royalties ($/Mcfe)	(0.99)	(0.12)	(0.54)	(0.44)
Production Costs ($/Mcfe)	(1.65)	(2.00)	(2.48)	(2.04)
Netback ($/Mcfe)	3.50	2.82	1.61	1.99
North Sea [3]				
Light & Medium Oil [4]				
Average Production (mboe/d)	86.1	72.0	83.8	74.0
Average Price Received ($/boe)	73.56	77.18	77.77	86.90
Royalties ($/boe)	—	—	—	—
Production Costs ($/boe)	(7.61)	(9.95)	(7.68)	(8.35)
Netback ($/boe)	65.95	67.23	70.09	78.55
United States [5]				
Natural Gas [2]				
Average Production (MMcfe/d)	52	—	—	—
Average Price Received ($/Mcfe)	8.12	—	—	—
Royalties ($/Mcfe)	(1.32)	—	—	—
Production Costs ($/Mcfe)	(1.95)	—	—	—
Netback ($/Mcfe)	4.85	—	—	—

Please see Notes (1) through (5) at the end of the Production History table.

Production History *(continued)*

	2010			
	Three months ended			
	Mar 31	Jun 30	Sept 30	Dec 31
Trinidad and Tobago [6]				
Natural Gas				
Average Production (MMcf/d)	70	11	4	—
Average Price Received ($/Mcf)	3.09	2.75	2.09	—
Royalties ($/Mcf)	—	—	(1.43)	—
Production Costs ($/Mcf)	(0.25)	(0.40)	(0.29)	—
Netback ($/Mcf)	2.84	2.35	0.37	—
Other International				
Light & Medium Oil				
Average Production (mboe/d)	35.4	35.4	35.4	34.7
Average Price Received ($/boe)	73.92	80.61	79.66	88.03
Royalties ($/boe)	(43.28)	(41.49)	(35.56)	(14.11)
Production Costs ($/boe)	(3.81)	(6.91)	(3.11)	(4.41)
Netback ($/boe)	26.83	31.75	40.99	69.50
Natural Gas [2][7]				
Average Production (MMcfe/d)	—	12.8	16.5	16.9
Average Price Received ($/boe)	—	65.54	65.77	71.94
Royalties ($/boe)	—	(24.54)	(24.56)	(27.09)
Production Costs ($/boe)	—	(10.53)	(9.25)	(9.42)
Netback ($/boe)	—	30.47	31.97	35.43

(1) Suncor tracks cash operating cost for its Oil Sands operations, which includes more expenses than production costs. For this reason a netback calculation is not presented in this table. Also, most of Suncor's bitumen production is upgraded, therefore a bitumen netback is not presented.

(2) Volumes include NGLs and crude oil from natural gas wells.

(3) North Sea includes Suncor's operations in the Netherlands up to the date of sale, August 13, 2010.

(4) Volumes include field production for natural gas and NGLs.

(5) Suncor sold its U.S. assets effective March 1, 2010.

(6) Suncor sold its Trinidad and Tobago assets effective August 5, 2010.

(7) Syria operations achieved first gas on April 10, 2010 and first oil on December 10, 2010.

The following table provides the production volumes for each of Suncor's important fields for the year ended December 31, 2010:

	SCO and Bitumen [1]	Light & Medium Oil	Natural Gas	Natural Gas Liquids	Total
	Mbbls/d	Mbbls/d	MMcf/d	Mbbls/d	MBoe/d
Mining – Suncor	208.2	—	—	—	208.2
Mining – Syncrude	35.1	—	—	—	35.1
Firebag	44.2	—	—	—	44.2
MacKay River	30.3	—	—	—	30.3
Terra Nova	—	23.2	—	—	23.2
Hibernia	—	30.9	—	—	30.9
White Rose	—	14.5	—	—	14.5
Buzzard	—	53.8	7.0	0.5	55.5

(1) Suncor does not distinguish which sources of bitumen are upgraded to SCO.

Contingent Resources

GLJ conducted an independent evaluation of best estimate contingent resource volumes for all of Suncor's mining properties and for Suncor's in situ properties for which GLJ evaluated reserves. For remaining in situ properties, GLJ audited Suncor's evaluation of best estimate contingent resource volumes. Best estimate contingent resources for conventional properties were

prepared by Suncor's own qualified reserves evaluators in accordance with the COGE Handbook. Based on the foregoing, effective December 31, 2010, Suncor's best estimates of gross contingent resources are set out in the table below.

Best Estimate Gross Contingent Resources as at December 31, 2010 [1][2][3][4]	SCO	Bitumen	Light & Medium Oil	Natural Gas	Natural Gas Liquids
	MMbbls	MMbbls	MMbbls	Bcf	MMbbls
Mining	6 050	—	—	—	—
In Situ	6 412	5 291	—	—	—
East Coast Canada	—	—	252	1 961	—
Natural Gas		—	108	7 943	11
Total Canada	12 462	5 291	360	9 904	11
North Sea [5]	—	—	106	45	—
Other International	—	—	490	287	5
U.S.	—	—	—	133	—
Total Best Estimate Gross Contingent Resources	**12 462**	**5 291**	**956**	**10 370**	**17**

(1) Numbers in the above table are rounded to the nearest MMbbl or Bcf, as the case may be, and may not add due to rounding.

(2) Volumes represent Suncor's working interest in properties with contingent resources.

(3) Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. There is no certainty that it will be commercially viable to produce the contingent resources.

(4) Best Estimate is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. The best estimate of potentially recoverable volumes is generally prepared independent of the risks associated with achieving commercial production.

(5) North Sea includes offshore U.K. and Norway.

Estimates of contingent resources have not been adjusted for risk based on the chance of development. There is no certainty as to the timing of such development. The economic viability of the contingent resources is dependent upon pricing and economic conditions. There is no certainty that all or any portion of the contingent resources will be commercially viable to produce. For movement of resources to reserves categories, all projects must have an economic depletion plan and may require, among other things: (i) additional delineation drilling and/or new technology for unrisked contingent resources; (ii) regulatory approvals; and (iii) company approvals to proceed with development.

Significant factors which may change the contingent resource estimates include further delineation drilling, which could change the estimates either positively or negatively, and future technology improvements, which would positively affect the estimates. Also, we have assumed that all mining and some in situ contingent resources will be upgraded and sold as SCO. To the extent that these volumes are not upgraded, but rather sold as bitumen, contingent resources volumes reported would be lower for SCO and higher for bitumen and total contingent resource volumes would be higher because of the yield factor applied to bitumen volumes when upgraded into SCO.

The contingencies which currently prevent the classification of the contingent resources as reserves include:

- the need for higher density corehole drilling to improve the certainty of in situ resources;
- the need for further facility design and the associated uncertainty in development costs and timelines;
- the preparation of firm development plans and regulatory applications (including associated reservoir studies and delineation drilling);
- regulatory approvals; and
- corporate approvals to proceed with development.

The additional facility design work, development plans, reservoir studies and delineation drilling are often completed in the course of preparing the company's application for regulatory approvals. Once all regulatory and corporate approvals are received and any other contingencies are removed, the resources may then be reclassified as reserves.

INDUSTRY CONDITIONS

The oil and natural gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, environmental, development, production, refining, transportation, and marketing) imposed by legislation enacted by various levels of government and with respect to export and taxation of oil and natural gas by agreements among the governments of Canada and Alberta, among others, (including the governments of the United States and other foreign jurisdictions in which we operate), all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these controls or regulations will affect the company's operations in a manner materially different than they would affect other oil and gas companies of similar size and with similar assets. All current legislation is a matter of public record, and the company is currently unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry.

Pricing and Marketing – Oil and Natural Gas

The producers of oil are entitled to negotiate sales and purchase agreements directly with oil purchasers. Most agreements are linked to global oil prices. Global oil prices are set by daily, weekly and monthly physical and financial transactions for crude oil around the world. Those prices are primarily based on worldwide fundamentals of supply and demand. Specific prices depend in part on oil quality, prices of competing fuels, distance to the markets, the value of refined products, the supply/demand balance, and other contractual terms. In Canada, oil exporters are also entitled to enter into export contracts. If the term of an export contract exceeds one year for light crude oil or exceeds two years for heavy crude oil (to a maximum of 25 years), the exporter is required to obtain an export licence from the National Energy Board (NEB) and the issuance of such licence requires a public hearing and the approval of the Governor in Council. If the term of an export contract does not exceed one year for light crude oil or does not exceed two years for heavy crude oil, the exporter is required to obtain an order approving such export from the NEB.

The price of natural gas is also determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) export contracts for volumes of more than 30,000 m^3/d with a term that exceeds two years (to a maximum of 25 years) require the exporter to obtain an export licence from the NEB, and the issuance of such licence requires a public hearing and the approval of the Governor in Council. Natural gas (other than propane, butane and ethane) export contracts for volumes of more than 30,000 m^3/d with a term that does not exceed two years, or export contracts for volumes of 30,000 m^3/d or less for a term of two to 20 years, must be made pursuant to an NEB order.

The Government of Alberta also regulates the volume of natural gas that may be removed from the province for consumption elsewhere based on such factors as reserves availability, transportation arrangements, and market considerations.

Internationally, prices for crude oil and natural gas fluctuate in response to changes in the supply of and demand for crude oil and natural gas, market uncertainty and a variety of other factors beyond Suncor's control. These factors include, but are not limited to, the actions of the Organization of the Petroleum Exporting Countries (OPEC), world economic conditions, government regulation, political developments, the foreign supply of oil, the price of foreign imports, the availability of alternate fuel sources and weather conditions.

Pipeline Capacity

Although pipeline expansions are ongoing, the pro-rationing of capacity on the pipeline systems can occur from time-to-time due to pipeline and downstream operating problems that can affect the ability to market western Canadian crude oil and natural gas.

Royalties and Incentives

Canada – General

In addition to federal regulation, each province has legislation and regulations governing land tenure, royalties, production rates, environmental protection, and other matters. The royalty regime is a significant factor in the profitability of crude oil, NGLs, sulphur, and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral freehold owner and the lessee, although production from such lands may be subject to certain provincial taxes. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery, depth of well, and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, from time-to-time, carved out of the owner's

working interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

Occasionally, the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs provide for royalty rate reductions, royalty holidays and tax credits, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. Royalty holidays and reductions would reduce the amount of Crown royalties paid by oil and gas producers to the provincial governments and would increase the net income and funds from operations of such producers.

The Canadian federal corporate income tax rate levied on taxable income is 18% effective January 1, 2010 for active business income, including resource income. With the elimination of the corporate surtax effective January 1, 2008 and other rate reductions introduced in the October 2007 Economic Statement and subsequently enacted, the federal corporate income tax rate will decrease to 15% in five steps: 19.5% on January 1, 2008, 19% on January 1, 2009, 18% on January 1, 2010, 16.5% on January 1, 2011 and 15% on January 1, 2012.

Alberta

In Alberta, companies are granted the right to explore, produce and develop petroleum and natural gas resources in exchange for royalties, bonus bid payments and rents. On October 25, 2007, the Alberta government released a report entitled "The New Royalty Framework", containing the government's proposals for Alberta's new royalty regime, and was followed by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*, which was given Royal Assent on December 2, 2008. The New Royalty Framework and the applicable new legislation became effective on January 1, 2009. The New Royalty Framework established new royalty rates for conventional oil, natural gas and oil sands. As at January 1, 2009, the new royalty rates for conventional oil were set by a single sliding-scale formula, which were applied monthly and increased the old royalty from 30% to 35%, applied to the old and new tiers, to up to 50% and with rate caps once the price of conventional oil reaches Cdn$120/bbl. The sliding-scale formula included in its calculation the price of oil and well production.

With respect to natural gas, and similar to the conventional oil framework, the royalties outlined in the New Royalty Framework were set by a single sliding-scale formula ranging from 5% to 50% with a rate cap once the price of natural gas reached Cdn$16.59/gigajoule. The New Royalty Framework determined rate was based on well depth, production rate, gas price and gas quality. Prior to the New Royalty Framework, the royalty reserved to the Crown in respect of natural gas production, subject to various incentives, was up to 30% in the case of new natural gas (discovered after 1974), and up to 35% in the case of old natural gas (discovered prior to 1974), depending upon a prescribed or corporate average reference price. The New Royalty Framework provides some royalty relief, under the Natural Gas Deep Drilling Program, for wells drilled beyond 2,000 metres true vertical depth, based on total depth and whether the well is exploratory or developmental. In response to the drop in commodity prices experienced during the second half of 2008, the Government of Alberta announced, on November 19, 2008, the introduction of a five-year program of transitional royalty rates with the intent of promoting new drilling. Under this New Well Royalty Reduction Program, which became effective January 1, 2009, companies drilling new natural gas or conventional oil deep wells (between 1,000 and 3,500 metres) will be given a one-time option, on a well-by-well basis, to adopt the new transitional royalty rates, which would cap the maximum royalty at 30%. However, their wells cannot also receive relief from the Natural Gas Deep Drilling Program. In order to qualify for this program, wells must be drilled during the period starting on January 1, 2009 and ending on December 31, 2013. Following this period, all new wells drilled will automatically be subject to the New Royalty Framework.

Further changes to the New Royalty Framework were announced March 11, 2010. Effective January 1, 2011, the maximum natural gas royalty rate is reduced to 36% and the option to elect transitional royalty rates is no longer available. The New Well Royalty Reduction Program has changed such that the current 5% royalty is now a permanent rate that applies to production from oil or gas wells, gas production from shale zones, gas production from coal bed zones and production from horizontal drilled oil or gas wells subject to certain limitations. The Natural Gas Deep Drilling Program is amended for wells spudded or deepened on or after May 2010 in that: a) production from intervals greater than 2,000 metres now qualify; b) benefits from the four new well royalty reduction programs discussed above apply first; c) the terms of both programs run concurrently; and d) certain technical changes no longer disqualify wells under this program.

Oil sands projects are also subject to the New Royalty Framework and regulated by, among other legislation, the *Oil Sands Royalty Regulation, 2009* approved by the Government of Alberta on December 10, 2008. Royalties on our current Firebag and MacKay River in situ projects were under the 1997 Generic Regime until the end of 2008, and assessed based on bitumen value. The New Royalty Framework, which increased royalty rates from the 1997 Generic Regime to a sliding-scale royalty of 25% to 40% of R – C (Revenue – Cost), subject to a minimum royalty of 1% to 9% of R, depending on oil price. In both cases, a sliding-scale royalty moves with increases in WTI prices from Cdn$55/bbl to the maximum rate at a WTI price of Cdn$120/bbl. Royalty on our base Oil Sands mining and associated upgrading operations are modified by Crown agreements (including the Suncor RAA) and assessed on the R – C difference subject to a minimum royalty as follows: (a) based on upgraded product values until December 31, 2008 with rates at 25% of R – C, subject to the 1% minimum royalty of R; (b) commencing January 1, 2009, a bitumen-based royalty applies pursuant to Suncor's exercise of its option to transition to the bitumen-based

Generic Royalty Regime. The royalty rates will remain at 25% of the R – C, subject to the 1% minimum royalty of R, but will apply to a revised R – C, where R will be based on bitumen value and C would exclude substantially all upgrading operating costs and related capital costs; (c) from January 1, 2010 through December 31, 2015, pursuant to our January 2008 Suncor RAA with the Government of Alberta, the New Royalty Framework rates described above will apply in the calculation of the bitumen royalty, subject to a cap of 30% of R – C, and a minimum royalty cap of 1.2% of R. In addition, the Suncor RAA provides Suncor with a level of guidance for various matters, including the BVM (discussed below), allowed cost, royalty in-kind and certain taxes; and (d) in 2016 and subsequent years, the royalty rates for all of our Oil Sands operations, comprised of our base mining operations and our in situ projects, will be the rates prescribed under the New Royalty Framework, unless as amended or superseded prior to that time.

As part of the implementation of the New Royalty Framework, the Alberta government enacted new BVM (Ministerial) Regulations effective January 1, 2009. These interim regulations determine the valuation of bitumen for 2009 to 2011. The final regulations are being developed by the Crown that will establish the BVM calculation for future years. For Suncor's mining operations, the BVM is based on the terms of the Suncor RAA, which we believe places certain limitations on the interim BVM. For the year 2009, Suncor filed a non-compliance notice with the Crown, citing that reasonable adjustments in the determination of the Suncor bitumen value were not considered by the Crown as permitted by Suncor's RAA. For 2009 and the majority of 2010, royalty payments to the Crown for our mining operations were determined in accordance with Suncor's RAA, and royalty expense was recorded under the Crown's interim BVM. In December 2010, the Minister of Energy notified Suncor of a modification to the Suncor BVM for quality and transportation, resulting in a pre-tax adjustment to earnings of $129 million recorded as a reduction to royalty expense. Suncor filed its second non-compliance notice with the Crown, for 2009 and 2010, related to the unreasonable quality adjustments made by the Minister. Pursuant to the Oil Sands Royalty Regulations 2009, Suncor provided replacement royalty reports for 2009 and 2010 as requested by the Minister and remitted, under protest, the balance of royalty payable at the end of January 2011. Suncor's RAA provides for an arbitration procedure failing an agreed settlement of these issues, and Suncor filed a Notice of Commencement of Arbitration with the Crown on January 29, 2011. See "Government Regulation" in the Risk Factors section of this AIF.

In November 2008, the Alberta government and the Syncrude joint venture owners reached an agreement for the implementation of the New Royalty Framework for the Syncrude project (similar to Suncor's RAA). Under the new royalty terms, the project would continue paying the greater of 1% gross revenue, or 25% of net revenue, until the end of 2015. On January 1, 2016, the royalty rates under the New Royalty Framework will apply to the Syncrude project. As part of this agreement, Syncrude exercised its option to pay royalty based on bitumen revenues rather than on SCO revenues. Due to this conversion to a bitumen-based royalty, the upgrader facility at the Syncrude project will no longer be considered as part of the oil sands project. The Syncrude owners have agreed to pay a total of $1.25 billion in royalties over the next 25 years, with interest to account for deductions of allowed costs related to the upgrader facility, which were previously received. The owners also agreed to pay an additional royalty of $975 million over a six-year period starting in 2010, contingent on achieving certain production levels. Syncrude also filed a non-compliance notice with the Crown, citing that reasonable adjustments in the determination of the bitumen value were not considered by the Crown, similar to the notice filed by Suncor in respect of its RAA.

East Coast Canada

The royalty regime for the Terra Nova project has three tiers. The royalty consists of a sliding-scale basic royalty payable throughout the project's life, with two additional tiers of incremental net royalties, which are payable upon the achievement of specified levels of profitability. The basic royalty is payable as a percentage of gross field revenue, with an initial rate of 1%, which rises to 10% depending on cumulative production levels and the occurrence of simple payout. After tier one payout has been reached, including a specified return allowance, tier one net royalty will become the greater of the basic royalty, or 30% of net revenue. An additional tier two net royalty equal to 12.5% of net revenue will be payable once a further level of payout, including an additional return allowance, is attained. In 2008, Suncor reached Terra Nova tier two royalty payout and the royalty rate increased to 42.5% of net revenue from 30% of net revenue. During 2010, the Terra Nova royalty averaged 35% of gross revenue.

The royalty regime for the Hibernia project has three tiers – gross royalty, net royalty and supplementary royalty. Gross royalty increased to 5% of gross field revenue on July 1, 2003. The gross royalty rate was at 5% until net royalty payout was reached. The gross royalty is indexed to crude oil prices under certain conditions. Upon achieving payout, including a specified return allowance, the net royalty payable becomes the greater of 30% of net revenue or 5% of gross revenue. Suncor reached Hibernia 30% net royalty in 2009. After a further level of payout is reached, which includes an additional return allowance, a supplementary royalty of 12.5% of net revenue also becomes payable. In addition, Hibernia production is subject to a federal government net profits interest of up to 10% of net revenue, which commenced in the first quarter of 2009. During 2010, the Hibernia royalty and net profits interest averaged 38% of gross revenue. Also in 2010, an agreement was reached with the Province of Newfoundland and Labrador on the eligibility of transportation costs for royalty deductibility.

In July 2003, the Government of Newfoundland and Labrador published regulations for the royalty regime that will apply to the development of petroleum resources in offshore areas other than at Hibernia and Terra Nova. The generic offshore royalty regime consists of a sliding-scale basic royalty payable throughout a project's life, and a two-tier incremental net royalty payable

upon the achievement of specified levels of profitability. The basic royalty is calculated as a percentage of gross field revenue, commencing at 1% and rising to 7.5%, depending on cumulative production levels and the achievement of simple payout. Upon reaching tier one payout, including a return allowance, the tier one net royalty is calculated as the greater of the basic royalty, or 20% of net revenue. An additional 10% tier two net royalty rate is payable once a higher level of return on investment is attained. In 2008, Suncor reached White Rose tier two royalty payout, and the royalty rate increased to 30% of net revenue from 20% of net revenue. In the second quarter of 2010, Suncor began to pay basic royalty of 1% on the production from the North Amethyst portion of its White Rose project. The royalty rates for the North Amethyst field follow the same scale as the rates for the White Rose base field with the exception of a super royalty of 6.5% to coincide with tier one, if WTI is greater than $50/bbl. The North Amethyst royalty remained at the 1% basic rate for 2010. Overall, the White Rose royalty averaged 25% of gross revenue during 2010.

See also "Government Regulation" in the Risk Factors section of this AIF.

Production Sharing Contracts

Amounts presented as royalties for production from our Libya and Syria operations are determined pursuant to PSCs. The amounts calculated reflect the difference between Suncor's working interest in the particular project and the net revenue attributable to Suncor under the terms of the PSC. All government interests in the operations, except for income taxes, are presented as royalties.

Suncor conducts its Libya operations pursuant to EPSAs, under which the company pays 50% of the costs and recovers these costs from 12% of production. Excess production is then shared between Suncor and the Libyan government.

In Syria, the Ebla gas project is operated pursuant to a PSC, under which the company pays 100% of the costs and recovers these costs from a 40% share of production after deduction for royalties of 12.5%. The remaining profit is shared between Suncor and the Syria government.

See also "Government Regulation" in the Risk Factors section of this AIF.

Land Tenure

In Canada, petroleum, bitumen and natural gas located in the western provinces are owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences, and permits for varying terms, and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated. In frontier areas of Canada, the mineral rights are primarily owned by the Canadian federal government, which, either directly or through shared jurisdiction agreements with the relevant provincial authorities (for example, the CNLOPB), grant tenure in the form of exploration, significant discovery and production licences.

In Suncor's international theatres of operation, petroleum and natural gas are most commonly owned by national governments that grant rights in the form of exploration licences and permits, production licences, production sharing agreements and other similar forms of tenure. In all cases, Suncor's right to explore, develop and produce petroleum and natural gas is subject to ongoing compliance with the regulatory requirements established by the relevant country.

Environmental Regulation

The company is subject to environmental regulation under a variety of Canadian, U.S., U.K., and other foreign, federal, provincial, territorial, state and municipal laws and regulations. These regulatory regimes are laws of general application that apply to us in the same manner as they apply to other international companies and enterprises in the energy industry. The regulatory regimes require us to obtain operating licences 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 generally required before initiating most new major projects or undertaking significant changes to existing operations. In addition, such legislation requires that the company abandon and reclaim well and facility sites to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licences and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties. In addition to these specific, known requirements, we expect future changes to environmental legislation, including anticipated legislation for air pollution (Criteria Air Contaminants) and GHG that will impose further requirements on companies operating in the energy industry.

A number of statutes, regulations and frameworks are under development or have been issued by various provincial regulators that oversee oil sands development. These statutes, regulations and frameworks relate to such issues as tailings management, water use and land use. While the financial implications of such statutes, regulations and frameworks are not yet known, the

company is committed to working with the appropriate regulatory bodies as they develop new policies, and to fully complying with all existing and new statutes, regulations and frameworks as they apply to the company's operations.

In the fall of 2009, the Government of Alberta enacted the Land Stewardship Act (LSA). Pursuant to the LSA, the province is divided into seven regions for planning purposes, and each region is to be managed pursuant to a cumulative effects management approach. One of the regions set out in the LSA is the Lower Athabasca Region, which includes Suncor's Oil Sands operations. The Lower Athabasca Region Plan is anticipated to be released in 2011 and its contents may impact existing or future Suncor operations.

In general, there remains uncertainty around the outcomes and impacts of climate change and environmental laws and regulations (whether currently in force or proposed laws and regulations as described herein or future laws and regulations). It is not currently possible to predict either the nature of any requirements or the impact on the company and its business, financial condition, results of operations and cash flow at this time. We continue to actively work to mitigate our environmental impact, including taking action to reduce GHG emissions, investing in renewable forms of energy such as wind power and biofuels, accelerating land reclamation, installing new emissions abatement equipment and pursuing other opportunities such as carbon capture and sequestration.

Climate Change Regulation

Suncor operates in jurisdictions that have regulated, or have proposed to regulate, industrial GHG emissions. Those jurisdictions that have announced the intent to regulate GHG emissions generally support policies based on a carbon price, possibly through a cap-and-trade system, a tax, a hybrid of the two, and possibly including other measures such as low carbon fuel and renewable fuel standards. Suncor participates both directly and through industry associations in the consultation process on the design of proposed regulations, as well as efforts to harmonize regulations across jurisdictions within North America.

International Climate Change Agreements and Treaties

At the end of 2009, the United Nations Framework on Climate Change Conference of the Parties (UNFCC COP 15) was held in Copenhagen, Denmark. One of the major outcomes of this conference was the Copenhagen Accord. The Accord was generally accepted by the member countries at the Copenhagen summit, but is not legally binding and does not contain any binding commitments for reducing CO_2 emissions, nor does it include any discussion on compliance mechanisms. Canada subsequently committed to reducing its GHG emissions by 17% below 2005 levels by 2020, in line with the reduction commitment made by the U.S.; however, a comprehensive plan for how these reductions will be achieved has not yet been developed. The Copenhagen Accord and the Kyoto Protocol remain intact subsequent to COP 16, held in Cancun, Mexico.

Canadian Federal GHG Regulations

The Canadian federal government has started to address the emissions of specific sectors of the economy, including implementing vehicle emissions standards in line with the U.S. as well as performance standards for the electrical power generating sector. Also in line with the U.S., Canada has adopted a Renewable Fuels Standard, mandating that 5% of the gasoline supply come from renewable sources such as ethanol and biodiesel. The Canadian federal government, however, has not yet passed any broad climate change legislation. It has gone on record as saying that it will align GHG emissions legislation with the U.S. Since it remains unclear which approach the U.S. will take, it is also unclear whether, or when, the Canadian government will implement economy-wide climate change legislation, or a sector specific approach, and what type of compliance mechanisms will be available to large emitters.

Canadian Provincial GHG Regulations

In the absence of a federal GHG emissions policy, various Canadian provinces have responded with their own GHG emissions reduction targets and passed legislation enabling regulation of large final emitters. Suncor will continue to engage the appropriate governmental bodies in meaningful dialogue in an effort to develop a harmonized system which focuses on achieving actual reduction goals and sustainable resource development.

In 2007, the Alberta government introduced the *Climate Change and Emissions Management Amendment Act (Alberta)*, which places intensity (GHG emissions per unit of production) limits on facilities emitting more than 100,000 tonnes of CO_2 equivalent (CO_{2e}) per year. Suncor's Alberta facilities are subject to this legislation. The Act, which commenced July 2007, calls for intensity reductions of 12% from an established intensity baseline.

In March 2011, Suncor will file compliance reports that show what actions the company took during the year to demonstrate that each facility either met its intensity target for 2010 or took action to offset its emissions intensity. Compliance options available to Suncor include emissions reductions, utilizing Alberta-sanctioned offset projects, or contributing to Alberta's Climate Change and Emissions Management Fund (Alberta Technology Fund) at a present cost of $15/tonne. For the compliance period of January 1 to December 31, 2010, the compliance costs to Suncor are estimated to be between $5 million

and $10 million. Final costs for 2010 will be determined when the company files its compliance report with the Province of Alberta in March 2011. 2010 compliance was achieved through reduced emissions per unit of production, purchase and retirement of offsets, and payments into the Technology Fund, which Suncor strongly supports as a policy option. No material changes are expected to the Alberta regulations for the coming year.

British Columbia's GHG Reduction Act came into effect on January 1, 2010. It requires reporting and verification of all large facilities emissions, and is intended as a first step towards compliance within the Western Climate Initiative (a California-lead reduction initiative with members from several U.S. states and Canadian provinces). Draft regulations for a cap-and-trade system, as well as offset regulations, have been posted by the B.C. Climate Action Secretariat, and are intended to be finalized sometime in 2011. The impact of a potential cap-and-trade system cannot be quantified, given the current lack of detail of how the system will operate. The Province of B.C. also enacted a carbon tax in 2008, which began at $10/tonne CO2, and escalates at $5 per year until 2012 when it caps out at $30/tonne. This tax is carbon neutral, in that revenues are recycled back to taxpayers via tax reductions, and is applied on consumption. Suncor currently operates natural gas production and gathering facilities in B.C.

Ontario and Quebec are also members of the Western Climate Initiative (WCI). Ontario implemented mandatory reporting regulations beginning with 2010 emissions, but has delayed action on any further GHG emissions regulations for now. Quebec is implementing mandatory reporting for large facilities beginning in 2011, and is evaluating the option of implementing a cap-and-trade system within the WCI regime. Both provinces are staging their reporting initiatives, starting with easily implemented reports, which gear up to more stringent requirements through the next few years. Suncor currently operates a refinery and petroleum products facility in Ontario and a refinery in Quebec.

U.S. GHG Regulations

Several attempts were made during the course of 2010 to enact GHG legislation in the United States, none of which made it through both the Senate and the House. Given this current void, the President is pressing ahead by endorsing the U.S. Environmental Protection Agency (EPA) to regulate GHG under the Clean Air Act. The implications of industry being regulated under the EPA are as yet unknown. In the meantime, the EPA has implemented a mandatory GHG reporting rule for all large (emitting greater than 25,000 tonnes per year) facilities. This will include Suncor's Commerce City refinery.

The EPA has also mandated Renewable Fuel Standards (2), which encourage ethanol blending up to 15%, from the current 10% limit. Several factors will impact the ability of refiners and producers to achieve these requirements, including the lead time required for fleet turnover, the ability of retail stations to simultaneously provide both 10% and 15% fuels, and the inherent liability for ensuring consumers use the appropriate fuel for their vehicle.

International Regulations

Phase II (2008-2012) of the European Union Emissions Trading Scheme (EU ETS) impacts Suncor's non-operated offshore production in the U.K. and Norway sectors of the North Sea. The EU ETS requires that member countries set emissions limits for installations in their country covered by the scheme and assigns such installations an emissions cap. Installations may meet their cap by reducing emissions or by buying allowances from other participants. Phase III of the EU ETS is scheduled to begin in 2013 and will run until 2020. However, this legislation has not been finalized, particularly in light of the fact that the COP 16 meeting failed to reach an agreement for continuation of the Kyoto Protocol beyond 2012.

RISK FACTORS

We are continually working to mitigate the impact of potential risks to our business. 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. The following provides a list of risk factors relating to Suncor and our business.

Volatility of Commodity Prices and Exchange Rate Fluctuation

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 OPEC and weather, among other things, can affect world oil supply and demand. Our natural gas price realizations in our Natural Gas segment 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. Given the continued global economic uncertainty, we expect continued volatility and uncertainty in crude oil and natural gas prices in the near term and beyond, with the possibility that crude oil prices could revert to the low levels experienced in 2008 and 2009. 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 natural gas prices and low crude oil prices in particular could have a material adverse effect on our business, financial condition, results of operations and cash flow.

For the year ended December 31, 2010, we conducted an assessment of the carrying value of our assets to the extent required by Canadian GAAP. 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 materially adversely affected.

Our downstream business is sensitive to wholesale and retail margins for its refined products, including, but not limited to, gasoline, diesel, petrochemicals and asphalt. Margin volatility is influenced by, among other things, overall marketplace competitiveness, weather, the cost of crude oil 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, the operating results for our Refining and Marketing business unit can be expected to fluctuate and may be materially adversely affected.

Our 2010 Consolidated Financial Statements are presented in Canadian dollars. Results of operations are affected significantly by the exchange rates between the Canadian dollar and the U.S. dollar, and are also affected by the exchange rates between the Canadian dollar, the euro and the British pound. These exchange rates may vary substantially and may give rise to foreign currency exposure, either favourable or unfavourable, creating another element of uncertainty. To the extent such fluctuation is unfavourable it may have a material adverse effect on our business, financial condition, results of operation and cash flow.

Government Regulation

The company, and the oil and gas industry generally, operates under federal, provincial, state and municipal legislation in numerous countries. 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 GHG and other 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. The following subsections provide more information on some of these regulations.

Environmental Regulation

The company is subject to environmental regulation under a variety of Canadian, U.S., U.K. and other foreign, federal, provincial, territorial, state and municipal laws and regulations. See "Industry Conditions – Environmental Regulation" in this AIF. Some of the issues that are or may in future be subject to environmental regulation include:

- The possible cumulative regional impacts of oil sands development;
- The manufacture, import, storage, treatment and disposal of hazardous or industrial waste and substances;
- The need to reduce or stabilize various emissions to air;
- Withdrawals, use of, and discharges to water;
- Issues relating to land reclamation, restoration and wildlife habitat protection;
- Reformulated gasoline to support lower vehicle emissions; and

- U.S. implementation of regulation or policy to limit its purchases of oil to oil produced from conventional sources, or U.S. state or federal calculation and regulation of fuel life cycle carbon content.

Changes in environmental regulation could have a material adverse effect on us from the standpoint of product demand, product reformulation and quality, methods of production, distribution 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 may result in the imposition of fines and penalties, liability for cleanup costs and damages, and the loss of important licences and permits, which may, in turn, have a material adverse effect on our business, financial condition, results of operations and cash flow.

Climate Change Regulation

While there is a well-defined GHG regulatory system with targets in place for all large industrial facilities in the province of Alberta, no other North American jurisdiction has yet enacted similar strict compliance measures. Suncor anticipates that this current situation will be replaced within the next few years by a series of regional regulatory regimes, or with an all-encompassing federal regime. In general, therefore, there remains uncertainty around the outcome and impacts of climate change and environmental laws and regulations (whether currently in force, or proposed laws and regulations as described herein or future laws and regulations); it is not currently possible to predict either the nature of any requirements or the impact on the company and its business, financial condition, results of operations and cash flow at this time.

The Canadian federal government has gone on record as saying that it will align GHG emissions legislation with the U.S. Since it remains unclear what approach the U.S. will take, or when, it also is unclear whether the federal government will implement economy-wide climate change legislation, or a sector specific approach, and what type of compliance mechanisms will be available to large emitters.

British Columbia has drafted regulations for a cap-and-trade system, as well as offset regulations, which are intended to be finalized later in 2011. The impact of these regulations cannot be quantified at this time, given the current lack of detail on how the system will operate.

While forthcoming laws and regulations may impose significant liabilities on a failure to comply with their requirements, the cost of meeting new environmental and climate change regulations is not expected to be so high as to cause a material disadvantage, or damage to our competitive positioning. As part of our ongoing business planning, Suncor assesses potential costs associated with carbon dioxide (CO_2) emissions in our evaluation of future projects, based on our current understanding of pending and possible greenhouse gas regulations. Both the U.S. and Canada have indicated that climate change policies that may be implemented will attempt to balance economic, environmental and energy security concerns. We expect that regulation will evolve with a moderate carbon price signal, and that the price regime will progress cautiously. Suncor will continue to review the impact of future carbon constrained scenarios on our strategy, using as a base case price range of $15-$45 per tonne of CO_2 equivalent, applied against a range of regulatory policy options and price sensitivities.

California has passed AB32, which provides for a Low Carbon Fuel Standard (LCFS); although Suncor does not actively market into the state of California, the implications of other states adopting similar LCFS legislation could pose a significant barrier to our exports of oil sands derived crude, if the importing jurisdictions fail to acknowledge the mandated 12% reduction requirement imposed by the company's exporting jurisdiction (Alberta).

While it appears fairly certain that GHG regulations and targets will continue to become more stringent, and while Suncor will continue efforts to reduce the CO_2 unit intensity of our operations, the absolute CO_2 emissions of our company will continue to rise as we pursue a prudent and planned growth strategy.

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. In February 2009, the ERCB released a directive, *Tailings Performance Criteria and Requirements for Oil Sands Mining Schemes*. The directive establishes performance criteria for tailings operations, a requirement for specific approval and monitoring of tailings ponds, a requirement for reporting tailings plans, and changes to the ERCB annual mine plan requirements and approval process to regulate tailings operations.

On October 15, 2009, the company applied to the ERCB and Alberta Environment for permission to amend its existing and/or approved operations east of the Athabasca River to move to the company's new planned TRO_{TM} strategy. In 2010, the company received regulatory approval for a new tailings management plan using the company's proprietary TRO_{TM} tailing management process. It is anticipated that TRO_{TM} will allow the company to accelerate the pace of reclamation and reduce costs in the long term.

At this time, no ponds have been fully reclaimed using this technology. The success of the TRO $_{TM}$ and the time to reclaim tailings ponds could increase or decrease the current asset retirement cost estimates. Our failure to adequately implement our reclamation plans could have a material adverse effect on our business, financial condition, results of operations and cash flow.

Royalties

The following risk factors could cause royalty expenses to differ materially from current estimates and impact the royalties payable.

Alberta

The Alberta government enacted new BVM (Ministerial) Regulations as part of the implementation of the New Royalty Framework, effective January 1, 2009. These interim regulations determine the valuation of bitumen for 2009 to 2011. The final regulations are being developed by the Crown that will establish the BVM for future years. For Suncor's mining operations, the BVM is based on the terms of Suncor's RAA, which we believe places certain limitations on the interim BVM as recently enacted. For the years 2009 and 2010, Suncor filed non-compliance notices with the Crown, citing that reasonable adjustments in the determination of the Suncor bitumen value were not considered by the Crown as permitted by Suncor's RAA. Suncor has also filed with the Crown a Notice of Commencement of Arbitration under the Suncor RAA. Syncrude has also filed a non-compliance notice in respect of the determination of the bitumen value under its agreements with the Crown. The final determination of these matters may have a material impact on future royalties payable to the Crown.

The government enacted the new Oil Sands Allowed Costs (Ministerial) Regulations as part of the implementation of the New Royalty Framework, effective January 1, 2009. Further clarification of some allowed cost business rules is still expected. The terms of Suncor's RAA, and the similar agreement entered into by Syncrude, determine the royalty obligation through 2015 for our mining operations. However, potential changes and the interpretation of the allowed cost regulations could, over time, have a significant impact on the amount of royalties payable.

In addition, royalty payments to the Crown could be impacted by changes in crude oil and natural gas pricing, production volumes, foreign exchange rates, and capital and operating costs for each oil sands project; changes to the New Royalty Framework by the Government of Alberta; changes in other legislation; and the occurrence of unexpected events.

East Coast Canada Royalties

Suncor and the Government of Newfoundland and Labrador are in discussions to resolve several outstanding issues that impact current and prior years. Settlement of these issues could impact royalty payments to the Crown. In addition, royalty payments to the Crown could be impacted by changes in crude oil and natural gas pricing, production volumes, foreign exchange rates, and capital and operating costs for each project; changes resulting from regulatory audits of prior year filings; further changes to applicable royalty regimes by the Government of Newfoundland and Labrador; changes in other legislation and the occurrence of unexpected events.

Production Sharing Contracts

Payments pursuant to PSCs could be impacted by changes in crude oil and natural gas pricing, production volumes, foreign exchange rates, and capital and operating costs; changes resulting from regulatory audits of prior year filings; further changes to applicable royalty regimes by governments or other applicable regulatory bodies; changes in other legislation and the occurrence of unexpected events all have the potential to have an impact on royalties payable in respect of our international operations in Libya and Syria.

Foreign Operations

The company has operations in a number of countries with different political, economic and social systems. As a result, the company's operations and related assets are subject to a number of risks, which may include, among other things, currency restrictions and exchange rate fluctuations, loss of revenue, property and equipment as a result of expropriation, nationalization, war, insurrection and geopolitical and other political risks, increases in taxes and governmental royalties, renegotiation of contracts with governmental entities and quasi-governmental agencies, changes in laws and policies governing operations of foreign-based companies, economic and legal sanctions (such as restrictions against countries that the U.S. government may deem to sponsor terrorism) and other uncertainties arising from foreign government sovereignty over the company's international operations. If a dispute arises in the company's foreign operations, the company may be subject to the exclusive jurisdiction of foreign courts or may not be able to subject foreign persons to the jurisdiction of a court in Canada or the U.S. Additionally, as a result of activities in these areas and a continuing evolution of an international framework for corporate responsibility and accountability for international crimes, the company could also be exposed to potential claims for alleged breaches of international law.

Operational Hazards and Other Uncertainties

Each of our principal operating businesses – Oil Sands, Natural Gas, International and Offshore, and Refining and Marketing – demand significant levels of investment and therefore carry 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, death, damage to property, information technology 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 connected with transporting, processing and storing crude oil, natural gas and other related products. Pipeline capacity constraints combined with plant capacity constraints could negatively impact our ability to produce at capacity levels in our crude oil and natural gas business. 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 SCO and other products involve particular risks and uncertainties. Oil Sands operations are 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. 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 are virtually no finding costs associated with oil sands resources, the costs to delineate the resources, the costs associated with production, including mine development and drilling wells for SAGD operations, and the costs associated with upgrading bitumen into SCO can entail significant capital outlays. The costs associated with production at Oil Sands are largely fixed in the short term. As a result, operating costs per unit are largely dependent on levels of production.

There are risks and uncertainties associated with our Natural Gas operations, including all of the risks normally associated with drilling for natural gas wells, the operation and development of such properties, including encountering unexpected formations or pressures, premature declines of reservoirs, fires, blowouts, 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 International and Offshore operations include drilling offshore of Newfoundland and Labrador and in the North Sea offshore of the U.K. and Norway, which are areas subject to hurricanes or other extreme weather conditions, and the drilling rigs in these regions may be exposed to damage or total loss by these storms, some of which may not be covered by insurance. The occurrence of these events could result in the suspension of drilling, operations, damage to or destruction of the equipment involved and injury or death of rig personnel. Damage to the environment, particularly through oil spillage in our operations or extensive uncontrolled fires or death, could result from these operations.

Our Refining and Marketing business is subject to all of the risks normally inherent in 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 incidents.

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

Losses resulting from the occurrence of any of these risks identified above could have a material adverse effect on our business, financial condition, results of operations and cash flow.

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 effect on our business, financial condition, results of operations and cash flow. In 1990, 2003 and 2005, we formed three self-insurance entities to provide additional business interruption coverage for potential losses. In the first quarter of 2010, these three entities were merged into one single entity.

Project Delivery

There are certain risks associated with the execution of our major projects. 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; risks relating to restarting projects placed in safe mode, including increased capital costs; 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 within our existing asset base could cause delays in achieving targets and objectives. 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. Losses resulting from the occurrence of any of these risks could have a material adverse effect on our business, financial condition, results of operations and cash flow.

Our Oil Sands business 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 flexibility to conduct periodic plant maintenance on one operation while continuing production and cash flow generation from the other. Our inability to sufficiently manage these risks could have a material adverse effect on our business, financial condition, results of operations and cash flow.

Reputational Risks

The public perception of oil companies and their operations, including GHG emissions related to current and planned projects in the oil sands area of Alberta, may pose issues related to development and operating approvals or market access for products, which may directly or indirectly impair profitability.

Permit Approval

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 have a material adverse effect on our business, financial condition, results of operations and cash flow. Such regulations may be changed from time-to-time in response to numerous factors, including 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 business, financial condition, results of operations and cash flow.

Labour and Materials Supply

The successful operation of the company's business and ability to expand its operations will depend upon the availability of, and competition for, skilled labour and materials supply. The demand for and supply of skilled labour remains limited, even in uncertain economic conditions, and there is a risk that we may have difficulty sourcing the required labour for current and future operations. As well, materials may be in short supply due to smaller labour forces in many manufacturing operations. Our ability to operate safely and effectively and complete all our projects on time and on budget has the potential to be significantly impacted by these risks. Risks associated with completion of significant capital projects are discussed in "Project Delivery" above.

Reliance on Key Personnel

Our success depends in a large measure on certain key personnel. The loss of the services of such key personnel could have a material adverse effect on the company. The contributions of the existing management team to the immediate and near-term operations of the company are likely to continue to be of central importance for the foreseeable future. In addition, the competition for qualified personnel in the oil and natural gas industry is intense, and there can be no assurance that we will be able to continue to attract and retain all personnel necessary for the development and operation of our business. Management continues to mitigate the effects of these risks through ongoing succession planning and by monitoring industry conditions.

Labour Relations

Hourly employees at our Oil Sands facilities near Fort McMurray, Alberta, all of our refineries, certain of our lubricants operations, certain of our terminalling operations, our Terra Nova FPSO and at Sun-Canadian Pipeline Company Limited are represented by labour unions or employee associations. Approximately 32% of our unionized employees are members of the Communications Energy and Paperworkers Union (CEP). Any work interruptions involving our employees, and/or contract trades utilized in our projects or operations, could have a material adverse effect on our business, financial condition, results of operations and cash flow. See "Suncor Employees" in this AIF.

Dependence on Oil Sands Business

Our significant capital commitment to further our growth projects and sustain operations at our Oil Sands business may require us to forego investment opportunities in other segments of our operations. The completion of future projects to increase production at our Oil Sands business will further increase our dependence on the Oil Sands business.

Integration Risk

The company completed the merger with Petro-Canada in order to strengthen its position in the oil and natural gas industry and to create the opportunity to realize certain benefits, including cost savings and other operational synergies. Achieving the

benefits of the merger depends in part on the ability of Suncor to effectively capitalize on its scale, scope and leadership position in the oil sands industry, to realize the anticipated capital and operating synergies, to profitably sequence the growth prospects of its asset base, to execute planned divestments and to maximize the potential of its improved growth opportunities and capital funding opportunities as a result of combining the businesses and operations of Suncor and Petro-Canada. A variety of factors, including those risk factors set forth in this AIF, may adversely affect the ability to achieve the anticipated benefits of the merger.

The ability to realize the benefits of the merger will also depend in part on successfully consolidating functions and integrating operations, procedures and personnel in a timely and efficient manner, as well as on Suncor's ability to realize the anticipated growth opportunities and synergies from integrating Suncor's and Petro-Canada's businesses. This integration is ongoing and requires the dedication of substantial management effort, time and resources, which may divert management's focus and resources from other strategic opportunities and from operational matters during this process. The integration process may result in the loss of key employees and the disruption of ongoing business, customer and employee relationships that may adversely affect the ability of Suncor to achieve the anticipated benefits of the merger.

Uncertainty of Reserves and Resources Estimates

The reserves and contingent resources estimates included in this AIF represent estimates only. There are numerous uncertainties inherent in estimating quantities and quality of these proved and probable reserves and contingent resources, including many factors beyond our control.

In general, estimates of economically recoverable reserves and the future net cash flow from these assets 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, the timing and amount of capital expenditures, future royalties, future operating costs and yield rates for production of SCO from bitumen, all of which may vary considerably from actual results. The accuracy of any reserves and resources estimates 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, reserves and resources estimates are based upon a geological assessment, including drilling and laboratory tests. These estimates also consider current production capacity and upgrading yields, current mine plans, operating life and regulatory constraints. The Firebag and MacKay River reserves and resources 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, if material. For these reasons, estimates of the economically recoverable reserves and resources attributable to any particular group of properties, and classification of such reserves and resources based on risk of recovery, prepared by different engineers or by the same engineers at different times, may vary substantially.

Actual production cash flow is derived from our oil and gas reserves and will vary from the estimates contained in the reserves evaluations, and such variations could be material. The reserves evaluations are based in part on the assumed success of activities we intend to undertake in future years. The reserves and estimated cash flow to be derived from the reserves contained in the reserves evaluations will be reduced to the extent that such activities do not achieve the level of success assumed in the reserves evaluations. The reserves evaluations are effective as of a specific effective date and have not been updated, and thus do not reflect changes in our reserves since that date.

Need to Replace Conventional Reserves

Future conventional oil and natural gas reserves and production from our International and Offshore and Natural Gas business units are highly dependent on our successful discovery or acquisition of additional reserves and exploitation of our current reserves base. Without conventional oil and natural gas reserves additions through exploration and development or acquisitions, our conventional oil and natural gas reserves and production will decline over time as reserves are depleted. 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 the company is unable 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 oil and natural gas reserves could be impaired. In addition, the long-term performance of the conventional oil and natural gas 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. There can be no assurance that we will be able to find and develop or acquire additional reserves to replace production at acceptable costs.

In Situ Recovery

Current 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 the steam 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. While SAGD technology is now being used by several producers, commercial application of this technology is still in the early stages relative to other methods of production and, accordingly, in the absence of an extended operating history, there can be no assurances with respect to the sustainability of SAGD operations.

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, particularly as the results of the technology in real-world applications, may differ from test environments. The success of projects incorporating new technologies, such as in situ technology, cannot be assured.

Energy Trading Activities

The nature of energy trading activities creates exposure to significant financial risks. These include risks that movements in prices or values could result in a financial loss to the company; a lack of counterparties, due to market conditions or other circumstances could leave us unable to liquidate or offset a position, or unable to do so at or near the previous market price; we may not receive funds or instruments from our counterparty at the expected time; the counterparty could fail to perform an obligation owed to us; we may suffer a loss as a result of human error or deficiency in our systems or controls; or we may 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, even with appropriate risk management, we may experience significant financial losses as a result of these risks, which may have a material adverse effect on our business, financial condition, results of operations and cash flow.

Control Environment

Based on their evaluation as of December 31, 2010, our chief executive officer and chief financial officer concluded that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the United States *Securities Exchange Act of 1934* (the Exchange Act)) are effective to ensure that information required to be disclosed by us in reports that we file or submit to Canadian and U.S. securities authorities is recorded, processed, summarized and reported within the time periods specified in Canadian and U.S. securities laws. In addition, as of December 31, 2010, there were no changes in our internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) to 15d-15(f)) that occurred during the year ended December 31, 2010 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. We will continue to periodically evaluate our disclosure controls and procedures and internal control over financial reporting and will make any modifications from time-to-time as deemed necessary.

Based on their inherent limitations, disclosure controls and procedures and internal controls over financial reporting may not prevent or detect misstatements, and even those controls determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

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 and floating rate bank facilities and commercial paper, with the remainder issued in fixed rate borrowings, which could increase the company's cost of capital and impact Suncor's financial performance. To manage such interest rate exposures, 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.

Capital Markets

Future capital expenditures will be financed out of cash generated from operations and borrowings. This ability is dependent on, among other factors, the overall state of the capital markets and investor appetite for investments in the energy industry generally and our securities in particular.

The market events and conditions witnessed over the past several years, including disruptions in international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility in commodity prices and increases in the rates at which we are able to borrow funds for our capital programs. There can be no certainty regarding the timing or extent of the recent economic recovery, and such continued uncertainty in the global economic situation means that the company, along with all other oil and gas entities, may continue to face restricted access to capital and increased borrowing costs. This could have an adverse effect on the company, as our future capital expenditures will be financed out of cash generated from operations and borrowings, and our ability to borrow is dependent on, among other factors, the overall state of the capital markets and investor appetite for investments in the energy industry generally and our securities in particular.

To the extent that external sources of capital become limited or unavailable or available on onerous terms, our ability to make capital investments and maintain existing properties may be impaired, and our business, financial condition, results of operations and cash flow may be materially adversely affected as a result. At December 31, 2010, we had approximately $5.3 billion of unused credit available under bank credit facilities. Based on current funds available and expected cash from operations and our divestures that we have announced but that had not yet closed as of December 31, 2010, we believe that we have sufficient funds available to fund our currently projected capital expenditures in 2011. If cash flow from operations is lower than expected or 2011 capital expenditures exceed current estimates, or if we incur major unanticipated expenses related to development or maintenance of our existing assets, we would need to undertake a serious evaluation of maintaining our capital program at planned levels and the possibility of adversely affecting our debt ratings should we seek additional capital. Choosing not to obtain the financing necessary for our capital expenditure plans may result in a delay in the planned development of production from our operations and strand significant capital, while increasing costs to keep projects in safe mode. This in turn could have a material adverse effect on our business, financial condition, results of operations and cash flow.

Issuance of Debt

From time-to-time, we may finance capital expenditures in whole or in part with debt, which may increase our debt levels above industry standards for oil and natural gas companies of similar size. Depending on future development plans, we may require additional debt financing that may not be available or, if available, may not be available on favourable terms, including higher interest rates and fees. Neither the company's articles nor its bylaws limit the amount of indebtedness that we may incur; however, we are subject to covenants in our existing bank facilities and seek to avoid onerous costs of debt. The level of our indebtedness, from time to time, could impair our ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise and could negatively affect our debt ratings. This in turn could have a material adverse effect on our business, financial condition, results of operations and cash flow.

Debt Covenants

We currently have $8.0 billion in credit facilities expiring primarily in 2013, and approximately $12.2 billion in outstanding debt. We are required to comply with financial and operating covenants under these credit facilities and debt securities. We routinely review the covenants based on actual and forecast results and have the ability to make changes to our development plans and/or dividend policy to comply with covenants under the credit facilities. In the event that we do not comply with such covenants under the credit facilities and debt securities, our access to capital could be restricted or repayment could be required, which could have a material adverse effect on our business, financial condition, results of operations and cash flow. In addition, our inability to refinance expiring credit facilities on favourable terms, if at all, and any restrictions imposed on our borrowings under these facilities due to our covenants, could have a material adverse effect on our business, financial condition, results of operations and cash flow.

Hedging

The company monitors its exposure to variations in commodity prices, interest rates and foreign exchange rates. In response, the company periodically enters into physical delivery transactions for commodities at fixed or collared prices and into derivative financial instruments to reduce exposure to unfavourable movements in commodity prices, interest rates and foreign exchange rates. The terms of these contracts or instruments may limit the benefit of favourable changes in commodity prices, interest rates and currency values and may result in financial or opportunity loss due to delivery commitments, royalty rates and counterparty risks associated with the contracts.

Competition

The petroleum industry is highly competitive globally 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 petrochemicals. 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 primary competition for our crude oil production is major international oil and natural gas producers.

A number of other companies have entered or have indicated their intention to enter the oil sands business and begin producing bitumen and SCO or expand their existing operations. It is difficult to assess the number, level of production and ultimate timing of all potential new projects or when existing production levels may increase. Increasing industry consolidation, a global focus on oil sands and additional competitors with financial capacity has, over the past number of years:

(a) Materially increased the supply of bitumen and SCO and other competing crude oil products in the marketplace;

(b) Exponentially increased land values and availability of new leases; and

(c) Placed stress on the availability and cost of all resources required to build and run new and existing oil sands operations. 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 will continue. In addition, to the extent that our downstream business unit participates in new product markets, it could be exposed to margin risk and volatility from either cost and/or selling price fluctuations.

Dividends

Our payment of future dividends on our common shares will be dependent on, among other things, our financial condition, results of operations, cash flow, the need for funds to finance ongoing operations, debt covenants and other business considerations as the Board of Directors of the company considers relevant. There can be no assurance that we will continue to pay dividends in the future.

Land Claims

First Nations peoples have claimed aboriginal title and rights to portions of Western Canada. In addition, First Nations peoples have filed claims against industry participants relating in part to land claims, which may affect our business. However, at the present time, we are unable to assess the effect, if any, that these land claims may have on our business.

Counterparties Exposure

In the normal course of business, the company enters into contractual relationships with counterparties in the energy industry and other industries, including counterparties to interest rate hedging, foreign exchange hedging and commodity derivative arrangements. If such counterparties do not fulfil their contractual obligations to the company, it may suffer losses, may have to proceed on a sole risk basis, may have to forego opportunities or may have to relinquish leases or blocks. While the company limits its exposure to any one counterparty to a level that management deems to be reasonable, losses due to counterparties failing to fulfil their contractual obligations may have a material adverse effect on our business, financial condition, results of operations and cash flow.

Suncor's Governance Process

Suncor believes that the responsibility for managing climate change related issues should be a shared responsibility across the company. A comprehensive roles and responsibilities matrix has been developed as part of Suncor's GHG management program.

The Environment, Health, Safety and Sustainable Development Committee of the Board of Directors reviews Suncor's effectiveness in meeting its obligations pertaining to environment, health and safety (EHS). The committee also reviews the effectiveness with which Suncor establishes appropriate environment, health and safety policies, including GHG performance and emission reduction plans given legal, industry and community standards. Management systems are maintained by the committee to implement such policies and ensure compliance with them.

Suncor's Chief Operating Officer holds top executive responsibility for sustainability issues. Together with the Vice President, Sustainable Development, the business units' EHS managers and selected internal technical representatives are responsible for the stewardship of the GHG management system. The GHG strategy team is responsible for developing company-wide strategies and operational goals and assessing sustainability progress, including GHG intensity reduction, across all areas of our business.

In advance of clear regulations in all jurisdictions that we operate, Suncor will continue to be guided by the seven-point climate change action plan we first adopted in 1997, which calls on us to:

- Manage our own GHG emissions;
- Develop renewable sources of energy;
- Invest in environmental and economic research through joint venture initiatives with other industry groups, and through internal initiatives focused on our core business;
- Use domestic and international offsets;
- Collaborate on policy development;
- Educate employees and the public; and
- Measure and report our progress;

Suncor remains committed to reducing overall GHG emission intensity, in addition to other goals related to improving energy efficiency, reducing water use, increasing land reclamation, and reducing air emissions. We continue to actively work to mitigate our environmental impact, including taking action to reduce GHG emissions, investing in renewable forms of energy such as wind power and biofuels, accelerating land reclamation, installing new emissions abatement equipment and pursuing other opportunities both internally, as well as through joint venture initiatives, such as our role in the Oil Sands Leadership Initiative, with other like-minded energy companies.

DIVIDENDS

Our Board of Directors has established a policy of paying dividends on a quarterly basis. We review our dividend policy from time-to-time with regard to 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 $0.10 per share from $0.05 per share in the third quarter of 2009. Dividends are paid subject to applicable law, if, as and when declared by the Board of Directors.

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

	Year Ended December 31		
	2010	2009	2008 [1]
Cash dividends per common share	$ 0.40	$ 0.30	$ 0.20

(1) Per share amounts have been adjusted to reflect a two-for-one share split in May 2008.

DESCRIPTION OF CAPITAL STRUCTURE

General Description of Capital Structure

The company's authorized share capital is comprised of an unlimited number of common shares, an unlimited number of preferred shares issuable in series designated as senior preferred shares and an unlimited number of preferred shares issuable in series designated as junior preferred shares. As at December 31, 2010, there were 1,565,489,162 common shares issued and outstanding. To the knowledge of the Board of Directors and executive officers of Suncor, no person beneficially owns or exercises control or direction over securities carrying 10% or more of the voting rights attached to any class of voting securities of the company. The holders of common shares are entitled to attend all meetings of shareholders and vote at any such meeting on the basis of one vote for each common share held. As no senior preferred shares or junior preferred shares are issued and outstanding, common shareholders are entitled to receive any dividend declared by the Board of Directors on the common shares and to participate in a distribution of the company's assets among its shareholders for the purpose of winding up its affairs. The holders of the common shares shall be entitled to share equally, share for share, in all distributions of such assets.

Constraints

The *Petro-Canada Public Participation Act* requires that the Articles of Suncor include certain restrictions on the ownership and voting of voting shares of the company. The common shares of Suncor are voting shares.

No person, together with associates of that person, may subscribe for, have transferred to that person, hold, beneficially own or control otherwise than by way of security only, or vote in the aggregate, voting shares of Suncor to which are attached more than 20% of the votes attached to all outstanding voting shares of Suncor. Additional restrictions include provisions for suspension of voting rights, forfeiture of dividends, prohibitions against share transfer, compulsory sale of shares, and redemption and suspension of other shareholder rights. The Board of Directors may at any time require holders of, or subscribers for, voting shares, and certain other persons, to furnish statutory declarations as to ownership of voting shares and certain other matters relevant to the enforcement of the restrictions. Suncor is prohibited from accepting any subscription for, and issuing or registering a transfer of, any voting shares if a contravention of the individual ownership restrictions results.

Suncor's Articles, as required by the *Petro-Canada Public Participation Act*, also include provisions requiring Suncor to maintain its head office in Calgary, Alberta; prohibiting Suncor from selling, transferring or otherwise disposing of all or substantially all of its assets in one transaction, or several related transactions, to any one person or group of associated persons, or to non-residents, other than by way of security only in connection with the financing of Suncor; and requiring Suncor to ensure (and to adopt, from time-to-time, policies describing the manner in which Suncor will fulfil the requirement to ensure) that any member of the public can, in either official language of Canada (English and French), communicate with and obtain available services from Suncor's head office and any other facilities where Suncor determines there is significant demand for communication with, and services from, that facility in that language.

Ratings

The following information regarding the company's credit ratings is provided as it relates to the company's cost of funds and liquidity and indicates whether or not the company's credit ratings have changed. In particular, the company's ability to access unsecured funding markets and to engage in certain collateralized business activities on a cost-effective basis is primarily dependent upon maintaining competitive credit ratings. A lowering of the company's credit rating may also have potentially

adverse consequences for the company's funding capacity or access to the capital markets, may affect the company's ability, and the cost, to enter into normal course derivative or hedging transactions and may require the company to post additional collateral under certain contracts.

The following table shows the ratings issued by the rating agencies noted therein as of December 31, 2010. The credit ratings are not recommendations to purchase, hold or sell the debt securities 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.

	Moody's Investors Service (Moody's)	Standard & Poor's (S&P)	Dominion Bond Rating Service (DBRS)
Outlook	Stable	Stable	Stable
Senior Unsecured	Baa2	BBB+	A (low)
Commercial Paper	—	A-1 (Low)	R-1 (low)

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 10 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 are considered to 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 or D categories.

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 Baa2 by Moody's is the fourth highest of nine categories. Obligations rated Baa are subject to moderate credit risk. They are considered medium-grade and, as such, may possess certain speculative characteristics. Moody's appends numerical modifiers 1, 2 or 3 to each generic rating classification. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category.

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 BBB+ by S&P is the fourth highest of 10 categories and indicates that the obligor exhibits adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitment on the obligation. 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 represents the range from highest to lowest quality of such securities rated. A rating of R-1 (low) by DBRS is the third highest of 10 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.

S&P's commercial paper credit ratings are on a short-term debt rating scale that ranges from A-1 (High) to D, which represents the range from highest to lowest quality of such securities rated. A short-term obligation rated A-1 is rated as the highest of eight categories by Standard & Poor's. A short-term obligation rated "A-1 (Low)" is slightly more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher rating categories. However, the obligor's capacity to meet its financial commitment on the obligation is satisfactory. Obligations rated "A-1 (Low)" on the Canadian commercial paper rating scale would qualify for a rating of "A-2" on Standard & Poor's global short-term rating scale.

MARKET FOR SECURITIES

Price Range and Trading Volume of Common Shares

Our common shares are listed on the Toronto Stock Exchange (TSX) in Canada, and on the New York Stock Exchange (NYSE) in the United States. The price ranges and the volumes traded on the TSX and NYSE for the year ended December 31, 2010, are as follows:

Toronto Stock Exchange

	Price Range ($Cdn)		
	High	Low	Trading Volume (000's)
2010			
January	39.45	33.56	67,463
February	34.86	29.93	115,117
March	33.35	30.36	110,834
April	35.82	32.81	104,327
May	35.59	29.91	121,481
June	35.31	31.28	108,655
July	34.04	30.72	69,069
August	34.94	31.08	73,844
September	34.47	31.80	94,774
October	35.48	32.25	80,396
November	36.55	32.66	90,386
December	38.56	34.87	70,631

New York Stock Exchange

	Price Range ($Cdn)		
	High	Low	Trading Volume (000's)
2010			
January	38.22	31.38	108,347
February	32.81	28.04	221,741
March	32.85	29.01	173,839
April	35.71	32.21	175,022
May	34.90	27.65	237,363
June	34.77	29.38	169,804
July	33.16	28.56	105,033
August	34.17	29.15	93,279
September	33.50	30.72	103,742
October	35.40	31.53	130,354
November	36.60	32.20	137,647
December	38.49	34.18	106,369

Options to Purchase Common Shares

For information in respect of options to purchase common shares of Suncor, see note 20 of our 2010 Consolidated Financial Statements, which is incorporated by reference into this AIF.

DIRECTORS AND EXECUTIVE OFFICERS

Directors

The following individuals are directors of Suncor. The term of each director is from the date of the meeting at which he or she is elected or appointed until the next annual meeting of shareholders or until a successor is elected or appointed.

Name and Jurisdiction of Residence	Period Served and Independence	Biography
Mel E. Benson [1][2] Alberta, Canada	Director since 2000 Independent	Mel Benson is president of Mel E. Benson Management Services Inc., an international management consulting firm based in Calgary, Alberta. In 2000, Mr. Benson retired from a major international oil company. Mr. Benson is an owner of Tenax Energy Inc., a director of Winalta Inc. and director of the Fort McKay Group of Companies, a community trust. He is active with several charitable organizations including Hull Family Services. He is also a member of the board of governors for the Northern Alberta Institute of Technology.
Brian A. Canfield [2][3] Washington, USA	Director since 1995 Independent	Brian Canfield is the chairman of TELUS Corporation, a telecommunications company. Beginning his career with TELUS as a telephone installer in 1956, Mr. Canfield rose through the corporate ranks to occupy positions as COO, President and CEO. Mr. Canfield is a member of the Order of Canada, a member of the Order of British Columbia and a fellow of the Institute of Corporate Directors. He was also the first businessperson to receive an honorary Doctorate of Technology from the BC Institute of Technology.
Dominic D`Alessandro [3][4] Ontario, Canada	Director since 2009 Independent	Dominic D'Alessandro was president and chief executive officer of Manulife Financial Corporation from 1994 to 2009 and is currently a director of CGI Group Inc. and Canadian Imperial Bank of Commerce. For his many business accomplishments, Mr. D'Alessandro was recognized as Canada's Most Respected CEO in 2004 and CEO of the Year in 2002, and was inducted into the Insurance Hall of Fame in 2008. Mr. D'Alessandro is an officer of the Order of Canada and has been appointed as a Commendatore of the Order of the Star of Italy. In 2009, he received the Woodrow Wilson Award for Corporate Citizenship and in 2005 was granted the Horatio Alger Award for community leadership. Mr. D'Alessandro is an FCA, and holds a Bachelor of Science from Concordia University in Montreal. He has also been awarded honorary doctorates from York University, the University of Ottawa, Ryerson University and Concordia University.
John T. Ferguson [5] Alberta, Canada	Director since 1995 Independent	John Ferguson is founder and chairman of the board of Princeton Developments Ltd. and Princeton Ventures Ltd. Mr. Ferguson is also a director of Fountain Tire Ltd., the Royal Bank of Canada and Strategy Summit Ltd. In addition, he is a board member of the Alberta Bone and Joint Institute, an advisory member of the Canadian Institute for Advanced Research, Honorary Lieutenant Colonel – South Alberta Light Horse and chancellor emeritus and chairman emeritus of the University of Alberta. Mr. Ferguson is a fellow of the Alberta Institute of Chartered Accountants and of the Institute of Corporate Directors.
W. Douglas Ford [1][4] Florida, USA	Director since 2004 Independent	W. Douglas Ford was chief executive, refining and marketing for BP p.l.c. from 1998 to 2002 and was responsible for the refining, marketing and transportation network of BP as well as the aviation fuels business, the marine business and BP shipping. Mr. Ford currently serves as a director of USG Corporation and Air Products and Chemicals Inc. He is also a director of the Home Run Inn and a member of the board of trustees of the University of Notre Dame.
Richard L. George Alberta, Canada	Director since 1991 Non-independent, management	Richard George is the president and chief executive officer of Suncor Energy Inc. He currently serves as the Canadian Chair of the North American Competitiveness Council and he chaired the 2008 Governor General's Canadian Leadership Conference. Mr. George was named a member of the Order of Canada in 2007.

Paul Haseldonckx [2][3] Essen, Germany	Director since 2009 (Petro-Canada 2002 to July 31, 2009) Independent	Paul Haseldonckx was a director of Petro Canada and a member of the management board of Veba Oel AG, Germany's largest downstream company, including Aral AG gas stations in Europe. Mr. Haseldonckx represented Veba's interests at the board of the Cerro Negro joint venture, an in situ oil sands development including an upgrader, during the construction and early production phase. Mr. Haseldonckx holds a Master of Science and completed Executive Programs at INSEAD, Fontainebleau and IMD, Lausanne.
John R. Huff [1][2] Texas, USA	Director since 1998 Independent	John Huff is chairman of Oceaneering International Inc., an oilfield services company. He also serves as director of KBR Inc.
Jacques Lamarre [1][2] Quebec, Canada	Director since 2009 Independent	Jacques Lamarre was the president and chief executive officer of SNC Lavalin from 1996-2009. Mr. Lamarre is an officer of the Order of Canada, and a founding member and past chair of the Commonwealth Business Council. He is also past chair of the Board of Directors of the Conference Board of Canada and a founding member of the World Economic Forum's Governors for Engineering & Construction. Currently, he serves as a director of The Royal Bank of Canada and of P3 Canada and as a member of the Engineering Institute of Canada, Engineers Canada and the Ordre des ingénieurs du Québec. Mr. Lamarre is also a strategic advisor to Heenan Blaikie LLP, a law firm. Mr. Lamarre holds a Bachelor of Arts and a Bachelor of Arts and Science in Civil Engineering from Laval University in Quebec City. He also completed Harvard University's Executive Development Program. In addition, Mr. Lamarre holds honorary doctorates from the University of Waterloo, the University of Moncton and Laval University.
Brian MacNeill [3][4] Alberta, Canada	Director since 2009 (Petro-Canada 1995 to July 31, 2009) Independent	Brian MacNeill is a Chartered Accountant, a Certified Public Accountant and holds a Bachelor of Commerce. Previously, Mr. MacNeill was a director and chairman of the board of Petro Canada. He is a director of TELUS Corporation, West Fraser Timber Co. Ltd., Capital Power Corp. and Oilsands Quest Inc. Mr. MacNeill is a member of the Canadian Institute of Chartered Accountants and the Financial Executives Institute. He is also a fellow of the Alberta Institute of Chartered Accountants and of the Institute of Corporate Directors. Mr. MacNeill is also a member of the Order of Canada.
Maureen McCaw [1][2] Alberta, Canada	Director since 2009 (Petro-Canada 2004 to July 31, 2009) Independent	Maureen McCaw was a director of Petro-Canada and is senior vice president (Edmonton) of Leger Marketing, formerly Criterion Research Corp., a company she founded in 1986. Ms. McCaw holds a Bachelor of Arts from the University of Alberta and an Institute of Corporate Directors certification (ICD.D). In addition to being president of Tinnakilly Inc. and a director of the Edmonton International Airport, Women Building Futures and Royal Alexandria Hospital, she is also managing partner at Prism Ventures. She is a past chair of the Edmonton Chamber of Commerce and serves on a number of Alberta boards and advisory committees.
Michael W. O'Brien [3][4] Alberta, Canada	Director since 2002 Independent	Michael O'Brien served as executive vice president, corporate development, and chief financial officer of Suncor Energy Inc. before retiring in 2002. Mr. O'Brien is lead director of Shaw Communications Inc. In addition, he is past chair of the board of trustees for Nature Conservancy Canada, past chair of the Canadian Petroleum Products Institute and past chair of Canada's Voluntary Challenge for Global Climate Change.
James Simpson [1][4] Alberta, Canada	Director since 2009 (Petro-Canada 2004 to July 31, 2009) Independent	James Simpson was a director of Petro-Canada and is past president of Chevron Canada Resources (oil and gas). He serves as Lead Director for Canadian Utilities Limited and is on its Corporate Governance, Nomination, Compensation and Succession Committee and Risk Review Committee, as well as being the chairman for the Audit Committee. Mr. Simpson holds a Bachelor of Science and Master of Science, and graduated from the Program for Senior Executives at M.I.T.'s Sloan School of Business. He is also past chairman of the Canadian Association of Petroleum Producers and past vice chairman of the Canadian Association of the World Petroleum Congresses.

Eira M. Thomas [3][4] British Columbia, Canada	Director since 2006 Independent	Eira Thomas assumed the role of executive chairman of Stornoway Diamond Corporation, a mineral exploration company, on January 1, 2009 after serving as chief executive officer since July 2003. Previously, Ms. Thomas was president of Navigator Exploration Corporation and chief executive officer of Stornoway Ventures Ltd. She is also a director of Strongbow Exploration Inc., Fortress Minerals Corp., Ashton Mining of Canada Inc. and Lucara Diamond Corp. In addition, Ms. Thomas is a director of the University of Toronto (U of T) Alumni Association, Lassonde Advisory Board of the U of T, Prospectors and Developers Association of Canada and the Northwest Territories and Nunavut Chamber of Mines. She also is a member of the U of T President's Internal Advisory Council.

(1) Human Resources and Compensation Committee.

(2) Environment, Health, Safety and Sustainable Development Committee.

(3) Audit Committee.

(4) Governance Committee.

(5) As chairman, by standing invitation, Mr. Ferguson is considered an ex-officio member of all committees.

Executive Officers

The following individuals are the executive officers of Suncor.

Name and Jurisdiction of Residence	Office
Richard L. George Alberta, Canada	President and Chief Executive Officer
Steve W. Williams Alberta, Canada	Chief Operating Officer
Bart Demosky Alberta, Canada	Chief Financial Officer
Kirk Bailey Alberta, Canada	Executive Vice President, Oil Sands Ventures
Boris Jackman Ontario, Canada	Executive Vice President, Refining and Marketing
Mark Little Alberta, Canada	Executive Vice President, Oil Sands
Kevin D. Nabholz Alberta, Canada	Executive Vice President, Major Projects
Jay Thornton Alberta, Canada	Executive Vice President, Energy Supply, Trading and Development
Eric Axford Alberta, Canada	Senior Vice President, Operations Support
Francois Langlois Alberta, Canada	Senior Vice President, Exploration and Production
Sue Lee Alberta, Canada	Senior Vice President, Human Resources and Communications
Mike MacSween Alberta, Canada	Senior Vice President, In Situ
Janice Odegaard Alberta, Canada	Senior Vice President, General Counsel and Corporate Secretary
Andrew Stephens Alberta, Canada	Senior Vice President, Business Services

As at December 31, 2010, the directors and executive officers of Suncor as a group beneficially owned, or controlled or directed, directly or indirectly, common shares of Suncor representing less than 1% of the then outstanding common shares.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

To the best of our knowledge, having made due inquiry, we confirm that, as at the date hereof:

(a) in the last ten years, no director or executive officer of Suncor is or has been a director or officer of another company or has owned a personal holding company that, while that person was acting in that capacity:

(i) 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 that was in effect for a period of more than 30 consecutive days; or

(ii) was subject to a cease trade order or an order similar to a cease trade order, or an order that denied the relevant company access to any exemption under securities legislation that was in effect for a period of more than 30 consecutive days, after the director or executive officer ceased to be a director or executive officer in the company and which resulted from an event that occurred while that person was acting in the capacity as a director or executive officer; or

(iii) 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.

(b) no director or executive officer of Suncor nor any holding company controlled by such person has:

(i) 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

(ii) 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; and

(c) 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.

Conflicts of Interest

No director or executive officer of Suncor, or any subsidiary of Suncor, has any existing or potential direct or indirect material conflicts of interest in respect of any matter that has materially affected or will materially affect Suncor or any of its subsidiaries.

SUNCOR EMPLOYEES

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

	As at December 31,	
	2010	2009
Oil Sands	4 753	4 616
Natural Gas	382	786
International and Offshore	516	582
Refining and Marketing	3 151	3 347
Corporate [1]	3 274	3 647
Total [2]	12 076	12 978

(1) Corporate employees include employees from our Major Projects group, which supports our business units, and employees from our Energy Supply, Trading and Development group.

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

Approximately 38% of the company's employees were covered by collective bargaining agreements in 2010.

The Communications, Energy and Paperworkers Union (CEP) represents the majority of the company's unionized employees. A new collective agreement with CEP Local 707, representing approximately 3,000 Oil Sands employees was entered into effective September 17, 2010. The terms of the three-year agreement include a wage increase of 2.5% in 2010, 4% in 2011 and 4% in 2012, and an initial lump sum payment of $1,500 per employee. The collective agreement with Local 707 will expire May 1, 2013.

Approximately 900 additional employees in the company's refinery, lubricants, natural gas, terminals, in situ and offshore production operations are also represented by the CEP. Three-year collective bargaining agreements with the CEP locals representing those employees were renewed in 2010 with wage increases of 2.5% in 2010, 3% in 2011 and 3.25% in 2012.

An independent union, the Suncor Employee Bargaining Association, represents approximately 220 employees at the Sarnia refinery. The agreement at the Sarnia refinery expires in May 2012.

The United Steel Workers Union (USW) represents approximately 240 employees at the Commerce City refinery. The USW collective agreement will expire in January 2012.

AUDIT COMMITTEE INFORMATION

Audit Committee Mandate

The Audit Committee Mandate is attached as Schedule "A" to this AIF.

Composition of the Audit Committee

The Audit Committee is comprised of Mr. Canfield (Chairman), Mr. D'Alessandro, Mr. MacNeill, Mr. O'Brien, Mr. Haseldonckx and Ms. Thomas. All members are independent and financially literate. The education and expertise of each member is described under the heading "Directors and Executive Officers".

For the purpose of making appointments to the company's Audit Committee, and in addition to the independence requirements, all directors nominated to the Audit Committee must meet the test of financial literacy as determined in the judgment of the board of directors. Also, at least one director so nominated must meet the test of financial expert as determined in the judgment of the Board of Directors. The designated financial experts on the Audit Committee are Michael W. O'Brien and Dominic D'Alessandro.

Financial Literacy

Financial literacy can be generally defined as the ability to read and understand a balance sheet, an income statement and a cash flow statement. In assessing a potential appointee's level of financial literacy, the Board of Directors must evaluate the totality of the individual's education and experience, including:

- the level of the person's accounting or financial education, including whether the person has earned an advanced degree in finance or accounting;
- whether the person is a professional accountant, or the equivalent, in good standing, and the length of time that the person actively has practised as a professional accountant, or the equivalent;

- whether the person is certified or otherwise identified as having accounting or financial experience by a recognized private body that establishes and administers standards in respect of such expertise, whether that person is in good standing with the recognized private body, and the length of time that the person has been actively certified or identified as having this expertise;
- whether the person has served as a principal financial officer, controller or principal accounting officer of a corporation that, at the time the person held such position, was required to file reports pursuant to securities laws and, if so, for how long;
- the person's specific duties while serving as a public accountant, auditor, principal financial officer, controller, principal accounting officer or position involving the performance of similar functions;
- the person's level of familiarity and experience with all applicable laws and regulations regarding the preparation of financial statements that must be included in reports filed under securities laws;
- the level and amount of the person's direct experience reviewing, preparing, auditing or analyzing financial statements that must be included in reports filed under provisions of securities laws;
- the person's past or current membership on one or more audit committees of companies that, at the time the person held such membership, were required to file reports pursuant to provisions of securities laws;
- the person's level of familiarity and experience with the use and analysis of financial statements of public companies; and
- whether the person has any other relevant qualifications or experience that would assist him or her in understanding and evaluating the corporation's financial statements and other financial information and to make knowledgeable and thorough inquiries whether:
- the financial statements fairly present the financial condition, results of operations and cash flows of the corporation in accordance with generally accepted accounting principles; and
- the financial statements and other financial information, taken together, fairly present the financial condition, results of operations and cash flows of the corporation.

Audit Committee Financial Expert

An "Audit Committee Financial Expert" means a person who, in the judgment of the Corporation's Board of Directors, has the following attributes:

a. an understanding of Canadian generally accepted accounting principles and financial statements;

b. the ability to assess the general application of such principles in connection with the accounting for estimates, accruals, and reserves;

c. experience preparing, auditing or analyzing or evaluating financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by Suncor's financial statements, or experience actively supervising one or more persons engaged in such activities;

d. an understanding of internal controls and procedures for financial reporting; and

e. an understanding of audit committee functions.

A person shall have acquired the attributes referred to in items (a) through (e) inclusive above through:

a. education and experience as a principal financial officer, principal accounting officer, controller, public accountant or auditor, or experience in one or more positions that involve the performance of similar functions;

b. experience actively supervising a principal financial officer, principal accounting officer, controller, public accountant, auditor or person performing similar functions;

c. experience overseeing or assessing the performance of companies or public accountants with respect to the preparation, auditing or evaluation of financial statements; or

d. other relevant experience.

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* and applicable Canadian law, is attached as Schedule "B" to this AIF.

Fees Paid to Auditors

Fees payable to PricewaterhouseCoopers LLP in 2010 and 2009 are detailed below:

($)	2010	2009
Audit Fees	4 873 000	4,307 000
Audit-Related Fees	637 000	807 000
All Other Fees	4 000	164 000
Total	5 514 000	5 278 000

The nature of each category of fees is described below.

Audit Fees

Audit fees were paid for professional services rendered by the auditors for the audit of Suncor's annual financial statements or services provided in connection with statutory and regulatory filings or engagements.

Audit-Related Fees

Audit-related fees were paid for professional services rendered by the auditors for preparation of reports on specified procedures as they relate to joint venture audits and attest services not required by statute or regulation.

All Other Fees

Fees disclosed under "All Other Fees" were paid-for subscriptions to auditor-provided and supported tools as well as externally sourced, direct or indirect, internal audit services in legacy Petro-Canada businesses.

The services described under the captions "Audit-Related Fees" and "All Other Fees" were approved by the Audit Committee pursuant to paragraph (c)(7)(i) of Rule 2-01 of Regulation S-X.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings to which we are or were a party, or of which any of our property is or was the subject since the beginning of the company's most recently completed financial year, nor are there any proceedings known by us to be contemplated that involve a claim for damages exceeding 10% of our current assets. In addition, there have not been any (a) penalties or sanctions imposed against the company by a court relating to securities legislation or by a securities regulatory authority during our financial year, (b) penalties or sanctions imposed by a court or regulatory body against the company that would likely be considered important to a reasonable investor in making an investment decision, or (c) settlement agreements entered into by the company before a court relating to securities legislation or with a securities regulatory authority during the financial year.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

No director, executive officer, or any person or company that beneficially owns or controls or directs, directly or indirectly, more than 10% of our securities or any associate or affiliate of these persons has, or has had, any material interests in any transaction or any proposed transaction that has materially affected or is reasonably expected to 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.

MATERIAL CONTRACTS

During the year ended December 31, 2010, 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 that are not required to be filed by Section 12.2 of National Instrument 51-102.

INTERESTS OF EXPERTS

Reserves and resources estimates contained in this AIF are based in part upon reports prepared by GLJ and Sproule, Suncor's Independent Reserve Engineering Evaluators. The 2010 Consolidated Financial Statements of the Company have been audited by PricewaterhouseCoopers LLP, Suncor's auditors. As at the date hereof, none of the partners, employees or consultants of GLJ or Sproule, respectively, as a group, through registered or beneficial interests, directly or indirectly, held or are entitled to receive more than 1% of any class of our outstanding securities, including the securities of our associates and affiliates, and PricewaterhouseCoopers LLP has advised Suncor's Audit Committee that they are independent with respect to Suncor within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

DISCLOSURE PURSUANT TO THE REQUIREMENTS OF THE NEW YORK STOCK EXCHANGE

As a Canadian issuer listed on the the NYSE, we are not required to comply with most of the NYSE rules and listing standards and instead may comply with domestic requirements. As a foreign private issuer, we are only required to comply with three of the NYSE rules (i) have an audit committee that satisfies the requirements of the United States *Securities Exchange Act of 1934*; (ii) the Chief Executive Officer must promptly notify the NYSE in writing after an executive officer becomes aware of any material non-compliance with the applicable NYSE rules; and (iii) provide a brief description of any significant differences between our corporate governance practices and those followed by U.S. companies listed under the NYSE. The company has disclosed in the corporate governance section of its website at www.suncor.com that, in certain instances, it is not required to obtain shareholder approval for material amendments to equity compensation plans and that Suncor, while in compliance with the independence requirements of applicable securities laws in Canada (specifically National Instrument 52-110 *Audit Committees*) and the U.S. (specifically Rule 10A-3 of the *Securities Exchange Act of 1934*), it has not adopted the director independence standards contained in Section 303A.02 of the NYSE's Listed Company Manual. Except as described herein, the company is in compliance with the NYSE corporate governance standards in all other significant respects.

ADDITIONAL INFORMATION

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of our securities, securities authorized for issuance under equity compensation plans 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 2010 Consolidated Financial Statements for our most recently completed financial year and the MD&A.

Further information about Suncor, filed with Canadian securities commissions and the SEC, including periodic quarterly and annual reports and the AIF/40-F is available online on SEDAR at www.sedar.com and on EDGAR at 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, and is not incorporated into the AIF by reference.

SCHEDULE "A"

AUDIT COMMITTEE MANDATE

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, excluding the Operations Integrity Audit department, which is specifically within the mandate of the Environment, Health & Safety Committee (references throughout this mandate to "Internal Audit" shall not include the Operations Integrity Audit department); and
- approving on behalf of the Board of Directors certain financial matters as delegated by the Board, including 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 Audit Committee has the following functions and responsibilities:

Internal Controls

1. Inquire 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 Standards of Business Conduct Code.
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 overseeing 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 Head of Internal Audit, annually review a summary of the remuneration of the Head of Internal Audit, and periodically review the performance and effectiveness of the Internal Audit function including compliance with The Institute of Internal Auditors' International Professional Practices Framework for Internal Auditing.

12. Review the Internal Audit Department Charter, and the plans, activities, organizational structure and qualifications of the Internal Auditors, and monitor the department's 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 the external auditor's management comment letter and management's responses thereto, and inquire 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 thereof.

15. Review with management and the 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. Authorize any changes to the categories of documents and information requiring audit committee review or approval prior to external disclosure, as set out in the Corporation's policy on external communication and disclosure of material information.

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 Evaluators, including the qualifications and independence of the Evaluators; review and approve any proposed change in the appointment of the Evaluators, and the reasons for such proposed change including whether there have been disputes between the Evaluators and management.

22. Annually review Suncor's reserves data and the report of the Evaluators 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 the report thereon of management and the directors to be included in or filed with the Statement, and (ii) the filing of the report of the Evaluators 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.

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

Reporting to the Board

29. Report to the Board of Directors on the activities of the Audit 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.

Approved by resolution of the Board of Directors on November 9, 2010. (1)

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(1) Previously revised on August 1, 2009

SCHEDULE "B"

*****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 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 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.

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 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

SCHEDULE "C"

FORM 51-101F2
REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the board of directors of Suncor Energy Inc. (the "company"):

1. We have evaluated the company's reserves data as at December 31, 2010. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2010, estimated using forecast prices and costs.

2. 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 carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. 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.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the company evaluated by us for the year ended December 31, 2010, and identifies the respective portions thereof that we have evaluated and reported on to the company's management and board of directors:

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – $MM)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants	Oil Sands In Situ January 11, 2011	Canada	—	18,477	—	18,477
GLJ Petroleum Consultants	Oil Sands Mining January 11, 2011	Canada	—	29,165	—	29,165
						47,642

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

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

EXECUTED as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, March 3, 2011

"Dana B. Laustsen"

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

SCHEDULE "D"

FORM 51-101F2
REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the board of directors of Suncor Energy Inc. (the "company"):

1. We have evaluated and reviewed the company's reserves data as at December 31, 2010. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2010, estimated using forecast prices and costs.

2. 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 and review.

   We carried out our evaluation and review in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook"), prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation and review to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation and review also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the company evaluated and reviewed by us as of December 31, 2010, and identifies the respective portions thereof that we have evaluated and reviewed and reported on to the company's management and board of directors:

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – $MM)			
			Audited	Evaluated	Reviewed	Total
Sproule Associates Limited	Conventional Offshore (East Coast Canada) February 18, 2011	Canada	—	6,399	—	6,399
Sproule Associates Limited	Conventional Onshore (Natural Gas) February 18, 2011	Canada	—	2,761	—	2,761
Sproule International Limited	North Sea February 18, 2011	North Sea, United Kingdom	—	8,014	1,094	9,108
Sproule International Limited	Other International February 18, 2011	Libya, Syria	—	5,590	—	5,590
			—	22,764	1,094	23,858

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

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

7. 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:

Sproule Associates Limited and Sproule International Limited, Calgary, Alberta, Canada, March 3, 2011

"R. Keith MacLeod"

R. Keith MacLeod, P.Eng.
President and Director

SCHEDULE "E"

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

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 activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2010, estimated using forecast prices and costs.

Independent qualified reserves evaluators have evaluated and reviewed 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 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 Form 51-101F1 containing reserves data and other oil and gas information;

(b) the filing of Form 51-101F2 which is 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

"*Bart Demosky*"
BART DEMOSKY
Chief Financial Officer

"*John T. Ferguson*"
JOHN T. FERGUSON
Chairman of the Board of Directors

"*Brian A. Canfield*"
BRIAN A. CANFIELD
Chairman of the Audit Committee

March 3, 2011



Box 2844, 150 - 6th Avenue S.W., Calgary,
Alberta, Canada T2P 3E3
tel: (403) 296-6000 fax: (403) 296-
3030 info@suncor.com www.suncor.com

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 51 and page 52 of Exhibit 99-1 and page 44 of Exhibit 99-2.

ATTESTATION REPORT OF THE REGISTERED PUBLIC ACCOUNTING FIRM

See page 53 and page 54 of Exhibit 99-1.

AUDIT COMMITTEE FINANCIAL EXPERT

See pages 76 and 77 of Annual Information Form.

CODE OF ETHICS

See page 79 of Annual Information Form.

FEES PAID TO PRINCIPAL ACCOUNTANT

See page 78 of Annual Information Form.

AUDIT COMMITTEE PRE-APPROVAL POLICIES

See Schedule "B" of Annual Information Form.

APPROVAL OF NON-AUDIT SERVICES

See Schedule "B" of Annual Information Form.

OFF-BALANCE SHEET ARRANGEMENTS

See pages 85 and 86 of Exhibit 99-1 and page 33 of Exhibit 99-2.

TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS

See page 33 of Exhibit 99-2.

IDENTIFICATION OF THE AUDIT COMMITTEE

See page 76 of Annual Information Form.

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 3, 2011

PER: /s/ BART DEMOSKY

Bart Demosky
Chief Financial Officer

EXHIBIT INDEX

Exhibit No.	Description
99-1	Audited Consolidated Financial Statements of Suncor Energy Inc. for the fiscal year ended December 31, 2010, including reconciliation to U.S. GAAP (Note 26)
99-2	Management's Discussion and Analysis for the fiscal year ended December 31, 2010, dated February 24, 2011
99-3	Consent of PricewaterhouseCoopers LLP
99-4	Consent of GLJ Petroleum Consultants Ltd.
99-5	Consent of Sproule Associates Limited and Sproule International Limited
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 the 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 Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as Enacted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

QuickLinks

ANNUAL INFORMATION FORM
UNDERTAKING AND CONSENT TO SERVICE OF PROCESS
DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING
ATTESTATION REPORT OF THE REGISTERED PUBLIC ACCOUNTING FIRM
AUDIT COMMITTEE FINANCIAL EXPERT
CODE OF ETHICS
FEES PAID TO PRINCIPAL ACCOUNTANT
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TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS
IDENTIFICATION OF THE AUDIT COMMITTEE
SIGNATURES
EXHIBIT INDEX

QuickLinks -- Click here to rapidly navigate through this document

EXHIBIT 99-1

Audited Consolidated Financial Statements of Suncor Energy Inc. for the fiscal year ended December 31, 2010, including reconciliation to U.S. GAAP (Note 26)

MANAGEMENT'S STATEMENT
OF RESPONSIBILITY FOR FINANCIAL REPORTING

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

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

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

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

The company retains independent petroleum consultants, GLJ Petroleum Consultants Ltd. and Sproule Associates Limited, to conduct independent evaluations of the company's oil and gas reserves and resources.

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





Richard L. George
President and
Chief Executive Officer

Bart Demosky
Chief Financial Officer

February 24 2011

The following report is provided by management in respect of the company's internal control over financial reporting (as defined in Rule 13a-15(f) and 15d-15(f) under the U.S. Securities Exchange Act of 1934):

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

1. Management is responsible for establishing and maintaining adequate internal control over the company's financial reporting.

2. Management has used the Committee of Sponsoring Organizations of the Treadway Commission (COSO) framework in Internal Control — Integrated Framework to evaluate the effectiveness of the company's internal control over financial reporting.

3. Management has assessed the effectiveness of the company's internal control over financial reporting as at December 31, 2010, and has concluded that such internal control over financial reporting was effective as of that date. Additionally, based on this assessment, management determined that there were no material weaknesses in internal control over financial reporting as at December 31, 2010. Because of inherent limitations, systems of internal control over financial reporting may not prevent or detect misstatements and even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

4. The effectiveness of the company's internal control over financial reporting as at December 31, 2010 has been audited by PricewaterhouseCoopers LLP, independent auditor, as stated in their report which appears herein.



Richard L. George
President and
Chief Executive Officer



Bart Demosky
Chief Financial Officer

February 24, 2011

INDEPENDENT AUDITOR'S REPORT

TO THE SHAREHOLDERS OF SUNCOR ENERGY INC.

We have completed integrated audits of Suncor Energy Inc.'s 2010, 2009 and 2008 consolidated financial statements and its internal control over financial reporting as at December 31, 2010. Our opinions, based on our audits, are presented below.

REPORT ON THE CONSOLIDATED FINANCIAL STATEMENTS

We have audited the accompanying consolidated financial statements of Suncor Energy Inc. ("the company"), which comprise the consolidated balance sheets as at December 31, 2010 and December 31, 2009 and the consolidated statements of earnings, comprehensive income, changes in shareholders' equity and of cash flows for each of the years in the three year period ended December 31, 2010, and the related notes including a summary of significant accounting policies.

Management's responsibility for the consolidated financial statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement. Canadian generally accepted auditing standards require that we comply with ethical requirements.

An audit involves performing procedures to obtain audit evidence, on a test basis, about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the company's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting principles and policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion on the consolidated financial statements.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the company as at December 31, 2010 and December 31, 2009 and the results of its operations and cash flows for each of the years in the three year period ended December 31, 2010 in accordance with Canadian generally accepted accounting principles.

REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

We have also audited the company's internal control over financial reporting as at December 31, 2010, based on criteria established in Internal Control – Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

Management's responsibility for internal control over financial reporting

Management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting.

Auditor's responsibility

Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company

Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control, based on the assessed risk, and performing such other procedures as we consider necessary in the circumstances.

We believe that our audit provides a reasonable basis for our audit opinion on the company's internal control over financial reporting.

Definition of internal control over financial reporting

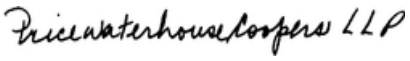
A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with Canadian generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Inherent limitations

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

Opinion

In our opinion, the company maintained, in all material respects, effective internal control over financial reporting as at December 31, 2010 based on criteria established in Internal Control – Integrated Framework, issued by COSO.



PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta

February 24, 2011

CONSOLIDATED STATEMENTS OF EARNINGS

For the years ended December 31 ($ millions)	**2010**	2009	2008
Revenues			
Operating revenues (note 21)	**33 198**	17 977	17 920
Less: Royalties (note 4)	**(1 937)**	(1 150)	(822)
Operating revenues (net of royalties)	**31 261**	16 827	17 098
Energy supply and trading activities (notes 7 and 21)	**2 700**	7 577	11 320
Interest and other income (notes 3 and 5)	**389**	444	28
	34 350	24 848	28 446
Expenses			
Purchases of crude oil and products	**14 911**	7 388	7 606
Operating, selling and general (note 20)	**7 810**	6 430	4 146
Energy supply and trading activities (notes 7 and 21)	**2 598**	7 381	11 323
Transportation	**656**	396	240
Depreciation, depletion and amortization (note 15)	**3 813**	1 860	961
Accretion of asset retirement obligations	**178**	136	60
Exploration	**197**	209	90
Loss (gain) on disposal of assets	**(107)**	66	13
Project start-up costs	**77**	51	35
Financing expenses (income) (note 8)	**(30)**	(488)	917
	30 103	23 429	25 391
Earnings before Income Taxes	**4 247**	1 419	3 055
Provisions for (Recovery of) Income Taxes (note 9)			
Current	**1 004**	841	514
Future	**555**	(628)	459
	1 559	213	973
Net Earnings from Continuing Operations	**2 688**	1 206	2 082
Net Earnings (Loss) from Discontinued Operations (note 6)	**883**	(60)	55
Net Earnings	**3 571**	1 146	2 137
Net Earnings from Continuing Operations per Common Share (dollars)			
Basic	**1.72**	1.01	2.23
Diluted	**1.71**	1.00	2.20
Net Earnings per Common Share (dollars) (note 10)			
Basic	**2.29**	0.96	2.29
Diluted	**2.27**	0.95	2.26
Cash Dividends per Common Share (dollars)	**0.40**	0.30	0.20

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

For the years ended December 31 ($ millions)	**2010**	2009	2008
Net earnings	**3 571**	1 146	2 137
Other comprehensive income (loss), net of tax			
Change in foreign currency translation adjustment	**(503)**	(332)	350
Reclassification to net earnings	**53**	—	—
Gain (loss) on derivative contracts designated as cash flow hedges	**—**	—	(7)
Reclassification to net earnings	**(1)**	2	7
Comprehensive Income	**3 120**	816	2 487

See accompanying notes to the consolidated financial statements.

CONSOLIDATED BALANCE SHEETS

As at December 31 ($ millions)	**2010**	2009
Assets		
Current assets		
Cash and cash equivalents (note 11)	**1 077**	505
Accounts receivable	**5 253**	3 703
Inventories (note 13)	**3 141**	2 947
Income taxes receivable	**734**	587
Future income taxes (note 9)	**210**	332
Assets of discontinued operations (note 6)	**98**	257
Total current assets	**10 513**	8 331
Property, plant and equipment, net (note 14)	**55 290**	54 198
Other assets (note 16)	**451**	491
Goodwill (note 2)	**3 201**	3 201
Future income taxes (note 9)	**56**	193
Assets of discontinued operations (note 6)	**658**	3 332
Total assets	**70 169**	69 746
Liabilities and Shareholders' Equity		
Current liabilities		
Short-term debt	**2**	2
Current portion of long-term debt	**518**	25
Accounts payable and accrued liabilities (note 18)	**6 942**	6 307
Income taxes payable	**929**	1 254
Future income taxes (note 9)	**37**	18
Liabilities of discontinued operations (note 6)	**98**	242
Total current liabilities	**8 526**	7 848
Long-term debt (note 17)	**11 669**	13 855
Accrued liabilities and other (note 18)	**4 154**	4 372
Future income taxes (note 9)	**8 615**	8 367
Liabilities of discontinued operations (note 6)	**484**	1 193
Shareholders' equity (see below)	**36 721**	34 111
Total liabilities and shareholders' equity	**70 169**	69 746

Commitments and contingencies (note 24)

SHAREHOLDERS' EQUITY

As at December 31 ($ millions)	**Number (thousands)**	**2010**	Number (thousands)	2009
Share capital (note 20)	**1 565 489**	**20 188**	1 559 778	20 053
Contributed surplus		**505**		526
Accumulated other comprehensive income (loss) (note 22)		**(684)**		(233)
Retained earnings		**16 712**		13 765
Total shareholders' equity		**36 721**		34 111

See accompanying notes to the consolidated financial statements.

Approved on behalf of the Board of Directors:



Richard L. George,
Director



Brian A. Canfield,
Director

February 24, 2011

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31 ($ millions)	**2010**	2009	2008
Operating Activities			
Net earnings from continuing operations	**2 688**	1 206	2 082
Adjustments for:			
Depreciation, depletion and amortization	**3 813**	1 860	961
Future income taxes	**555**	(628)	459
Accretion of asset retirement obligations	**178**	136	60
Unrealized foreign exchange (gain) loss on U.S. dollar denominated long-term debt (note 8)	**(426)**	(858)	919
Change in fair value of derivative contracts (note 21)	**(285)**	980	(638)
Loss (gain) on disposal of assets	**(107)**	66	13
Stock-based compensation	**114**	262	(22)
Gain on effective settlement of pre-existing contract with Petro-Canada (note 3)	**—**	(438)	—
Other	**(446)**	(278)	(7)
Exploration expenses	**80**	126	61
Change in non-cash working capital related to operating activities (note 12)	**(1 230)**	(237)	403
Cash flow provided by continuing operations	**4 934**	2 197	4 291
Cash flow provided by discontinued operations	**552**	378	171
Cash flow from operating activities	**5 486**	2 575	4 462
Investing Activities			
Capital and exploration expenditures	**(5 833)**	(4 020)	(7 947)
Other investments	**3**	(9)	(18)
Cash acquired through business combination (note 3)	**—**	248	—
Proceeds from disposal of assets	**307**	148	33
Change in non-cash working capital related to investing activities (note 12)	**(196)**	(791)	415
Cash flow used in continuing investing activities	**(5 719)**	(4 424)	(7 517)
Cash flow provided by (used in) discontinued investing activities	**2 607**	(247)	(73)
Cash flow used in investing activities	**(3 112)**	(4 671)	(7 590)
Financing Activities			
Change in short-term debt	**—**	—	(1)
Net proceeds from issuance of long-term debt	**—**	—	2 704
Change in revolving-term debt	**(1 257)**	2 325	422
Issuance of common shares under stock option plan	**81**	41	190
Dividends paid on common shares	**(611)**	(401)	(180)
Cash flow provided by (used in) financing activities	**(1 787)**	1 965	3 135
Increase (Decrease) in Cash and Cash Equivalents	**587**	(131)	7
Effect of Foreign Exchange on Cash and Cash Equivalents	**(15)**	(24)	84
Cash and Cash Equivalents at Beginning of Period	**505**	660	569
Cash and Cash Equivalents at End of Period	**1 077**	505	660

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

For the years ended December 31 ($ millions)	Share Capital	Contributed Surplus	Accumulated Other Comprehensive Income (Loss)	Retained Earnings
At December 31, 2007	881	194	(253)	11 074
Net earnings	—	—	—	2 137
Dividends paid on common shares	—	—	—	(180)
Issued for cash under stock option plans	226	(36)	—	—
Issued under dividend reinvestment plan	6	—	—	(6)
Stock-based compensation expense	—	120	—	—
Income tax benefit of stock option deductions in the U.S.	—	10	—	—
Other comprehensive income (loss)	—	—	350	—
At December 31, 2008	1 113	288	97	13 025
Net earnings	—	—	—	1 146
Dividends paid on common shares	—	—	—	(401)
Issued for cash under stock option plans	57	(16)	—	—
Issued under dividend reinvestment plan	5	—	—	(5)
Stock-based compensation expense	—	103	—	—
Issued for Petro-Canada acquisition (note 3)	18 878	—	—	—
Fair value of Petro-Canada stock options exchanged for Suncor stock options (note 3)	—	147	—	—
Income tax benefit of stock option deduction in the U.S.	—	4	—	—
Other comprehensive income (loss)	—	—	(330)	—
At December 31, 2009	**20 053**	**526**	**(233)**	**13 765**
Net earnings	**—**	**—**	**—**	**3 571**
Dividends paid on common shares	**—**	**—**	**—**	**(611)**
Issued for cash under stock option plans	**122**	**(34)**	**—**	**—**
Issued under dividend reinvestment plan	**13**	**—**	**—**	**(13)**
Stock-based compensation expense	**—**	**13**	**—**	**—**
Other comprehensive income (loss)	**—**	**—**	**(451)**	**—**
At December 31, 2010	**20 188**	**505**	**(684)**	**16 712**

See accompanying notes to the consolidated financial statements.

SUNCOR ENERGY INC.
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Suncor Energy Inc. (Suncor or the company) is an integrated energy company headquartered in Canada. Suncor's operations include oil sands development and upgrading, onshore and offshore oil and gas production, petroleum refining, and product marketing primarily under the Petro-Canada brand.

(a) Principles of Consolidation and the Preparation of Financial Statements

These consolidated financial statements are prepared and reported in Canadian dollars in accordance with Canadian generally accepted accounting principles (GAAP), which differ in some respects from GAAP in the United States. The differences that are relevant to the company's financial statements are quantified and explained in note 26.

The consolidated financial statements include the accounts of Suncor and its subsidiaries and the company's proportionate share of the assets, liabilities, equity, revenues, expenses and cash flows of its joint ventures. Subsidiaries are defined as entities in which the company holds a controlling interest, is the general partner or where it is subject to the majority of expected losses or gains.

The timely preparation of financial statements requires that management make estimates and assumptions, and use judgment regarding assets, liabilities, revenues and expenses. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur. Significant estimates used in the preparation of the financial statements include, but are not limited to, asset retirement obligations, employee future benefits, valuation of property, plant and equipment and depreciation, depletion and amortization, purchase price allocation, valuation of goodwill, income taxes, and the estimates of oil and natural gas reserves.

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

(b) Revenues

Revenue from the sale of crude oil, natural gas, natural gas liquids, purchased products and refined petroleum products is recorded when title passes to the customer and collection is reasonably assured. Revenue from crude oil and natural gas production represents Suncor's working interest share before royalty payments to governments and other mineral interest owners. Crude oil and natural gas sold below, or above, the company's working interest share of production, results in production underlifts or overlifts. Underlifts are recorded as a receivable at market value with a corresponding increase to revenues while overlifts are recorded as a payable at market value with a corresponding decrease to revenues.

Intersegment sales of crude oil and natural gas are recorded at market values. Intersegment profits and losses are eliminated on consolidation.

International operations conducted pursuant to exploration and production-sharing agreements (EPSAs) are accounted for based on the company's working interest. Under the EPSAs, the company and other non-governmental partners, if any, pay all exploration costs and a pro-rata share of costs to develop and operate the concessions. Each EPSA establishes specific terms for the company to recover these costs (Cost Recovery Oil) and to share in the production profits (Profit Oil). Cost Recovery Oil is determined in accordance with a formula that is generally limited to a specified percentage of production during each fiscal year. Profit Oil is that portion of production remaining after deducting Cost Recovery Oil and is shared between the joint venture partners and the respective government. Cost Recovery Oil, Profit Oil and amounts in respect of all income taxes payable by the company under the laws of the respective country are reported as sales revenue. All other government stakes, other than income taxes, are considered royalty interests.

Physical and financial contracts entered into for trading purposes are considered to be derivative financial instruments, and any changes in fair value are recorded on a net basis in Energy Supply and Trading Activities revenue. Settlement of physical purchase and sales contracts entered into for the company's own usage are recorded on a gross basis in Energy Supply and Trading Activities revenue and Energy Supply and Trading Activities expense.

(c) Transportation Costs

Transportation costs billed to customers are classified as product revenues with the related transportation costs classified as transportation costs in the Consolidated Statements of Earnings and Comprehensive Income.

(d) Foreign Currency Translation

Monetary assets and liabilities denominated in foreign currencies are translated to Canadian dollars at rates of exchange in effect at the end of the period. The resulting exchange gains and losses are included in earnings. With the exception of balances pertaining to self-sustaining operations, other assets and related depreciation, depletion and amortization, other liabilities, revenues and expenses are translated at rates of exchange in effect at the respective transaction dates. The resulting exchange gains and losses are included in earnings.

International operations, refining and marketing operations in the United States, and the company's self-insurance operations, are classified as self-sustaining and are translated into Canadian dollars using the current rate method. Assets and liabilities are translated at the period-end exchange rate, while revenues and expenses are translated using average exchange rates during the period. Translation gains or losses are included in other comprehensive income (loss).

(e) Income Taxes

Suncor follows the liability method of accounting for income taxes. Future income taxes are recorded for the effect of any difference between the accounting and income tax basis of an asset or liability, using enacted or substantively enacted income tax rates. Accumulated future income tax balances are adjusted to reflect changes in income tax rates that are substantively enacted with the adjustment being recognized in net earnings in the period that the change occurs.

Any investment tax credits received by the company are recorded as an offset to the related expenditures.

(f) Earnings per Share

Basic earnings per share are calculated by dividing the net earnings by the weighted-average number of common shares outstanding. Diluted earnings per share reflect the potential dilution that would occur if stock options, excluding those with a cash payment alternative or a tandem stock appreciation right, were exercised. The treasury stock method is used in calculating diluted earnings per share, which assumes that any proceeds received from the exercise of in-the-money stock options would be used to purchase common shares at the average market price for the period.

(g) Cash and Cash Equivalents

Cash and cash equivalents consist primarily of cash in banks, term deposits, certificates of deposit and all other highly liquid investments with a maturity at the time of purchase of three months or less.

(h) Inventories

Crude oil and refined products inventories, other than those held for trading purposes, are valued at the lower of cost and net realizable value. Cost is determined using the first-in, first-out (FIFO) method, and is calculated as the direct and indirect expenditures incurred to bring an item or product to its existing condition and location.

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

Inventories held for trading purposes in the company's energy trading operations are carried at fair value less costs to sell and any changes in fair value are recognized as gains or losses within Energy Supply and Trading Activities revenue.

(i) Investments

Investments in companies over which the company has significant influence are accounted for using the equity method. Other investments are carried at cost.

(j) Property, Plant and Equipment

Cost

Property, plant and equipment are recorded at cost.

The company follows the successful efforts method of accounting for the exploration and development expenditures of oil and gas producing activities. Under successful efforts, acquisition costs of proved and unproved properties are capitalized. Costs of unproved properties are transferred to proved properties when proved reserves are confirmed. Exploration drilling costs are initially capitalized pending evaluation as to whether sufficient quantities of reserves have been found to justify commercial production. If commercial quantities of reserves are not found, exploratory drilling costs are expensed as dry hole costs in exploration expense. All other exploration costs, including geological and geophysical costs are expensed as incurred.

Development costs and production facilities, which include the costs of wellhead equipment, development drilling costs, applicable geological and geophysical costs, gas plants and handling facilities, offshore platforms and subsea structures, upgraders, extraction plants and the costs of acquiring or constructing support facilities and equipment are capitalized. Costs incurred to operate and maintain wells and equipment are expensed as operating costs.

Development costs to expand the capacity of existing mines or to develop mine areas substantially in advance of current production are capitalized. Drilling and related seismic costs for regulatory approved mining areas are capitalized when planned future development timelines do not exceed 10 years.

Planned major maintenance and expenditures that increase capacity or extend the useful lives of assets are capitalized.

Interest Capitalization

Interest costs relating to major capital projects in progress are capitalized as part of property, plant and equipment. Capitalization of interest ceases when the capital asset is substantially complete and ready for its intended productive use or during construction stoppages.

Leases

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

Depreciation, Depletion and Amortization

Depreciation and depletion of property, plant and equipment for oil and gas producing properties follow successful efforts accounting. Acquisition costs of unproved properties for natural gas and conventional crude are amortized over the lease term until proved reserves are confirmed. Exploration drilling and development costs are depleted over the remaining proved developed reserves. Proved property acquisition costs are depleted over the remaining proved reserves.

Mine and mobile equipment costs are depleted on unit-of-production basis over proved developed reserves or depreciated over periods ranging from two to 20 years. Mining, extraction and upgrading facilities and other property and equipment, including leases in service, are depreciated on a straight-line basis ranging from four to 40 years. Gas plants, central processing facilities of in situ oil sands activities and support facilities and equipment are depreciated on a straight-line basis over their useful lives, which range from three years to 30 years.

Costs associated with significant development projects are not depleted until facilities are substantially complete and ready for their intended productive use.

Depreciation of property, plant and equipment in the refining and marketing operations is on a straight-line basis over the useful lives of assets, which range from three years to 40 years.

Planned major maintenance activities are capitalized and amortized on a straight-line basis over the period to the next shutdown, which varies from three to nine years.

Depreciation, depletion and amortization rates are reviewed at least annually, or when events or conditions occur that impact capitalized costs, reserves or estimated service lives.

(k) Intangible Assets

Intangible assets, other than goodwill, include acquired customers lists and brand value and are stated at the amount initially recognized, less accumulated amortization. Intangible assets with a finite life are amortized over their expected useful lives which range from five to 10 years, while intangible assets with an indefinite useful life are not subject to amortization. Expected useful lives of intangible assets are reviewed on an annual basis and, if necessary, changes in useful lives are accounted for prospectively.

(l) Impairment

Property, plant and equipment are reviewed for impairment whenever events or conditions indicate that their net carrying amount may not be recoverable from estimated undiscounted future cash flows. If it is determined that the estimated net recoverable amount is less than the net carrying amount, a write-down to the asset's fair value is recognized during the period, with a charge to Depreciation, Depletion and Amortization expense. In assessing unproven properties for impairment, Suncor considers future plans, the remaining lease terms, and other factors that may indicate impairment.

The carrying values of intangible assets with a finite life are reviewed for impairment whenever events or changes in circumstances indicate the carrying value may not be recoverable. Intangible assets with an indefinite useful life are assessed for impairment annually, or more frequently as economic events dictate. If it is determined that the estimated net recoverable amount is less than the net carrying amount, a write-down to the intangible asset's net recoverable value is recognized in Depreciation, Depletion and Amortization expense during the period.

(m) Goodwill

Goodwill represents the excess of the purchase price over the fair value of net assets, and mainly relates to the company's acquisition of Petro-Canada. The carrying value of each reporting unit's goodwill is assessed for impairment annually, or more frequently as economic events dictate, by comparing the fair value of the reporting unit to its carrying value, including goodwill. If the fair value of the reporting unit is less than its carrying value, goodwill impairment is recognized as the excess of the carrying value of the goodwill over the fair value of the goodwill.

(n) Asset Retirement Obligations

A liability, based on current legislation and industry practice, is recognized for future asset retirement obligations (ARO) associated with property, plant and equipment. The fair value of the ARO is recorded on a discounted basis using the company's credit-adjusted risk-free interest rate and is added to the carrying amount of the related asset and amortized consistent with the underlying asset. The liability is accreted until it is expected to settle, with actual expenditures charged against the liability. Changes in the estimated obligation resulting from revisions to the estimated timing or amount of undiscounted cash flows are recognized as a change in the ARO liability and related asset.

(o) Stock-Based Compensation Plans

The company's common stock-based compensation plans consist of stock options, stock appreciation rights and share units, and are granted to executives, employees and non-employee directors.

For stock options that give the holder the right to purchase a common share at a predetermined price, the expense is based on the fair values of the option at the time of grant over the estimated vesting periods of the respective options. A corresponding increase is recorded as contributed surplus in the Consolidated Statements of Changes in Shareholders' Equity. On exercise of options, consideration paid to the company, and the associated contributed surplus, are both credited to share capital.

Stock appreciation rights, share units, and stock options which can be settled for a cash payment, are measured using the intrinsic value method at each period end. A liability and expense are recorded over the vesting period of the options based on the difference of the market price of the underlying shares and the option exercise price. When awards are surrendered for cash, the cash settlement paid reduces the outstanding liability. When awards are exercised for common shares, consideration paid by the holder and the previously recognized liability associated with the stock options is credited to share capital.

For employees eligible to retire prior to the vesting date, the compensation expense is recognized over the shorter period. In instances where an employee is eligible to retire at the time of grant, the full expense is recognized immediately.

Stock-based compensation expense is recorded in Operating, Selling and General expense.

(p) Employee Future Benefits

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

The estimated future cost of providing defined benefit pension and other post-retirement benefits is actuarially determined using management's best estimates of demographic and financial assumptions, and such cost is accrued proportionately from the date of hire of the employee to the date the employee becomes fully eligible to receive the benefits. The discount rate used to determine accrued benefit obligations is based on a year-end market rate of interest for high-quality corporate debt instruments with cash flows that match the timing and amount of expected benefit payments. The excess of the cumulative unamortized net actuarial gain or loss over 10% of the greater of the accrued benefit obligation and the fair value of plan assets at the beginning of the year is amortized over the average remaining service life of active employees.

Company contributions to the defined contribution plan are expensed as incurred.

(q) Financial Instruments

All financial instruments are initially recognized at fair value on the balance sheet. The company has classified each financial instrument into one of the following categories: held-for-trading financial assets and liabilities, loans and receivables, held-to-maturity financial assets, and other financial liabilities. Subsequent measurement of financial instruments is based on their classification.

Held-for-trading financial assets and liabilities are subsequently measured at fair value with changes in those fair values recognized in net earnings. Derivative financial instruments are considered held-for-trading unless they are designated as a hedge. Loans and receivables, held-to-maturity financial assets and other financial liabilities are subsequently measured at amortized cost using the effective interest method.

The company classifies cash and cash equivalents as held-for-trading financial assets, accounts receivable as loans and receivables, and accounts payable and accrued liabilities, short-term debt, long-term debt and accrued liabilities and other as other financial liabilities.

The company amortizes transaction costs and premiums or discounts related to issuance of long-term debt using the effective interest method.

Derivative Financial Instruments

The company uses derivative financial instruments for risk management purposes to manage certain exposures to fluctuations in interest rates, commodity prices, foreign exchange rates, and also for trading purposes. Gains or losses arising from risk management activities are reported in the same caption as the underlying item. Earnings impacts from trading activities are recorded on a net basis in Energy Supply and Trading Activities revenue.

Hedge Accounting

The company may apply hedge accounting to arrangements that qualify for designated hedge accounting treatment, which include fair value and cash flow hedges. If the derivative is designated as a fair value hedge, changes in the fair value of the derivative and changes in the fair value of the hedged portion of the underlying item are recognized in net earnings. If the derivative is designated as a cash flow hedge, the effective portions of the changes in fair value of the derivative are initially recorded in other comprehensive income and are recognized in net earnings when the hedged item is realized. Designated hedges are assessed at each reporting date to determine if the relationship between the derivative and the underlying hedged exposure is still effective and to quantify any ineffectiveness in the relationship. Any ineffectiveness in designated hedges is recognized in net earnings immediately.

(r) Recent Accounting Pronouncements

Business Combinations

In 2009, the Canadian Institute of Chartered Accountants issued section 1582 "Business Combinations" to replace section 1581, and issued sections 1601 "Consolidated Financial Statements" and 1602 "Non-Controlling Interests" to replace section 1600 "Consolidated Financial Statements". The new standards revised guidance on the determination of the carrying amount of the assets acquired and liabilities assumed, goodwill and accounting for non-controlling interests at the time of a business combination. Prospective application was effective for fiscal years beginning on or after January 1, 2011.

Early adoption was permitted, but the company applied section 1581 to the Petro-Canada business combination that occurred in August 2009.

2. SEGMENTED DISCLOSURES

The company has classified its continuing operations as follows:

- Oil Sands includes operations in northeast Alberta to develop and produce synthetic crude oil and related products, through the recovery and upgrading of bitumen from mining and in situ operations.
- Natural Gas includes exploration and production of natural gas, crude oil and natural gas liquids, primarily in Western Canada.
- International and Offshore includes offshore activity in East Coast Canada, with interests in the Hibernia, Terra Nova, White Rose and Hebron oilfields, and exploration and production of crude oil and natural gas in the United Kingdom (U.K.), Libya, Syria, and Norway.
- Refining and Marketing includes the refining of crude oil products, and the distribution and marketing of these and other purchased products through refineries located in Canada and the U.S., as well as a lubricants plant located in Eastern Canada.
- Corporate, Energy Trading and Eliminations includes investments in renewable energy projects, third-party energy trading activities, and activities not directly attributable to an operating segment.

In 2010, the company combined its International and East Coast Canada segments into one segment, International and Offshore. All prior periods have been reclassified to conform to these segment definitions. Operations that have been discontinued are disclosed in note 6.

Segmented Results of Continuing Operations

For the years ended December 31 ($ millions)	Oil Sands			Natural Gas			International and Offshore		
	2010	2009	2008	**2010**	2009	2008	**2010**	2009	2008
EARNINGS									
Revenues									
Operating revenues	**7 028**	4 135	8 045	**682**	338	437	**4 654**	1 526	—
Intersegment revenues	**2 758**	2 609	1 309	**124**	121	34	**593**	159	—
Less: Royalties	**(681)**	(645)	(715)	**(76)**	(36)	(107)	**(1 180)**	(469)	—
Operating revenues (net of royalties)	**9 105**	6 099	8 639	**730**	423	364	**4 067**	1 216	—
Energy supply and trading activities	**—**	—	—	**—**	—	—	**—**	—	—
Interest and other income	**318**	440	—	**4**	—	—	**256**	1	—
	9 423	6 539	8 639	**734**	423	364	**4 323**	1 217	—
Expenses									
Purchases of crude oil and products	**1 070**	325	574	**—**	—	—	**302**	33	—
Operating, selling and general	**4 545**	4 277	3 203	**338**	233	120	**414**	164	—
Energy supply and trading activities	**—**	—	—	**—**	—	—	**—**	—	—
Transportation	**291**	248	229	**94**	41	11	**89**	38	—
Depreciation, depletion and amortization	**1 318**	922	580	**773**	287	137	**1 172**	299	—
Accretion of asset retirement obligations	**120**	111	55	**29**	14	4	**27**	10	—
Exploration	**6**	10	17	**14**	125	73	**177**	74	—
Loss (gain) on disposal of assets	**14**	70	36	**(132)**	(20)	(22)	**2**	—	—
Project start-up costs	**74**	51	35	**—**	—	—	**3**	—	—
Financing expenses (income)	**(1)**	1	—	**(1)**	—	—	**(18)**	(1)	—
	7 437	6 015	4 729	**1 115**	680	323	**2 168**	617	—
Earnings (loss) before income taxes	**1 986**	524	3 910	**(381)**	(257)	41	**2 155**	600	—
Income taxes	**494**	(33)	1 035	**(104)**	(72)	7	**1 041**	277	—
Net earnings (loss) from continuing operations	**1 492**	557	2 875	**(277)**	(185)	34	**1 114**	323	—
CAPITAL AND EXPLORATION EXPENDITURES – continuing operations	**(3 709)**	(2 831)	(7 413)	**(170)**	(228)	(269)	**(927)**	(511)	—

For the years ended December 31 ($ millions)	Refining and Marketing 2010	Refining and Marketing 2009	Refining and Marketing 2008	Corporate, Energy Trading and Eliminations 2010	Corporate, Energy Trading and Eliminations 2009	Corporate, Energy Trading and Eliminations 2008	Total 2010	Total 2009	Total 2008
EARNINGS									
Revenues									
Operating revenues	**20 769**	11 800	9 257	**65**	178	181	**33 198**	17 977	17 920
Intersegment revenues	**249**	51	—	**(3 724)**	(2 940)	(1 343)	**—**	—	—
Less: Royalties	**—**	—	—	**—**	—	—	**(1 937)**	(1 150)	(822)
Operating revenues (net of royalties)	**21 018**	11 851	9 257	**(3 659)**	(2 762)	(1 162)	**31 261**	16 827	17 098
Energy supply and trading activities	**—**	—	—	**2 700**	7 577	11 320	**2 700**	7 577	11 320
Interest and other income	**44**	—	1	**(233)**	3	27	**389**	444	28
	21 062	11 851	9 258	**(1 192)**	4 818	10 185	**34 350**	24 848	28 446
Expenses									
Purchases of crude oil and products	**17 100**	9 607	8 367	**(3 561)**	(2 577)	(1 335)	**14 911**	7 388	7 606
Operating, selling and general	**2 192**	1 284	719	**321**	472	104	**7 810**	6 430	4 146
Energy supply and trading activities	**—**	—	—	**2 598**	7 381	11 323	**2 598**	7 381	11 323
Transportation	**200**	87	16	**(18)**	(18)	(16)	**656**	396	240
Depreciation, depletion and amortization	**475**	317	198	**75**	35	46	**3 813**	1 860	961
Accretion of asset retirement obligations	**2**	1	1	**—**	—	—	**178**	136	60
Exploration	**—**	—	—	**—**	—	—	**197**	209	90
Loss (gain) on disposal of assets	**(30)**	16	6	**39**	—	(7)	**(107)**	66	13
Project start-up costs	**—**	—	—	**—**	—	—	**77**	51	35
Financing expenses (income)	**9**	4	—	**(19)**	(492)	917	**(30)**	(488)	917
	19 948	11 316	9 307	**(565)**	4 801	11 032	**30 103**	23 429	25 391
Earnings (loss) before income taxes	**1 114**	535	(49)	**(627)**	17	(847)	**4 247**	1 419	3 055
Income taxes	**313**	128	(27)	**(185)**	(87)	(42)	**1 559**	213	973
Net earnings (loss) from continuing operations	**801**	407	(22)	**(442)**	104	(805)	**2 688**	1 206	2 082
CAPITAL AND EXPLORATION EXPENDITURES – continuing operations	**(667)**	(380)	(207)	**(360)**	(70)	(58)	**(5 833)**	(4 020)	(7 947)

Goodwill and Total Assets by Segment

As at December 31 ($ millions)	Goodwill 2010	Goodwill 2009	Total Assets 2010	Total Assets 2009
Oil Sands	**3 019**	3 019	**40 246**	37 553
Natural Gas	**—**	—	**3 091**	3 369
International and Offshore	**—**	—	**12 232**	12 729
Refining and Marketing	**182**	182	**11 778**	10 304
Corporate	**—**	—	**2 066**	2 202
Discontinued operations	**—**	—	**756**	3 589
Total	**3 201**	3 201	**70 169**	69 746

Geographic Information

For the years ended December 31 ($ millions)	2010	2009	2008
Revenues [1]			
Canada	**27 217**	20 184	23 742
U.S.	**4 804**	4 010	4 794
Other	**3 199**	1 286	101
Total	**35 220**	25 480	28 637

(1) Includes revenues from continuing and discontinued operations.

As at December 31 ($ millions)	**2010**	2009
Total assets		
Canada	**58 676**	54 259
U.S.	**3 332**	5 239
Other	**8 161**	10 248
Total	**70 169**	69 746

3. BUSINESS COMBINATION WITH PETRO-CANADA

On August 1, 2009, Suncor completed its merger with Petro-Canada. The company has accounted for this business combination as prescribed by Canadian Institute of Chartered Accountants (CICA) Handbook section 1581 "Business Combinations". As the acquirer, the company is required to recognize Petro-Canada assets and liabilities as at August 1, 2009. The results of Petro- Canada operations are included in the consolidated financial statements of the company from August 1, 2009.

The final calculation of the purchase price and allocation to assets and liabilities acquired as at August 1, 2009 is as follows:

($ millions)	
Calculation of Purchase Price:	
621.1 million common shares issued to Petro-Canada shareholders	18 878
7.1 million Petro-Canada share options exchanged for share options of Suncor	147
Transaction costs	167
Effective settlement of pre-existing contract with Petro-Canada	438
Total purchase price	19 630
Allocation of Purchase Price:	
Current assets	4 645
Property, plant and equipment	27 407
Other assets	537
Total assets	32 589
Current liabilities	3 741
Long-term debt	4 410
Accrued liabilities and other	3 416
Future income taxes	4 570
Total liabilities	16 137
Net assets purchased	16 452
Goodwill	3 178
Total purchase price	19 630
Goodwill Allocation:	
Oil Sands	3 019
Refining and Marketing	159
Total goodwill	3 178

Cash acquired was $248 million, net of transaction costs of $167 million.

Other assets include $236 million for intangible assets, relating to the Petro-Canada brand, with an indefinite life, and customer lists, which will be amortized over their estimated useful lives.

Suncor and Petro-Canada had a fee-for-service contract in place prior to the merger, where effective January 1, 2009, Suncor had started upgrading bitumen supplied by Petro-Canada. At the date of the merger, the terms of the contract resulted in it being favourable to Suncor, and the assigned fair value of $438 million was recorded in Interest and Other Income.

4. BITUMEN VALUATION METHODOLOGY

In the fourth quarter of 2010, the Minister of Energy for Alberta provided notice to the company for the quality adjustment to be used under the Bitumen Valuation Methodology (Ministerial) Regulations for the interim period January 1, 2009 to December 31, 2010. As a result, the company recognized a royalty recovery of $140 million.

The company continues to negotiate final adjustments to the bitumen valuation calculation for the 2009 and 2010 interim period and for the term of the Suncor Royalty Amending Agreement that expires December 31, 2015.

5. TERRA NOVA REDETERMINATION

In the fourth quarter of 2010, the joint owners of the Terra Nova oilfield finalized the redetermination of working interests required under the Terra Nova Development and Operating Agreement following field payout on February 1, 2005. Suncor's working interest increased to 37.675% from 33.990%, and the other owners have agreed to reimburse the company for its increased working interest from February 1, 2005 to December 31, 2010. As a result, the company has recognized a $295 million gain in Interest and Other Income.

Suncor's financial presentation will reflect the increased working interest in Terra Nova beginning January 1, 2011.

6. DISCONTINUED OPERATIONS

During 2010, the company divested certain non-core assets as part of its continuing strategic alignment.

Natural Gas

In the first quarter of 2010, the company completed the sale of its oil and gas producing assets in the U.S. Rockies for net proceeds of US$481 million (Cdn$502 million).

In the second quarter of 2010, the company completed the sale of non-core natural gas properties located in northeast British Columbia (Blueberry and Jedney) for net proceeds of $383 million, and non-core assets in central Alberta (Rosevear and Pine Creek) for net proceeds of $229 million.

In the third quarter of 2010, the company completed the sale of non-core natural gas properties located in west central Alberta (Bearberry and Ricinus) for net proceeds of $275 million, and non-core assets in southern Alberta (Wildcat Hills) for net proceeds of $351 million.

International and Offshore

In the third quarter of 2010, the company completed the Trinidad and Tobago asset sale, for net proceeds of US$378 million (Cdn$383 million), and the sale of its shares in Petro-Canada Netherlands BV, for net proceeds of €316 million (Cdn$420 million).

In the fourth quarter of 2010, the company completed the sale of certain non-core U.K. offshore assets for net proceeds of £55 million (Cdn$86 million). The company expects to close the remaining agreed sales of non-core U.K. offshore assets for gross proceeds of £184 million in the first half of 2011.

Net income from discontinued operations reported in the Consolidated Statements of Earnings is as follows:

For the years ended December 31 ($ millions)	Natural Gas			International and Offshore			Total		
	2010	2009	2008	**2010**	2009	2008	**2010**	2009	2008
Revenues									
Operating revenues [1]	**280**	307	283	**693**	407	—	**973**	714	283
Less: Royalties	**(41)**	(49)	(68)	**—**	—	—	**(41)**	(49)	(68)
Operating revenues (net of royalties)	**239**	258	215	**693**	407	—	**932**	665	215
Gain on disposal of assets	**642**	—	—	**172**	—	—	**814**	—	—
	881	258	215	**865**	407	—	**1 746**	665	215
Expenses									
Operating, selling and general	**66**	89	40	**119**	150	—	**185**	239	40
Transportation	**24**	17	6	**23**	14	—	**47**	31	6
Depreciation, depletion and amortization [2]	**95**	161	88	**169**	285	—	**264**	446	88
Accretion of asset retirement obligations	**8**	8	4	**19**	11	—	**27**	19	4
Exploration	**1**	2	—	**20**	57	—	**21**	59	—
Financing expenses (income)	**7**	—	—	**11**	1	—	**18**	1	—
	201	277	138	**361**	518	—	**562**	795	138
Earnings before income taxes	**680**	(19)	77	**504**	(111)	—	**1 184**	(130)	77
Income taxes	**174**	(5)	22	**127**	(65)	—	**301**	(70)	22
Net earnings (loss)	**506**	(14)	55	**377**	(46)	—	**883**	(60)	55

(1) Operating revenues reported in Natural Gas include sales to other operating segments that would be eliminated upon consolidation in the Consolidated Statements of Earnings. These totaled $62 million in the year ended December 31, 2010 (2009 – $33 million, 2008 – $24 million).

(2) For the year ended December 31, 2010, depreciation, depletion and amortization includes a write-down of $106 million in International and Offshore, and a write-down of $27 million in Natural Gas (2009 – write-down of $83 million in International and Offshore, 2008 – $nil).

For the years ended December 31 (dollars)	**2010**	2009	2008
Basic earnings per share from discontinued operations	**0.57**	(0.05)	0.06
Diluted earnings per share from discontinued operations	**0.56**	(0.05)	0.06

The assets and liabilities of discontinued operations presented in the Consolidated Balance Sheets are as follows:

	Natural Gas		International and Offshore		Total	
As at December 31 ($ millions)	**2010**	2009	**2010**	2009	**2010**	2009
Assets						
Current assets	**—**	34	**98**	223	**98**	257
Property, plant and equipment, net	**—**	1 600	**658**	1 732	**658**	3 332
Total assets	**—**	1 634	**756**	1 955	**756**	3 589
Liabilities						
Current liabilities	**—**	64	**98**	178	**98**	242
Accrued liabilities and other	**—**	286	**302**	404	**302**	690
Future income taxes	**—**	31	**182**	472	**182**	503
Total liabilities	**—**	381	**582**	1 054	**582**	1 435

7. ENERGY TRADING ACTIVITIES

($ millions)	**2010**	2009	2008
Non-trading physical contracts [1]	**3 957**	8 008	11 295
Change in fair value of contracts entered into for trading purposes [1]	**81**	(50)	127
Gains (losses) on inventory valuation	**(4)**	47	—
Less: Intercompany eliminations	**(1 334)**	(428)	(102)
Energy Supply and Trading Activities revenue	**2 700**	7 577	11 320
Non-trading physical contracts [1]	**3 932**	7 929	11 331
Less: Intercompany eliminations	**(1 334)**	(548)	(8)
Energy Supply and Trading Activities expense	**2 598**	7 381	11 323

(1) The merger with Petro-Canada in 2009 provided the company with the ability to capitalize on future trading opportunities due to increased transactional and trading capacity. The company determined that the new transaction levels for certain physical trading commodity contracts exceeded the company's expected purchase, sale or usage requirements. Effective October 1, 2009, these contracts are now considered derivative financial instruments, whereby realized and unrealized gains and losses and the underlying settlement of these contracts is now recognized and reported on a net basis in the Energy Supply and Trading Activities revenue. The related inventory is carried at fair value less costs to sell, with changes in fair value recognized as gains or losses within Energy Supply and Trading Activities revenue.

Prior to October 1, 2009 the settlement of these contracts was recorded on a gross basis within Energy Supply and Trading Activities revenue and Energy Supply and Trading Activities expense.

8. FINANCING EXPENSES (INCOME)

($ millions)	**2010**	2009	2008
Interest on debt	**691**	573	352
Capitalized interest	**(301)**	(136)	(352)
Interest expense	**390**	437	—
Unrealized foreign exchange loss (gain) on U.S. dollar denominated long-term debt	**(426)**	(858)	919
Foreign exchange loss (gain) and other	**6**	(67)	(2)
Total financing expenses (income) from continuing operations [1]	**(30)**	(488)	917

(1) For 2010, financing expense of $18 million (2009 – financing income of $1 million, 2008 – $nil) has been reclassified to net earnings from discontinued operations.

9. INCOME TAXES

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

($ millions)	**2010**	2009	2008
Earnings before income taxes	**4 247**	1 419	3 055
Canadian statutory tax rate	**28.91%**	30.95%	29.52%
Statutory tax	**1 228**	439	902
Add (deduct) the tax effect of:			
Non-taxable component of capital gains and losses	**(67)**	(133)	136
Stock-based compensation and other permanent items	**1**	42	36
Assessments and adjustments	**20**	(42)	(48)
Effect of changes to statutory enacted rates	**—**	(148)	—
Impact of income tax rate adjustments on future income tax liabilities	**(15)**	152	—
Change in valuation allowance	**—**	(59)	—
Canadian tax rate differential	**(71)**	(28)	(112)
Foreign tax rate differential	**459**	115	12
Non-taxable gain on effective settlement of pre-existing contract with Petro-Canada	**—**	(105)	—
Other	**4**	(20)	47
Provision for income taxes from continuing operations [(1)]	**1 559**	213	973

(1) For the year ended December 31, 2010, income tax expense of $301 million (2009 – income tax recovery of $70 million, 2008 – income tax expense of $22 million) has been reclassified to net earnings from discontinued operations.

At December 31, geographic distribution of income tax provisions were as follows:

($ millions)	**2010**	2009	2008
Provision for (recovery of) income taxes:			
Current:			
Canada	**57**	599	493
Foreign	**947**	242	21
Future:			
Canada	**569**	(699)	493
Foreign	**(14)**	71	(34)
Provision for income taxes from continuing operations	**1 559**	213	973

At December 31, future income taxes related to continuing operations were comprised of the following:

($ millions)	**2010**	2009
Future income tax liabilities:		
Property, plant and equipment	**9 798**	9 167
Risk management and energy trading	**27**	—
Other	**212**	177
Future income tax assets:		
Asset retirement obligations	**(640)**	(813)
Employee future benefits	**(401)**	(352)
Risk management and energy trading	**—**	(113)
Other assets	**(610)**	(206)
Net future income tax liabilities	**8 386**	7 860
Less: Current portion of future income tax (assets)/liabilities	**(173)**	(314)
Future income tax liabilities[(1)]	**8 559**	8 174

(1) For 2010, future income tax liabilities of $182 million (2009 – $503 million) have been reclassified to liabilities of discontinued operations.

Included in the above table are unused non-capital tax losses of $955 million (2009 – $464 million), the majority of which relate to Canada and are available to reduce taxable income in future years. These non-capital tax losses will expire between 2026 and 2030.

Deferred distribution taxes associated with International and Offshore business operations have not been recorded. Based on current plans, repatriation of funds in excess of foreign reinvestment will not result in material additional income tax expense.

10. EARNINGS PER COMMON SHARE

Net earnings per common share is calculated by dividing net earnings by the weighted-average number of common shares outstanding.

(millions of common shares)	**2010**	2009	2008
Weighted-average number of common shares	**1 562**	1 198	932
Dilutive effect of stock options	**12**	13	13
Weighted-average number of diluted common shares	**1 574**	1 211	945

11. CASH AND CASH EQUIVALENTS

($ millions)	**2010**	2009
Cash	**358**	205
Cash equivalents	**719**	300
Total	**1 077**	505

12. SUPPLEMENTAL CASH FLOW INFORMATION

The (increase) decrease in non-cash working capital from continuing operations is comprised of:

($ millions)	**2010**	2009 [1]	2008
Accounts receivable	**(699)**	105	230
Inventories	**(190)**	(585)	103
Accounts payable and accrued liabilities	**(79)**	(511)	(235)
Taxes payable/receivable	**(458)**	(37)	(110)
Total	**(1 426)**	(1 028)	(12)
Relating to:			
Operating activities	**(1 230)**	(237)	403
Investing activities	**(196)**	(791)	(415)

(1) Balances do not include amounts acquired from Petro-Canada as a result of the merger, but do reflect the changes in these working capital accounts subsequent to August 1, 2009.

($ millions)	**2010**	2009	2008
Interest paid	**839**	581	328
Income taxes paid	**1 193**	872	638

13. INVENTORIES

($ millions)	**2010**	2009
Crude oil	**916**	776
Refined products	**1 289**	1 303
Materials, supplies and merchandise	**564**	513
Energy trading commodity inventories [1]	**372**	355
Total [2]	**3 141**	2 947

(1) Recorded at fair value.

(2) For 2010, inventories of $11 million (2009 – $24 million) have been reclassified to current assets of discontinued operations.

During 2010, product inventories of $17.2 billion (2009 – $14.9 billion) were expensed.

14. PROPERTY, PLANT AND EQUIPMENT

($ millions)	2010 Cost	2010 Accumulated Provision	2009 Cost	2009 Accumulated Provision
Oil Sands				
Oil and gas properties	**4 320**	**644**	3 978	469
Plant and equipment	**21 760**	**4 663**	18 930	3 687
Assets not subject to depreciation or depletion	**13 980**	**—**	13 929	—
	40 060	**5 307**	36 837	4 156
Natural Gas				
Oil and gas properties	**4 000**	**1 619**	3 812	1 034
Plant and equipment	**250**	**109**	234	70
Assets not subject to depreciation or depletion	**22**	**—**	27	—
	4 272	**1 728**	4 073	1 104
International and Offshore				
Oil and gas properties	**7 046**	**1 407**	6 526	294
Plant and equipment	**741**	**62**	100	31
Assets not subject to depreciation or depletion	**3 886**	**—**	4 806	—
	11 673	**1 469**	11 432	325
Refining and Marketing				
Plant and equipment	**7 668**	**1 935**	7 433	1 649
Assets not subject to depreciation or depletion	**1 392**	**—**	1 264	—
	9 060	**1 935**	8 697	1 649
Corporate and Energy Trading				
Plant and equipment	**575**	**236**	483	181
Assets not subject to depreciation or depletion	**325**	**—**	91	—
	900	**236**	574	181
	65 965	**10 675**	61 613	7 415
Net property, plant and equipment [1]		**55 290**		54 198

(1) For 2010, net property, plant and equipment of $658 million (2009 – $3,332 million) has been reclassified to discontinued operations.

Assets not subject to depreciation or depletion primarily consists of development assets and assets under construction.

Property, plant and equipment, at December 31, 2010, includes Oil Sands capital leases at a net book value of $257 million (2009 – $225 million) and International and Offshore capital leases at a net book value of $45 million (2009 – $48 million).

15. ASSET WRITE-DOWNS

During the second quarter of 2010, the company recognized a write-down of $189 million related to certain extraction equipment in the Oil Sands operating segment. These assets were being used in the development of an alternative extraction process to crush and slurry oil sands at the mine face, which the company has discontinued.

During the second quarter of 2010, the company recognized a write-down of $44 million of certain land leases in the Natural Gas operating segment. These assets are in areas of Western Canada and Alaska that the company does not plan to pursue given its strategic business alignment.

During the third quarter of 2010, the company recognized a charge of $222 million to reflect the write-down of certain assets in the Natural Gas operating segment to reflect fair value based on discounted future cash flows.

Also during the third quarter of 2010, the company recognized a write-down of $106 million related to certain North Sea assets in the International and Offshore operating segment. An agreement to sell these assets was entered into during the quarter and the assets were written down to reflect fair value less cost to sell.

During 2009, the company recognized a write-down of $83 million to reflect the fair value of certain non-core North Sea assets in the International and Offshore operating segment. An agreement to sell these assets was entered into during 2009 and the assets were written down to reflect fair value less cost to sell. There were no write-downs recognized in 2008.

These charges are included in depreciation, depletion and amortization expenses and net earnings from discontinued operations in the Consolidated Statements of Earnings.

16. OTHER ASSETS

($ millions)	**2010**	2009
Intangible assets	**222**	233
Investments	**135**	148
Other	**94**	110
Total	**451**	491

Intangible assets acquired in 2009 as part of the business combination with Petro-Canada include $166 million related to the Petro-Canada brand, which has an indefinite life, and $70 million related to Petro-Canada customer lists which are amortized over their estimated useful lives ranging from five to ten years. During 2010, amortization expense related to intangible assets was $11 million (2009 – $4 million; 2008 – $nil).

17. LONG-TERM DEBT AND CREDIT FACILITIES

($ millions)	**2010**	2009
Fixed-term debt, redeemable at the option of the company		
6.85% Notes, due in 2039 (US$750)	**746**	785
6.80% Notes, due in 2038 (US$900)	**922**	972
6.50% Notes, due in 2038 (US$1150)	**1 144**	1 204
5.95% Notes, due in 2035 (US$600)	**552**	578
5.95% Notes, due in 2034 (US$500)	**497**	523
5.35% Notes, due in 2033 (US$300)	**255**	266
7.15% Notes, due in 2032 (US$500)	**497**	523
6.10% Notes, due in 2018 (US$1250)	**1 243**	1 308
6.05% Notes, due in 2018 (US$600)	**609**	643
5.00% Notes, due in 2014 (US$400)	**406**	429
4.00% Notes, due in 2013 (US$300)	**298**	313
7.00% Debentures, due in 2028 (US$250)	**257**	271
7.875% Debentures, due in 2026 (US$275)	**307**	325
9.25% Debentures, due in 2021 (US$300)	**375**	402
5.39% Series 4 Medium Term Notes, due in 2037	**600**	600
5.80% Series 4 Medium Term Notes, due in 2018	**700**	700
6.70% Series 2 Medium Term Notes, due in August 2011 (i)	**500**	500
	9 908	10 342
Revolving-term debt, with variable interest rates		
Commercial paper (ii), bankers' acceptances and LIBOR loans (interest rate at December 31, 2010 – 1.2%, 2009 – 0.7%)	**1 982**	3 244
Total unsecured long-term debt	**11 890**	13 586
Secured long-term debt	**13**	13
Capital leases (iii)	**335**	326
Fair value adjustment related to interest rate swaps	**8**	18
Deferred financing costs	**(59)**	(63)
	12 187	13 880
Current portion of long-term debt		
6.70% Series 2 Medium Term Notes, due in August 2011 (i)	**(500)**	—
Capital leases (iii)	**(10)**	(14)
Fair value adjustment related to interest swaps	**(8)**	(11)
Total current portion of long-term debt	**(518)**	(25)
Total long-term debt	**11 669**	13 855

(i) The company has entered into interest rate swap transactions on $200 million of the principal amount of this note. The interest rate swaps resulted in an average effective interest rate on the $200 million principal of 1.9% in 2010 (2009 – 2.0%).

(ii) The company is authorized to issue commercial paper to a maximum of $2.5 billion having a term not to exceed 365 days. Commercial paper is supported by unutilized credit facilities.

(iii) Interest rates range from 4.7% to 13.4%, and maturity dates range from 2012 to 2037.

Required Debt Repayments

Required debt repayments for capital leases and long-term debt are as follows:

($ millions)	
2011	**2 492**
2012	**10**
2013	**322**
2014	**418**
2015	**13**
Thereafter	**8 983**
Total	**12 238**

Credit Facilities

A summary of available and unutilized credit facilities is as follows:

($ millions)	**2010**
Term period of one year and expires in 2011	**4**
Fully revolving for a period of four years and expires in 2013	**199**
Fully revolving for a period of five years and expires in 2013	**7 320**
Can be terminated at any time at the option of the lenders	**461**
Total available credit facilities	**7 984**
Credit facilities supporting outstanding commercial paper, bankers' acceptances and LIBOR loans	**(1 982)**
Credit facilities supporting standby letters of credit	**(713)**
Total unutilized credit facilities	**5 289**

18. ACCRUED LIABILITIES AND OTHER

($ millions)	**2010**	2009
Asset retirement obligations [(a)]	**1 969**	2 198
Employee future benefits liability (note 19)	**1 060**	1 128
Stock-based compensation plans [(b)]	**304**	219
Deferred revenue	**94**	94
Contract provisions [(c)]	**224**	33
Long-term financial liabilities [(d)]	**365**	602
Other	**138**	98
Total	**4 154**	4 372

(a) Asset Retirement Obligations (ARO)

The following table presents the reconciliation of the beginning and ending aggregate carrying amount of the total obligations associated with the retirement of property, plant and equipment.

($ millions)	**2010**	2009
Asset retirement obligations, beginning of year	**3 200**	1 600
Liabilities incurred	**80**	253
Changes in estimates	**(157)**	(145)
Liabilities settled	**(417)**	(248)
Accretion	**205**	155
Asset divestitures	**(441)**	—
Petro-Canada liabilities acquired	**—**	1 605
Foreign exchange	**(52)**	(20)
Asset retirement obligations, end of year	**2 418**	3 200
Less: Current portion	**147**	312
Less: Amount related to discontinued operations	**302**	690
	1 969	2 198

The total undiscounted amount of estimated future cash flows required to settle the obligations at December 31, 2010, was approximately $7.4 billion (2009 – $8.3 billion). Substantially all of the liability recognized in 2010 was discounted using a weighted-average credit-adjusted risk free rate of 5.4% (2009 – 6.2%). The credit-adjusted risk-free rate used reflects the expected timeframe of the related liability. Payments to settle the ARO occur on an ongoing basis and will continue over the lives of the operating assets, which can exceed fifty years. The current portion of asset retirement obligations is included in accounts payable and accrued liabilities.

A significant portion of the company's assets, including the upgrading facilities at the oil sands operation and the downstream refineries, have retirement obligations for which the fair value cannot be reasonably determined because the expected timing of the reclamation activity cannot be estimated at this time. The asset retirement obligation for these assets will be recorded in the first period in which the lives of the assets are determinable.

(b) Stock-Based Compensation Plans

The current portion of the stock-based compensation plans of $240 million (2009 – $198 million) is included in current liabilities. See note 20 for further information on the company's liability-based stock-based compensation awards.

(c) Contract Provisions

Amount relates to provisions for future pipeline leases with terms extending to 2015, and building leases with terms extending to 2019.

(d) Long-Term Financial Liabilities

As part of the acquisition of Petro-Canada in 2009, the company assumed an obligation relating to Petro-Canada's acquisition of an additional 5% interest in the Fort Hills project in 2007 from another partner in the project. To pay for this investment the company will fund $375 million of expenditures in excess of its working interest. At December 31, 2010, the discounted carrying amount of the Fort Hills obligation was $327 million (2009 – $322 million).

The company also assumed the remaining US$500 million obligation for a signature bonus relating to Petro-Canada's ratification of six Exploration and Production Sharing Agreements in Libya in 2008, payable in several installments through 2013. At December 31, 2010, the carrying amount of the Libya obligation was $287 million (2009 – $511 million), of which the current portion is $249 million (2009 – $231 million) and is recorded in accounts payable and accrued liabilities.

19. EMPLOYEE FUTURE BENEFITS LIABILITY

Suncor employees are eligible to receive certain pension, health care and insurance benefits when they retire under the terms of the company's defined benefit plans.

The company also provides a number of defined contribution plans, including a U.S. 401(k) savings plan, that provide for an annual contribution of 5% to 8% of each participating employee's pensionable earnings.

Defined Benefit Pension Plans and Other Post-Retirement Benefits

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

Funding of the registered retirement plans complies with applicable regulations that require actuarial valuations of the pension funds at least once every three years in Canada, depending on funding status, and every year in the United States. The most recent valuation was performed as at December 31, 2010. The next valuation will be performed as at December 31, 2011.

The company's other post-retirement benefits programs are unfunded and include certain health care and life insurance benefits provided to retired employees and eligible surviving dependants.

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

Defined Benefit Obligations and Funded Status

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

($ millions)	Pension Benefits 2010	Pension Benefits 2009	Other Post-Retirement Benefits 2010	Other Post-Retirement Benefits 2009
Change in benefit obligation				
Benefit obligation at beginning of year	**2 855**	806	**424**	149
Service costs	**85**	64	**8**	6
Interest costs	**168**	96	**25**	15
Plan participants' contributions	**11**	17	**—**	—
Foreign exchange	**(14)**	(13)	**(1)**	(4)
Actuarial loss	**265**	59	**39**	1
Benefits paid	**(151)**	(86)	**(12)**	(8)
Plan acquisition upon merger [a]	**—**	1 912	**—**	265
Benefit obligation at end of year [b],[e]	**3 219**	2 855	**483**	424
Change in plan assets [c]				
Fair value of plan assets at beginning of year	**2 072**	613	**—**	—
Actual return on plan assets	**224**	175	**—**	—
Employer contributions	**188**	105	**—**	—
Foreign exchange	**(9)**	(7)	**—**	—
Plan participants' contributions	**11**	17	**—**	—
Benefits paid	**(151)**	(86)	**—**	—
Plan acquisition upon merger	**—**	1 255	**—**	—
Fair value of plan assets at end of year [e]	**2 335**	2 072	**—**	—
Net unfunded obligation	**(884)**	(783)	**(483)**	(424)
Items not yet recognized in earnings:				
Unamortized net actuarial loss [d]	**234**	50	**45**	8
Unamortized past service costs	**5**	9	**(11)**	(14)
Accrued benefit liability	**(645)**	(724)	**(449)**	(430)
Current liability	**(38)**	(30)	**(3)**	(3)
Long-term liability	**(614)**	(701)	**(446)**	(427)
Long-term asset	**7**	7	**—**	—
Total accrued benefit liability	**(645)**	(724)	**(449)**	(430)

(a) The valuation of accrued benefit obligations for plans acquired through the business combination with Petro-Canada assumed a discount rate of 5.25%, a rate of compensation increase of 3.00% and an expected return on plan assets rate of 6.75%.

(b) Obligations are based on the following assumptions:

(per cent)	Pension Benefit Obligations 2010	Pension Benefit Obligations 2009	Other Post-Retirement Benefits Obligations 2010	Other Post-Retirement Benefits Obligations 2009
Discount rate	**5.10**	5.85	**5.25**	6.00
Rate of compensation increase	**3.70**	3.90	**4.00**	4.00

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

($ millions)	1% increase	1% decrease
Increase (decrease) to total of service and interest cost components of net periodic post-retirement health care benefit cost	2	(2)
Increase (decrease) to the health care component of the accumulated post-retirement benefit obligation	38	(31)

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

(d) The unamortized net actuarial loss represents annually calculated differences between actual and projected plan performance. These amounts are amortized as part of the net periodic benefit cost over the expected average remaining service life of employees of 7 years for pension benefits (2009 – 7 years; 2008 – 11 years), and over the expected average future service life to full eligibility age of 14 years for other post-retirement benefits (2009 – 11 years; 2008 – 11 years).

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

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

($ millions)	Pension Benefits 2010	2009	Other Post-Retirement Benefits 2010	2009
Partially funded plans	**3 219**	2 855	**—**	—
Unfunded plans	**—**	—	**483**	424
Benefit obligation at end of year	**3 219**	2 855	**483**	424

Benefit Plans Expense

($ millions)	Pension Benefits 2010	2009	2008	Other Post-Retirement Benefits 2010	2009	2008
Current service costs	**85**	64	56	**8**	6	4
Interest costs	**168**	96	49	**25**	15	9
Actual (return) loss on plan assets [(i)]	**(224)**	(175)	107	**—**	—	—
Actuarial (gain) loss	**265**	59	(168)	**39**	1	(27)
Pension expense before adjustments for the long-term nature of employee future benefit costs	**294**	44	44	**72**	22	(14)
Difference between actual and expected return on plan assets [(i)]	**82**	98	(152)	**—**	—	—
Difference between actual and recognized actuarial losses	**(260)**	(36)	188	**(36)**	3	33
Difference between actual and recognized past service costs	**2**	2	2	**(3)**	(3)	(3)
Defined benefit plans expense [(ii)]	**118**	108	82	**33**	22	16
Defined contribution plans expense	**40**	28	15	**—**	—	—
Total benefit plans expense	**158**	136	97	**33**	22	16

(i) The expected return on plan assets is the expected long-term rate of return on plan assets for the year. It is based on plan assets at the beginning of the year that have been adjusted on a weighted-average basis for contributions and benefit payments expected for the year. The expected return on plan assets is included in the net periodic benefit cost for the year to which it relates, while the difference between the expected rate and the actual return realized on plan assets in the same year is amortized over the expected average remaining service life of employees of 7 years for pension benefits.

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

(ii) Defined benefit plans pension expense is based on the following assumptions:

(per cent)	Pension Benefit Expense 2010	2009	2008	Other Post-Retirement Benefits Expense 2010	2009	2008
Discount rate	**5.85**	6.50	5.25	**6.00**	6.00	5.25
Expected return on plan assets	**6.65**	6.70	6.50	**N/A**	N/A	N/A
Rate of compensation increase	**3.90**	3.90	5.00	**4.00**	4.00	4.75

Plan Assets and Investment Objectives

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

The company's weighted-average pension plan asset allocation based on market values as at December 31, 2010 and 2009, and the target allocation for 2011, are as follows:

Asset Category	Target Allocation % 2011	Plan Assets % **2010**	2009
Equities	58	**58**	59
Fixed income	42	**42**	41
Total	100	**100**	100

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

Cash Flows

The company expects that cash contributions to its defined benefit pension plans in 2011 will be $193 million. Expected benefit payments from all of the plans for the next ten years are as follows:

	Pension Benefits	Other Post-Retirement Benefits
2011	153	19
2012	162	21
2013	170	22
2014	178	24
2015	186	25
2016 – 2020	1 035	146
Total	1 884	257

20. SHARE CAPITAL

Authorized

Common Shares

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

Preferred Shares

The company is authorized to issue an unlimited number of preferred shares in series, without nominal or par value.

Issued

	Common Shares Number (thousands)	Amount ($ millions)
Balance as at December 31, 2007	925 566	881
Issued for cash under stock options plan	9 823	226
Issued under dividend reinvestment plan	135	6
Balance as at December 31, 2008	935 524	1 113
Shares issued to Petro-Canada shareholders on merger	621 142	18 878
Issued for cash under stock options plan	2 968	57
Issued under dividend reinvestment plan	144	5
Balance as at December 31, 2009	1 559 778	20 053
Issued for cash under stock option plans	**5 292**	**122**
Issued under dividend reinvestment plan	**419**	**13**
Balance as at December 31, 2010	**1 565 489**	**20 188**

Stock-Based Compensation

A stock option gives the holder the right to purchase common shares at or greater than the grant date market price subject to fulfilling vesting terms. Certain options are subject to accelerated vesting should the company meet predetermined performance criteria.

(a) Stock Option Plans

Continuing plans

(i) Suncor Energy Inc. Stock Options

This plan replaced the pre-merger stock option plans of legacy Suncor and legacy Petro-Canada. Outstanding options that are cancelled, expire or otherwise result in no underlying common share being issued, will be available for issuance as options under this plan. These options have a seven-year life and vest annually over a three-year period.

Options granted under this plan before August 1, 2010 included a tandem stock appreciation right (TSAR). The company granted 4,275,000 options with TSARs during 2010 (2009 - 4,000). Effective August 1, 2010, options granted under this plan no longer include TSARs. The company granted 22,000 options with no TSARs during 2010.

Discontinued plans

The following plans were discontinued on August 1, 2009:

(i) SunShare 2012 Performance Stock Option Plan

Options under this plan were granted to all eligible permanent full-time and part-time employees. On January 1, 2010, 25% of the outstanding options vested. The remaining 75% of outstanding options may vest on January 1, 2013 if further specified performance targets are met. All outstanding unvested options at January 1, 2013, will automatically expire.

(ii) Executive Stock Plan

Options under this plan were granted to non-employee directors and certain executives and other senior employees of the company. Options granted have a 10-year life and vest annually over a three-year period.

(iii) Key Contributor Stock Option Plan

Options under this plan were granted to non-insider senior managers and key employees. Options granted have a 10-year life and vest annually over a three-year period.

(iv) Petro-Canada Stock Options ("Adjusted Options")

The Adjusted Options, issued to officers and certain employees, have a 10-year life if granted prior to 2004 and seven years if granted subsequent to 2003. Options granted after 2003 can be exercised for a cash payment alternative (CPA) and are therefore recorded at their intrinsic value at each period end. All Adjusted Options vest over periods of up to four years.

Changes in the number of outstanding stock options were as follows:

	Number (thousands)	Range of Exercise Prices Per Share ($)	Weighted-Average Exercise Price Per Share ($)
Outstanding, December 31, 2008	46 402	5.06 – 69.97	34.55
Granted	2 490	20.99 – 49.67	35.78
Adjusted options issued to Petro-Canada stock option holders	29 900	8.22 – 44.27	28.05
Exercised	(2 870)	5.06 – 36.68	13.69
Forfeited/expired	(3 898)	13.31 – 71.12	40.48
Outstanding, December 31, 2009	72 024	7.84 – 72.68	32.52
Granted	**4 297**	**30.93 – 35.76**	**31.86**
Exercised	**(5 292)**	**7.84 – 47.55**	**15.49**
Forfeited/expired	**(3 391)**	**13.82 – 67.58**	**42.51**
Outstanding, December 31, 2010	**67 638**	**8.72 – 69.97**	**32.94**
Exercisable, December 31, 2010	**46 266**	**8.72 – 69.97**	**29.91**

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

(thousands of common shares)	**2010**	2009	2008
	18 854	22 306	12 345

Outstanding and exercisable common share options as at December 31, 2010:

	Outstanding			Exercisable	
Exercise Prices ($)	Number (thousands)	Weighted-Average Remaining Contractual Life (years)	Weighted-Average Exercise Price Per Share ($)	Number (thousands)	Weighted-Average Exercise Price Per Share ($)
8.72 – 14.99	11 582	1	13.34	11 582	13.34
15.00 – 19.99	5 062	4	18.69	2 720	18.05
20.00 – 29.99	10 075	2	22.88	9 206	23.15
30.00 – 44.99	20 812	4	37.37	13 885	39.26
45.00 – 49.99	18 872	4	47.35	8 495	47.07
50.00 – 69.97	1 235	4	58.35	378	58.01
Total	67 638	3	32.94	46 266	29.91

Fair Value of Options Granted

The fair values of common share options that do not have the option of cash settlement are estimated as at the grant date using the Monte Carlo simulation approach for the SunShare 2012 plan and the Black-Scholes option-pricing model for all other plans. The weighted-average fair values of the options granted during the various periods and the weighted-average assumptions used in their determination are as noted below:

	2010	2009	2008
Annual dividend per share	**$0.40**	$0.30	$0.20
Risk-free interest rate	**2.02%**	2.31%	3.35%
Expected life	**5 years**	5 years	6 years
Expected volatility	**50%**	47%	30%
Weighted-average fair value per option	**$12.98**	$10.28	$13.86

(b) Stock Appreciation Rights (SARs)

A SAR entitles the holder to receive a cash payment equal to the difference between the stated exercise price and the market price of the company's common shares on the date the SAR is exercised.

Continuing plan

(i) Suncor Energy Inc. SARs

These SARs have a seven-year life and vest annually over a three-year period. The company granted 353,000 SARs during 2010 (2009 – nil).

Discontinued plan

(i) Petro-Canada SARs

Legacy Petro-Canada had a SARs plan for which grants ended on July 31, 2009. These SARs have a seven-year life and vest annually over a four-year period.

Changes in the number of outstanding SARs were as follows:

	Number (thousands)	Range of Exercise Prices Per Share ($)	Weighted-Average Exercise Price Per Share ($)
SARs issued to holders of Petro-Canada SARs, August 1, 2009	15 353	19.13 – 46.13	28.74
Exercised	(306)	19.13 – 39.41	35.01
Forfeited	(982)	19.13 – 46.13	28.28
Outstanding, December 31, 2009	14 065	19.13 – 46.13	28.63
Granted	**353**	**31.67 – 32.48**	**31.85**
Exercised	**(734)**	**19.13 – 36.82**	**24.00**
Forfeited	**(2 399)**	**19.44 – 46.13**	**28.99**
Outstanding, December 31, 2010	**11 285**	**19.13 – 46.13**	**28.97**
Exercisable, December 31, 2010	**4 939**	**19.13 – 46.13**	**32.28**

Outstanding and exercisable SARs as at December 31, 2010:

	Outstanding			Exercisable	
Exercise Prices ($)	Number (thousands)	Weighted-Average Remaining Contractual Life (years)	Weighted-Average Exercise Price Per Share ($)	Number (thousands)	Weighted-Average Exercise Price Per Share ($)
19.13 – 24.99	4 649	5	19.45	1 002	19.46
25.00 – 34.99	3 174	3	34.13	2 171	34.29
35.00 – 39.99	3 368	4	36.84	1 701	36.85
40.00 – 46.13	94	4	43.70	65	43.66
Total	11 285	4	28.97	4 939	32.28

(c) Share Unit Plans

A performance share unit (PSU) is a time-vested award entitling employees to receive varying degrees of cash (0% – 200% of the company's share price at time of vesting) contingent upon Suncor's total shareholder return (stock price appreciation and dividend income) relative to a peer group of companies. PSUs vest approximately three years after the grant date.

A restricted share unit (RSU) is a time-vested award entitling employees to receive cash equal to the company's share price at time of vesting. Typically, RSUs vest approximately three years after the grant date.

A deferred share unit (DSU) is redeemable for cash or a common share for a period of time after a unitholder ceases employment or Board membership. The DSU plan is limited to executives and members of the Board of Directors. Members of the Board of Directors receive one-half or, at their option, all of their compensation in the form of DSUs.

Changes in the number of outstanding share units were as follows:

Number (thousands)	PSU	RSU	DSU
Outstanding, December 31, 2008	2 175	965	1 903
Granted	1 149	2 715	104
Units issued to Petro-Canada unitholders	945	1 018	1 008
Redeemed for cash	(69)	(21)	(443)
Forfeited	(957)	(432)	—
Reinvested	4	5	44
Outstanding, December 31, 2009	3 247	4 250	2 616
Granted	**1 673**	**2 838**	**80**
Redeemed for cash	**(282)**	**(118)**	**(426)**
Forfeited	**(917)**	**(563)**	**—**
Reinvested	**26**	**43**	**29**
Outstanding, December 31, 2010	**3 747**	**6 450**	**2 299**

Stock-Based Compensation Expense (Recovery)

The following table summarizes the stock-based compensation expense (recovery) recorded for all plans within operating, selling and general expense in the Consolidated Statements of Earnings:

($ millions)	**2010**	2009	2008
Stock option plans	**53**	148	120
SARs	**27**	35	—
PSUs	**21**	30	(30)
RSUs	**90**	50	8
DSUs	**4**	30	(51)
Total	**195**	293	47

21. FINANCIAL INSTRUMENTS AND FINANCIAL RISK FACTORS

Financial Instruments

The company's financial instruments consist of cash and cash equivalents, accounts receivable, derivative contracts, substantially all accounts payable and accrued liabilities, debt, and a portion of non-current accrued liabilities and other.

(a) Fair Value of Non-Derivative Financial Instruments

The fair values of cash and cash equivalents, accounts receivable, short-term debt, and accounts payable and accrued liabilities approximate their carrying values due to the short-term maturities of those instruments.

The company's long-term debt and long-term financial liabilities are recorded at amortized cost using the effective interest method, with the exception of the portion of debt that is recorded at fair value as part of a fair value hedging relationship. At December 31, 2010, the carrying value of fixed-term debt accounted for under the amortized cost method was $9.7 billion (December 31, 2009 – $10.1 billion) and the fair value at December 31, 2010 was $10.7 billion (December 31, 2009 – $10.7 billion).

(b) Fair Value of Derivative Financial Instruments

To estimate fair value of derivatives, the company uses quoted market prices when available, or third-party models and valuation methodologies that utilize observable market data. In addition to market information, the company incorporates transaction specific details that market participants would utilize in a fair value measurement, including the impact of non-performance risk. However, these fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction. The company characterizes inputs used in determining fair value using a hierarchy that prioritizes inputs depending on the degree to which they are observable. The three levels of the fair value hierarchy are as follows:

- Level 1 – inputs represent quoted prices in active markets for identical assets or liabilities. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.
- Level 2 – inputs other than quoted prices that are observable, either directly or indirectly, as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, market interest rates, and volatility factors, which can be observed or corroborated in the marketplace.
- Level 3 – inputs that are less observable, unavailable or where the observable data does not support the majority of the instrument's fair value.

In forming estimates, the company utilizes the most observable inputs available for valuation purposes. If a fair value measurement reflects inputs of different levels within the hierarchy, the measurement is categorized based upon the lowest level of input that is significant to the fair value measurement.

The following table presents the company's derivative financial instrument assets and liabilities measured at fair value for each hierarchy level as of December 31, 2010:

($ millions)	Level 1	Level 2	Level 3	Total Fair Value
Accounts receivable	11	3	13	**27**
Accounts payable	(72)	(14)	(7)	**(93)**
Total	**(61)**	**(11)**	**6**	**(66)**

(c) Derivative Financial Instruments – Designated as Part of a Qualifying Hedge Relationship

Fair Value Hedges

The company periodically enters into derivative financial instrument contracts such as interest swaps as part of its risk management strategy to manage its exposure to benchmark interest rate fluctuations. The interest rate swap contracts involve an exchange of floating rate versus fixed rate interest payments between the company and investment grade counterparties. The differentials on the exchange of periodic interest payments are recognized in earnings as an adjustment to interest expense. The swap contracts and underlying debt are recorded at fair value with changes in fair value recognized in interest expense. At December 31, 2010, the company had interest rate swaps designated as fair value hedges expiring in August 2011. The fair value of the swaps, which related to $200 million of its fixed-rate debt, was $8 million as at December 31, 2010 (2009 – $18 million) and was recorded in accounts receivable (2009 – $10 million recorded in accounts receivable and $8 million recorded in other assets). There was no ineffectiveness recognized on interest rate swaps designated as fair value hedges during the years ended December 31, 2010 and December 31, 2009.

(d) Other Derivative Financial Instruments

Risk Management Derivatives

The company periodically enters into derivative contracts which although not accounted for as hedges because they have not been documented as such, or do not qualify under GAAP, are believed to be economically effective at mitigating exposure to commodity price movements and are a component of Suncor's overall risk management program. These derivative contracts include crude oil, natural gas, refined products and foreign exchange contracts. The earnings impact associated with these contracts for the year ended December 31, 2010, was a gain of $89 million (2009 – a loss of $1.024 billion).

Energy Trading Derivatives

The company's Energy Trading group also uses physical and financial energy contracts, including swaps, forwards and options to earn trading and marketing revenues. These energy contracts are comprised of crude oil, refined products and natural gas contracts.

The earnings impact associated with these contracts for the year ended December 31, 2010, was a gain of $81 million (2009 – a loss of $70 million).

Change in Fair Value of Other Derivative Financial Instruments

($ millions)	Risk Management	Energy Trading	Total
Fair value of contracts at December 31, 2009	(312)	(47)	(359)
Fair value of contracts realized during the period	**236**	**(121)**	**115**
Changes in fair value during the period	**89**	**81**	**170**
Fair value of contracts outstanding at December 31, 2010	**13**	**(87)**	**(74)**

Financial Risk Factors

The company is exposed to a number of different risks arising from financial instruments. These risk factors include market risks relating to commodity prices, foreign currency risk and interest rate risk, as well as liquidity risk and credit risk.

The company maintains a formal governance process to manage its financial risks. The company's Commodity Risk Management Committee (CRMC) is charged with the oversight of the company's risk management for trading activities which are defined as strategic hedging, optimization trading, marketing and speculative trading. The CRMC, acting under board authority, meets regularly to monitor limits on risk exposures, review policy compliance and validate risk-related methodologies and procedures. All risk management activity is carried out by specialist teams that have the appropriate skills, experience and supervision with the appropriate financial and management controls, and is unchanged from the prior year.

1) Market Risk

Market risk is the risk or uncertainty arising from possible market price movements and their impact on the future performance of the business. The market price movements that could adversely affect the value of the company's financial assets, liabilities and expected future cash flows include commodity price risk, foreign currency exchange risk and interest rate risk.

(a) Commodity Price Risk

The company's financial performance is closely linked to crude oil prices (including pricing differentials for various product types), and to a lesser extent, natural gas and refined product prices. The company's policies permit the use of various financial instruments in managing these price exposures.

Impacts on the company's pre-tax earnings from changes in the fair value of outstanding derivative financial instruments at December 31, 2010 resulting from changes in commodity prices (with all other variables held constant) are disclosed in the following table. This sensitivity analysis is limited to the impact of commodity price changes applied to derivative financial instruments only, and do not represent the impact of a change in the commodity price on the financial results of the company taken as a whole.

Sensitivity Analysis

($ millions)	December 31, 2010[(1)]	Change	Pre-tax Earnings
Crude Oil	US$93.37/barrel		
Price increase		US$1.00/barrel	(4)
Price decrease		US$1.00/barrel	4
Natural Gas	US$4.99/mcf		
Price increase		US$0.10/mcf	(4)
Price decrease		US$0.10/mcf	4

(1) Prices represent average futures' prices at December 31, 2010.

(b) Foreign Currency Exchange Risk

The company is exposed to changes in foreign exchange rates as revenues, capital expenditures, or financial instruments may fluctuate due to changing rates. As crude oil is priced in U.S. dollars, fluctuations in US$/Cdn$ exchange rates may have a significant impact on revenues. The company's exposure is partially offset through the issuance of U.S. dollar denominated long-term debt and by sourcing capital projects in U.S. dollars. The effect on the company's financial instruments of a $0.01 change in the US$/Cdn$ exchange rate would change pre-tax earnings by approximately $90 million for the year ended December 31, 2010. The company is also exposed to foreign currency exchange risk from its self-sustaining foreign operations whose functional currency is different from the company's functional currency. The effect on the company's financial instruments of a $0.01 change in the US$/Cdn$ exchange rate would change other comprehensive income by approximately $15 million for the year ended December 31, 2010.

(c) Interest Rate Risk

The company is exposed to interest rate risk as changes in interest rates may affect future cash flows and the fair values of its financial instruments. The primary exposure is related to revolving-term debt (commercial paper, bankers' acceptances and LIBOR loans).

To manage the company's position with respect to interest expense, the company targets 30% to 50% of total debt to be exposed to floating interest rates. This floating/fixed rate mix will fluctuate based on prevailing market conditions and management's assessment of overall risk.

The proportion of floating interest rate exposure inclusive of interest rate swaps at December 31, 2010 was 18% of total debt outstanding (December 31, 2009 – 25%). The weighted-average interest rate on total debt for the year ending December 31, 2010 was 5.7% (December 31, 2009 – 5.6%).

The company's net earnings are sensitive to changes in interest rates on the floating rate portion of the company's debt. If the interest rates applicable to floating rate instruments were to have increased by 1%, it is estimated that the company's pre-tax earnings for the year ended December 31, 2010 would decrease by approximately $22 million.

2) Liquidity Risk

Liquidity risk is the risk that an entity will encounter difficulty in meeting obligations associated with financial liabilities. The company believes that it has access to sufficient capital through internally generated cash flows and external sources (bank credit markets and debt capital markets), and to undrawn committed borrowing facilities to meet current spending forecasts.

Surplus cash is invested into a range of short-dated money market securities and the company seeks to ensure the security and liquidity of those investments by only investing in high credit quality government or corporate securities. Diversification of these investments is supported through maintaining counterparty credit limits.

The following table shows the timing of cash outflows relating to trade and other payables and debt.

($ millions)	**December 31, 2010 Trade and other payables [1]**	**Debt [2]**	December 31, 2009 Trade and other payables [1]	Debt [2]
Within one year	**6 942**	**3 127**	6 529	3 796
1 to 3 years	**359**	**1 560**	653	1 811
3 to 5 years	**32**	**1 611**	—	1 591
Over 5 years	**—**	**17 338**	—	18 900
Total	**7 333**	**23 636**	7 182	26 098

(1) Includes the Fort Hills purchase obligation and the Libya EPSAs signature bonus.

(2) Debt includes short-term debt, long-term debt, capital leases and interest payments on fixed-term debt and commercial paper.

3) Credit Risk

Credit risk is the risk that a customer or counterparty will fail to perform an obligation or fail to pay amounts due causing a financial loss. The company has a credit policy that is designed to ensure there is a standard credit practice throughout the company to measure and monitor credit risk. The policy outlines delegation of authority, the due diligence process required to approve a new customer or counterparty and the maximum amount of credit exposure per single entity. Before transactions begin with a new customer or counterparty, its creditworthiness is assessed, a credit rating is assigned and a maximum credit limit is allocated. The assessment process is outlined in the credit policy and considers both quantitative and qualitative factors. The company constantly monitors the exposure to any single customer or counterparty along with the financial position of the customer or counterparty. If it is deemed that a customer or counterparty has become materially weaker, the company will work to reduce the credit exposure and lower the credit limit allocated. Regular reports are generated to monitor credit risk and the Credit Committee meets quarterly to ensure compliance with the credit policy and review the exposures.

A substantial portion of the company's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risk. At December 31, 2010, substantially all of the company's trade receivables were current, and there were no counterparties that individually constituted more than 10% of the outstanding balance.

The company may be exposed to certain losses in the event that counterparties to derivative financial instruments are unable to meet the terms of the contracts. The company's exposure is limited to those counterparties holding derivative contracts with positive fair values at the reporting date. At December 31, 2010, the company's exposure was $27 million (December 31, 2009 – $231 million).

22. ACCUMULATED OTHER COMPREHENSIVE INCOME

The components of accumulated other comprehensive income (loss), net of income taxes, are as follows:

As at December 31 ($ millions)	**2010**	2009
Unrealized foreign currency translation adjustment	**(698)**	(248)
Unrealized gains on derivative hedging activities	**14**	15
Total	**(684)**	(233)

23. CAPITAL STRUCTURE FINANCIAL POLICIES

The company's primary capital management objective is to maintain a conservative balance sheet, which supports a solid investment-grade credit rating profile. This objective affords the company the financial flexibility and access to the capital it requires to execute on its growth objectives.

The company's capital is monitored through net debt to cash flow from operations [1] and total debt to total debt plus shareholders' equity.

Net debt to cash flow from operations is calculated as short-term debt plus total long-term debt less cash and cash equivalents divided by cash flow from operations for the year then ended.

Total debt to total debt plus shareholders' equity is calculated as short-term debt plus total long-term debt divided by short-term debt plus total long-term debt plus shareholders' equity.

Financial covenants associated with the company's various banking and debt arrangements are reviewed regularly and controls are in place to maintain compliance with these covenants. The company complied with all financial covenants for the years ended December 31, 2010 and 2009.

The company's strategy during 2010, which was unchanged from 2009, was to maintain the measure set out in the following schedule. The company believes that achieving this capital target helps to provide the company access to capital at a reasonable cost by maintaining solid investment-grade credit ratings. The company operates in a cyclical business environment and ratios may periodically fall outside of management targets.

At December 31, ($ millions)	Capital Measure Target	**2010**	2009
Components of ratios			
Short-term debt		**2**	2
Current portion of long-term debt		**518**	25
Long-term debt		**11 669**	13 855
Total debt		**12 189**	13 882
Less: Cash and equivalents		**1 077**	505
Net debt		**11 112**	13 377
Shareholders' equity		**36 721**	34 111
Total capitalization (total debt plus shareholders' equity)		**48 910**	47 993
Cash flow from operations [(1)]		**6 656**	2 799
Net debt to cash flow from operations	<2.0 times	**1.7**	4.8
Total debt to total debt plus shareholders' equity		**25%**	29%

(1) Cash flow from operations is expressed before changes in non-cash working capital.

24. COMMITMENTS, CONTINGENCIES, AND GUARANTEES

(a) Commitments

($ millions)	Pipeline Capacity and Energy Services[(1)]	Operating Leases
2011	759	330
2012	667	250
2013	726	227
2014	692	170
2015	642	119
Later years	7 822	852
Total	11 308	1 948

(1) Includes annual tolls payable under transportation service agreements with major pipeline companies to use a portion of their pipeline capacity and tankage, as applicable, for transportation of product within Canada and the U.S. Suncor has commitments under long-term energy agreements to obtain a portion of the power and the steam generated by certain cogeneration facilities owned by a major third-party energy company.

In addition to the operating commitments quantified in the above table, the company has other obligations for goods and services and raw materials entered into in the normal course of business, which may terminate on short notice. Commodity purchase obligations for which an active, highly liquid market exists, and which are expected to be re-sold shortly after purchase, are one example of excluded items.

Crude Oil

At December 31, 2010, Suncor had purchase commitments relating to crude oil predominately for refinery supply. Crude oil commitments consisted of market price evergreen contracts for a total volume of 289,000 barrels per day of crude oil, of which most have industry standard thirty-day cancellation clauses.

Natural Gas

At December 31, 2010, Suncor had purchase commitments relating to natural gas for physical trading. Natural gas commitments consist of fixed price contracts with a total volume of 13 million GJ within a price range of $3.22–$5.20 per GJ and having terms extending to October 2012, as well as market price contracts for a total volume of 134 million GJ with terms extending to October 2015.

Refined Products

At December 31, 2010, Suncor's significant purchase commitments relating to finished products at its refineries consisted of market price contracts for a total volume of 4,648 million litres and having terms extending to 2017.

(b) Contingencies

The company is subject to various regulatory and statutory requirements relating to the protection of the environment. These requirements, in addition to contractual agreements and management decisions, result in the recognition of estimated asset retirement obligations. Estimates of asset retirement obligation costs can change significantly based on such factors as operating experience and changes in legislation and regulations.

The company reduces exposure to some operational risks by maintaining a comprehensive insurance program at limits and deductible amounts that management believes to be acceptable.

The company carries third-party property damage and business interruption insurance with varying coverage limits and deductible amounts based on the asset. As of December 31, 2010, Suncor's insurance program includes a coverage limit of up to US$1.3 billion for oil sands risks, up to US$1.25 billion for offshore risks and up to US$600 million for refining risks. These limits are all net of deductible amounts or waiting periods and subject to certain price and volume caps. The company also has third-party primary property insurance for US$250 million that covers all of Suncor's assets.

Suncor believes its liability, property and business interruption insurance is appropriate to its business, although such insurance will not provide coverage in all circumstances or fully protect against prolonged outages. In the future, the insurance program may change due to market conditions or other business considerations.

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

Costs attributable to these commitments and contingencies are expected to be incurred over an extended period of time and to be funded from the company's cash flow from operating activities. Although the ultimate impact of these matters on net earnings cannot be determined at this time, the impact may be material.

(c) Guarantees

In certain of the retail licensee arrangements, the company has provided loan guarantees. The company's maximum exposure to loss from these arrangements is not expected to be significant.

The company has agreed to indemnify holders of all notes and debentures and the company's credit facility lenders for added costs relating to taxes, assessments or other government charges or conditions, including any required withholding amounts. Similar indemnity terms apply to certain facility and equipment leases.

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

25. JOINT VENTURE WITH TOTAL

On December 17, 2010, Suncor announced that it plans to enter into a joint venture with Total E&P Canada Ltd (Total). The two companies plan to develop the Fort Hills and Joslyn oil sands mining projects together with the other project partners, and restart construction of the Voyageur upgrader.

Total will acquire a 49% interest in Suncor's Voyageur upgrader, and an additional 19.2% in the Fort Hills project, reducing Suncor's interest from 60% to 40.8%. In return, Suncor will acquire a 36.75% interest in the Joslyn project and receive cash consideration of approximately $1.75 billion.

The agreement is subject to certain regulatory and other approvals, with closing targeted in the first quarter of 2011. The development of the Fort Hills and Joslyn oil sands mining projects, as well as the continued construction of the Voyageur upgrader, is subject to approval by all of the partners in these ventures and by Suncor's Board of Directors.

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

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

($ millions)	Notes	**2010**	2009	2008
Net earnings as reported, Canadian GAAP		**3 571**	1 146	2 137
Adjustments				
Transaction costs and provisions	(a)	**(68)**	(302)	—
Stock-based compensation expense	(b)	**(13)**	41	(7)
Energy supply and trading activities (inventory valuation)	(e)	**4**	(47)	—
Income taxes		**20**	80	1
Net earnings, U.S. GAAP		**3 514**	918	2 131
Pension and post-retirement obligation, net of income taxes of $52 (2009 – $22; 2008 – $20)	(c)	**(168)**	43	43
Other comprehensive income (loss) items		**(451)**	(330)	350
Comprehensive income, U.S. GAAP		**2 895**	631	2 524

(dollars)	**2010**	2009	2008
Net earnings per common share, U.S. GAAP			
Basic	**2.25**	0.77	2.29
Diluted	**2.23**	0.76	2.26

The application of U.S. GAAP would have the following effects on the consolidated balance sheets as reported:

		December 31, 2010		December 31, 2009	
	Notes	**As Reported**	**U.S. GAAP**	As Reported	U.S. GAAP
Current assets	(a,e)	**10 513**	**10 544**	8 331	8 318
Property, plant and equipment, net		**55 290**	**55 290**	54 198	54 198
Other assets	(d)	**451**	**510**	491	554
Goodwill	(a)	**3 201**	**5 762**	3 201	5 762
Future income taxes		**56**	**139**	193	193
Assets of discontinued operations		**658**	**658**	3 332	3 332
Total assets		**70 169**	**72 903**	69 746	72 357
Current liabilities	(a,b)	**8 526**	**8 608**	7 848	7 881
Long-term borrowings	(d)	**11 669**	**11 728**	13 855	13 918
Accrued liabilities and other	(b,c)	**4 154**	**4 462**	4 372	4 429
Future income taxes		**8 615**	**8 620**	8 367	8 320
Liabilities of discontinued operations		**484**	**484**	1 193	1 193
Share capital	(b)	**20 188**	**23 047**	20 053	22 908
Contributed surplus	(b)	**505**	**521**	526	546
Retained earnings	(a,b,e)	**16 712**	**16 321**	13 765	13 431
Accumulated other comprehensive income (loss)	(c)	**(684)**	**(888)**	(233)	(269)
Total liabilities and shareholders' equity		**70 169**	**72 903**	69 746	72 357

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

(a) Business Combination with Petro-Canada

Under U.S. GAAP, the total purchase price for the acquisition was $22.225 billion. U.S. GAAP requires the 621.1 million Suncor shares offered as consideration to complete the merger to be valued at $34.84 per share, which was the Suncor share price as at the transaction close date of August 1, 2009. Under Canadian GAAP the share price is that value as at the merger announcement date. In addition, transaction costs of $124 million (net of income taxes of $43 million) are not permitted to be included in consideration under U.S. GAAP, and are expensed instead.

Under Canadian GAAP, the transaction costs were netted against cash acquired in the business combination and presented as part of cash flow from investing activities in the Consolidated Statements of Cash Flows. Under U.S. GAAP, the $124 million of transaction costs would be included in net earnings and thus be presented as a reduction in cash flow from operating activities.

The fair value of current liabilities assumed by Suncor in the business combination under Canadian GAAP included $160 million (net of income taxes of $56 million) for provisions for severance and other costs associated with exiting certain activities of Petro-Canada that cannot be recognized at the time of the merger under U.S. GAAP and must be expensed as incurred. At December 31, 2010, $128 million, net of income taxes of $45 million, of amounts related to these provisions had been incurred (2009 – $99 million, net of income taxes of $36 million). During 2010, the original provision set up under Canadian GAAP was reduced by $22 million (net of income taxes of $8 million) as a result of an adjustment made to the cost estimate for the Montreal coker provision. At December 31, 2010, $4 million, net of income taxes of $2 million, related to provisions remains in current liabilities under U.S. GAAP (2009 – $12 million, net of income taxes of $4 million).

As per note (b), under U.S. GAAP stock-based compensation awards recognized as liabilities are measured using different methods than Canadian GAAP. At August 1, 2009, the value of CPAs, SARs, RSUs and PSUs calculated using methods prescribed by U.S. GAAP was $126 million (net of income taxes of $43 million) greater than the value calculated using methods prescribed under Canadian GAAP.

As a result of these differences in accounting for this business combination, the resulting value for goodwill under U.S. GAAP is $5,762 million, of which $5,474 million would be allocated to the Oil Sands segment and the remaining $288 million would be allocated to the Refining and Marketing segment.

(b) Stock-Based Compensation

Under Canadian GAAP, the company's stock options with a cash payment alternative (CPAs), stock appreciation rights (SARs), performance share units (PSUs) and restricted share units (RSUs) are measured using an intrinsic approach, which is a fair-value technique not permitted under U.S. GAAP. For U.S. GAAP, the company's CPAs, SARs and RSUs have been measured at fair value using the Black-Scholes option-pricing model, while PSUs have been measured using a Monte Carlo Simulation approach to determine fair value. The impact on net earnings for the year ended December 31, 2010 is additional expense of $10 million, net of income taxes of $3 million (2009 – recovery of previously recognized expense of $31 million, net of income taxes of $10 million; 2008 – expense of $2 million, net of income taxes of $1 million).

Under Canadian GAAP, compensation expense related to common share options granted prior to January 1, 2003 (pre-2003 options) is not recognized in the Consolidated Statements of Earnings. U.S. GAAP requires the recognition of expense related to the company's pre-2003 options. There was no additional compensation expense to recognize in 2010 or 2009, as the remaining expense of $4 million for pre-2003 options was recognized in 2008. There was no impact on income taxes.

(c) Accounting for Defined Benefit Pension and Other Post-Retirement Plans

U.S. GAAP requires the company recognize the over funded or under funded status of a defined benefit post-retirement plan as an asset or liability on the balance sheet, with changes to funded status in the year recorded through comprehensive income, net of income taxes. Canadian GAAP currently does not require the company to recognize the funded status of these plans in the Consolidated Balance Sheets. In 2010, other comprehensive income under U.S. GAAP would decrease by $168 million, net of income taxes of $52 million (2009 – increase by $43 million, net of income taxes of $22 million; 2008 – increase by $43 million, net of income taxes of $20 million).

(d) Deferred Financing Costs

Effective January 1, 2007, under Canadian GAAP, deferred financing costs on long-term debt are included in the carrying value of the related debt. Under U.S. GAAP, these costs are recorded as a deferred charge. As a result, $59 million would have been reclassified from long-term debt to other assets at December 31, 2010 (December 31, 2009 – $63 million).

(e) Inventory

U.S. GAAP requires inventory to be measured at the lower of cost or net realizable value and does not permit the measurement of held for trading inventories at fair value less costs to sell. As a result, the value of energy trading inventories at December 31, 2010 is lower by $40 million (2009 — $47 million). Earnings for the twelve months ended December 31, 2010 would increase by $3 million, net of income taxes of $1 million, as a result of not recognizing fair value changes (2009 — decrease earnings by $32 million, net of income taxes of $15 million).

(f) Cash Flow Information

Other than described in note (a), the application of U.S. GAAP would not have a material effect on cash flow from total operating, investing, or financing activities on the Consolidated Statements of Cash Flows.

Recently Adopted Accounting Standards

Effective January 1, 2010, the company adopted amendments to Topic 810 "Consolidations". The adoption of these amendments had no impact on net earnings or financial position.

QUARTERLY SUMMARY (unaudited)

FINANCIAL DATA [1]

($ millions, except per share amounts)	Mar 31 2010	For the Quarter Ended June 30 2010	Sept 30 2010	Dec 31 2010	Total Year 2010	Mar 31 2009	For the Quarter Ended June 30 2009	Sept 30 2009	Dec 31 2009	Total Year 2009
Revenues from continuing operations	**6 946**	**8 979**	**8 636**	**9 789**	**34 350**	4 607	4 748	8 257	7 236	24 848
Net earnings (loss) from continuing operations										
Oil Sands	**76**	**517**	**412**	**487**	**1 492**	(110)	(307)	738	236	557
Natural Gas	**23**	**(68)**	**(167)**	**(65)**	**(277)**	(10)	(23)	(97)	(55)	(185)
International and Offshore	**209**	**217**	**236**	**452**	**1 114**	—	—	93	230	323
Refining and Marketing	**139**	**138**	**152**	**372**	**801**	112	99	45	151	407
Corporate, Energy Trading and Eliminations	**17**	**(486)**	**(24)**	**51**	**(442)**	(181)	185	186	(86)	104
	464	**318**	**609**	**1 297**	**2 688**	(189)	(46)	965	476	1 206
Per common share										
Net earnings (loss) from continuing operations										
– basic	**0.30**	**0.20**	**0.39**	**0.83**	**1.72**	(0.20)	(0.05)	0.72	0.30	1.01
– diluted	**0.30**	**0.20**	**0.39**	**0.82**	**1.71**	(0.20)	(0.05)	0.71	0.30	1.00
Net earnings (loss)										
– basic	**0.46**	**0.31**	**0.65**	**0.87**	**2.29**	(0.20)	(0.06)	0.69	0.29	0.96
– diluted	**0.46**	**0.31**	**0.65**	**0.86**	**2.27**	(0.20)	(0.06)	0.68	0.29	0.95
Cash dividends	**0.10**	**0.10**	**0.10**	**0.10**	**0.40**	0.05	0.05	0.10	0.10	0.30
Cash flow from (used in) operations from continuing operations										
Oil Sands	**262**	**933**	**779**	**795**	**2 769**	480	174	242	355	1 251
Natural Gas	**132**	**82**	**56**	**50**	**320**	35	33	39	70	177
International and Offshore	**542**	**517**	**568**	**885**	**2 512**	—	—	238	500	738
Refining and Marketing	**328**	**263**	**326**	**619**	**1 536**	205	194	264	258	921
Corporate, Energy Trading and Eliminations	**(314)**	**(196)**	**(244)**	**(219)**	**(973)**	63	(115)	(299)	(302)	(653)
	950	**1 599**	**1 485**	**2 130**	**6 164**	783	286	484	881	2 434

(1) The comparative financial data includes the results of post-merger Suncor from August 1, 2009. As such, the amounts reflect results of the post-merger Suncor from August 1, 2009 together with the results of lergacy Suncor only from January 1, 2009 through July 31, 2009.

QUARTERLY SUMMARY (unaudited) (continued)

OPERATING DATA

	For the Quarter Ended				Total Year	For the Quarter Ended				Total Year
	Mar 31 2010	**June 30 2010**	**Sept 30 2010**	**Dec 31 2010**	**2010**	Mar 31 2009	June 30 2009	Sept 30 2009	Dec 31 2009	2009
OIL SANDS										
Production (kbpd)										
Total production (excluding Syncrude)	**202.3**	**295.5**	**306.6**	**325.9**	**283.0**	278.0	301.0	305.3	278.9	290.6
Firebag (kbpd of bitumen)	**55.7**	**55.7**	**50.4**	**52.9**	**53.6**	42.4	48.3	54.3	51.1	49.1
Mackay River (kbpd of bitumen)	**31.8**	**32.5**	**28.8**	**32.9**	**31.5**	—	—	26.5**	31.7	29.7 **
Syncrude	**32.3**	**38.9**	**31.7**	**37.9**	**35.2**	—	—	37.4**	39.3	38.5 **
Sales (kbpd) (excluding Syncrude)										
Light sweet crude oil	**61.0**	**99.0**	**84.5**	**84.5**	**82.3**	108.8	99.4	89.6	100.8	99.6
Diesel	**12.9**	**30.7**	**25.8**	**12.2**	**20.4**	22.8	25.3	36.9	31.4	29.1
Light sour crude oil	**80.5**	**143.1**	**165.8**	**189.8**	**145.2**	102.7	150.5	146.8	142.4	135.7
Bitumen	**42.3**	**37.4**	**21.2**	**24.9**	**31.4**	9.1	10.5	14.3	13.0	11.8
Total sales	**196.7**	**310.2**	**297.3**	**311.4**	**279.3**	243.4	285.7	287.6	287.6	276.2
Average sales price [1] (dollars per barrel) (excluding Syncrude)										
Light sweet crude oil*	**80.84**	**77.55**	**75.49**	**83.02**	**79.03**	54.64	65.83	71.99	77.71	67.26
Other (diesel, light sour crude oil and bitumen)*	**69.53**	**68.53**	**66.39**	**70.29**	**68.63**	48.80	62.71	67.51	72.93	64.18
Total *	**73.03**	**71.41**	**68.97**	**73.75**	**71.69**	51.46	63.79	68.91	74.61	65.29
Total	**70.21**	**69.79**	**67.53**	**70.95**	**69.58**	59.45	59.34	62.01	65.42	61.66
Syncrude average sales price [1] (dollars per barrel)	**83.21**	**77.32**	**78.83**	**84.40**	**80.93**	—	—	75.17	78.81	77.36
Operating costs – Total operations (excluding Syncrude) (dollars per barrel)										
Cash costs	**46.50**	**31.70**	**32.45**	**34.35**	**35.30**	30.65	29.65	30.65	35.10	31.50
Natural gas	**5.40**	**3.55**	**1.10**	**2.30**	**2.85**	3.00	1.65	1.55	3.40	2.40
Imported bitumen	**2.95**	**0.65**	**0.05**	**0.05**	**0.70**	0.05	—	0.05	0.20	0.05
Cash operating costs [2]	**54.85**	**35.90**	**33.60**	**36.70**	**38.85**	33.70	31.30	32.25	38.70	33.95
Project start-up costs	**0.55**	**0.55**	**0.75**	**0.95**	**0.70**	0.65	0.35	0.45	0.50	0.45
Total cash operating costs [3]	**55.40**	**36.45**	**34.35**	**37.65**	**39.55**	34.35	31.65	32.70	39.20	34.40
Depreciation, depletion and amortization	**12.65**	**15.35**	**9.00**	**8.80**	**11.25**	7.30	7.20	7.60	10.00	8.00
Total operating costs [4]	**68.05**	**51.80**	**43.35**	**46.45**	**50.80**	41.65	38.85	40.30	49.20	42.40
Operating costs – Syncrude (dollars per barrel)***										
Cash costs	**39.60**	**28.75**	**39.20**	**32.85**	**34.70**	—	—	29.50	29.65	29.60
Natural gas	**4.50**	**2.85**	**2.75**	**3.05**	**3.25**	—	—	2.10	3.45	2.90
Cash operating costs [2]	**44.10**	**31.60**	**41.95**	**35.90**	**37.95**	—	—	31.60	33.10	32.50
Project start-up costs	**—**	**—**	**—**	**—**	**—**	—	—	—	—	—
Total cash operating costs [3]	**44.10**	**31.60**	**41.95**	**35.90**	**37.95**	—	—	31.60	33.10	32.50
Depreciation, depletion and amortization	**13.70**	**11.35**	**14.85**	**9.65**	**12.20**	—	—	12.70	11.80	12.15
Total operating costs [4]	**57.80**	**42.95**	**56.80**	**45.55**	**50.15**	—	—	44.30	44.90	44.65
Operating costs – In situ bitumen production only (dollars per barrel)										
Cash costs	**12.30**	**13.65**	**17.15**	**16.50**	**14.85**	15.25	16.40	13.25	14.25	14.55
Natural gas	**7.05**	**5.05**	**5.25**	**4.80**	**5.55**	7.90	5.30	4.30	6.05	5.70
Cash operating costs [5]	**19.35**	**18.70**	**22.40**	**21.30**	**20.40**	23.15	21.70	17.55	20.30	20.25
Project start-up costs	**0.95**	**1.45**	**2.50**	**3.35**	**2.05**	2.30	1.45	0.65	1.35	1.35
Total cash operating costs [6]	**20.30**	**20.15**	**24.90**	**24.65**	**22.45**	25.45	23.15	18.20	21.65	21.60
Depreciation, depletion and amortization	**5.05**	**4.70**	**5.90**	**5.20**	**5.20**	6.95	6.00	5.95	6.65	6.35
Total operating costs [7]	**25.35**	**24.85**	**30.80**	**29.85**	**27.65**	32.40	29.15	24.15	28.30	27.95

Footnotes, definitions and abbreviations, see page 100.

QUARTERLY SUMMARY (unaudited) (continued)

OPERATING DATA (continued)

	For the Quarter Ended				Total Year	For the Quarter Ended				Total Year
	Mar 31 2010	**June 30 2010**	**Sept 30 2010**	**Dec 31 2010**	**2010**	Mar 31 2009	June 30 2009	Sept 30 2009	Dec 31 2009	2009
NATURAL GAS										
Gross production										
Natural gas (mmcf/d)										
Continuing operations	**419**	**398**	**380**	**399**	**399**	140	145	335	424	262
Discontinued operations	**230**	**138**	**120**	**8**	**123**	60	47	182	250	135
Natural gas liquids and crude oil (kbpd)										
Continuing operations	**6.2**	**5.5**	**5.4**	**4.9**	**5.5**	1.1	1.0	4.8	6.2	3.3
Discontinued operations	**7.8**	**2.8**	**2.2**	**0.2**	**3.3**	2.0	2.2	5.9	8.8	4.8
Total gross production (mmcfe/d)										
Continuing operations	**456**	**431**	**412**	**429**	**432**	147	151	363	461	282
Discontinued operations	**277**	**155**	**134**	**9**	**143**	72	60	218	303	164
Average sales price from continuing operations [1]										
Natural gas (dollars per mcf)	**5.34**	**3.42**	**3.66**	**3.39**	**3.99**	5.42	3.26	2.70	3.92	3.63
Natural gas (dollars per mcf) *	**5.34**	**3.42**	**3.66**	**3.39**	**3.99**	5.41	3.23	2.68	3.91	3.62
Natural gas liquids and crude oil (dollars per barrel)	**74.71**	**82.82**	**68.03**	**71.56**	**77.37**	45.08	40.04	58.31	65.74	59.41
INTERNATIONAL AND OFFSHORE**										
East Coast Canada										
Production (kbpd)										
Terra Nova	**29.6**	**27.2**	**17.2**	**19.0**	**23.2**	—	—	16.0	24.0	20.8
Hibernia	**30.2**	**30.1**	**32.3**	**30.9**	**30.9**	—	—	28.5	26.3	27.2
White Rose	**14.8**	**13.3**	**16.8**	**13.0**	**14.5**	—	—	5.1	13.3	10.0
Total production	**74.6**	**70.6**	**66.3**	**62.9**	**68.6**	—	—	49.6	63.6	58.0
Average sales price [1] (dollars per barrel)	**78.69**	**76.88**	**78.78**	**87.12**	**80.20**	—	—	75.22	77.71	76.86
International										
Production (kboe/d)										
North Sea										
Buzzard	**58.6**	**49.3**	**58.6**	**55.6**	**55.5**	—	—	29.4	59.9	47.8
Discontinued operations	**27.5**	**22.7**	**25.2**	**18.7**	**23.5**	—	—	25.2	31.1	28.7
Total North Sea	**86.1**	**72.0**	**83.8**	**74.3**	**79.0**	—	—	54.6	91.0	76.5
Other International										
Libya	**35.4**	**35.4**	**35.4**	**34.7**	**35.2**	—	—	42.7	26.0	32.6
Syria****	**—**	**12.8**	**16.5**	**16.9**	**11.6**	—	—	—	—	—
Discontinued operations	**11.7**	**11.1**	**4.2**	**—**	**6.7**	—	—	11.3	12.0	11.7
Total Other International	**47.1**	**59.3**	**56.1**	**51.6**	**53.5**	—	—	54.0	38.0	44.3
Total production	**133.2**	**131.3**	**139.9**	**125.9**	**132.5**	—	—	108.6	129.0	120.8
Average sales price from continuing operations [1] (dollars per boe)										
Buzzard	**72.36**	**78.57**	**75.60**	**85.46**	**77.91**	—	—	72.02	68.71	69.53
Other International	**73.40**	**76.14**	**74.90**	**83.06**	**78.07**	—	—	75.60	79.06	77.53
Total International and Offshore Production (kboe/d)	**207.8**	**201.9**	**206.2**	**188.8**	**201.1**	—	—	158.2	192.6	178.8

Footnotes, definitions and abbreviations, see page 100.

QUARTERLY SUMMARY (unaudited) (continued)

OPERATING DATA (continued)

	For the Quarter Ended				Total Year	For the Quarter Ended				Total Year
	Mar 31 2010	**June 30 2010**	**Sept 30 2010**	**Dec 31 2010**	**2010**	Mar 31 2009	June 30 2009	Sept 30 2009	Dec 31 2009	2009
REFINING AND MARKETING										
Eastern North America										
Refined product sales (thousands of m^3/d)										
Transportation fuels										
Gasoline	**21.0**	**22.5**	**22.5**	**22.9**	**22.2**	8.2	8.7	18.3	23.0	14.6
Distillate	**12.3**	**12.5**	**11.7**	**13.7**	**12.4**	5.1	5.4	10.3	13.9	8.8
Total transportation fuel sales	**33.3**	**35.0**	**34.2**	**36.6**	**34.6**	13.3	14.1	28.6	36.9	23.4
Petrochemicals	**2.2**	**2.8**	**2.5**	**2.4**	**2.5**	1.0	1.0	1.7	1.2	0.8
Asphalt	**1.8**	**3.0**	**3.7**	**2.4**	**2.7**	0.8	0.7	2.4	2.0	1.5
Other	**4.3**	**6.0**	**6.0**	**5.3**	**5.5**	0.5	1.0	3.0	1.9	2.0
Total refined product sales	**41.6**	**46.8**	**46.4**	**46.7**	**45.3**	15.6	16.8	35.7	42.0	27.7
Crude oil supply and refining										
Processed at refineries (thousands of m^3/d)	**31.0**	**30.6**	**30.7**	**29.7**	**30.5**	11.3	11.8	25.5	28.3	29.6 **
Utilization of refining capacity (%)	**91**	**90**	**90**	**87**	**89**	84	87	94	83	87
Western North America										
Refined product sales (thousands of m^3/d)										
Transportation fuels										
Gasoline	**18.1**	**19.2**	**19.9**	**18.3**	**18.9**	8.2	8.9	16.1	18.4	13.0
Distillate	**16.9**	**16.3**	**17.4**	**23.2**	**18.5**	5.4	5.0	11.8	15.6	9.5
Total transportation fuel sales	**35.0**	**35.5**	**37.3**	**41.5**	**37.4**	13.6	13.9	27.9	34.0	22.5
Asphalt	**1.2**	**1.5**	**1.5**	**0.9**	**1.3**	1.2	1.4	1.7	0.9	1.3
Other	**4.4**	**5.2**	**3.7**	**2.0**	**3.8**	1.0	1.8	4.6	6.0	3.4
Total refined product sales	**40.6**	**42.2**	**42.5**	**44.4**	**42.5**	15.8	17.1	34.2	40.9	27.2
Crude oil supply and refining										
Processed at refineries (thousands of m^3/d)	**33.5**	**31.7**	**36.6**	**36.5**	**34.6**	14.2	15.6	27.8	33.4	33.6 **
Utilization of refining capacity (%)	**92**	**87**	**101**	**101**	**95**	96	106	100	96	97

Footnotes, definitions and abbreviations, see page 100.

QUARTERLY SUMMARY (unaudited) (continued)

OPERATING DATA (continued)

	For the Quarter Ended				Total Year	For the Quarter Ended				Total Year
	Mar 31 2010	**June 30 2010**	**Sept 30 2010**	**Dec 31 2010**	**2010**	Mar 31 2009	June 30 2009	Sept 30 2009	Dec 31 2009	2009
NETBACKS – Continuing Operations										
Natural Gas (dollars per mcfe)										
Average price realized [8]	**6.23**	**5.06**	**4.76**	**4.40**	**5.16**	5.87	3.56	3.69	5.02	4.50
Royalties	**(0.91)**	**(0.06)**	**(0.50)**	**(0.45)**	**(0.49)**	(0.98)	(0.88)	(0.18)	(0.71)	(0.37)
Transportation costs	**(0.37)**	**(0.55)**	**(0.39)**	**(0.33)**	**(0.41)**	(0.32)	(0.28)	(0.43)	(0.45)	(0.41)
Operating costs	**(1.30)**	**(1.55)**	**(1.53)**	**(1.71)**	**(1.52)**	(1.55)	(1.27)	(1.37)	(1.43)	(1.39)
Operating netback	**3.65**	**2.90**	**2.34**	**1.91**	**2.74**	3.02	1.13	1.71	2.43	2.33
International and Offshore										
East Coast Canada (dollars per barrel)										
Average price realized [8]	**80.79**	**78.99**	**81.06**	**89.35**	**82.38**	—	—	77.85	79.69	79.07
Royalties	**(28.78)**	**(28.45)**	**(25.49)**	**(29.17)**	**(27.99)**	—	—	(21.02)	(25.26)	(23.82)
Transportation costs	**(2.10)**	**(2.11)**	**(2.28)**	**(2.23)**	**(2.18)**	—	—	(2.63)	(1.98)	(2.21)
Operating costs	**(6.38)**	**(6.08)**	**(6.80)**	**(7.57)**	**(6.68)**	—	—	(10.36)	(5.63)	(7.24)
Operating netback	**43.53**	**42.35**	**46.49**	**50.38**	**45.53**	—	—	43.84	46.82	45.80
North Sea – Buzzard (dollars per barrel)										
Average price realized [8]	**74.19**	**80.35**	**77.43**	**87.30**	**79.73**	—	—	75.49	70.38	71.64
Transportation costs	**(1.83)**	**(1.78)**	**(1.83)**	**(1.84)**	**(1.82)**	—	—	(3.47)	(1.67)	(2.11)
Operating costs	**(3.09)**	**(3.57)**	**(2.90)**	**(2.80)**	**(3.07)**	—	—	(2.82)	(2.90)	(2.88)
Operating netback	**69.27**	**75.00**	**72.70**	**82.66**	**74.84**	—	—	69.20	65.81	66.65
Other International (dollars per boe)										
Average price realized [8]	**73.92**	**76.61**	**75.24**	**82.74**	**78.30**	—	—	76.02	79.97	78.19
Royalties	**(43.28)**	**(36.99)**	**(32.06)**	**(18.37)**	**(35.06)**	—	—	(46.46)	(32.12)	(39.88)
Transportation costs	**(0.52)**	**(0.47)**	**(0.34)**	**0.32**	**(0.23)**	—	—	(0.42)	(0.91)	(0.66)
Operating costs	**(3.29)**	**(7.40)**	**(4.72)**	**(6.38)**	**(5.60)**	—	—	(1.79)	(5.12)	(3.39)
Operating netback	**26.83**	**31.75**	**38.12**	**58.31**	**37.41**	—	—	27.35	41.82	34.26

Footnotes, definitions and abbreviations, see page 100.

FIVE-YEAR FINANCIAL SUMMARY (unaudited)

($ millions)	**2010**	2009	2008	2007	2006
Revenues from continuing operations					
Oil Sands	**9 423**	6 539	8 639	6 175	6 457
Natural Gas	**734**	423	364	284	313
International and Offshore	**4 323**	1 217	—	—	—
Refining and Marketing	**21 062**	11 851	9 258	8 220	7 174
Corporate and eliminations	**(1 192)**	4 818	10 185	2 492	894
	34 350	24 848	28 446	17 171	14 838
Net earnings (loss) from continuing operations					
Oil Sands	**1 492**	557	2 875	2 474	2 775
Natural Gas	**(277)**	(185)	34	7	78
International and Offshore	**1 114**	323	—	—	—
Refining and Marketing	**801**	407	(22)	406	227
Corporate and eliminations	**(442)**	104	(805)	78	(139)
	2 688	1 206	2 082	2 965	2 941
Cash flow from (used in) operations					
Oil Sands	**2 769**	1 251	3 507	3 165	3 902
Natural Gas	**445**	329	367	251	279
International and Offshore	**2 879**	951	—	—	—
Refining and Marketing	**1 536**	921	220	660	422
Corporate and eliminations	**(973)**	(653)	(37)	(39)	(57)
	6 656	2 799	4 057	4 037	4 546
Capital and exploration expenditures					
Oil Sands	**3 709**	2 831	7 413	4 566	2 463
Natural Gas	**178**	320	342	537	458
International and Offshore	**1 096**	666	—	—	—
Refining and Marketing	**667**	380	207	351	747
Corporate	**360**	70	58	175	27
	6 010	4 267	8 020	5 629	3 695
Total assets	**70 169**	69 746	32 528	24 509	18 959
Ending capital employed [(A)]					
Short-term and long-term debt, less cash and cash equivalents	**11 112**	13 377	7 226	3 248	1 849
Shareholders' equity	**36 721**	34 111	14 523	11 896	9 084
	47 833	47 488	21 749	15 144	10 933
Less capitalized costs related to major projects in progress	**(12 889)**	(13 365)	(6 583)	(4 148)	(2 649)
	34 944	34 123	15 166	10 996	8 284
Total Suncor employees (number at year-end)	**12 076**	12 978	6 798	6 465	5 766

Footnotes, see page 95.

FIVE-YEAR FINANCIAL SUMMARY (unaudited) (continued)

($ millions)	**2010**	2009	2008	2007	2006
Dollars per common share					
Net earnings attributable to common shareholders	**2.29**	0.96	2.29	3.23	3.23
Cash dividends	**0.40**	0.30	0.20	0.19	0.15
Cash flow from operations	**4.26**	2.34	4.36	4.38	4.95
Ratios					
Return on capital employed (%) [(B)]	**10.1**	2.6	22.5	29.3	40
Return on capital employed (%) [(C)]	**7.4**	1.8	16.3	21.5	30.1
Return on shareholders' equity (%) [(D)]	**10.2**	5.1	16.2	28.4	39
Debt to debt plus shareholders' equity (%) [(E)]	**25**	29	35	24	21
Net debt to cash flow from operations (times) [(F)]	**1.7**	4.8	1.8	0.8	0.4
Interest coverage – cash flow basis (times) [(G)]	**11.9**	7.2	13.0	23.4	30.6
Interest coverage – net earnings basis (times) [(H)]	**8.4**	3.0	8.9	18.8	25.5

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

(B) Net earnings adjusted for after-tax financing expenses (income) for the twelve month period ended; divided by average capital employed. Average capital employed is the sum of shareholders' equity and short-term debt plus long-term debt less cash and cash equivalents, less average capitalized costs related to major projects in progress (as applicable), on a weighted-average basis. For a detailed annual reconciliation of this measure see the Non-GAAP Financial Measures Advisory section of Suncor's 2010 Management Discussion and Analysis.

(C) Average capital employed including capitalized costs related to major projects in progress.

(D) Net earnings as a percentage of average shareholders' equity.

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

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

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

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

SUPPLEMENTAL FINANCIAL AND OPERATING INFORMATION (unaudited)

	2010	2009	2008	2007	2006
OIL SANDS					
Production (kbpd)					
Total production (excluding Syncrude)	**283.0**	290.6	228.0	235.6	260.0
Syncrude	**35.2**	38.5**	—	—	—
Sales (kpbd)					
Light sweet crude oil	**82.3**	99.6	77.0	101.7	110.5
Diesel	**20.4**	29.1	19.8	25.0	28.2
Light sour crude oil	**145.2**	135.7	128.7	102.3	118.2
Bitumen	**31.4**	11.8	1.5	5.7	6.2
	279.3	276.2	227.0	234.7	263.1
Average sales price [1] (dollars per barrel) (excluding Syncrude)					
Light sweet crude oil*	**79.03**	67.26	98.66	78.03	71.98
Other (diesel, light sour crude oil and bitumen)*	**68.63**	64.18	95.14	70.86	65.17
Total*	**71.69**	65.29	96.33	74.07	68.03
Total	**69.58**	61.66	95.96	74.01	68.03
Syncrude average sales price [1] (dollars per barrel)	**80.93**	77.36	—	—	—
Operating costs – Total operations (excluding Syncrude) (dollars per barrel)					
Cash operating costs [2]	**38.85**	33.95	38.50	27.80	21.70
Total cash operating costs [3]	**39.55**	34.40	38.90	28.75	22.10
Total operating costs [4]	**50.80**	42.40	45.85	34.15	26.15
Operating costs – Syncrude (dollars per barrel)***					
Cash operating costs [2]	**37.95**	32.50	—	—	—
Total cash operating costs [3]	**37.95**	32.50	—	—	—
Total operating costs [4]	**50.15**	44.65	—	—	—
Operating costs – In situ bitumen production only (dollars per barrel)					
Cash operating costs [5]	**20.40**	20.25	25.30	20.75	17.30
Total cash operating costs [6]	**22.45**	21.60	25.95	20.75	19.00
Total operating costs [7]	**27.65**	27.95	32.30	26.95	24.55

Footnotes, definitions and abbreviations, see page 100.

SUPPLEMENTAL FINANCIAL AND OPERATING INFORMATION (unaudited) (continued)

	2010	2009	2008	2007	2006
NATURAL GAS					
Gross production					
Natural gas (mmcf/d)					
Continuing operations	**399**	262	135	138	138
Discontinued operations	**123**	135	67	58	53
Natural gas liquids and crude oil (kbpd)					
Continuing operations	**5.5**	3.3	1.1	1.2	1.4
Discontinued operations	**3.3**	4.8	2.0	1.9	1.6
Total (mmcfe/d)					
Continuing operations	**432**	282	141	146	147
Discontinued operations	**143**	164	79	69	62
Average sales price from continuing operations [(1)]					
Natural gas (dollars per mcf)	**3.99**	3.63	8.21	6.50	7.30
Natural gas (dollars per mcf) *	**3.99**	3.62	8.23	6.41	6.95
Natural gas liquids and crude oil (dollars per barrel)	**77.37**	59.41	68.05	51.44	45.15

Footnotes, definitions and abbreviations, see page 100.

SUPPLEMENTAL FINANCIAL AND OPERATING INFORMATION (unaudited) (continued)

	2010	2009	2008	2007	2006
INTERNATIONAL AND OFFSHORE**					
East Coast Canada					
Production (kbpd)					
Terra Nova	**23.2**	20.8	—	—	—
Hibernia	**30.9**	27.2	—	—	—
White Rose	**14.5**	10.0	—	—	—
Total production	**68.6**	58.0	—	—	—
Average sales price [1] (dollars per barrel)	**80.20**	76.86	—	—	—
International					
Production (kboe/d)					
North Sea					
Buzzard	**55.5**	47.8	—	—	—
Production from discontinued operations	**23.5**	28.7	—	—	—
Total North Sea	**79.0**	76.5			
Other International					
Libya	**35.2**	32.6	—	—	—
Syria****	**11.6**	—			
Production from discontinued operations	**6.7**	11.7	—	—	—
Total Other International	**53.5**	44.3	—	—	—
Total production	**132.5**	120.8	—	—	—
Average sales price from continuing operations [1] (dollars per boe)					
Buzzard	**77.91**	69.53	—	—	—
Other International	**78.07**	77.53			
Total International and Offshore Production (kboe/d)	**201.1**	178.8	—	—	—

Footnotes, definitions and abbreviations, see page 100.

SUPPLEMENTAL FINANCIAL AND OPERATING INFORMATION (unaudited) (continued)

	2010	2009	2008	2007	2006
REFINING AND MARKETING					
Eastern North America					
Refined product sales (thousands of m^3/d)					
Transportation fuels					
Gasoline	**22.2**	14.6	7.9	8.8	8.4
Distillate	**12.4**	8.8	5.2	5.4	3.9
Total transportation fuel sales	**34.6**	23.4	13.1	14.2	12.3
Petrochemicals	**2.5**	0.8	0.8	0.9	0.9
Asphalt	**2.7**	1.5	0.6	0.3	—
Other	**5.5**	2.0	1.0	2.2	1.9
Total refined product sales	**45.3**	27.7	15.5	17.6	15.1
Crude oil supply and refining					
Processed at refineries (thousands of m^3/d)	**30.5**	29.6**	11.0	10.9	8.6
Utilization of refining capacity (%)	**89**	87	99	98	78
Western North America					
Refined product sales (thousands of m^3/d)					
Transportation fuels					
Gasoline	**18.9**	13.0	8.0	8.0	7.5
Distillate	**18.5**	9.5	5.6	5.2	4.6
Total transportation fuel sales	**37.4**	22.5	13.6	13.2	12.1
Asphalt	**1.3**	1.3	1.2	1.4	1.2
Other	**3.8**	3.4	1.2	1.3	1.1
Total refined product sales	**42.5**	27.2	16.0	15.9	14.4
Crude oil supply and refining					
Processed at refineries (thousands of m^3/d)	**34.6**	33.6**	13.7	14.2	13.1
Utilization of refining capacity (%)	**95**	97	96	99	92
Retail outlets (number at year-end)	**1 723**	1 813	427	419	417

Footnotes, definitions and abbreviations, see page 100.

SUPPLEMENTAL FINANCIAL AND OPERATING INFORMATION (unaudited) (continued)

Definitions

(1) Average sales price – This operating statistic is calculated before royalties (where applicable) and net of related transportation costs.

(2) Cash operating costs – Include cash costs that are defined as operating, selling and general expenses (excluding inventory changes), accretion expense and the cost of bitumen imported from third parties. Per barrel amounts are based on total production volumes. For a reconciliation of this non-GAAP financial measure see Management's Discussion and Analysis.

(3) Total cash operating costs – Include cash operating costs as defined above and cash start-up costs. Per barrel amounts are based on total production volumes.

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

(5) Cash operating costs – In situ bitumen production - Include cash costs that are defined as operating, selling and general expenses (excluding inventory changes) and accretion expense. Per barrel amounts are based on in situ production volumes only.

(6) Total cash operating costs – In situ bitumen production - Include cash operating costs – In situ bitumen production as defined above and cash start-up operating costs. Per barrel amounts are based on in situ production volumes only.

(7) Total operating costs – In situ bitumen production - Include total cash operating costs – In situ bitumen production as defined above and non-cash operating costs. Per barrel amounts are based on in situ production volumes only.

(8) Average price realized - This operating statistic is calculated before transportation costs and royalties and excludes the impact of hedging activities.

Explanatory Notes

* Excludes the impact of realized hedging activities.

** For the three months ended September 30, 2009 and the twelve months ended December 31, 2009, operating summary information reflects results of operations since the merger with Petro-Canada on August 1, 2009.

*** Users are cautioned that the Syncrude costs per barrel measure may not be fully comparable to similar information calculated by other entities (including Suncor's own cash costs per barrel excluding Syncrude) due to differing treatments for operations and capital costs among producers.

**** Commercial production for Syria commenced on April 19, 2010.

Abbreviations

kbpd	—	thousands of barrels per day
mcf	—	thousands of cubic feet
mcfe	—	thousands of cubic feet equivalent
mmcf/d	—	millions of cubic feet per day
mmcfe/d	—	millions of cubic feet equivalent per day
boe	—	barrels of oil equivalent
kboe/d	—	thousands of barrels of oil equivalent per day
m^3/d	—	cubic metres per day

Metric conversion

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

RESERVES SUMMARY (1) (2) (3)

This data summarizes Suncor's oil, liquids and natural gas reserves and the net present values of future net revenues for these reserves using forecast prices and costs and prepared in accordance with *National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities*. For more information regarding our reserves and resources disclosure, please see the Statement of Reserves Data and Other Oil and Gas Information in our Annual Information Form (AIF), dated March 3, 2011. Reserves volumes are presented in millions of barrels (MMbbls), billions of cubic feet (Bcf) or millions of barrels of oil equivalent (MMboe).

The recovery and reserves estimates of oil, natural gas liquids (NGL) and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Estimates of net present value for future net revenues do not represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material.

Reserves Summary
(forecast prices and costs)

	Synthetic Crude Oil (SCO)		Bitumen		Light & Medium Oil		Natural Gas		NGL		Total	
	Gross MMbbls	Net MMbbls	Gross MMbbls	Net MMbbls	Gross MMbbls	Net MMbbls	Gross Bcf	Net Bcf	Gross MMbbls	Net MMbbls	Gross MMboe	Net MMboe
Proved	2 906	2 500	397	337	350	241	1 376	1 124	17	11	3 900	3 276
Probable	1 003	821	1 887	1 523	313	198	660	468	13	8	3 325	2 628
Proved Plus Probable	3 909	3 321	2 284	1 860	663	439	2 036	1 592	29	19	7 225	5 904

Net Present Value of Future Net Revenues for Proved Plus Probable Reserves
(forecast prices and costs)

($ millions, discounted at % per year)	0%	5%	10%	15%	20%
Mining	91 520	47 876	29 165	19 876	14 696
In Situ	110 937	39 954	18 477	10 126	6 172
East Coast Canada	9 994	7 842	6 399	5 384	4 640
Natural Gas	6 294	3 869	2 761	2 133	1 730
North Sea	13 927	11 014	9 108	7 775	6 794
Other International (4)	11 942	7 813	5 590	4 264	3 406
Total	**244 614**	**118 368**	**71 500**	**49 558**	**37 438**

Gross Reserves Reconciliation for Proved Plus Probable Reserves
(forecast prices and costs)

	SCO MMbbls	Bitumen MMbbls	Light & Medium Oil MMbbls	Natural Gas Bcf	NGL MMbbls	Total MMboe
December 31, 2009 (5)	4 192	2 010	743	3 757	55	7 626
Extensions and improved recoveries (6)	6	8	22	116	—	55
Technical revisions (7)	(184)	276	2	(427)	(11)	13
Discoveries (8)	—	—	2	2	—	2
Dispositions	—	—	(39)	(1 036)	(10)	(222)
Economic factors (9)	—	—	—	(136)	—	(23)
Production	(106)	(10)	(67)	(241)	(3)	(226)
December 31, 2010	**3 909**	**2 284**	**663**	**2 036**	**29**	**7 225**

(1) Gross refers to Suncor's working interest (operating and non-operating) share before deduction of royalties and without including any royalty interests of Suncor; Net refers to Suncor's working interest (operating and non-operating) share after deduction of royalty obligations, plus the company's royalty interests in production or reserves.

(2) Reserves volumes in the above tables are rounded to the nearest MMbbls, Bcf or MMboe, as the case may be, and may not add due to rounding.

(3) The reserves data are based upon evaluations or reviews by GLJ Petroleum Consultants Ltd., Sproule Associates Limited and Sproule International Limited all completed with an effective date of December 31, 2010.

(4) Other International reserves, which include Libya and Syria, include quantities of crude oil and natural gas reserves that will be produced under PSCs, which involve the company in upstream risks and rewards, but which do not transfer title of the product to the company. Please see the Definitions for Reserves Data Tables section in the AIF.

(5) For the year ended December 31, 2009, Suncor had presented disclosures in accordance with U.S. disclosure requirements under an exemption from Canadian securities requirements. As a result, closing balances presented in our 2009 AIF disclosure have been restated to comply with NI 51-101, consistent with the presentation format for December 31, 2010 reserves disclosure.

(6) Extensions and improved recoveries are positive increases to the reserves resulting from step-out drilling, infill drilling and installation of improved recovery schemes.

(7) Technical revisions include changes in previous estimates, upward or downward, resulting from new technical data or revised interpretations.

(8) Discoveries are additions to reserves in reservoirs where no reserves were previously booked.

(9) Economic factors are changes due to product pricing.

SHARE TRADING INFORMATION (unaudited)

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

	For the Quarter Ended				For the Quarter Ended			
	Mar 31 2010	**June 30 2010**	**Sept 30 2010**	**Dec 31 2010**	Mar 31 2009	June 30 2009	Sept 30 2009	Dec 31 2009
Share ownership								
Average number outstanding, weighted monthly (thousands) [(a)]	**1 560 744**	**1 561 650**	**1 562 538**	**1 564 170**	936 550	937 005	1 349 263	1 559 512
Share price (dollars)								
Toronto Stock Exchange								
High	**39.45**	**35.82**	**34.94**	**38.56**	34.22	40.13	39.84	40.79
Low	**29.93**	**29.91**	**30.72**	**32.25**	21.15	27.44	29.90	34.66
Close	**33.03**	**31.33**	**33.50**	**38.28**	28.14	35.37	37.40	37.21
New York Stock Exchange – US$								
High	**38.22**	**35.71**	**34.17**	**38.49**	27.92	36.93	37.31	39.62
Low	**28.04**	**27.65**	**28.56**	**31.53**	16.95	21.61	25.51	31.84
Close	**32.54**	**29.44**	**32.55**	**38.29**	22.21	30.34	34.56	35.31
Shares traded (thousands)								
Toronto Stock Exchange	**293 414**	**334 463**	**237 687**	**241 413**	408 851	361 886	339 790	277 779
New York Stock Exchange	**503 927**	**582 189**	**302 054**	**374 370**	778 887	697 065	541 485	436 930
Per common share information (dollars)								
Net earnings attributable to common shareholders	**0.46**	**0.31**	**0.65**	**0.87**	(0.20)	(0.06)	0.69	0.29
Cash dividends	**0.10**	**0.10**	**0.10**	**0.10**	0.05	0.05	0.10	0.10

(a) The company had approximately 3,600 holders of record of common shares as at January 31, 2011.

Information for Security Holders Outside Canada

Cash dividends paid to shareholders resident in countries with which Canada has an income tax convention are usually subject to Canadian non-resident withholding tax of 15%. The withholding tax rate is reduced to 5% on dividends paid to a corporation if it is a resident of the United States that owns at least 10% of the voting shares of the company.

QuickLinks

EXHIBIT 99-1

Audited Consolidated Financial Statements of Suncor Energy Inc. for the fiscal year ended December 31, 2010, including reconciliation to U.S. GAAP (Note 26)

QuickLinks -- Click here to rapidly navigate through this document

EXHIBIT 99-2

**Management's Discussion and Analysis for the fiscal year ended December 31, 2010,
dated February 24, 2011**

MANAGEMENT'S DISCUSSION AND ANALYSIS

February 24, 2011

This Management's Discussion and Analysis (MD&A) should be read in conjunction with Suncor's December 31, 2010 audited Consolidated Financial Statements and the accompanying notes.

All financial information is reported in Canadian dollars (Cdn$) and in accordance with Canadian generally accepted accounting principles (GAAP), unless noted otherwise. Certain amounts in prior years have been reclassified to conform to the current year's presentation.

Additional information about Suncor filed with Canadian securities commissions and the United States (U.S.) Securities and Exchange Commission (SEC), including periodic quarterly and annual reports and the Annual Information Form dated March 3, 2011 (the 2010 AIF), which is also filed with the SEC under cover of Form 40-F, is available online at www.sedar.com, www.sec.gov and our website www.suncor.com.

References to "we," "our," "Suncor," or "the company" mean Suncor Energy Inc., its subsidiaries, partnerships and joint venture investments, unless the context otherwise requires. References to "legacy Suncor" and "legacy Petro-Canada" refer to the applicable consolidated entity on a standalone basis prior to the August 1, 2009 merger date.

Petro-Canada Merger

On August 1, 2009, Suncor completed its merger with Petro-Canada, referred to in this MD&A as the "merger". Amounts disclosed in the audited Consolidated Financial Statements and this MD&A for 2009 and 2010 reflect results of the post-merger Suncor from August 1, 2009 together with results of legacy Suncor only from January 1, 2009 through July 31, 2009. The comparative figures from 2008 reflect solely the results of legacy Suncor. For further information with respect to the merger, please refer to note 3 of the December 31, 2010 audited Consolidated Financial Statements and the accompanying notes.

Non-GAAP Financial Measures

Certain financial measures referred to in this MD&A, namely operating earnings, cash flow from operations, return on capital employed (ROCE), and Oil Sands cash operating costs, are not prescribed by Canadian GAAP.

Operating earnings are reconciled to GAAP net earnings in the Consolidated Financial Analysis and Segmented Earnings and Cash Flows sections of this MD&A. Oil Sands cash operating costs are reconciled to GAAP expenses in the Oil Sands – Operating Expenses section of this MD&A. Cash flow from operations and ROCE are defined in the Non-GAAP Financial Measures Advisory section of this MD&A.

These non-GAAP financial measures do not have any standardized meaning and therefore are unlikely to be comparable to similar measures presented by other companies. These non-GAAP financial measures are included as management uses this information to analyze operating performance, leverage and liquidity. Therefore, these non-GAAP financial measures should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP.

Legal Advisories

This MD&A contains forward-looking information based on Suncor's current expectations, estimates, projections and assumptions. This information is subject to a number of risks and uncertainties, including those discussed in this MD&A and Suncor's other disclosure documents, many of which are beyond the company's control. Users of this information are cautioned that actual results may differ materially. Refer to the Legal Advisory – Forward-Looking Information section of this MD&A for information on material risk factors and assumptions underlying our forward-looking information.

Certain crude oil and natural gas liquids (NGL) volumes have been converted to thousands of cubic feet equivalent (mcfe) and millions of cubic feet equivalent (mmcfe) of natural gas on the basis of one barrel (bbl) to six thousand cubic feet (mcf). Also, certain natural gas volumes have been converted to barrels of oil equivalent (boe) or thousands of boe (mboe) on the same basis. Mmcfe, mcfe, boe and mboe may be misleading, particularly if used in isolation. A conversion ratio of one bbl of crude oil or NGL to six mcf of natural gas is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent value equivalency at the wellhead.

SUNCOR OVERVIEW

Suncor Energy Inc. is an integrated energy company headquartered in Calgary, Alberta. Suncor has classified its operations into the following segments:

- **Oil Sands**, includes operations in northeast Alberta to develop and produce synthetic crude through the recovery and upgrading of bitumen from mining and in situ operations. The company has a 12% ownership interest in the Syncrude oil sands mining and upgrading joint venture, located near Fort McMurray, Alberta.

- **Natural Gas**, includes exploration and production of natural gas, crude oil and NGL, primarily in Western Canada.

- **International and Offshore**, includes offshore activity in East Coast Canada, with interests in the Terra Nova, Hibernia, the Hibernia South Extension, White Rose, White Rose Extensions and Hebron oilfields, and exploration and production of crude oil and natural gas in the United Kingdom (U.K.), Norway, Libya and Syria.

- **Refining and Marketing**, includes the refining of crude oil products, and the distribution and marketing of these and other purchased products through refineries located in Canada and the U.S., as well as a lubricants plant located in Canada.

In addition, the company engages in third-party energy marketing and trading activities, and has investments in renewable energy assets, including Canada's largest ethanol plant by volume and partnerships in several wind power projects.

2010 HIGHLIGHTS

- **Strong financial results.** Net earnings more than tripled to $3.571 billion in 2010 from $1.146 billion in 2009, and our cash flow from operations[(1)] increased to $6.656 billion in 2010, from $2.799 billion in 2009. Our 2010 results reflected the improving economic environment for crude oil and refined products, and solid performance from our assets during the first full year after the August 2009 merger with Petro-Canada. Our return on capital employed[(1)] (excluding major projects in progress) increased to 10.1% in 2010, up from 2.6% in 2009.

- **Ten-year growth strategy.** In December 2010, we announced our new growth strategy. This plan begins in 2011, when we expect to direct approximately $2.8 billion towards a range of growth projects, as part of our overall 2011 capital-spending plan of $6.7 billion.

- **Strategic partnership with Total.** As part of the company's growth strategy, Suncor announced a strategic partnership with Total E&P Canada Ltd. (Total), setting the terms for our two companies to develop the Fort Hills and Joslyn oil sands mining projects together with the other project partners, and restart construction of the Voyageur Upgrader. The transaction is subject to certain regulatory and other approvals, with closing targeted late in the first quarter of 2011.

- **Improved operational reliability.** Oil Sands production steadily increased through 2010, finishing the year with record quarterly production volumes of 325,900 barrels per day (excluding Syncrude), compared to 202,300 barrels per day in the first quarter of this year, as a result of improved upgrader performance and strong bitumen supply across all of our Oil Sands assets. Western North America refinery utilization increased through 2010 to 101% in the fourth quarter from 92% in the first quarter.

- **Benefits of integration.** International and Offshore assets acquired in the merger generated strong cash flows, and the increased refining capacity and additional locations in our Refining and Marketing business allowed us to respond to opportunities from both improved margins and logistical constraints in the second half of 2010.

- **Planned divestments.** We successfully completed the planned disposal of approximately $3.5 billion of certain non-core assets from our Natural Gas and International and Offshore businesses. We also reached an agreement to sell non-core U.K. offshore assets, which we expect to complete during the first half of 2011.

- **Balance sheet strength.** Proceeds from our planned divestments have been largely directed to reduce our net debt to $11.1 billion at year-end 2010, from $13.4 billion last year. This, along with our strong financial results, enabled us to improve our key debt ratios, with net debt to cash flow from operations now down to 1.7, from 4.8 last year, well below our target of less than 2.0, and our total debt to total debt plus shareholders' equity measure down to 25%, from 29% in 2009.

- **Tailings pond reclamation.** During the year, Suncor became the first oil sands company to complete surface reclamation of a tailings pond. We also received regulatory approval for a new tailings management plan using the company's proprietary TRO$_{TM}$ tailings management process, which is expected to significantly reduce pond reclamation time.

(1) Cash flow from operations and return on capital employed are non-GAAP measures. See the Non-GAAP Financial Measures Advisory section of this MD&A.

BUSINESS ENVIRONMENT

Commodity Price Indicators and Exchange Rates

(average for the year ended December 31)		**2010**	2009	2008
West Texas Intermediate (WTI) crude oil at Cushing	US$/barrel	**79.55**	61.80	99.65
Dated Brent crude oil at Sullom Voe	US$/barrel	**79.50**	61.50	97.00
Dated Brent/Maya FOB price differential	US$/barrel	**9.30**	5.00	13.15
Canadian 0.3% par crude oil at Edmonton	Cdn$/barrel	**78.05**	65.80	103.05
Light/heavy crude oil differential of WTI at Cushing less Western Canadian Select (WCS) at Hardisty	US$/barrel	**14.20**	9.70	20.10
Natural gas (Alberta spot) at AECO	Cdn$/mcf	**4.15**	4.15	8.15
New York Harbour 3-2-1 crack	US$/barrel	**10.55**	8.80	11.05
Chicago 3-2-1 crack	US$/barrel	**9.00**	7.75	10.40
Seattle 3-2-1 crack	US$/barrel	**13.55**	11.40	12.10
Gulf Coast 3-2-1 crack	US$/barrel	**7.90**	7.10	9.45
Exchange rate	US$/Cdn$	**0.97**	0.88	0.94

Suncor's synthetic crude oil price realization is influenced by the market for light crude and our customers' alternatives. WTI crude oil at Cushing is the most common alternative benchmark. Oil prices strengthened in 2010 with WTI increasing from US$61.80/bbl to US$79.55/bbl since 2009.

Suncor's heavy crude oil price realization is influenced by customers' alternatives. WCS at Hardisty is a common reference price for Canadian heavy crude oil. The light/heavy crude differential between WTI and WCS widened in the second half of the year due to supply and demand factors including the Enbridge pipeline disruptions that limited the export capacity of heavy crude products from Western Canada, resulting in reduced and discounted sales. For the year ended December 31, 2010, this differential represented an average price discount of US$14.20/bbl to WTI, compared to US$9.70/bbl to WTI in 2009.

Suncor's price realization for International and Offshore production is influenced by the widely posted Brent crude oil price marker. Brent crude prices for the year ended December 31, 2010 averaged US$79.50/bbl, up from US$61.50/bbl for the year ended December 31, 2009.

Suncor's natural gas production is primarily referenced to the Alberta spot price at AECO. Natural gas prices for the year ended December 31, 2010 averaged $4.15/mcf, consistent with 2009.

The 3-2-1 crack spreads are industry indicators that roughly approximate the gross refining margin on a barrel of oil for gasoline and distillate. They are calculated by taking two times the spot price of gasoline at a certain location plus one multiplied by the spot price of diesel at the same location, subtracting three times the near-month contract price for NYMEX Light Sweet Crude Oil delivered at Cushing, Oklahoma, and then dividing the entire sum by three. Note that these prices do not necessarily reflect the actual crude purchase costs, product sales realizations, or product configurations of a specific refinery. These crack spreads were all higher for the year ended December 31, 2010 compared to 2009.

The majority of Suncor's revenues from the sale of oil and gas commodities receive prices that are determined by, or referenced to, U.S. dollar benchmark prices. The majority of Suncor's expenditures are realized in Canadian dollars. An increase in the value of the Canadian dollar relative to the U.S. dollar will decrease the revenues received from the sale of commodities and, correspondingly, a decrease in the value of the Canadian dollar relative to the U.S. dollar will increase the revenues received from the sale of commodities.

Economic Sensitivities

The following table illustrates the estimated effects that changes in certain factors would have had on Suncor's 2010 cash flow from operations and net earnings if they had occurred. Each separate line item in the sensitivity analysis shows the effects of a change in that variable only with all other variables being held constant.

	Approximate Change in Net Earnings ($ millions)	Approximate Change in Cash Flow from Operations [1] ($ millions)
Price		
Crude oil – WTI US$1.00/bbl	89	114
Natural gas – AECO Cdn$0.10/mcf	7	9
Light/heavy differential – (WTI/WCS) US$1.00/bbl	34	44
Sales Volume		
Crude oil – 10,000 bbl/day	129	163
Natural gas – 10 mmcf/d	1	11
Foreign currency [2]		
$0.01 change in US$/Cdn$	(39)	(129)

(1) Non-GAAP measure. See the Non-GAAP Financial Measures Advisory section of this MD&A.

(2) The net earnings sensitivity includes the gain or loss on the revaluation of U.S. dollar denominated long-term debt, the change in interest expense on that debt, and the estimated effect on upstream sales realizations and refining margins. The cash flow from operations sensitivity includes the change in interest payments on U.S. dollar denominated long-term debt, and the estimated effect on realizations and margins.

SELECTED FINANCIAL INFORMATION

Annual Financial Data

($ millions, except as noted)	**2010**	2009	2008
Revenues (net of royalties)			
Continuing operations	**34 350**	24 848	28 446
Discontinued operations [1]	**870**	632	191
	35 220	25 480	28 637
Net earnings (loss)			
Continuing operations	**2 688**	1 206	2 082
Discontinued operations	**883**	(60)	55
	3 571	1 146	2 137
Net earnings from continuing operations per common share			
Basic	**1.72**	1.01	2.23
Diluted	**1.71**	1.00	2.20
Net earnings per common share [2]			
Basic	**2.29**	0.96	2.29
Diluted	**2.27**	0.95	2.26
Cash flow from operations [3]			
Continuing operations	**6 164**	2 434	3 888
Discontinued operations	**492**	365	169
	6 656	2 799	4 057
Total assets	**70 169**	69 746	32 528
Long-term debt, including current portion	**12 187**	13 880	7 884
Dividends on common shares	**611**	401	180
Cash dividends per common share	**0.40**	0.30	0.20

(1) Net of $62 million of operating revenues that would be eliminated upon consolidation in the Consolidated Statements of Earnings for the year ended December 31, 2010 (2009 – $33 million, 2008 – $24 million). See note 6 of the audited Consolidated Financial Statements.

(2) Includes continuing and discontinued operations.

(3) Non-GAAP measure. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Upstream Production Volumes

mboe per day (mboe/d)	**2010**	2009	2008
Continuing operations			
Oil Sands	**318.2**	306.7	228.0
Natural Gas	**72.0**	47.0	23.5
International and Offshore	**170.9**	58.0	—
	561.1	411.7	251.5
Discontinued operations			
Natural Gas	**23.8**	27.4	13.2
International and Offshore	**30.2**	16.9	—
	54.0	44.3	13.2
Total	**615.1**	456.0	264.7

Downstream Sales Volumes

Thousands of cubic metres per day (thousands of m^3/d)	**2010**	2009	2008
Total refined product sales	**87.8**	54.9	31.5

CONSOLIDATED FINANCIAL ANALYSIS

Net Earnings

Positive factors impacting Suncor's net earnings from continuing operations for 2010, compared to 2009, included:

- Upstream production for 2010 averaged 561,100 boe per day (boe/d), compared to 411,700 boe/d in 2009. Total sales of refined petroleum products averaged 87,800 cubic metres per day (m^3/d) during 2010, up from 54,900 m^3/d in 2009. Both production and sales volumes increases were primarily due to the additional volumes resulting from the merger.

- Realized prices were higher in 2010 compared to 2009. Increases in benchmark pricing were only partially offset by the widening of heavy crude differentials and the stronger Canadian dollar relative to the U.S. dollar.

- Suncor recognized a pre-tax gain of $295 million pertaining to the redetermination of working interests for the Terra Nova oilfield, after the joint owners reached an agreement on December 1, 2010.

These positive factors were partially offset by the following:

- Operating, selling and general expenses of $7.810 billion were higher in 2010, compared to $6.430 billion in 2009, primarily due to the inclusion of a full twelve months of legacy Petro-Canada operations in 2010, compared to only five months after the merger in 2009, as well as higher planned and unplanned maintenance activities in 2010, compared to 2009.

- Depreciation, depletion and amortization (DD&A) of $3.813 billion was higher in 2010, compared to $1.860 billion in 2009, primarily due to the additional assets acquired through the merger and asset write-downs recorded in 2010.

- Royalties of $1.937 billion were higher in 2010, compared to $1.150 billion in 2009, primarily due to the full year of legacy Petro-Canada production, higher royalty rates, a higher commodity price environment, and receipt of insurance proceeds from Suncor's captive insurance company. These increases were partially offset by a $140 million royalty recovery (pre-tax) booked in the fourth quarter of 2010 related to a notice received by the company from the Alberta government modifying the bitumen valuation methodology (BVM) calculation under Suncor's Royalty Amending Agreement (RAA) that expires in December 2015.

- Financing income was $30 million in 2010, compared to financing income of $488 million in 2009, largely due to lower foreign exchange gains on U.S. dollar denominated long-term debt in 2010.

- In 2009, net earnings included a pre-tax gain of $438 million on the effective settlement of a pre-existing processing contract with Petro-Canada, whereby Suncor processed MacKay River bitumen production for a fee.

Income tax expense was $1.860 billion in 2010 (34% effective tax rate), compared to $143 million in 2009 (11% effective tax rate). The lower effective tax rate in 2009 was primarily due to the lower tax rate applicable to the company's foreign exchange gains on U.S. dollar denominated long-term debt, and no tax impact on the gain on effective settlement of the pre-existing processing contract with Petro-Canada.

Discontinued operations

In 2010, Suncor divested a number of non-core assets in the Natural Gas and International and Offshore segments. Results up to the closing date and any associated gain or loss on disposals of assets are presented as discontinued operations, as determined in accordance with GAAP. Current year net earnings from discontinued operations of $883 million includes pre-tax gains of $814 million on the asset disposals.

Cash flow from operations

Cash flow from operations was $6.656 billion in 2010, compared to $2.799 billion in 2009. The increase in cash flow from operations was primarily due to increased production volumes, higher refining and marketing sales, and higher realized prices. Cash flow from operations is a non-GAAP measure that the company uses to measure performance. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Net Earnings for 2009 compared with 2008

Net earnings from continuing operations were $1.206 billion in 2009, compared with $2.082 billion in 2008. The decrease in net earnings from continuing operations was due primarily to lower price realizations, as well as costs related to deferring growth projects, and merger and integration costs associated with the merger with Petro-Canada on August 1, 2009. These impacts more than offset the increased upstream production, increased refined product sales volumes, and the gain on the effective settlement of a pre-existing processing contract with Petro-Canada. Net earnings in 2009 also included losses on commodity derivatives used for risk management, compared to a gain on these derivatives in 2008.

The merger increased Suncor's asset base by $35.8 billion, including goodwill, and long-term debt by $4.4 billion.

Operating Earnings [1]

Year ended December 31 ($ millions after-tax)	**2010**	2009	2008
Net earnings from continuing operations	**2 688**	1 206	2 082
Change in fair value of commodity derivatives used for risk management, net of realizations [2]	**(233)**	499	(372)
Unrealized foreign exchange gain on U.S. dollar denominated long-term debt	**(372)**	(798)	852
Mark-to-market valuation of stock-based compensation	**103**	124	(107)
Project start-up costs	**58**	40	24
Costs related to deferral of growth projects	**94**	300	—
Merger and integration costs	**79**	151	—
(Gain)/Loss on disposals [3]	**(121)**	39	—
Other income [4]	**(166)**	24	—
Adjustments to provisions [5]	**(51)**	50	—
Impairment and write-offs [6]	**317**	—	—
Adjustments to provisions for assets acquired through the merger [7]	**68**	—	—
Gain on effective settlement of pre-existing contract with Petro- Canada [8]	**—**	(438)	—
Impact of recording acquired inventory at fair value [9]	**—**	97	—
Impact of income tax rate adjustments on future income tax liabilities [10]	**—**	4	—
Operating earnings from continuing operations	**2 464**	1 298	2 479
Net earnings (loss) from discontinued operations	**883**	(60)	55
Gain on disposals of discontinued operations [3]	**(689)**	—	—
Impairment and write-offs of discontinued operations [6]	**74**	42	—
Operating earnings from total operations	**2 732**	1 280	2 534

(1) Operating earnings is a non-GAAP measure that adjusts net earnings for significant items that management believes are not indicative of operating performance and reduces the comparability of the underlying financial performance between periods. All reconciling items are presented on an after-tax basis. See the Non-GAAP Financial Measures Advisory section of this MD&A.

(2) The company adjusts operating earnings for the change in fair value of significant crude oil risk management derivatives. The company also holds less significant risk management derivatives in other segments that are not adjusted.

(3) The 2010 total includes Natural Gas non-core asset sales and International and Offshore asset and share sales, a gain on unproven land in Natural Gas, and gains on Refining and Marketing sale of retail sites. The 2009 total related to a loss recognized when a highway interchange constructed by Suncor was transferred to the Government of Alberta, and fair value adjustments to assets acquired in the merger.

(4) Other income resulting from the settlement payment due to Suncor related to the Terra Nova redetermination. The payment will effectively reimburse Suncor for certain revenue related to its increased working interest (to 37.675% from 33.990%) back to the payout date of February 1, 2005. Operating earnings for 2010 and 2009 have been restated to reflect the portion of settlement attributable to the respective year.

(5) Impact from a royalty recovery related to a notice received by the company from the Alberta government modifying the BVM calculation for the interim period January 1, 2009 to December 31, 2010. As a result, the company reduced its royalty expense reserve by approximately $105 million (after-tax) in the fourth quarter of 2010. Operating earnings for prior years have been restated to effectively remove the original

provision booked. The company continues to negotiate final adjustments to the BVM calculation for the 2009 and 2010 interim period and for the term of the Suncor Royalty Amending Agreement that expires December 31, 2015.

(6) The 2010 total includes a write-down related to certain extraction equipment in the Oil Sands segment, a write-down of land leases no longer being pursued by the Natural Gas segment, an impairment of natural gas properties due to the lower gas price environment, an adjustment to spare parts inventory and an impairment of assets from the International and Offshore segment based on agreed sale price.

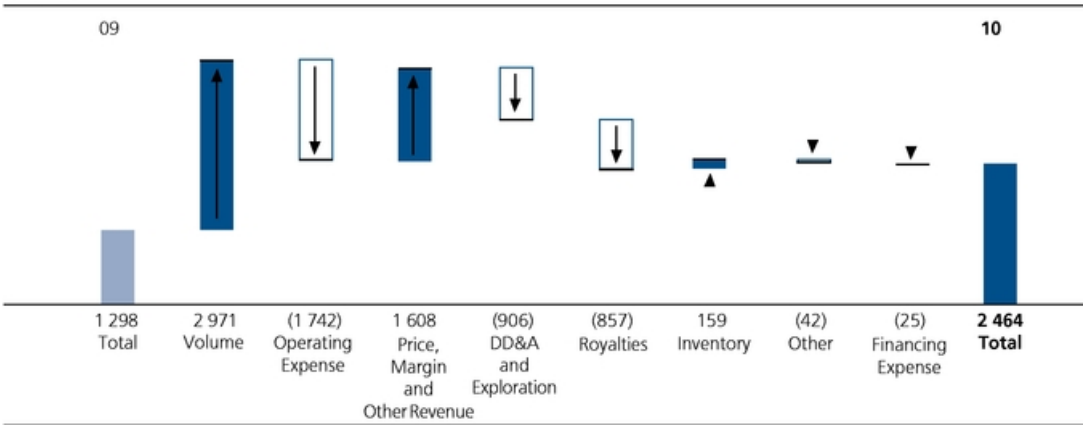
(7) The 2010 total includes adjustments for unfavourable pipeline commitments, adjustments made for past cost reconciliation related to the Exploration and Production Sharing Contracts (EPSAs) in Libya, a dry hole in Libya, a write-off of unproven land in Natural Gas, and a reduction to the provision related to the Montreal coker project.

(8) Impact from the deemed settlement value assigned to the bitumen processing contract with Petro-Canada upon close of the merger.

(9) Inventory acquired through the merger with Petro-Canada at fair value was sold during the third quarter of 2009, resulting in a one-time negative impact on earnings.

(10) Net impact from an increase in the future income tax liability resulting from a revised provincial allocation for income tax purposes because of the merger and a decrease in the future income tax liability resulting from the provincial rate reduction in Ontario.

Consolidated Operating Earnings from Continuing Operations
($ millions)



Operating Earnings by Segment

Year ended December 31 ($ millions after-tax)	**2010**	2009	2008
Continuing operations			
Oil Sands	**1 535**	1 116	2 522
Natural Gas	**(137)**	(173)	34
International and Offshore	**993**	362	—
Refining and Marketing	**782**	473	(23)
Corporate, Energy Trading and Eliminations	**(709)**	(480)	(54)
	2 464	1 298	2 479
Discontinued operations			
Natural Gas	**49**	(14)	55
International and Offshore	**219**	(4)	—
	268	(18)	55
Total operating earnings (1)	**2 732**	1 280	2 534

(1) Non-GAAP measure. See the Non-GAAP Financial Measures Advisory section of this MD&A.

SEGMENTED EARNINGS AND CASH FLOWS

Oil Sands

Located in northeast Alberta, the Oil Sands operations recover bitumen from mining and in situ operations (Firebag and MacKay River) and upgrade the majority of this production into refinery feedstock, diesel fuel and byproducts. The company's marketing plan also includes sales of bitumen when market conditions are favourable or when operating conditions warrant. The Oil Sands business also includes a 12% ownership interest in the Syncrude oil sands joint venture and a share in the Fort Hills project.

On December 17, 2010, Suncor announced a strategic partnership with Total. Subject to certain conditions, the agreement provides that the two companies plan to develop the Fort Hills and Joslyn oil sands mining projects together with the other project partners, and restart construction on the Voyageur Upgrader, all with targeted operational dates ranging from 2016 to 2018.

On closing, it is expected that Total will acquire a 49% interest in Suncor's Voyageur Upgrader, and an additional 19.2% in the Fort Hills project, reducing Suncor's interest from 60% to 40.8%. In return, it is expected that Suncor will acquire a 36.75% interest in the Joslyn project and receive cash consideration of approximately $1.75 billion.

The transaction is subject to certain regulatory and other approvals, with closing targeted during the first quarter of 2011. The development of the Fort Hills and Joslyn oil sands mining projects, as well as the continued construction of the Voyageur Upgrader, is subject to approval by all of the partners in these ventures and by Suncor's Board of Directors.

Year ended December 31 ($ millions, unless otherwise noted)	**2010**	2009	2008
Gross revenues and other income	**10 104**	7 184	9 354
Less: Royalties	**(681)**	(645)	(715)
Net revenues	**9 423**	6 539	8 639
Total production in thousands of barrels per day (mbbls/d)	**318.2**	306.7	228.0
Average sales price – includes the impact of realized risk management activities (excluding Syncrude) ($/bbl) [1]	**69.58**	61.66	95.96
Net earnings	**1 492**	557	2 875
Operating earnings [2]	**1 535**	1 116	2 522
Cash flow from operations [2]	**2 769**	1 251	3 507
Cash operating costs (excluding Syncrude) ($/bbl) [2]	**38.85**	33.95	38.50
Sales mix (sweet/sour mix) (%)	**37/63**	47/53	43/57

(1) Before royalties and net of related transportation costs.

(2) Non-GAAP measures. Operating earnings and cash operating costs are reconciled below. Cash flow from operations is reconciled in the Non-GAAP Financial Measures Advisory section of this MD&A.

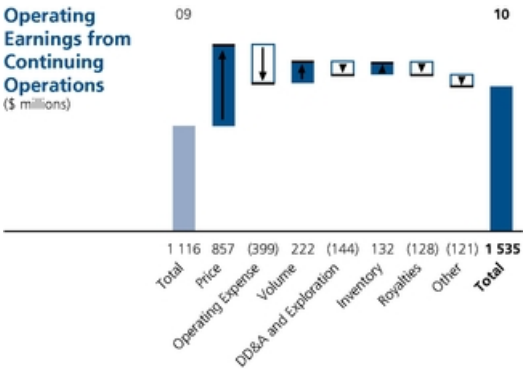
Operating Earnings Reconciliation

Year ended December 31 ($ millions)	**2010**	2009	2008
Net earnings	**1 492**	557	2 875
Change in fair value of commodity derivatives used for risk management, net of settlements	**(233)**	499	(372)
Mark-to-market valuation of stock-based compensation	**31**	28	(5)
Project start-up costs	**55**	40	24
Costs related to deferral of growth projects	**94**	299	—
Losses on disposals	**4**	39	—
Impairment and write-offs	**143**	—	—
Adjustment to provisions	**(51)**	50	—
Impact of income tax rate adjustments on future income tax liabilities	**—**	37	—
Gain on effective settlement of pre-existing contract with Petro-Canada	**—**	(438)	—
Impact of recording acquired inventory at fair value	**—**	5	—
Operating earnings [1]	**1 535**	1 116	2 522

(1) Non-GAAP measure. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Oil Sands net earnings were $1.492 billion in 2010, compared to $557 million in 2009. Net earnings in 2010 included the impacts of higher average prices for oil sands crude products, a gain on commodity derivatives used for risk management, compared to a loss in 2009, increased total production and lower costs related to deferral of growth projects. Net earnings in 2010 also included a $140 million (pre-tax) royalty provision recovery related to a notice received by the company from the Alberta Government modifying the BVM calculation for the interim period January 1, 2009 to December 31, 2010, under Suncor's RAA. These factors were partially offset by higher 2010 operating costs, including higher project start-up costs for Firebag Stages 3 and 4, a write-down of certain extraction assets that were being developed as an alternative extraction process to crush and slurry oil sands at the mine face and a gain on the effective settlement of a pre-existing contract with Petro-Canada in 2009, whereby Suncor processed MacKay River bitumen production for a fee.

Continuing Operations



Operating earnings for 2010 were $1.535 billion, compared to $1.116 billion in 2009. The 38% increase in 2010 operating earnings was primarily due to higher realized prices and increased total production, partially offset by higher operating expenses.

Production Volumes

Year ended December 31 (mbbls/d)	**2010**	2009	2008
Production excluding Syncrude	**283.0**	290.6	228.0
Syncrude production [1]	**35.2**	16.1	—
Total production	**318.2**	306.7	228.0

(1) Production for the five months ended December 31, 2009 was 38.5 mbbls/d.

Total production increased 4% in 2010, compared to 2009, primarily due to additional production from Syncrude as a result of the timing of the merger. Apart from the Syncrude production, the merger did not result in increased Oil Sands production volumes, as production from MacKay River was included in Suncor's reported production during 2009 as volumes processed by Suncor under a processing fee agreement. However, the addition of seven months of MacKay River production in 2010 due to the timing of the merger has resulted in increased sales volumes for Oil Sands, as volumes under the processing agreement with Petro-Canada were not included in sales prior to August 1, 2009.

Production of 283,000 bpd in 2010, excluding Syncrude, was 3% lower compared with 290,600 bpd in 2009. The beginning of 2010 was negatively impacted by both planned and unplanned maintenance, which was partially offset by improved upgrader reliability and bitumen supply in the latter part of the year. Oil Sands completed the year with record production of 325,900 bpd in the fourth quarter of 2010. Unplanned maintenance at the beginning of the year included rebuild work on Upgrader 2 and Upgrader 1 following fires in December 2009 and February 2010. As a result, production for the year was reduced by approximately 29,500 bpd. The production impacts of the fire were mitigated by Suncor's ability to sell bitumen in the market, avoiding a shut-in of production.

Syncrude production contributed 35,200 bpd of sweet synthetic crude production in 2010, compared to 16,100 bpd in 2009. The increase was due to the additional seven months of production included in 2010, compared to 2009, as a result of the timing of the merger. Excluding the effects related to the timing of the merger, production from Syncrude decreased 9% due to planned and unplanned upgrader maintenance.

Prices

Year ended December 31 (in Cdn$ per bbl)	**2010**	2009	2008
Average sales price – includes the impact of realized risk management activities (excluding Syncrude)	**69.58**	61.66	95.96
Average sales price – Syncrude	**80.93**	77.36	—
Sales mix (sweet/sour mix) (%)	**37/63**	47/53	43/57
Sales volumes (mbbls/d) – excluding Syncrude	**279.3**	276.2	227.0
Syncrude sales volumes (mbbl/d)	**35.2**	16.1	—

Oil Sands benefited from higher benchmark crude oil prices and lower realized losses in 2010 compared to 2009, partially offset by wider heavy crude differentials, change in sales mix and the stronger Canadian dollar relative to the U.S. dollar. Heavy crude oil differentials widened in the second half of 2010, as a result of the Enbridge pipeline disruptions that limited the export capacity of heavy crude products from Western Canada, resulting in reduced and discounted sales. These disruptions, and the resulting increase in supply of heavy crude products, negatively impacted both sour crude and bitumen price realizations.

Sales mix was negatively impacted in 2010 by the upgrader fires that occurred in December 2009 and February 2010, and by hydrogen supply and hydrotreating capacity issues in the latter part of 2010. This resulted in a lower percentage of higher value sweet crude product produced, increasing the sales volumes of lower value sour crude and bitumen.

In 2010, the Suncor average price realization on the crude sales basket, excluding Syncrude and derivatives used for risk management, was WTI less US$9.92 per bbl, or 88% of WTI, in comparison to 2009 when the price realization was WTI less US$5.22 per bbl, or 92% of WTI.

Operating Expenses

Operating expenses were higher in 2010, compared to 2009, primarily due to the inclusion of a full year of operating costs from the company's proportionate share of the Syncrude joint venture, higher costs from planned and unplanned maintenance, and the full year of operating costs from MacKay River operations, due to the timing of the merger. As noted previously in this MD&A, MacKay River production volumes were included in the 2009 results, whereas the associated operating expenses were not included as the volumes had originally been recorded under a processing agreement.

Third-party crude and diesel product purchases were higher in 2010, compared to 2009, to facilitate placement of Oil Sands heavy production and to fulfill contractual obligations. Product purchases have a minimal effect on earnings as these are largely offset in revenue.

Cash Operating Costs Reconciliation (1)(2)

Year ended December 31 ($ millions, unless otherwise noted)	**2010**		2009		2008	
	$ millions	**$/bbl**	$ millions	$/bbl	$ millions	$/bbl
Operating, selling and general expenses	**4 545**		4 277		3 203	
Adjustments:						
Syncrude-related operating, selling and general expenses	**(473)**		(199)		—	
Other non-production related costs (3)	**(60)**		(479)		9	
Cash operating costs – excluding Syncrude	**4 012**	**38.85**	3 599	33.95	3 212	38.50

(1) Excludes Suncor's proportionate production share and operating costs from the Syncrude joint venture.

(2) Non-GAAP measure. See the Non-GAAP Financial Measures Advisory section of this MD&A.

(3) Other adjustments includes items such as safe mode costs (the cost of placing a growth project on hold or in "safe mode"), inventory changes, stock-based compensation, gas swaps, accretion of asset retirement obligations and imported bitumen (excluding other reported product purchases). For the twelve months ended December 31, other non-production related costs were lower in 2010 compared to 2009, primarily due to lower safe mode costs ($254 million) offset by higher imported bitumen costs ($67 million).

Cash operating costs (excluding Syncrude) increased to $4.012 billion in 2010 from $3.599 billion in 2009. On a per barrel basis, these costs increased to $38.85/bbl in 2010 compared to $33.95/bbl in 2009, an increase of 14% year-over-year. The increase in cash operating costs was primarily due to the additional seven months of operating costs from the MacKay River operation, and reduced volumes and higher costs from planned and unplanned maintenance.

Cash operating costs for Suncor's interest in Syncrude operations averaged $37.95 per bbl in 2010, compared to $32.50 per bbl for the last five months of 2009. The increase in the current year was primarily due to the effects of planned maintenance on 2010 production, compared to 2009, where the five-month period included in 2009 due to the timing of the merger excluded significant effects of planned and unplanned maintenance.

Users are cautioned that the cash operating costs per barrel measure is not directly comparable to similar information calculated by other entities (including Syncrude), due to different accounting treatments for operating and capital costs amongst producers.

DD&A

The increase in DD&A expense from 2010 was due to newly commissioned assets and additional depreciation due to the assets acquired during the merger. Oil Sands assets are primarily depreciated on a straight-line basis.

Royalties

The increase in royalty expense was primarily due to the inclusion of a full twelve months of royalty payable production acquired in the merger (versus only five months in 2009) related to MacKay River and Suncor's proportionate share of Syncrude production, higher royalty rates and receipt of insurance proceeds from Suncor's captive insurance company for which royalties were payable. Suncor's MacKay River project moved to post-payout in November 2010, thereby increasing the percentage of royalties paid to approximately 31% of revenues minus costs for this period. Suncor's Firebag operation continued in the pre-payout phase and royalties were calculated at the minimum royalty percentage of revenues, which was a rate based on the Canadian dollar equivalent of WTI up to a maximum of 9%.

Safe Mode Costs

The company continues to incur costs related to placing certain growth projects into "safe mode" due to unfavourable market conditions in prior years. Safe mode costs are defined as the costs of deferring the projects, maintaining the equipment and facilities in a safe manner in order to expedite remobilization and the actual remobilization cost of growth projects placed into safe mode. As a result of placing certain projects into safe mode, pre-tax costs of $126 million were incurred in 2010, compared to $380 million in 2009. In 2010, Firebag Stage 3, Firebag Stage 4 and the Millennium Naphtha Unit (MNU) projects were all remobilized.

Planned Maintenance Turnarounds

Suncor's Oil Sands business has a six-week planned turnaround scheduled for Upgrader 2 in the second quarter of 2011. Production volumes are expected to be reduced by approximately 215,000 bpd over the duration of the turnaround.

Natural Gas

Suncor's Natural Gas business, operating primarily in Western Canada, explores for, acquires, develops and produces natural gas, NGLs, oil and byproducts that are used for internal consumption and sale to customers across North America.

Year ended December 31 ($ millions, unless otherwise noted)	**2010**	2009	2008
Gross revenues from continuing operations	**810**	459	471
Less: Royalties from continuing operations	**(76)**	(36)	(107)
Net revenues from continuing operations	**734**	423	364
Gross production			
Continuing operations (mmcfe per day – mmcfe/d)	**432**	282	141
Discontinued operations (mmcfe/d)	**143**	164	79
	575	446	220
Average sales price from continuing operations			
Natural gas – includes the impacts of realized risk management activities ($/mcf) [1]	**3.99**	3.63	8.21
Natural gas liquids and crude oil ($/bbl) [1]	**77.37**	59.41	68.05
Net earnings (loss)			
Continuing operations	**(277)**	(185)	34
Discontinued operations	**506**	(14)	55
	229	(199)	89
Operating earnings (loss) [2]			
Continuing operations	**(137)**	(173)	34
Discontinued operations	**49**	(14)	55
	(88)	(187)	89
Cash flow from operations [2]			
Continuing operations	**320**	177	198
Discontinued operations	**125**	152	169
	445	329	367

(1) Calculated before royalties and net of transportation costs.

(2) Non-GAAP measures. Operating earnings is reconciled below. Cash flow from operations is reconciled in the Non-GAAP Financial Measures Advisory section of this MD&A.

Operating Earnings Reconciliation

Year ended December 31 ($ millions)	**2010**	2009	2008
Net loss from continuing operations	**(277)**	(185)	34
Mark-to-market valuation of stock-based compensation	**9**	11	—
Gains on disposals	**(99)**	—	—
Impact of income tax rate adjustments on future income tax liabilities	**—**	1	—
Impairment and write-offs	**174**	—	—
Adjustments to provisions for assets acquired through the merger	**56**	—	—
Operating loss from continuing operations [1]	**(137)**	(173)	34
Net earnings (loss) from discontinued operations	**506**	(14)	55
Gains on disposals of discontinued operations	**(479)**	—	—
Impairment and write-offs	**22**	—	—
Operating loss from total operations [1]	**(88)**	(187)	89

(1) Non-GAAP measure. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Natural Gas had total net earnings of $229 million in 2010, compared with a net loss of $199 million in 2009. Net earnings in 2010 were positively impacted, compared to 2009, by pre-tax gains of $774 million on asset dispositions for non-core assets and unproven land sold in 2010, and increased total production as a result of the merger. These factors were partially offset by a $222 million write-down (pre-tax) of certain assets where the carrying value of the assets was greater than their expected discounted future cash flows, and the $44 million write-down (pre-tax) of certain land leases in Western Canada and Alaska that the company was no longer pursuing as part of its strategic business realignment.

Continuing Operations

Operating loss from continuing operations in 2010 was $137 million, compared to an operating loss from continuing operations of $173 million in 2009. The decrease in operating loss from continuing operations in 2010 was primarily due to higher production volumes as a result of the merger, lower exploration expenses and higher realized prices. This was partially offset by higher lifting costs as a result of the merger and higher DD&A expense.

Production Volumes

Year ended December 31 (mmcfe/d)	**2010**	2009	2008
Natural gas	**399**	262	135
Natural gas liquids and crude oil	**33**	20	6
Gross production	**432**	282	141

Gross production from continuing operations increased 53% in 2010, compared to 2009. The increase primarily reflects additional production associated with the assets acquired as a result of the merger, partially offset by asset dispositions and natural declines.

Prices

Natural gas average realized prices were higher in 2010, compared to 2009, although the average AECO benchmark was unchanged year-over-year, due to the volume and timing of sales in 2009. As a result of the merger, sales were higher in the second half of 2009 when the AECO benchmark price was lower, which had an overall impact of decreasing the natural gas realized price in 2009. In 2010, sales volumes and realized prices were more consistent throughout the year and transportation costs were lower.

Operating Expenses

Operating expenses from continuing operations increased in 2010, compared to 2009, due to the operating expenses associated with the assets acquired as a result of the merger being included for the full 2010 year, compared to only five months in 2009, due to the timing of the merger. Operating expenses per unit of production of $2.18/mcfe were higher than 2009 ($1.98/mcfe), primarily due to plant turnaround costs incurred in the fourth quarter of 2010.

DD&A and Exploration Expenses

DD&A from continuing operations increased in 2010, compared to 2009, primarily due to higher production volumes from assets acquired as a result of the merger. Natural Gas assets are primarily depleted on a unit-of-production basis.

Exploration expenses from continuing operations decreased due to reduced exploration activity and increased drilling success in 2010, resulting in lower dry hole costs.

Royalties

In 2010, total Crown royalties from continuing operations increased compared to 2009. The increased royalties were primarily associated with the production acquired as a result of the merger, higher realized prices in 2010 versus 2009 and higher royalty credits received in 2009.

Discontinued Operations

Natural Gas has divested a number of non-core natural gas assets throughout 2010. Discontinued operations as determined in accordance with GAAP includes the results, up to the closing date, of assets that have been sold during the year. Comparative results have been restated to reflect the impact of operations that have been classified as discontinued during 2010. The following is a summary of key divestitures:

- On March 1, 2010, the company completed the sale of substantially all of its U.S. Rockies upstream assets for net proceeds of US$481 million. Remaining U.S. Rockies upstream assets were sold shortly thereafter.
- On March 31, 2010, the company completed the sale of certain non-core natural gas properties located in northeast British Columbia, known as Blueberry and Jedney, for net proceeds of $383 million.
- On May 31, 2010, the company completed the sale of non-core natural gas properties located in central Alberta, known as Rosevear and Pine Creek, for net proceeds of $229 million.
- On August 31, 2010, the company completed the sale of its non-core natural gas properties located in west central Alberta, known as Bearberry and Ricinius, for net proceeds of $275 million.
- On September 30, 2010, the company completed the sale of its non-core natural gas properties located in southern Alberta, known as Wildcat Hills, for net proceeds of $351 million.

International and Offshore

Suncor's International and Offshore operations comprise production and exploration activity offshore Newfoundland and in the North Sea, onshore production and exploration activity in Libya and Syria, and exploration acreage in Norway.

In East Coast Canada, Suncor operates Terra Nova, holding a working interest of 37.675% that increased from 33.990% effective January 1, 2011. This working interest redetermination was finalized in December 2010 in accordance with the Terra Nova Development and Operating Agreement. Suncor also holds a 20% interest in Hibernia and a 19.5% interest in the Hibernia South Extension, a 27.5% interest in White Rose and a 26.125% interest in White Rose North Amethyst and West White Rose Extension, and a 22.7% interest in Hebron. In the North Sea, Suncor holds a 29.9% working interest in Buzzard. Suncor also operates in Libya, pursuant to EPSAs, to design and implement jointly the development of oil fields in the Sirte Basin, and in Syria, pursuant to a production sharing contract (PSC), on the Ebla gas project to develop the Ash Shaer and Cherrife areas.

In late February, civil unrest swept Libya. At the time of filing this report, the degree and duration of impact on Suncor's operations is not known.

Year ended December 31 ($ millions, unless otherwise noted)	**2010**	2009
Gross revenues from continuing operations	**5 503**	1 686
Less: Royalties	**(1 180)**	(469)
Net revenues from continuing operations	**4 323**	1 217
Production from continuing operations (mboe/d)		
East Coast Canada	**68.6**	24.3
U.K. (Buzzard)	**55.5**	20.0
Libya	**35.2**	13.7
Syria	**11.6**	—
Total production from continuing operations (mboe/d)	**170.9**	58.0
Total production from discontinued operations (mboe/d)	**30.2**	16.9
Total production (mboe/d) [1]	**201.1**	74.9
Average sales price from continuing operations [2]		
East Coast Canada ($/bbl)	**80.20**	76.86
U.K. (Buzzard) ($/boe)	**77.91**	69.53
Other International ($/boe)	**78.07**	77.53
Net earnings (loss)		
Continuing operations	**1 114**	323
Discontinued operations	**377**	(46)
	1 491	277
Operating earnings (loss) [3]		
Continuing operations	**993**	362
Discontinued operations	**219**	(4)
	1 212	358
Cash flow from operations [3]		
Continuing operations	**2 512**	738
Discontinued operations	**367**	213
	2 879	951

(1) Production for the five months ended December 31, 2009 was 178.8 mboe/d.

(2) Calculated before royalties and net of transportation costs.

(3) Non-GAAP measure. Operating earnings is reconciled below. Cash flow from operations is reconciled in the Non-GAAP Financial Measures Advisory section of the MD&A.

Operating Earnings Reconciliation

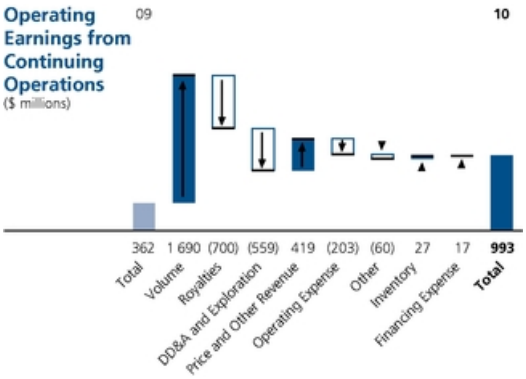
Year ended December 31 ($ millions)	2010	2009
Net earnings from continuing operations	**1 114**	323
Mark-to-market valuation of stock-based compensation	**14**	10
Other income [1]	**(166)**	24
Project start-up costs	**3**	—
Impact of income tax rate adjustments on future income tax liabilities	**—**	(20)
Impact of recording acquired inventory at fair value	**—**	25
Adjustments to provisions for assets acquired through the merger	**28**	—
Operating earnings from continuing operations [2]	**993**	362
Net earnings (loss) from discontinued operations	**377**	(46)
Gains on disposals of discontinued operations	**(210)**	—
Impairment and write-offs	**52**	42
Operating earnings from total operations [2]	**1 212**	358

(1) Other income resulting from the settlement payment due to Suncor related to the Terra Nova redetermination. The payment of $220 million (after-tax) reimburses Suncor for certain net revenues related to its increased interest from the field payout date of February 1, 2005 to December 31, 2010. Operating earnings for 2010 and 2009 have been restated to include only the amount that relates to the comparative period.

(2) Non-GAAP measure. See the Non-GAAP Financial Measures Advisory section of the MD&A.

International and Offshore had net earnings of $1.491 billion in 2010, compared to $277 million in 2009. Net earnings in 2010 were positively impacted by increased production as a result of the timing of the merger and new production coming on-stream in 2010, higher realized commodity prices, pre-tax gains of $170 million on asset dispositions and the $295 million pre-tax gain recognized pertaining to the Terra Nova redetermination.

Continuing Operations



Operating earnings from continuing operations were $993 million in 2010, compared to $362 million in 2009. Operating earnings from continuing operations were higher in 2010 due to increased production as a result of the timing of the merger and new production coming on-stream, and higher realized commodity prices. These increases were partially offset by increases to royalty expense and DD&A expense, due to the additional seven months of operations as a result of the timing of the merger.

Production Volumes

Year ended December 31 (mboe/d)	2010	2009
Production from continuing operations		
East Coast Canada		
Terra Nova	**23.2**	8.7
Hibernia	**30.9**	11.4
White Rose	**14.5**	4.2
U.K.		
Buzzard	**55.5**	20.0
Libya	**35.2**	13.7
Syria	**11.6**	—
Total production[1]	**170.9**	58.0

(1) Production from continuing operations for the five months ended December 31, 2009 averaged 138.4 mboe/d.

Production from continuing operations was significantly higher in 2010, compared to 2009, primarily due to the seven additional months of production included in 2010 as a result of the timing of the merger. Excluding the volume impacts due to the merger, there was higher production in 2010, compared with 2009, as a result of new production that came on-stream in 2010 in Syria and the North Amethyst portion of the White Rose Extensions (North Amethyst), and from new production from the AA Block area of Hibernia that came on-stream at the end of 2009. Buzzard also had higher production in 2010 due to the smaller scope of maintenance activity as compared to 2009.

Prices

International and Offshore benefited from higher price realizations in 2010, due to higher benchmark commodity prices relative to 2009.

Operating Expenses

Operating expenses from continuing operations increased in 2010, compared to 2009, primarily due to the additional seven months of production included in 2010 as a result of the timing of the merger, and costs associated with the new production delivered from Syria and North Amethyst, partially offset by cost reduction initiatives undertaken during the year.

DD&A

DD&A from continuing operations was higher in 2010, compared to 2009. The increase was primarily due to higher production from the additional seven months of production included as a result of the timing of the merger and new production coming on-stream in 2010.

Royalties

Royalties were higher in 2010, compared to 2009, primarily due to the additional seven months of production included in 2010 as a result of the timing of the merger, additional production coming on-stream in 2010 and higher realized prices, partially offset by increases in capital and operating expenditures for East Coast Canada operations.

Royalties are not paid on U.K. production. Suncor's operations in Libya and Syria are conducted pursuant to PSCs. The royalty amounts presented reflect the difference between Suncor's working interest in the particular project and the net revenue attributable to Suncor under the terms of the applicable contract. All government interests in the operations, except for income taxes, are presented as royalties.

Planned Maintenance Turnarounds

At Terra Nova, a 15-week dockside maintenance program is planned in 2011. Production volumes are expected to be reduced by approximately 25,000 bpd over the duration of the turnaround. However, Suncor is working with partners to consider the possibility of delaying this to 2012.

Also in 2011, White Rose has a three-week routine turnaround planned and Buzzard has a one-week shutdown planned.

Discontinued Operations

International and Offshore substantially completed its strategic divestment activities and has divested a number of assets throughout 2010. Discontinued operations, determined in accordance with GAAP, include the results, up to the closing date, of assets that have been sold during the quarter, as well as results from certain assets the company expects to sell. Comparative results have been restated to reflect the impact of operations that have been classified as discontinued during the third quarter of 2010.

- On August 5, 2010, the company completed the sale of its assets in Trinidad and Tobago, for net proceeds of US$378 million with an effective date of January 1, 2010.
- On August 13, 2010, the company completed the sale of its shares in Petro-Canada Netherlands B.V., for net proceeds of €316 million with an effective date of January 1, 2010.
- On September 8, 2010, the company reached an agreement to sell its non-core U.K. offshore assets (Scott/Telford and Triton) for gross proceeds of £240 million, effective July 1, 2010. The sale involves interests in 12 offshore production and exploration licences in the U.K. sector of the North Sea. Divestment of a portion of those assets was completed in 2010 for net proceeds of £55 million. The sales of the remaining assets are expected to close during the first half of 2011. The remaining divestments are subject to closing conditions, closing adjustments to the purchase price and regulatory and other approvals customary for transactions of this nature.

Refining and Marketing

Refining and Marketing refines crude oil into a broad range of petroleum and petrochemical products at refineries located in Edmonton, Montreal and Sarnia in Canada, and Commerce City, Colorado in the U.S. Products are sold to retail, commercial and industrial customers through a combination of company-owned, branded-dealer and joint venture- operated retail stations in Canada and Colorado, a nationwide Canadian commercial road transport network and a bulk sales channel. Refining and Marketing also owns and operates a lubricants business located in Mississauga, Ontario that manufactures, blends and markets high quality products worldwide. Other assets include interests in a petrochemical plant, pipelines and product terminals in Canada and the United States.

Year ended December 31 ($ millions, unless otherwise noted)	**2010**	2009	2008
Revenues	**21 062**	11 851	9 258
Refined product sales (thousands of m^3/d)			
Gasoline	**41.1**	27.6	15.9
Distillates	**30.9**	18.3	10.8
Other, including petrochemicals	**15.8**	9.0	4.8
Total refined product sales [1]	**87.8**	54.9	31.5
Crude oil processed by Suncor (thousands of m^3/d) [2]	**65.1**	42.2	24.7
Net earnings (loss)	**801**	407	(22)
Operating earnings [3]			
Refining and product supply	**523**	321	(60)
Marketing	**259**	152	37
Total operating earnings (loss)	**782**	473	(23)
Cash flow from operations [3]	**1 536**	921	220

(1) Total refined product sales for the five months ended December 31, 2009 was 84.8 thousands of m^3/d.

(2) Crude oil processed by Suncor for the five-month period ended December 31, 2009 was 63.5 thousands of m^3/d.

(3) Non-GAAP measure. Operating earnings is reconciled below. Cash flow from operations is reconciled in the Non-GAAP Financial Measures Advisory section of this MD&A.

Operating Earnings Reconciliation

Year ended December 31 ($ millions)	**2010**	2009	2008
Net earnings (loss)	**801**	407	(22)
Mark-to-market valuation of stock-based compensation	**29**	17	(1)
Gains on disposals	**(26)**	—	—
Adjustments to provisions for assets acquired through the merger	**(22)**	—	—
Impact of income tax rate reductions on opening future income tax liabilities	**—**	(19)	—
Impact of recording acquired inventory at fair value	**—**	67	—
Costs related to deferral of growth projects	**—**	1	—
Operating earnings [1]	**782**	473	(23)

(1) Non-GAAP measure. See the Non-GAAP Financial Measures Advisory section of this MD&A.

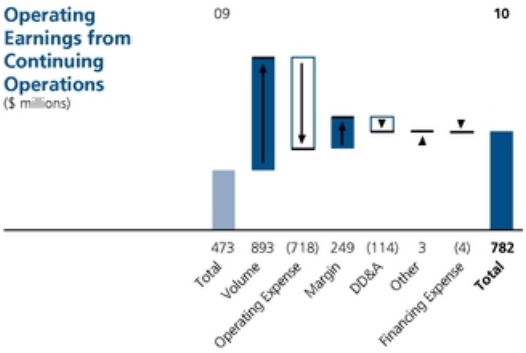
The Refining and Marketing business recorded net earnings of $801 million in 2010 compared with $407 million in 2009. The higher net earnings in 2010 relative to 2009 were primarily due to additional refining capacity gained through the merger, favourable margins and a $67 million negative fair value adjustment (after-tax) included in 2009 net earnings related to the acquisition of inventory as part of the merger. These items were partially offset by higher operating expenses and DD&A. Operating earnings in 2010 were $782 million, which was a $309 million increase over 2009 primarily due to increased volumes from the seven additional months of merged operations in 2010 and improved refining margins, partially offset by higher operating expenses.

Refining and product supply activities contributed operating earnings of $523 million in 2010, up from $321 million in 2009. The increase was due to improved operational reliability and increased production gained from the addition of the Edmonton refinery, Montreal refinery, and the lubricants plant, as a result of the merger. The 2009 comparative period included five months of post-merger results, compared to a full year in

2010. Other positive contributions to operating earnings included wider light/heavy and light/sour synthetic crude pricing differentials and stronger distillate cracking margins. These were somewhat offset by lower utilization of the Sarnia refinery due to Enbridge pipeline disruptions that limited crude availability in the latter part of 2010.

Marketing activities contributed operating earnings of $259 million in 2010, compared with $152 million in 2009. The increase reflected higher sales volumes due to the additional seven months of operations from the retail, wholesale and lubricants businesses included in 2010 as a result of the timing of the merger.

Continuing Operations



Volumes

Year ended December 31 (thousands of m ^{3}/d)	**2010**	2009	2008
Refined Product Sales			
Gasoline			
Eastern North America	**22.2**	14.6	7.9
Western North America	**18.9**	13.0	8.0
	41.1	27.6	15.9
Distillates			
Eastern North America	**12.4**	8.8	5.2
Western North America	**18.5**	9.5	5.6
	30.9	18.3	10.8
Other, including petrochemicals	**15.8**	9.0	4.8
Total refined product sales	**87.8**	54.9	31.5
Crude oil processed by Suncor			
Eastern North America	**30.5**	19.3	11.0
Western North America	**34.6**	22.9	13.7
Total crude oil processed by Suncor	**65.1**	42.2	24.7

Total sales of refined petroleum products averaged 87,800 m ^{3}/d, compared to 54,900 m ^{3}/d in 2009. Sales volumes increased largely due to the merger. After the completion of the merger in 2009, total sales of refined petroleum product averaged 84,800 m ^{3}/d during the last five months of 2009.

Overall, refinery utilization averaged 92% in 2010, compared to a post-merger rate of 92% in 2009, which included twelve months of results for the Sarnia and Commerce City refineries and five months for the Edmonton and Montreal refineries. Sarnia ran less crude in the latter part of 2010 primarily due to Enbridge pipeline disruptions that limited western Canadian crude availability. This shortfall was partially mitigated by processing foreign light crudes and higher utilization at the Montreal refinery to maintain product supply in Ontario.

Margins

Gross margins, in absolute terms, increased in 2010 compared to 2009 due to the additional volume resulting from the merger and improved refining crack spreads that resulted in higher price realizations for our refined products.

Refining and product supply activities benefited from more favourable light/heavy and light/sour synthetic crude price differentials and an improved business environment in 2010, with higher cracking margins in every major market area and stronger product demand compared to 2009. The Edmonton refinery benefited from lower feedstock costs due to wider light/heavy and light/sour synthetic crude differentials. The Sarnia refinery was negatively impacted by the Enbridge pipeline service disruptions that restricted deliveries of lower cost sour crude received from Western Canada and necessitated processing more expensive offshore crude.

Marketing activities continued to benefit from the merger in 2010 with increased volumes. However, the gross petroleum margin on a per litre basis was lower, compared to 2009, due to the broader geographic market base and product offering mix of the merged retail network.

Operating Expenses

Operating expenses were higher in 2010, compared to 2009, primarily due to the inclusion of an additional seven months of operations in 2010 as a result of the timing of the merger.

DD&A

DD&A expense was higher in 2010, primarily due to the larger merged asset base.

Planned Maintenance Turnarounds

Major maintenance turnaround work was completed in 2010 at three of the four refineries and the lubricants production facility. Major turnaround work is planned in

2011 at the Sarnia, Edmonton and Commerce City refineries.

For planned turnarounds, the company enters into transactions to ensure sufficient additional finished product is available to mitigate the impact of lost production on customers.

Corporate, Energy Trading and Eliminations

Corporate, Energy Trading and Eliminations includes the company's investment in renewable energy projects, results related to energy trading activities with third-parties, and activities not directly attributable to any operating segment.

Operating Earnings Reconciliation

Year ended December 31 ($ millions)	**2010**	2009	2008
Net (loss) earnings	**(442)**	104	(805)
Unrealized foreign exchange (gain) loss on U.S. dollar denominated long-term debt	**(372)**	(798)	852
Mark-to-market valuation of stock-based compensation	**19**	58	(101)
Merger and integration costs	**86**	151	—
Impact of income tax rate adjustments on future income tax liabilities	**—**	5	—
Operating loss [1]	**(709)**	(480)	(54)

(1) Non-GAAP measure. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Year ended December 31 ($ millions)	**2010**	2009	2008
Operating earnings (loss) [1]			
Renewable energy	**33**	29	28
Energy trading	**53**	44	56
Corporate	**(808)**	(460)	(129)
Group eliminations	**13**	(93)	(9)
	(709)	(480)	(54)
Cash flow used in operations [1]	**(973)**	(653)	(37)

(1) Non-GAAP measure. See the Non-GAAP Financial Measures Advisory section of this MD&A.

The net loss in 2010 for the Corporate, Energy Trading and Eliminations segment was $442 million, compared to net earnings of $104 million in 2009. The decrease in net earnings of 2010 was primarily due to a smaller unrealized foreign exchange gain on U.S. dollar denominated long-term debt compared to 2009. Operating loss in 2010 was higher than 2009 primarily due to captive insurance payments made in 2010 and additional interest expense.

Renewable Energy

Renewable energy contributed $33 million of operating earnings in 2010, which was comparable with those in 2009 ($29 million). Suncor has an ethanol plant and joint ownership in four wind farm projects. The expansion to double the design capacity of the ethanol plant from 200 million litres per year to 400 million litres per year was completed in January 2011. There are two additional wind farm projects under construction.

Energy Trading

Energy trading activities primarily involve marketing and trading of crude oil, natural gas, refined products and byproducts, and the use of financial derivatives. These activities resulted in operating earnings of $53 million in 2010 compared to $44 million in 2009. In 2010, earnings were driven by buying heavy oil in Western Canada at wide price differentials relative to WTI and transporting this product to more favourable markets. In 2009 results were positively impacted by realized physical gains on crude inventory positions.

Corporate and Eliminations

Corporate experienced an operating loss of $808 million in 2010, compared to an operating loss of $460 million in 2009. The increased operating loss was primarily due to captive insurance payments made in the first and third quarters of 2010 and additional interest expense, resulting from additional debt acquired through the merger.

Group eliminations reflects the elimination of profit on crude oil sales between Oil Sands or East Coast Canada and Refining and Marketing, where profits are realized when the products are sold to third parties. During 2010, $13 million of profits previously eliminated were recognized in earnings, compared to profits of $93 million that were eliminated in 2009.

QUARTERLY FINANCIAL DATA

($ millions, except as noted)	2010 Three months ended Dec 31	Sept 30	June 30	Mar 31	2009 Three months ended Dec 31	Sept 30	June 30	Mar 31
Revenues (net of royalties)								
Continuing operations	**9 789**	8 636	8 979	6 946	7 236	8 257	4 748	4 607
Discontinued operations [1]	**150**	211	207	302	400	186	20	26
	9 939	8 847	9 186	7 248	7 636	8 443	4 768	4 633
Net earnings (loss)								
Continuing operations	**1 297**	609	318	464	476	965	(46)	(189)
Discontinued operations	**56**	413	162	252	(19)	(36)	(5)	—
	1 353	1 022	480	716	457	929	(51)	(189)
Net earnings (loss) from continuing operations per common share								
Basic	**0.83**	0.39	0.20	0.30	0.30	0.72	(0.05)	(0.20)
Diluted	**0.82**	0.39	0.20	0.30	0.30	0.71	(0.05)	(0.20)
Net earnings (loss) per common share [2]								
Basic	**0.87**	0.65	0.31	0.46	0.29	0.69	(0.06)	(0.20)
Diluted	**0.86**	0.65	0.31	0.45	0.29	0.68	(0.06)	(0.20)
Operating earnings (loss) [2],[3]								
Continuing operations	**890**	600	752	220	319	398	61	398
Discontinued operations	**56**	75	53	84	23	(36)	(5)	—
	946	675	805	304	342	362	56	398
Operating earnings per common share [2],[3]	**0.60**	0.43	0.52	0.19	0.22	0.29	0.06	0.43
Cash flow from operations [2],[4]	**2 144**	1 630	1 758	1 124	1 129	574	295	801
Return on capital employed (twelve months ended) (%) [4],[5]	**10.1**	7.9	7.0	4.9	2.6	3.7	7.3	16.0

(1) Discontinued operations per note 6 of the audited Consolidated Financial Statements, excluding gain on disposal.

(2) Includes continuing and discontinued operations.

(3) Non-GAAP measure. See the Non-GAAP Financial Measures Advisory section of this MD&A.

(4) Non-GAAP measure. See the reconciliation in the Non-GAAP Financial Measures Advisory section of this MD&A.

(5) Excludes capitalized costs related to major projects in progress.

In addition to changes in production and product sales, commodity price fluctuations and the impacts of changes to foreign exchange rates, variations in quarterly net earnings from continuing operations during 2010 and 2009 include the following factors:

- The fourth quarter of 2010 included a gain for the redetermination of Terra Nova oilfield working interests and an adjustment to royalty expense with respect to the modification to the BVM calculation.
- The third quarter of 2010 included impairments to Natural Gas assets.
- The second quarter of 2010 included impairments of Oil Sands assets that were being used in the development of an alternative extraction process and Natural Gas properties that the company decided not to pursue.
- The first quarter of 2010 and the fourth quarter of 2009 were negatively impacted by upgrader fires that significantly reduced Oil Sands production and altered our product mix.
- The fourth quarter of 2009 included a gain from the impacts of income tax rate adjustments, partially offset by losses on asset disposal.
- The third quarter of 2009 included the additional upstream production and refining product sales resulting from the merger and an effective gain on a pre-existing contract with Petro-Canada.
- The first quarter of 2009 included significant costs associated with the deferral of certain growth projects.

CONSOLIDATED FINANCIAL ANALYSIS – FOURTH QUARTER 2010

Fourth Quarter 2010 Highlights

- Results from Refining and Marketing in the fourth quarter of 2010 were strong, with net earnings of $372 million, which was more than double the fourth quarter of 2009, primarily as a result of higher realized margins and increased refinery utilization. Total sales of refined petroleum products averaged 91,100 m^3/d during the fourth quarter of 2010 compared to 82,900 m^3/d in the fourth quarter of 2009, reflecting more reliable operations in all of the company's facilities and improved product demand.

- Total upstream production in the fourth quarter was 625,600 boe/d, compared to 638,200 boe/d in the fourth quarter of 2009. However, production from continuing operations increased to 605,400 boe/d in the fourth quarter of 2010, from 544,500 boe/d in the fourth quarter of 2009. Overall, lower production volumes were primarily due to asset sales in Suncor's Natural Gas and International and Offshore businesses, partially offset by production increases in continuing International and Offshore operations and improved operational reliability at Oil Sands.

Net Earnings by Segment

	Three months ended December 31		Year ended December 31	
	2010	2009	**2010**	2009
Continuing operations				
Oil Sands	**487**	236	**1 492**	557
Natural Gas	**(65)**	(55)	**(277)**	(185)
International and Offshore	**452**	230	**1 114**	323
Refining and Marketing	**372**	151	**801**	407
Corporate, Energy Trading and Eliminations	**51**	(86)	**(442)**	104
	1 297	476	**2 688**	1 206
Discontinued operations				
Natural Gas	**(2)**	5	**506**	(14)
International and Offshore	**58**	(24)	**377**	(46)
	56	(19)	**883**	(60)
Net earnings	**1 353**	457	**3 571**	1 146

Upstream Production Volumes

(mboe/d)	Three months ended December 31		Year ended December 31	
	2010	2009	**2010**	2009
Continuing operations				
Oil Sands (includes Syncrude)	**363.8**	318.2	**318.2**	306.7
Natural Gas	**71.5**	76.8	**72.0**	47.0
International and Offshore	**170.1**	149.5	**170.9**	58.0
	605.4	544.5	**561.1**	411.7
Discontinued operations				
Natural Gas	**1.5**	50.6	**23.8**	27.4
International and Offshore	**18.7**	43.1	**30.2**	16.9
	20.2	93.7	**54.0**	44.3
Total	**625.6**	638.2	**615.1**	456.0

Downstream Sales Volumes

(m^3/d)	Three months ended December 31		Year ended December 31	
	2010	2009	**2010**	2009
Total refined product sales	**91.1**	82.9	**87.8**	54.9

Oil Sands

Oil Sands net earnings for the fourth quarter of 2010 were $487 million, compared to $236 million for the fourth quarter of 2009. Net earnings in the fourth quarter of 2010 compared to 2009 included the impacts of a bitumen valuation royalty provision recovery, which was partially offset by lower gains on change in fair value of commodity derivatives used for risk management and lower costs related to deferral of growth projects.

Oil Sands production, excluding Suncor's share of production from Syncrude, was 17% higher in the fourth quarter of 2010 compared to the fourth quarter of 2009. Higher bitumen supply from all of the Oil Sands assets contributed to a record quarterly production average volume of 325,900 bpd in the fourth quarter of 2010. The prior year quarter was negatively impacted by the fire that occurred in December 2009 at Upgrader 2.

Syncrude production decreased 4% in the fourth quarter of 2010, compared to the fourth quarter of 2009, primarily due to upgrader outages that occurred during the quarter.

Oil Sands benefited from higher benchmark crude oil prices in the fourth quarter of 2010 compared to the fourth quarter of 2009, partially offset by wider heavy crude oil differentials and the stronger Canadian dollar relative to the U.S. dollar. Enbridge pipeline disruptions limited the export capacity of heavy crude products from Western Canada, reducing both sour crude and bitumen price realizations during the fourth quarter of 2010.

The six-week planned turnaround for Upgrader 2 that began in September continued for three weeks into the fourth quarter of 2010. Hydrogen supply and hydrotreating issues, which also surfaced initially in the third quarter of 2010, increased the percentage of sour crude produced during the fourth quarter and negatively impacted product mix and price realizations.

Natural Gas

Natural Gas had a net loss from continuing operations of $65 million in the fourth quarter of 2010, compared with a net loss of $55 million in the fourth quarter of 2009. Net loss from continuing operations in the fourth quarter of 2010 included the impacts of a $13 million write-down of spare parts inventory and higher costs related to stock-based compensation. Gross production from continuing operations decreased by 7% in the fourth quarter of 2010, compared to the fourth quarter of 2009, mainly due to natural declines.

International and Offshore

International and Offshore had net earnings from continuing operations of $452 million in the fourth quarter of 2010, compared to $230 million in the fourth quarter of 2009. Net earnings in the fourth quarter of 2010 included the settlement payment of $295 million (pre-tax) due to Suncor related to the Terra Nova redetermination. Net earnings from continuing operations in the fourth quarter of 2010 also included increased production from continuing operations and higher price realizations.

Overall, production from continuing operations was higher in the fourth quarter of 2010, compared to the fourth quarter of 2009, primarily due to Syrian gas production coming on-stream in the second quarter of 2010.

Refining and Marketing

Refining and Marketing had net earnings of $372 million in the fourth quarter of 2010, compared to $151 million in the fourth quarter of 2009, primarily due to higher margins in the fourth quarter of 2010. Increased production enabled refining and product supply activities to benefit from an improved business environment, with higher cracking margins in every major market area and stronger product demand compared to the fourth quarter of 2009. The Sarnia refinery was negatively impacted from the lingering effects of the Enbridge crude pipeline disruptions that restricted deliveries of lower cost sour crudes received from Western Canada and necessitated processing of more expensive offshore crude. The Edmonton refinery benefited from lower feedstock costs due to wider light/heavy and light/sour synthetic crude differentials.

Total sales of refined petroleum products increased 10% due to stronger operations and improved product demand as the economy recovered in the fourth quarter of 2010, compared to the fourth quarter of 2009. Overall, refinery utilization averaged 94% in the fourth quarter of 2010, compared to 90% in the fourth quarter of 2009, due largely to fewer scheduled maintenance turnarounds. The reductions to the Sarnia refinery production were partially offset by increasing throughputs at the Montreal refinery to support Ontario market demands.

Marketing network sales volumes in the fourth quarter of 2010 were marginally higher than in the fourth quarter of 2009. Strong sales in both the retail and wholesale divisions were partially offset by the loss of volume associated with the divestment of merger remedy sites.

Corporate, Energy Trading and Eliminations

Net earnings for the Corporate, Energy Trading and Eliminations were $51 million in the fourth quarter of 2010, compared to a net loss of $86 million in the fourth quarter of 2009. The increase in net earnings was due primarily to a higher unrealized foreign exchange gain on U.S. dollar denominated long-term debt.

CAPITAL INVESTMENT UPDATE

Suncor spent $5.7 billion on capital and exploration in 2010, which was marginally higher than Suncor's original 2010 budget of $5.5 billion. The capital expenditures were primarily focused on sustaining safe and reliable existing operations throughout the company, and the continued development of the Firebag Stage 3 and 4 expansions.

Year ended December 31	**2010**	2009
Oil Sands	**3 709**	2 831
Natural Gas	**178**	320
International and Offshore	**1 096**	666
Refining and Marketing	**667**	380
Corporate, Energy Trading and Renewable Energy	**360**	70
Less: Capitalized Interest	**(301)**	(136)
Total	**5 709**	4 131

This capital investment update contains forward-looking information. See the Legal Advisory – Forward-Looking Information section of this MD&A for the material risks and assumptions underlying this forward-looking information.

Oil Sands

Oil Sands capital expenditures were $3.709 billion in 2010. Growth spending in 2010 was primarily focused on the construction of Firebag Stage 3.

The company is continuing with its planned in situ growth initiatives:

- Firebag Stage 3 – The planned expansion is targeted to begin production late in the second quarter of 2011, ramping up toward capacity of 62,500 bpd of bitumen over approximately 24 months thereafter. The 2010 expenditures focused primarily on construction of cogeneration and central plant facilities and well pads.

- Firebag Stage 4 – This project was put into safe mode in early 2009, then restarted in late 2010. The planned expansion is targeted to begin production late in the first quarter of 2013, ramping up toward capacity of 62,500 bpd of bitumen over approximately 24 months thereafter. The 2010 expenditures focused primarily on remobilization of workforce.

As of December 31, 2010, cumulative capital expenditures for the Firebag Stages 3 and 4 expansions were $4.3 billion.

Capital expenditures on Suncor's TRO$_{TM}$ tailings reclamation technology related to its implementation across existing operations. Project activities during 2010 included engineering, procurement of certain long-lead items, site preparation and construction of temporary facilities. The project is scheduled to be completed by the end of 2012 at a cumulative capital cost in excess of $1.0 billion.

The MNU project was also taken out of safe mode and restarted in 2010. As of December 31, 2010, cumulative capital expenditures were $763 million. Project activities during 2010 consisted primarily of the remobilization of the construction workforce to complete the remaining scope of work. The project is scheduled to be completed by the end of 2011 and will provide additional hydrogen and hydrotreating capacity to increase the percentage mix of sweet synthetic crude oil production.

With the growth plans announced in December 2010 involving the strategic partnership with Total, the company plans to restart the Voyageur Upgrader in 2011 and plans to begin the Fort Hills mine development.

- Voyageur Upgrader – The focus in 2011 is anticipated to be the remobilization of the workforce, the confirmation of the current design and the modification of the project execution plans.

- Fort Hills – The focus in 2011 is anticipated to be design base memorandum engineering.

In 2010, Suncor also focused on a number of sustaining capital projects required to maintain the mining, upgrading, extraction and in situ assets operating effectively. Major planned maintenance and turnarounds were completed on Upgrader 2 in the spring and fall.

Natural Gas

Natural Gas is focused on improving profitability by investing in low risk drilling programs conducive to low cost repeatable drilling and those with a high percentage of liquids production. In 2010, Natural Gas spent $178 million on exploration and development activities, of which $8 million was related to assets disposed of during the year. In 2010, spending was focused primarily on unconventional gas opportunities, as well as land acquisitions in northeast British Columbia.

Suncor's key shallow gas producing properties near Medicine Hat, in southeastern Alberta, continued with drilling and tie-in activity. In total, 324 wells were drilled in 2010, with overall production from this area averaging 72 mmcfe/d during the year.

Two significant drilling programs began in the fourth quarter of 2010: one in the Ferrier area located in central Alberta and another at Pouce Coupe in western Alberta. Tie-in activities for both programs started in the first quarter of 2011.

International and Offshore

International and Offshore spent $264 million on capital and exploration in 2010 related primarily to the White Rose and Hibernia areas of East Coast Canada operations.

- At North Amethyst, first oil was achieved May 31, 2010. Facility construction was completed during the year and the remainder of the project is focused on development drilling of 11 wells in total and is planned to continue until 2013. Data provided by a delineation well will be used to optimize future well placement.

- Development drilling for the first phase of the West White Rose portion of the White Rose Extensions began in August 2010, with first oil expected by mid-2011. Drilling results from the first phase, combined with production evaluation and ongoing reservoir evaluation, are expected to define the full field development scope.

- Capital spending continues on the Hibernia South Extension project, where early production from the unit is expected in mid-2011.

- The contract for front-end engineering and design and topsides engineering, procurement and construction for Hebron was awarded in September 2010. The development plan approval submission is expected to be made in the second quarter of 2011 with first oil expected in 2017.

International and Offshore expenditures on capital and exploration in 2010 related to its other operations were $832 million, of which $169 million was related to assets disposed of during the year. Spending has been primarily focused on exploration drilling in Libya, development spending in the U.K. and Syria, and exploration drilling in Norway.

- Seismic survey projects continue to acquire data in relation to the Libya EPSAs. Two exploration wells, four appraisal wells and 26 development wells were completed in the year with seismic data acquisition continuing into the first quarter of 2011.

- The Buzzard enhancement project, which included the shutdown and the tie-in of a fourth platform, was completed and staged commissioning began on the sulphur handling platform in October 2010. Production disruptions during ramp-up have been less than anticipated to date. Commissioning of the new platform will continue into the first quarter of 2011.

- In Syria, facility development was completed to support first commercial gas and condensate production, which was achieved in April 2010, and first liquefied petroleum gas, which was achieved in May 2010 from the Ebla gas project. First oil was achieved in December 2010.

- Following the Beta Brent discovery offshore Norway completed earlier in 2010, the Beta Statfjord appraisal well was successfully tested. Additional appraisal well testing is required to delineate the discovery further.

Refining and Marketing

Refining and Marketing spent $667 million on capital in 2010, primarily focused on planned turnarounds and rebranding former Sunoco retail sites to the Petro-Canada brand.

Major maintenance turnaround work was completed in 2010 at three of the four refineries and the lubricants production facility to support continued safe and reliable operations.

Corporate, Energy Trading and Eliminations

Corporate capital expenditures were $360 million in 2010, with a focus on merger integration related activities and renewable energy. Work continues to integrate legacy Suncor and legacy Petro-Canada systems onto one common platform, where appropriate, as well as integrate processes, information and technology.

Construction on the Wintering Hills wind power project, which began in the second half of 2010, is expected to be completed by the end of 2011. At peak operation, the project is expected to generate enough electricity to power approximately 35,000 Alberta homes and displace 200,000 tonnes of carbon dioxide (CO_2) per year.

Construction on the Kent Breeze wind power project, which commenced in the second half of 2010, is expected to be completed by mid-2011.

Suncor's ethanol plant, located in Sarnia, Ontario, has a current capacity of 400 million litres per year, after a plant expansion was completed in January 2011 that doubled the capacity of the ethanol plant. The plant displaces the equivalent of 300,000 tonnes of CO_2 per year.

LIQUIDITY AND CAPITAL RESOURCES

At December 31 ($ millions, except ratios)	**2010**	2009
Working capital (deficit) [1]	**1 257**	(324)
Short-term debt	**2**	2
Current portion of long-term debt	**518**	25
Long-term debt	**11 669**	13 855
Total debt	**12 189**	13 882
Less: Cash and cash equivalents	**1 077**	505
Net debt	**11 112**	13 377
Shareholders' equity	**36 721**	34 111
Total capitalization (total debt and shareholders' equity)	**48 910**	47 993
Total debt to debt plus shareholders' equity (%) [2]	**25**	29

Year ended December 31	**2010**	2009
ROCE (%) – excludes capitalized costs related to major projects [3]	**10.1**	2.6
ROCE (%) – includes capitalized costs related to major projects [3]	**7.4**	1.8
Net debt to cash flow from operations (times) [4]	**1.7**	4.8
Interest coverage on long-term debt (times)		
Net earnings [5]	**8.4**	3.0
Cash flow from operations [3],[6]	**11.9**	7.2

(1) Calculated as current assets less current liabilities, excluding cash and cash equivalents, short-term debt, current portion of long-term debt and future income taxes. Current assets and liabilities of discontinued operations are excluded.

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

(3) Non-GAAP measure. See the Non-GAAP Financial Measures Advisory section of this MD&A.

(4) Short-term debt plus long-term debt less cash and cash equivalents, divided by cash flow from operations.

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

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

Capital Resources

Suncor's capital resources consist primarily of cash flow from operations and available lines of credit. Suncor's management believes the company will have the capital resources to fund its planned 2011 capital spending program and to meet current and long-term working capital requirements through cash flow from operations, proceeds from the agreement with Total, other planned asset divestitures and its available committed credit facilities. The expected proceeds from the agreement with Total are approximately $1.75 billion, subject to closing adjustments. The company's cash flow from operations depends on a number of factors, including commodity prices, production/sales levels, refining and marketing margins, operating expenses, taxes, royalties, and foreign exchange rates. If additional capital is required, Suncor's management believes adequate additional financing will be available in the debt capital markets at commercial terms and rates.

Financing Activities

Management of debt levels continues to be a priority given the company's long-term growth plans. Suncor's management believes a phased and flexible approach to existing and future growth projects should assist Suncor in maintaining its ability to manage project costs and debt levels.

At December 31, 2010, Suncor's net debt was $11.1 billion, compared to $13.4 billion at December 31, 2009. Net debt decreased by $2.3 billion largely due to proceeds from asset dispositions being directed to debt retirement and the appreciation of the Canadian dollar relative to the U.S. dollar through the period. Unutilized lines of credit at December 31, 2010 were approximately $5.3 billion, compared to $4.2 billion at December 31, 2009.

A summary of available and unutilized credit facilities is as follows:

($ millions)	2010
Facility that has a term period of one year and expires in 2011	**4**
Facility that is fully revolving for a period of four years and expires in 2013	**199**
Facilities that are fully revolving for a period of five years and expire in 2013	**7 320**
Facilities that can be terminated at any time at the option of the lenders	**461**
Total available credit facilities	**7 984**
Credit facilities supporting outstanding commercial paper, bankers' acceptances and LIBOR loans	**(1 982)**
Credit facilities supporting standby letters of credit	**(713)**
Total unutilized credit facilities	**5 289**

Interest expense on debt continues to be influenced by the composition of the debt portfolio, and is currently benefiting from short-term floating interest rates that remain at low levels, compared to historical short-term rates. To manage fixed versus floating rate exposure, we have entered into fixed to floating interest rate swaps with investment grade counterparties. At December 31, 2010, the company had interest rate swaps relating to $200 million of its fixed-rate debt, due in August 2011.

Suncor has an operating working capital of $1.257 billion at December 31, 2010, compared to a deficiency of $324 million at December 31, 2009. The working capital change from a deficit to a surplus during 2010 was primarily a result of increased accounts receivable balances, resulting from higher volumes and prices and the recording of the Terra Nova redetermination receivable, partially offset by an increase in accounts payable as a result of higher royalties payable from increased production.

Suncor is subject to financial and operating covenants related to its public market and bank debt. Failure to meet the terms of one or more of these covenants may constitute an Event of Default as defined in the respective debt agreements, potentially resulting in accelerated repayment of one or more of the debt obligations. The company is in compliance with its financial covenant that requires total debt to not be more than 60% of its total capitalization. At December 31, 2010, total debt to total capitalization was 25% (December 31, 2009 – 29%). The company is also currently in compliance with all operating covenants.

Credit Ratings

The following information regarding the company's credit ratings is provided as it relates to the company's cost of funds and liquidity and indicates whether or not the company's credit ratings have changed. In particular, the company's ability to access unsecured funding markets and to engage in certain collateralized business activities on a cost-effective basis is primarily dependent upon maintaining competitive credit ratings. A lowering of the company's credit rating may also have potentially adverse consequences for the company's funding capacity or access to the capital markets, may affect the company's ability, and the cost, to enter into normal course derivative or hedging transactions, and may require the company to post additional collateral under certain contracts.

All of the company's debt ratings are investment grade. The company's current long-term senior debt ratings are BBB+, with a Stable Outlook from Standard & Poor's (S&P); A(low), with a Stable Trend from Dominion Bond Rating Service (DBRS); and Baa2, with a Stable Outlook from Moody's Investors Service. Suncor's current commercial paper ratings are A-1 (Low) from S&P and R-1 (low) from DBRS. These have not changed from December 31, 2009.

Outstanding Shares

At December 31, 2010 (thousands)	
Common shares	1 565 489
Common share options – exercisable and non-exercisable	67 638
Common share options – exercisable	46 266

As at February 24, 2011, the total number of common shares outstanding was 1,570,039,616 and the total number of exercisable and non-exercisable common share options outstanding was 67,838,293.

Aggregate Contractual Obligations

In the normal course of business, the company is obligated to make future payments. These obligations represent contracts and other commitments that are known and non-cancellable.

($ millions)	Total	Payments Due by Period 2011	2012-2013	2014-2015	Later Years
Fixed-term debt and revolving-term debt [1]	11 903	2 482	311	406	8 704
Interest payments on fixed-term debt	11 015	609	1 175	1 131	8 100
Capital lease payments	718	36	74	74	534
Asset retirement obligations [2]	7 434	127	330	244	6 733
Operating lease agreements, pipeline capacity and energy services commitments [3]	13 256	1 089	1 870	1 623	8 674
Exploration work commitments	425	137	288	—	—
Other long-term obligations [4]	649	239	359	51	—
Total	45 400	4 719	4 407	3 529	32 745

(1) Includes $8.108 billion of U.S. and $1.800 billion of Canadian dollar denominated debt that is redeemable at our option. Maturities range from 2011 to 2039. Interest rates vary from 4.00% to 9.25%. We entered into interest rate swap transactions maturing in 2011 that resulted in an average effective interest rate in 2010 of 1.9% on $200 million of our Medium Term Notes. Approximately $1.982 billion of revolving-term debt with an effective interest rate of 1.2% was issued and outstanding at December 31, 2010.

(2) Represents the undiscounted amount of legal obligations associated with site restoration on the retirement of assets with determinable lives.

(3) Includes annual tolls payable under transportation service agreements with major pipeline companies to use a portion of their pipeline capacity and tankage, as applicable, for transportation of product within Canada and the United States. The figure also includes commitments under long-term energy agreements to obtain a portion of the power and the steam generated by certain cogeneration facilities owned by a major third-party energy company.

(4) Includes Libya EPSA signature bonus and Fort Hills purchase obligations. See note 18 to the Consolidated Financial Statements.

In addition to the enforceable and legally binding obligations quantified in the above table, we have other obligations for goods and services and raw materials entered into in the normal course of business, which may terminate on short notice, including commodity purchase obligations for which an active, highly liquid market exists, and which are expected to be re-sold shortly after purchase.

FINANCIAL INSTRUMENTS

Suncor periodically enters into derivative contracts such as forwards, futures, swaps, options and costless collars to manage exposure to fluctuations in commodity prices and foreign exchange rates and to optimize the company's position with respect to interest expense. The company also uses physical and financial energy derivatives to earn trading revenues.

To estimate fair value of financial instruments, the company uses quoted market prices when available, or models that utilize observable market data. In addition to market information, Suncor incorporates transaction specific details that market participants would utilize in a fair value measurement, including the impact of non-performance risk. Inputs used are characterized in determining fair value using a hierarchy that prioritizes inputs depending on the degree to which they are observable. However, these fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction.

Hedge Accounting for Fair Value Hedges

At December 31, 2010, the company had interest rate swaps classified as fair value hedges outstanding until August 2011, relating to $200 million of its fixed-rate debt. The fair value of these swaps was $8 million at December 31, 2010 (December 31, 2009 – $18 million), and was recorded in accounts receivable in the Consolidated Balance Sheets.

Risk Management Activities

Suncor uses derivative contracts to hedge risks related to purchases and sales of commodities, to manage exposure to interest rates, and to hedge risks specific to individual transactions. Gains or losses on risk management derivatives are recorded in the Consolidated Statements of Earnings in the same caption as the related transaction. The earnings impact associated with our risk management derivatives for the year ended December 31, 2010 was a net pre-tax gain of $89 million (2009 – pre-tax loss of $1.024 billion). There are no significant risk management derivative contracts outstanding at December 31, 2010.

Energy Trading Activities

Suncor uses crude oil, natural gas and refined product derivative contracts to earn supply and trading revenues. The results of these supply and trading activities are reported as energy supply and trading activities revenues and expenses in the Consolidated Statements of Earnings. The net pre-tax gain associated with our energy trading activities in 2010 was $81 million (2009 – pre-tax loss of $70 million).

The change in fair value of derivatives pertaining to risk management and energy trading activities are as follows:

($ millions)	**2010**
Fair value of contracts at December 31, 2009	(359)
Fair value of contracts realized during the period	**115**
Change in fair value during the period	**170**
Fair value of derivative contracts outstanding at December 31, 2010	**(74)**

The fair value of derivatives pertaining to risk management and energy trading activities are recorded in the Consolidated Balance Sheets as follows:

($ millions)	**2010**	2009
Accounts receivable	**19**	213
Accounts payable and accrued liabilities	**(93)**	(572)
	(74)	(359)

Risks Associated with Derivative Financial Instruments

Suncor's price risk management strategies are subject to periodic management reviews to determine appropriate hedge requirements based on the company's tolerance for exposure to market volatility, as well as the need for stable cash flow to finance future growth.

Suncor may be exposed to certain losses in the event that the counterparties to derivative financial instruments are unable to meet the terms of the contracts. The company minimizes this risk by entering into agreements with investment grade counterparties. Risk is also minimized through regular management review of the potential exposure to and credit ratings of such counterparties. Suncor's exposure is limited to those counterparties holding derivative contracts with net positive fair values at the reporting date.

Energy supply and trading activities are governed by a separate risk management group which reviews and monitors practices and policies and provides independent verification and valuation of these activities.

For further details on our derivative financial instruments, including a sensitivity analysis of the effect of changes in commodity prices on our derivative financial instrument contracts and additional discussion of exposure to risks and our mitigation activities, see note 21 to the 2010 audited Consolidated Financial Statements.

RISK FACTORS

We are continually working to mitigate the impact of potential risks to our business. 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. The following provides a list of some of the risk factors relating to Suncor and our business. A detailed discussion of additional risk factors related to Suncor and our business is presented in our most recent Annual Information Form (AIF)/Form 40-F, filed with securities regulatory authorities.

Volatility of Commodity Prices and Exchange Rate Fluctuations

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 the Petroleum Exporting Companies, and weather, among other things, can affect world oil supply and demand. Our natural gas price realizations in our Natural Gas segment 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. Given the continued global economic uncertainty, we expect continued volatility and uncertainty in crude oil and natural gas prices in the near term and beyond, with the possibility that crude oil prices could revert to the low levels experienced in 2008 and 2009. 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 natural gas prices and low crude oil prices in particular could have a material adverse effect on our business, financial condition, results of operations and cash flow.

For the year ended December 31, 2010, we conducted an assessment of the carrying value of our assets to the extent required by Canadian GAAP. 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 materially adversely affected.

Our downstream business is sensitive to wholesale and retail margins for its refined products, including, but not limited to, gasoline, diesel, petrochemicals and asphalt. Margin volatility is influenced by, among other things, overall marketplace competitiveness, weather, the cost of crude oil, 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, the operating results for our Refining and Marketing business unit can be expected to fluctuate and may be materially adversely affected.

Our 2010 Consolidated Financial Statements are presented in Canadian dollars. Results of operations are affected significantly by the exchange rates between the Canadian dollar and the U.S. dollar, and are also affected by the exchange rates between the Canadian dollar, the euro and the British pound. These exchange rates may vary substantially and may give rise to foreign currency exposure, either favourable or unfavourable, creating another element of uncertainty. To the extent such fluctuation is unfavourable, it may have a material adverse effect on our business, financial condition, results of operation and cash flow.

Government Regulation

The company, and the oil and gas industry generally, operates under federal, provincial, state and municipal legislation in numerous countries. 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 (GHG) and other 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. The following subsections provide more information on some of these regulations.

Environmental Regulation

The company is subject to environmental regulation under a variety of Canadian, U.S., U.K. and other foreign, federal, provincial, territorial, state and municipal laws and regulations. Some of the issues that are or may in future be subject to environmental regulation include:

- The possible cumulative regional impacts of oil sands development;
- The manufacture, import, storage, treatment and disposal of hazardous or industrial waste and substances;
- The need to reduce or stabilize various emissions to air;
- Withdrawals, use of, and discharges to water;
- Issues relating to land reclamation, restoration and wildlife habitat protection;
- Reformulated gasoline to support lower vehicle emissions; and
- U.S. implementation of regulation or policy to limit its purchases of oil to oil produced from conventional sources, or
- U.S. state or federal calculation and regulation of fuel life cycle carbon content.

Changes in environmental regulation could have a material adverse effect on us from the standpoint of product demand, product reformulation and quality, methods of production, distribution 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 may result in the imposition of fines and penalties, liability for cleanup costs and damages, and the loss of important licences and permits,

which may, in turn, have a material adverse effect on our business, financial condition, results of operations and cash flow.

Climate Change

While there is a well-defined GHG regulatory system with targets in place for all large industrial facilities in the province of Alberta, no other North American jurisdiction has yet enacted similar strict compliance measures. Suncor anticipates that this current situation will be replaced within the next few years by a series of regional regulatory regimes, or with an all-encompassing federal regime. In general, therefore, there remains uncertainty around the outcome and impacts of climate change and environmental laws and regulations (whether currently in force, or proposed laws and regulations as described herein or future laws and regulations); it is not currently possible to predict either the nature of any requirements or the impact on the company and its business, financial condition, results of operations and cash flow at this time.

The Canadian federal government has gone on record as saying that it will align GHG emissions legislation with the U.S. Since it remains unclear what approach the U.S. will take, or when, it also is unclear whether the federal government will implement economy-wide climate change legislation, or a sector specific approach, and what type of compliance mechanisms will be available to large emitters.

British Columbia has drafted regulations for a cap-and-trade system, as well as offset regulations, which are intended to be finalized later in 2011. The impact of these regulations cannot be quantified at this time, given the current lack of detail on how the system will operate.

While forthcoming laws and regulations may impose significant liabilities on a failure to comply with their requirements, the cost of meeting new environmental and climate change regulations is not expected to be so high as to cause a material disadvantage, or damage to our competitive positioning.

As part of our ongoing business planning, Suncor assesses potential costs associated with carbon dioxide (CO_2) emissions in our evaluation of future projects, based on our current understanding of pending and possible greenhouse gas regulations. Both the U.S. and Canada have indicated that climate change policies that may be implemented will attempt to balance economic, environmental and energy security concerns. We expect that regulation will evolve with a moderate carbon price signal, and that the price regime will progress cautiously. Suncor will continue to review the impact of future carbon constrained scenarios on our strategy, using as a base case price range of $15-$45 per tonne of CO_2 equivalent, applied against a range of regulatory policy options and price sensitivities.

California has passed AB32, which provides for a Low Carbon Fuel Standard (LCFS); although Suncor does not actively market into the state of California, the implications of other states adopting similar LCFS legislation could pose a significant barrier to our exports of oil sands derived crude, if the importing jurisdictions fail to acknowledge the mandated 12% reduction requirement imposed by the company's exporting jurisdiction (Alberta).

While it appears fairly certain that GHG regulations and targets will continue to become more stringent, and while Suncor will continue efforts to reduce the CO_2 unit intensity of our operations, the absolute CO_2 emissions of our company will continue to rise as we pursue a prudent and planned growth strategy.

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. In February 2009, the Energy Resources Conservation Board (ERCB) of the Government of Alberta released a directive, *Tailings Performance Criteria and Requirements for Oil Sands Mining Schemes* . The directive establishes performance criteria for tailings operations, a requirement for specific approval and monitoring of tailings ponds, a requirement for reporting tailings plans, and changes to the ERCB annual mine plan requirements and approval process to regulate tailings operations.

On October 15, 2009, the company applied to the ERCB and Alberta Environment for permission to amend its existing and/or approved operations east of the Athabasca River to move to the company's new planned TRO™ strategy. In 2010, the company received regulatory approval for a new tailings management plan using the company's proprietary TRO™ tailing management process. It is anticipated that TRO™ will allow the company to accelerate the pace of reclamation and reduce costs in the long term.

At this time, no ponds have been fully reclaimed using this technology. The success of the TRO™ and the time to reclaim tailings ponds could increase or decrease the current asset retirement cost estimates. Our failure to adequately implement our reclamation plans could have a material adverse effect on our business, financial condition, results of operations and cash flow.

Royalties

The following risk factors could cause royalty expenses to differ materially from current estimates and impact the royalties payable.

Alberta

The Alberta government enacted new Bitumen Valuation Methodology (BVM) (Ministerial) Regulations as part of the implementation of the New Royalty Framework, effective January 1, 2009. These interim regulations determine the valuation of bitumen for 2009 to 2011. The final regulations are being developed by the Crown that will establish the BVM for future years. For Suncor's mining operations, the BVM is based on the terms of Suncor's RAA, which we believe places certain limitations on the interim BVM as recently enacted. For the years 2009 and 2010, Suncor filed non-compliance notices with the Crown, citing that reasonable adjustments in the determination of the Suncor bitumen value were not considered by the Crown as permitted by Suncor's RAA. Suncor has also filed with the Crown a Notice of Commencement of Arbitration under the Suncor RAA. Syncrude has also filed a non-compliance notice in respect of the determination of the bitumen value under its agreements with the Crown. The final determination of these matters may have a material impact on future royalties payable to the Crown.

The government enacted the new Oil Sands Allowed Costs (Ministerial) Regulations as part of the implementation of the New Royalty Framework, effective January 1, 2009. Further clarification of some allowed cost business rules is still expected. The terms of Suncor's RAA, and the similar agreement entered into by Syncrude, determine the royalty obligation through 2015 for our mining operations. However, potential changes and the interpretation of the allowed cost regulations could, over time, have a significant impact on the amount of royalties payable.

In addition, royalty payments to the Crown could be impacted by changes in crude oil and natural gas pricing, production volumes, foreign exchange rates, and capital and operating costs for each oil sands project, changes to the New Royalty Framework by the Government of Alberta, changes in other legislation, and the occurrence of unexpected events.

East Coast Canada Royalties

Suncor and the Government of Newfoundland and Labrador are in discussions to resolve several outstanding issues that impact current and prior years. Settlement of these issues could impact royalty payments to the Crown. In addition, royalty payments to the Crown could be impacted by changes in crude oil and natural gas pricing, production volumes, foreign exchange rates, and capital and operating costs for each project, changes resulting from regulatory audits of prior year filings, further changes to applicable royalty regimes by the Government of Newfoundland and Labrador, changes in other legislation, and the occurrence of unexpected events.

Production Sharing Contracts

Payments pursuant to PSCs could be impacted by changes in crude oil and natural gas pricing, production volumes, foreign exchange rates, and capital and operating costs; changes resulting from regulatory audits of prior year filings, further changes to applicable royalty regimes by governments or other applicable regulatory bodies, changes in other legislation, and the occurrence of unexpected events, all which have the potential to have an impact on royalties payable in respect of our international operations in Libya and Syria.

Foreign Operations

The company has operations in a number of countries with different political, economic and social systems. As a result, the company's operations and related assets are subject to a number of risks, which may include, among other things, currency restrictions and exchange rate fluctuations, loss of revenue, property and equipment as a result of expropriation, nationalization, war, insurrection and geopolitical and other political risks, increases in taxes and governmental royalties, renegotiation of contracts with governmental entities and quasi-governmental agencies, changes in laws and policies governing operations of foreign-based companies, economic and legal sanctions (such as restrictions against countries that the U.S. government may deem to sponsor terrorism) and other uncertainties arising from foreign government sovereignty over the company's international operations. If a dispute arises in the company's foreign operations, the company may be subject to the exclusive jurisdiction of foreign courts or may not be able to subject foreign persons to the jurisdiction of a court in Canada or the U.S. Additionally, as a result of activities in these areas and a continuing evolution of an international framework for corporate responsibility and accountability for international crimes, the company could also be exposed to potential claims for alleged breaches of international law.

Operating Hazards and Other Uncertainties

Each of our principal operating businesses – Oil Sands, Natural Gas, International and Offshore, and Refining and Marketing – demand significant levels of investment and therefore carry 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, death, damage to property, information technology 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 connected with transporting, processing and storing crude oil, natural gas and other related products. Pipeline capacity constraints combined with plant capacity constraints could negatively impact our ability to produce at capacity levels in our crude oil and natural gas business. 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 involve particular risks and uncertainties. Oil Sands operations are 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. 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 are virtually no finding costs associated with oil sands resources, the costs to delineate the resources, the costs associated with production, including mine development and drilling wells for in situ operations, and the costs associated with upgrading bitumen into synthetic crude oil can entail significant capital outlays. The costs associated with oil sands production are largely fixed in the short term. As a result, operating costs per unit are largely dependent on levels of production.

There are risks and uncertainties associated with our Natural Gas operations, including all of the risks normally associated with drilling for natural gas wells, the operation and development of such properties, including encountering unexpected formations or pressures, premature declines of reservoirs, fires, blowouts, 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 International and Offshore operations include drilling offshore of Newfoundland and Labrador and in the North Sea offshore of the U.K. and Norway, which are areas subject to hurricanes or other extreme weather conditions, and the drilling rigs in these regions may be exposed to damage or total loss by these storms, some of which may not be covered by insurance. The occurrence of these events could result in the suspension of drilling, operations, damage to or destruction of the equipment involved and injury or death of rig personnel. Damage to the environment, particularly through oil spillage in our operations or extensive uncontrolled fires or death, could result from these operations.

Our Refining and Marketing business is subject to all of the risks normally inherent in 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, oil spills or other incidents.

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

Losses resulting from the occurrence of any of these risks identified above could have a material adverse effect on our business, financial condition, results of operations and cash flow.

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 effect on our business, financial condition, results of operations and cash flow. In 1990, 2003 and 2005, we formed three self-insurance entities to provide additional business interruption coverage for potential losses. In the first quarter of 2010, these three entities were merged into one single entity.

Project Delivery

There are certain risks associated with the execution of our major projects. 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; risks relating to restarting projects placed in safe mode, including increased capital costs; 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 within our existing asset base could cause delays in achieving targets and objectives. 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. Losses resulting from the occurrence of any of these risks could have a material adverse effect on our business, financial condition, results of operations and cash flow.

Our Oil Sands business 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 flexibility to conduct periodic plant maintenance on one operation while continuing production and cash flow generation from the other. Our inability to sufficiently manage these risks could have a material adverse effect on our business, financial condition, results of operations and cash flow.

Reputational Risk

The public perception of oil companies and their operations, including GHG emissions related to current and planned projects in the oil sands area of Alberta, may pose issues related to development and operating approvals or market access for products, which may directly or indirectly impair profitability.

Permit Approval

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 have a material adverse effect on our business, financial condition, results of operations and cash flow. Such regulations may be changed from time-to-time in response to numerous factors, including 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 business, financial condition, results of operations and cash flow.

Labour and Materials Supply

The successful operation of the company's business and ability to expand its operations will depend upon the availability of, and competition for, skilled labour and materials supply. The demand for and supply of skilled labour remains limited, even in uncertain economic conditions, and there is a risk that we may have difficulty sourcing the required labour for current and future operations. As well, materials may be in short supply due to smaller labour forces in many manufacturing operations. Our ability to operate safely and effectively and complete all our projects on time and on budget has the potential to be significantly impacted by these risks. Risks associated with completion of significant capital projects are discussed in "Project Delivery" above.

Suncor's Governance Process

Suncor believes that the responsibility for managing climate change related issues should be a shared responsibility across the company. A comprehensive "roles and responsibilities" matrix has been developed as part of Suncor's GHG management program.

The Environment, Health, Safety and Sustainable Development Committee of the Board of Directors reviews Suncor's effectiveness in meeting its obligations pertaining to environment, health and safety (EHS). The committee also reviews the effectiveness with which Suncor establishes appropriate environment, health and safety policies, including GHG performance and emission reduction plans given legal, industry and community standards. Management systems are maintained by the committee to implement such policies and ensure compliance with them.

Suncor's Chief Operating Officer holds top executive responsibility for sustainability issues. Together with the Vice President, Sustainable Development, the business units' EHS Managers and selected internal technical representatives are responsible for the stewardship of the GHG management system. The GHG strategy team is responsible for developing company-wide strategies and operational goals and assessing sustainability progress, including GHG intensity reduction, across all areas of our business.

In advance of clear regulations in all jurisdictions that we operate, Suncor will continue to be guided by the seven-point climate change action plan we first adopted in 1997, which calls on us to:

- Manage our own GHG emissions;
- Develop renewable sources of energy;

- Invest in environmental and economic research through joint venture initiatives with other industry groups, and through internal initiatives focused on our core business;
- Use domestic and international offsets;
- Collaborate on policy development;
- Educate employees and the public; and
- Measure and report our progress;

Suncor remains committed to reducing overall greenhouse gas emission intensity, in addition to other goals related to improving energy efficiency, reducing water use, increasing land reclamation, and reducing air emissions. We continue to actively work to mitigate our environmental impact, including taking action to reduce greenhouse gas emissions, investing in renewable forms of energy such as wind power and biofuels, accelerating land reclamation, installing new emission abatement equipment and pursuing other opportunities both internally, as well as through joint venture initiatives, such as our role in the Oil Sands Leadership Initiative, with other like-minded energy companies.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in accordance with GAAP requires management to make estimates, judgments and assumptions that affect reported assets and liabilities, disclosures of contingencies and revenues and expenses. These estimates and assumptions are subject to change based on experience and new information. Critical accounting estimates are defined as estimates that are important to the portrayal of our financial position and operations, and require management to make judgments based on underlying assumptions about future events and their effects. These underlying assumptions are based on historical experience and other factors that management believes to be reasonable under the circumstances, and are subject to change as new events occur, as more industry experience is acquired, as additional information is obtained and as our operating environment changes. Critical accounting estimates are reviewed annually by the Audit Committee of the Board of Directors. The following are the critical accounting estimates used in the preparation of Suncor's Consolidated Financial Statements.

Asset Retirement Obligations (ARO)

Suncor is required to recognize a liability for the future retirement obligations associated with the legal requirement to retire tangible long-lived assets such as tailings ponds, producing well sites, and crude oil and natural gas processing plants. An ARO liability is only recognized to the extent there is a legal obligation associated with the retirement of a tangible long-lived asset that we are required to settle as a result of an existing or enacted law, statute, ordinance, written or oral contract, or by legal construction of a contract under the doctrine of promissory estoppel. The ARO is based on estimated costs, taking into account the anticipated method and extent of restoration consistent with legal requirements, technological advances and the possible use of the site. Since these estimates are specific to the sites involved, there are many individual assumptions underlying Suncor's total ARO amount. These individual assumptions can be subject to change based on experience.

The estimated fair values of ARO related to long-term assets are recognized as a liability in the period in which they are incurred. Retirement costs equal to the estimated fair value of the ARO are capitalized as part of the cost of associated capital assets and are amortized to expense through DD&A over the life of the asset. The fair value of the ARO is estimated by discounting the expected future cash flows to settle the ARO at the company's weighted average credit-adjusted risk-free interest rate, which is currently 5.4% (2009 – 6.2%). In subsequent periods, the ARO is adjusted for the passage of time, adjusted to estimated costs to settle the liability, and changes to the timing of the underlying future cash flows. These changes to estimates impact both the DD&A on the retirement cost and the accretion expense on the ARO reported in the Consolidated Statements of Earnings. In addition, differences between actual and estimated costs to settle the ARO, timing of cash flows to settle the obligation and future inflation rates may result in gains and losses on the final settlement of the ARO.

An ARO is not recognized for assets with an indeterminate useful life because the amount cannot be reasonably estimated. An ARO for these assets will be recorded in the first period in which the lives of the assets are determinable.

In connection with company and third-party reviews of ARO during 2010, Suncor decreased the estimated undiscounted total obligation to $7.4 billion from the previous estimate of $8.3 billion. The decrease was primarily due to significant disposals in the International and Offshore segment and the Natural Gas segment, where the ARO obligation was assumed by the purchasing entity. In addition, the Oil Sands segment decreased its obligation mainly due to the 2010 ARO obligation being calculated using the company's proprietary TRO$_{TM}$ tailings management process, compared to a combination of methods in 2009. The company anticipates that TRO$_{TM}$ will allow the company to accelerate the pace of reclamation and reduce costs in the long term. The estimated discounted total obligation at December 31, 2010, was

$2.4 billion, compared to $3.2 billion at December 31, 2009.

Employee Future Benefits

Suncor provides a range of benefits to employees and retired employees, including pensions and other post-retirement benefits. The determination of obligations under these benefit plans and related expenses requires the use of actuarial valuation methods and assumptions. Assumptions typically used in determining these amounts include, as applicable, rates of employee turnover, future claim costs, discount rates, future salary and benefit levels, return on plan assets, mortality rates and future medical costs. The fair value of plan assets is determined using market values. Actuarial valuations are subject to management judgment. Management continually reviews these assumptions in light of considering actual experience and expectations for the future. Changes in assumptions are accounted for on a prospective basis. Employee future benefit costs are reported as part of operating, selling and general expenses in our Consolidated Statements of Earnings. The accrued net benefit liability is reported as part of accrued liabilities and other.

The assumed rate of return on plan assets considers the current level of expected returns on the fixed income portion of the plan's asset portfolio, the historical level of risk premium associated with other asset classes in the portfolio and the expected future returns on each asset class. The discount rate assumption is based on the year-end interest rate on high-quality bonds with maturity terms equivalent to the benefit obligations. The rate of compensation increases is based on management's judgment. The accrued benefit obligation and net periodic benefit cost for both pensions and other post-retirement benefits may differ significantly if different assumptions are used.

Successful Efforts Accounting

Suncor follows the successful efforts method for exploration and production development activities related to conventional oil and gas producing properties.

The application of the successful efforts method of accounting requires management apply judgment to determine, among other things, the designation of activities as developmental or exploratory. All development costs are capitalized. Costs of drilling exploratory wells are initially capitalized, pending the evaluation of commercially recoverable reserves. The results of an exploratory drilling program can take considerable time to analyze, and the determination that commercial reserves have been discovered requires both judgment and industry experience. Where it is determined that exploratory drilling will not result in commercial production, the drilling costs of the exploratory well are charged to exploration expense.

Asset Impairment

Producing properties and significant unproved properties are assessed annually, or as economic events dictate, for potential impairment. Impairment is assessed by comparing the estimated net undiscounted future cash flows with the carrying value of the asset. The cash flows used in the impairment assessment require management to make assumptions and estimates about recoverable reserves, production quantities, future commodity prices, operating costs and future development costs. Changes in any of the assumptions, such as a downward revision in reserves, a decrease in future commodity prices or an increase in operating costs, could result in an impairment of an asset's carrying value. Where properties are assessed by management to be fully or partially impaired, the book value of the properties is reduced to fair value, with the difference reported as part of DD&A expense.

Assets held for sale are also required to undergo an impairment test and are valued at the lower of carrying value and net recoverable value, which often equates to discounted cash flow estimates, or expected sale proceeds when an offer has been received.

Oil and Gas Reserves

Our oil and gas reserves are evaluated by independent qualified reserves evaluators. The estimation of reserves is a subjective process. Estimates are based on projected future rates of production, estimated commodity prices, engineering data and the timing of future expenditures, all of which are subject to uncertainty and interpretation. Reserves estimates can be revised either upwards or downwards based on updated information such as future drilling, testing and production levels. Reserves estimates, although not reported as part of the company's Consolidated Financial Statements, can have a significant effect on net earnings as a result of their impact on depreciation and depletion rates, asset impairments and goodwill impairments.

For December 31, 2010, reserves estimates for our Syria assets were reduced to reflect only those parts of the Ash Shaer field with existing well control, and to reflect interpreted higher porosity cut-offs in a significant secondary zone.

Income Taxes

The company follows the liability method of accounting for income taxes, whereby future income taxes are recognized based on the differences between the carrying

amounts of assets and liabilities reported in the financial statements and their respective tax bases. The determination of the income tax provision is an inherently complex process, requiring management to interpret continually changing regulations and to make certain judgments. While income tax filings are subject to audits and reassessments, management believes adequate provision has been made for all income tax obligations. However, changes in the interpretations or judgments may result in an increase or decrease in the company's current and future income tax provisions, future income tax assets and liabilities, and net earnings.

Contingencies

The company is involved in litigation and claims in the normal course of operations. Management is of the opinion that any resulting settlements would not materially affect the financial position of the company as at December 31, 2010. However, the determination of contingent liabilities relating to litigation and claims is a complex process that involves judgments as to the outcomes and interpretation of laws and regulations. Changes in the judgments or interpretations may result in an increase or decrease in the company's contingent liabilities in the future.

Purchase Price Allocation

The 2009 merger with Petro-Canada was treated as a business acquisition and accounted for by the purchase method of accounting. Under this method, the purchase price was allocated to the assets acquired and the liabilities assumed based on the fair value at the time of the acquisition. The excess purchase price over the fair value of identifiable assets and liabilities acquired is goodwill. Management finalized the purchase price allocation during the second quarter of 2010 and did not make any amendments to the preliminary allocation.

CHANGES IN ACCOUNTING POLICIES

International Financial Reporting Standards (IFRS)

IFRS Conversion Project

The company's IFRS conversion project continues to be on target to release first quarter 2011 IFRS financial statements. The following is a status update of the IFRS conversion project.

IFRS Financial Statement Preparation

First quarter and annual 2011 IFRS financial statements and disclosures have been drafted and provided to senior management and the company's external auditor for review. The first quarter 2011 financial statements and disclosures will be presented to the IFRS Steering Committee and Audit Committee in the first quarter of 2011.

IFRS Training

IFRS training and communication sessions continued for key individuals, senior management and the Audit Committee.

IFRS Infrastructure

Significant IFRS information technology activities were completed during the fourth quarter, including recording of IFRS entries for the first three quarters of 2010 into the company's dual reporting system. Testing of the 2011 conversion plan was completed in 2010. Comprehensive training for implementation of business process changes will occur in the first quarter of 2011 with implementation targeted for the second quarter of 2011.

IFRS Control Environment

The company has completed testing of internal control documentation related to the preparation of the 2010 IFRS financial statements. Review of internal and disclosure controls over financial reporting for 2011 will be completed in the first quarter of 2011. No material changes are expected to the controls over financial reporting.

IFRS Expected Accounting Policy Impacts

In addition to the policy changes outlined below, the company continues to monitor IFRS developments. Accounting policies selected for the draft IFRS opening Consolidated Balance Sheets remain subject to change. The company is not required to finalize IFRS accounting policies prior to the release of the first annual audited IFRS financial statements for the year ending December 31, 2011.

The following discussion provides further details on the impacts of accounting policy choices and changes on the draft IFRS opening Consolidated Balance Sheets, including exemptions available under IFRS 1 *First-Time Adoption of International Financial Reporting Standards*. IFRS 1 provides entities adopting IFRS for the first time with a number of optional exemptions and mandatory exceptions, in certain areas, to the general requirement for full retrospective application of IFRS.

- **Property, Plant and Equipment (PP&E)**

Although the principles of componentization and derecognition exist under both IFRS and Canadian GAAP, the standards differ in certain respects. Under

IFRS, the basis that the company has used to apply these principles will be at a lower component level, resulting in a decrease to the January 1, 2010 PP&E balance of approximately $110 million.

Upon adoption of IFRS, Suncor will reclassify approximately $4.5 billion of Exploration and Evaluation (E&E) assets from PP&E to E&E. E&E assets include unproven land, exploratory drilling and exploratory project costs.

IFRS 1 contains an exemption where an entity may elect to use fair value as its deemed cost for assets at the date of transition. The company elected to use this exemption for certain Natural Gas and Refining and Marketing assets. As a result, approximately $900 million of asset value was derecognized and charged to retained earnings.

- **Provisions, Contingent Liabilities and Contingent Assets**

The company is planning to utilize the IFRS 1 exemption permitting the recalculation of the ARO cost included in PP&E as at January 1, 2010, using a simplified retrospective calculation. The company has made a preliminary decision to discount the estimated fair value of its ARO using the credit-adjusted risk-free rate. However, the discount rate under IFRS at transition differs from the credit-adjusted risk-free rate utilized for Canadian GAAP. These differences have resulted in an increase of approximately $300 million to the ARO liability, a decrease of approximately $700 million to the related PP&E assets and a corresponding reduction to retained earnings at January 1, 2010. If the company elected to use a risk-free discount rate the adjustment to opening retained earnings would be significantly higher.

- **Share-Based Payments**

IFRS 2 *Share-based Payment* requires that cash-settled share-based payments be measured (both initially and at each reporting period) at the fair values of the awards. Canadian GAAP requires that such awards be measured based on the intrinsic values of the awards. This difference has resulted in an increase to the company's share-based payments liability of approximately $120 million at January 1, 2010 with a corresponding reduction to retained earnings. In addition, a change to the graded vesting method for stock-based compensation has resulted in a $10 million increase in the contributed surplus balance at January 1, 2010. The company will elect to use the IFRS 1 exemption under which IFRS 2 is not required to be applied to equity-settled instruments.

- **Employee Future Benefits**

The company has opted to elect to use the IFRS 1 exemption to recognize immediately in retained earnings all cumulative actuarial gains and losses existing at the date of transition (approximately $60 million). This impact will be partially offset by approximately $30 million for a change to the attribution method for post-retirement benefits and recognition of unamortized past service costs not fully vested.

- **Foreign Exchange**

First-time adopters of IFRS can elect to deem cumulative translation differences to be zero at the date of transition. The company has elected to take this IFRS 1 exemption which has resulted in a reclassification of approximately $250 million from other reserves (previously termed "accumulated other comprehensive income") to retained earnings.

- **Income Taxes**

In transitioning to IFRS, the company's future tax liability is impacted by the tax effects resulting from the IFRS changes discussed above. The company expects to recognize a decrease in the deferred tax liability of approximately $600 million at January 1, 2010.

- **Business Combinations and Joint Ventures**

Business combinations and joint ventures entered into prior to January 1, 2010 will not be retrospectively restated using IFRS principles as permitted by IFRS 1.

Additional IFRS accounting policy choices and changes have not had a material impact on the IFRS opening Consolidated Balance Sheets and will continue to be monitored throughout 2011.

IFRS Quarterly Earnings Impacts

The company is currently finalizing the 2010 quarterly earnings impacts, but expects earnings to be impacted by:

- Lower depreciation expense as a result of opening Balance Sheet impairments, derecognition of assets and a reduction to the ARO asset;
- Lower accretion expense due to a decrease in the discounted rate;
- Restated share-based compensation expense due to remeasurement of cash-settled awards at fair value for each reporting period;
- Reclassifications for assets held for sale, to the respective financial statement line items, previously reported as discontinued operations under Canadian

GAAP. Dispositions did not meet the definition of discontinued operations under IFRS, resulting in additional reclassifications on the Consolidated Statements of Comprehensive Income.

CONTROL ENVIRONMENT

Based on their evaluation as of December 31, 2010, our chief executive officer and chief financial officer concluded that the company's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the United States Securities Exchange Act of 1934 (the Exchange Act)) are effective to ensure that information required to be disclosed by the company in reports that are filed or submitted to Canadian and U.S. securities authorities is recorded, processed, summarized and reported within the time periods specified in Canadian and U.S. securities laws. In addition, as of December 31, 2010, there were no changes in the internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) – 15d-15(f)) that occurred during 2010 that have materially affected, or are reasonably likely to materially affect, the company's internal control over financial reporting. Management will continue to periodically evaluate the disclosure controls and procedures and internal control over financial reporting and will make any modifications from time-to-time as deemed necessary.

The company has undertaken a comprehensive review of the effectiveness of its internal control over financial reporting based on the Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). For the year ended December 31, 2010, based on that evaluation, the company's internal controls were found to be operating free of any material weaknesses.

The company continues to integrate legacy Petro-Canada's historical internal control over financial reporting with Suncor's internal control over financial reporting. This integration will lead to changes in these controls in future fiscal periods, but it is not yet known whether these changes will materially affect internal control over financial reporting. This integration process is expected to be substantially completed by the end of 2011.

The effectiveness of our internal control over financial reporting as at December 31, 2010 was audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report, which is included in our audited Consolidated Financial Statements for the year ended December 31, 2010.

Based on their inherent limitations, disclosure controls and procedures and internal controls over financial reporting may not prevent or detect misstatements, and even those options determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

OUTLOOK

Detailed guidance on 2011 capital expenditures and production outlook can be found in Suncor's December 17, 2010 press release and on the Suncor website at www.suncor.com/guidance, which is not incorporated by reference herein.

NON-GAAP FINANCIAL MEASURES ADVISORY

Certain financial measures referred to in this MD&A, namely operating earnings, cash flow from operations, return on capital employed and Oil Sands cash operating costs, are not prescribed by Canadian GAAP.

These non-GAAP financial measures do not have any standardized meaning and therefore are unlikely to be comparable to similar measures presented by other companies. These non-GAAP financial measures are included because management uses this information to analyze operating performance, leverage and liquidity. Therefore, these non-GAAP financial measures should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP.

Operating Earnings

Operating earnings is a non-GAAP measure that adjusts net earnings for significant items that management believes are not indicative of operating performance and that reduce the comparability of the underlying financial performance between periods. Management uses operating earnings to evaluate operating performance, because management believes it provides better comparability between periods. All reconciling items are presented on an after-tax basis.

Return on Capital Employed (ROCE)

ROCE is included because management uses this information to analyze operating performance, leverage and liquidity.

For the year ended December 31 ($ millions, except ROCE)		**2010**	2009	2008
Adjusted net earnings				
Net earnings		**3 571**	1 146	2 137
Add: after-tax financing expense (income)		**(80)**	(509)	852
	A	**3 491**	637	2 989
Capital employed – beginning of year				
Short-term and long-term debt, less cash and cash equivalents		**13 377**	7 226	3 248
Shareholders' equity		**34 111**	14 523	11 896
	B	**47 488**	21 749	15 144
Capital employed – end of year				
Short-term and long-term debt, less cash and cash equivalents		**11 112**	13 377	7 226
Shareholders' equity		**36 721**	34 111	14 523
	C	**47 833**	47 488	21 749
Average capital employed (1)	D	**47 519**	35 128	18 447
Average capitalized costs related to major projects in progress	E	**12 889**	10 655	5 149
ROCE (%)	A/(D-E)	**10.1**	2.6	22.5

(1) Average capital employed for 2008 is calculated on a simple-average basis (B+C)/2. For 2009 and 2010, as a result of the significant capital employed that was acquired during the year due to the merger with Petro-Canada, average capital employed is now calculated on a monthly weighted average basis.

Cash Flow from Operations

Cash flow from operations is expressed before changes in non-cash working capital.

Year ended December 31 ($ millions)	Oil Sands 2010	Oil Sands 2009	Oil Sands 2008	Natural Gas 2010	Natural Gas 2009	Natural Gas 2008	International and Offshore 2010	International and Offshore 2009	International and Offshore 2008
Net earnings (loss) from continuing operations	**1 492**	557	2 875	**(277)**	(185)	34	**1 114**	323	—
Adjustments for:									
Depreciation, depletion and amortization	**1 318**	922	580	**773**	287	137	**1 172**	299	—
Future income taxes	**484**	(643)	535	**(96)**	(47)	(7)	**108**	48	—
Accretion of asset retirement obligations	**120**	111	55	**29**	14	4	**27**	10	—
Unrealized (gain) loss on translation of U.S. dollar denominated long-term debt	**—**	—	—	**—**	—	—	**—**	—	—
Change in fair value of derivative contracts	**(316)**	960	(590)	**—**	—	—	**—**	—	—
Loss (gain) on disposal of assets	**14**	70	36	**(132)**	(20)	(22)	**2**	—	—
Stock-based compensation	**48**	90	54	**12**	19	4	**18**	12	—
Gain on effective settlement of pre-existing contract with Petro-Canada	**—**	(438)	—	**—**	—	—	**—**	—	—
Other	**(391)**	(378)	(38)	**(6)**	(11)	(13)	**8**	40	—
Exploration expenses	**—**	—	—	**17**	120	61	**63**	6	—
Cash flow from (used in) operations from continuing operations	**2 769**	1 251	3 507	**320**	177	198	**2 512**	738	—
Cash flow provided by discontinued operations	**—**	—	—	**125**	152	169	**367**	213	—
Total cash flow from (used in) operations	**2 769**	1 251	3 507	**445**	329	367	**2 879**	951	—

Year ended December 31 ($ millions)	Refining and Marketing 2010	Refining and Marketing 2009	Refining and Marketing 2008	Corporate, Energy Trading and Eliminations 2010	Corporate, Energy Trading and Eliminations 2009	Corporate, Energy Trading and Eliminations 2008	Total 2010	Total 2009	Total 2008
Net earnings (loss) from continuing operations	**801**	407	(22)	**(442)**	104	(805)	**2 688**	1 206	2 082
Adjustments for:									
Depreciation, depletion and amortization	**475**	317	198	**75**	35	46	**3 813**	1 860	961
Future income taxes	**261**	99	(14)	**(202)**	(85)	(55)	**555**	(628)	459
Accretion of asset retirement obligations	**2**	1	1	**—**	—	—	**178**	136	60
Unrealized (gain) loss on translation of U.S. dollar denominated long-term debt	**—**	—	—	**(426)**	(858)	919	**(426)**	(858)	919
Change in fair value of derivative contracts	**—**	(14)	27	**31**	34	(75)	**(285)**	980	(638)
Loss (gain) on disposal of assets	**(30)**	16	6	**39**	—	(7)	**(107)**	66	13
Stock-based compensation	**40**	35	16	**(4)**	106	(96)	**114**	262	(22)
Gain on effective settlement of pre-existing contract with Petro-Canada	**—**	—	—	**—**	—	—	**—**	(438)	—
Other	**(13)**	60	8	**(44)**	11	36	**(446)**	(278)	(7)
Exploration expenses	**—**	—	—	**—**	—	—	**80**	126	61
Cash flow from (used in) operations from continuing operations	**1 536**	921	220	**(973)**	(653)	(37)	**6 164**	2 434	3 888
Cash flow provided by discontinued operations	**—**	—	—	**—**	—	—	**492**	365	169
Total cash flow from (used in) operations	**1 536**	921	220	**(973)**	(653)	(37)	**6 656**	2 799	4 057

LEGAL ADVISORY – FORWARD LOOKING INFORMATION

This Management's Discussion and Analysis contains certain forward-looking statements and other information based on Suncor's current expectations, estimates, projections and assumptions that were made by the company in light of its experience and its perception of historical trends including expectations and assumptions concerning the accuracy of reserve and resource estimates; commodity prices and interest and foreign exchange rates; capital efficiencies and cost-savings; applicable royalty rates and tax laws; future production rates; the sufficiency of budgeted capital expenditures in carrying out planned activities; the availability and cost of labour and services; and the receipt, in a timely manner, of regulatory and third-party approvals. All statements and other information that address expectations or projections about the future, and other statements and information about Suncor's strategy for growth, expected and future expenditures, commodity prices, costs, schedules, production volumes, operating and financial results and expected impact of future commitments are forward-looking statements. Some of the forward-looking statements and information may be identified by words like "expects", "anticipates", "estimates", "plans", "scheduled", "intends", "believes", "projects", "indicates", "could", "focus", "vision", "goal", "outlook", "proposed", "target", "objective", and similar expressions. Forward-looking statements in this Management's Discussion and Analysis include references to:

- *Our plan in 2011 to direct approximately $2.8 billion towards a range of oil sands growth projects, as part of our overall $6.7 billion 2011 capital-spending plan;*
- *Suncor's strategic partnership with Total, which is expected to close in the first quarter of 2011, and the terms of same, including the consideration to be received by Suncor (approximately $1.75 billion) and the expected assets to be exchanged between the parties: Total will acquire a 49% interest in Suncor's Voyageur Upgrader, and an additional 19.2% in the Fort Hills project; and Suncor will acquire a 36.75% interest in the Joslyn project;*
- *Timelines and plans for the Voyageur Upgrader, the Fort Hills mine and the Joslyn mine;*
- *Suncor's sale of certain of its U.K. offshore assets, and the expected completion of same during the first half of 2011;*
- *Suncor's proprietary TRO$_{TM}$ tailings reclamation, which is expected to significantly reduce pond reclamation time, and the plan to have it completed by the end of 2012 at a cumulative capital cost in excess of $1.0 billion;*
- *Oil Sands' six-week planned turnaround scheduled for Upgrader 2 in the second quarter of 2011 and the expectation that production volumes will be reduced by approximately 215,000 bpd over the duration of the turnaround;*
- *Fifteen-week dockside maintenance program at Terra Nova planned for 2011, where production volumes are anticipated to be reduced by approximately 25,000 bpd over the duration of the turnaround;*
- *Turnarounds, including the three-week routine turnaround planned at White Rose, the one-week planned shutdown at Buzzard and planned major turnarounds for the Sarnia, Edmonton and Commerce City refineries in 2011;*
- *Planned expansions for Firebag Stage 3, where production is targeted to begin late in the second quarter of 2011, ramping up toward capacity of 62,500 bpd of bitumen over approximately 24 months thereafter;*
- *Planned expansion for Firebag Stage 4, where production is targeted to begin late in the first quarter of 2013, ramping up toward capacity of 62,500 bpd of bitumen over approximately 24 months thereafter;*
- *Suncor's MNU project, which is expected to be completed by the end of 2011;*
- *Expected tie-in during the first quarter of 2011 of Suncor's drilling programs in the Ferrier area located in central Alberta and the Pouce Coupe area in western Alberta;*
- *Planned drilling at North Amethyst and the White Rose Extensions;*
- *Expected production for the first phase of the West White Rose portion of the White Rose Extension (first oil expected by mid-2011), the Hibernia South Extension project (early production from the unit is expected in mid-2011) and Hebron (first oil expected in 2017);*
- *Projected completion by the end of 2011 of Suncor's Wintering Hills wind power project, and the expectation that the project will generate enough electricity to power approximately 35,000 Alberta homes and displace 200,000 tonnes of carbon dioxide per year;*
- *Anticipated completion of the Kent Breeze wind power project (mid-2011);*
- *Suncor's management's belief that Suncor will have the capital resources to fund its planned 2011 capital spending program and to meet current and long-term working capital requirements and that if additional capital is required, adequate additional financing will be available to Suncor in the debt capital markets at commercial terms and rates; and*
- *Expected effects of changeover to IFRS.*

This Management's Discussion and Analysis also contains forward-looking statements and information concerning the anticipated completion and timing of the proposed transaction with Total E&P Canada Ltd. and our transaction to sell our non-core U.K. assets. Suncor has provided

these anticipated times in reliance on certain assumptions that we believe are reasonable at this time,

including assumptions as to the timing of receipt of the necessary regulatory, court and other third-party approvals, and the time necessary to satisfy the conditions to the closing of the transaction. These dates may change for a number of reasons, including unforeseen delays in the ability to secure necessary regulatory or other third party approvals or the need for additional time to satisfy the conditions to the completion of the transaction. The transaction may not close as scheduled or at all. As a result of the foregoing, readers should not place undue reliance on the forward-looking statements and information contained in this Management's Discussion and Analysis concerning these items.

Forward-looking statements and information are not guarantees of future performance and involve a number of risks and uncertainties, some that are similar to other oil and gas companies and some that are unique to Suncor. Suncor's actual results may differ materially from those expressed or implied by its forward-looking statements and information and readers are cautioned not to place undue reliance on them.

The financial and operating performance of the company's business segments, including Oil Sands, Natural Gas, International and Offshore and Refining and Marketing, may be affected by a number of factors, including, but not limited to, the following:

Factors that affect our Oil Sands business:

- *Production reliability risk. Our ability to reliably operate our oil sands facilities in order to meet production targets.*
- *Our ability to finance oil sands growth and sustaining capital expenditures in a volatile commodity pricing environment.*
- *Bitumen supply. The unavailability of third party bitumen, poor ore grade quality, unplanned mine equipment and extraction plant maintenance, tailings storage and in situ reservoir and equipment performance could impact production targets.*
- *Performance of recently commissioned facilities. Production rates while new equipment is being lined out are difficult to predict and can be impacted by unplanned maintenance.*
- *Our ability to manage production operating costs. Operating costs could be impacted by inflationary pressures on labour, volatile pricing for natural gas used as an energy source in oil sands processes, and planned and unplanned maintenance. We continue to address these risks through strategies such as application of technologies that help manage operational workforce demand, offsetting natural gas purchases through internal production, investigation of technologies that mitigate reliance on natural gas as an energy source, and an increased focus on preventative maintenance.*
- *Our ability to complete projects both on time and on budget. This could be impacted by competition from other projects (including other oil sands projects) for goods and services and demands on infrastructure in Fort McMurray and the surrounding area (including housing, roads and schools). We continue to address these issues through a comprehensive recruitment and retention strategy, working with the community to determine infrastructure needs, designing Oil Sands expansion to reduce unit costs, seeking strategic alliances with service providers and maintaining a strong focus on engineering, procurement and project management.*
- *Potential changes in the demand for refinery feedstock and diesel fuel. Our strategy is to reduce the impact of this issue by entering into long-term supply agreements with major customers, expanding our customer base and offering a variety of blends of refinery feedstock to meet customer specifications.*
- *Volatility in light/heavy and sweet/sour crude oil differentials.*
- *Logistical constraints and variability in market demand, which can impact crude movements. These factors can be difficult to predict and control.*
- *Changes to royalty and tax legislation and related agreements that could impact our business (including our current dispute with the Alberta Department of Energy in respect of the Bitumen Valuation Methodology Regulation). While fiscal regimes in Alberta and Canada are generally stable relative to many global jurisdictions, royalty and tax treatments are subject to periodic review, the outcome of which is not predictable and could result in changes to the company's planned investments, and lower rates of return on existing investments.*
- *Our relationship with our trade unions. Work disruptions have the potential to adversely affect Oil Sands operations and growth projects.*

Factors that affect our Natural Gas business:

- *Volatility in natural gas prices.*
- *Risk associated with a depressed market for asset sales, leading to losses on disposition.*
- *The accessibility and cost of mineral rights. Market demand influences the cost and available opportunities for mineral leases and acquisitions.*
- *Risks and uncertainties associated with weather conditions, which can shorten the winter drilling season and impact the spring and summer drilling program, which may result in increased costs and/or delays in bringing on new production.*

Factors that affect our International and Offshore business:

- *Risks and uncertainties associated with international and offshore operations normally inherent in such activities such as drilling,*

operation and development of such properties including unexpected formations or pressures, premature declines of reservoirs, fires, blow-outs,

equipment failures and other accidents, uncontrollable flows of crude oil, natural gas or well fluids, pollution and other environmental risks.

- *Performance after completion of maintenance is not predictable and can significantly impact production rates.*
- *Risks and uncertainties associated with consulting with stakeholders and obtaining regulatory approval for exploration and development activities.*

These risks could increase costs and/or cause delays to or cancellation of projects and expansions to existing projects.

- *Risks and uncertainties associated with weather conditions, which may result in increased costs and/or delays in exploration, operations or abandonment activities.*
- *Suncor's foreign operations and related assets are subject to a number of political, economic and socio-economic risks. Suncor's operations in Libya may be constrained by production quotas.*

Factors that affect our Refining and Marketing business:

- *Production reliability risk. Our ability to reliably operate our refining and marketing facilities in order to meet production targets.*
- *Management expects that fluctuations in demand and supply for refined products, margin and price volatility, and market competition, including potential new market entrants, will continue to impact the business environment.*
- *There are certain risks associated with the execution of capital projects, including the risk of cost overruns. Numerous risks and uncertainties can affect construction schedules, including the availability of labour and other impacts of competing projects drawing on the same resources during the same time period.*
- *Our relationship with our trade unions. Hourly employees at our London, Ontario terminal operation, our Sarnia refinery, our Commerce City refinery, our Montreal refinery, certain of our lubricants operations, certain of our terminalling operations and at Sun-Canadian Pipeline Company Limited 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 have an adverse effect on our business, financial condition, results of operations and cash flow.*

Additional Risks, Uncertainties and Other Factors

Additional risks, uncertainties and other factors that could influence the actual results of all of Suncor's business segments include but are not limited to, market instability affecting Suncor's ability to borrow in the capital debt markets at acceptable rates; consistently and competitively finding and developing reserves that can be brought on-stream economically; success of hedging strategies; maintaining a desirable debt to cash flow ratio; changes in the general economic, market and business conditions; our ability to finance capital investment to replace reserves or increase processing capacity in a volatile commodity pricing and credit environment; fluctuations in supply and demand for Suncor's products; commodity prices, interest rates and currency exchange; volatility in natural gas and liquids prices is not predictable and can significantly impact revenues; Suncor's ability to respond to changing markets and to receive timely regulatory approvals; the successful and timely implementation of capital projects including growth projects and regulatory projects; risks and uncertainties associated with consulting with stakeholders and obtaining regulatory approval for exploration and development activities in Suncor's operating areas (these risks could increase costs and/or cause delays to or cancellation of projects); effective execution of planned turnarounds; the accuracy of cost estimates, some of which are provided at the conceptual or other preliminary stage of projects and prior to commencement or conception of the detailed engineering needed to reduce the margin of error and increase the level of accuracy; the integrity and reliability of Suncor's capital assets; the cumulative impact of other resource development; the cost of compliance with current and future environmental laws; the accuracy of Suncor's reserve, resource and future production estimates and its success at exploration and development drilling and related activities; the maintenance of satisfactory relationships with unions, employee associations and joint venture partners; competitive actions of other companies, including increased competition from other oil and gas companies or from companies that provide alternative sources of energy; labour and material shortages; 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, our negotiations with the Alberta Department of Energy in respect of the Bitumen Valuation Methodology Regulation; 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 (including in respect of any planned divestitures); risks and uncertainties associated with the ability of closing conditions to be met with respect to the sale of any of Suncor's assets, the timing of closing and the consideration to be received with respect to the planned sale of any of Suncor's assets, including the ability of counterparties to comply with their obligations in a timely manner and the receipt of any required regulatory or other third party approvals outside of Suncor's control; the occurrence of unexpected events such as fires, blowouts, freeze-ups, equipment failures and other similar events affecting Suncor or other parties whose operations or assets directly or indirectly affect Suncor; failure to realize anticipated synergies or cost savings; risks regarding the integration of Suncor and Petro-Canada after the merger;

and incorrect assessments of the values of Petro-Canada. The foregoing important factors are not exhaustive.

Many of these risk factors and other assumptions related to Suncor's forward-looking statements and information are discussed in further detail throughout this Management's Discussion and Analysis, including under the heading "Risk Factors" and its Annual Information Form/Form 40-F on file with Canadian securities commissions at www.sedar.com and the United States Securities and Exchange Commission (SEC) at www.sec.gov. Readers are also referred to the risk factors and assumptions described in other documents that Suncor files from time to time with securities regulatory authorities. Copies of these documents are available without charge from the company.

QuickLinks

EXHIBIT 99-2

Management's Discussion and Analysis for the fiscal year ended December 31, 2010, dated February 24, 2011

QuickLinks -- Click here to rapidly navigate through this document

EXHIBIT 99-3

Consent of PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Chartered Accountants
111 5th Avenue SW, Suite 3100
Calgary, Alberta
Canada T2P 5L3
Telephone +1 (403) 509 7500
Facsimile +1 (403) 781 1825

CONSENT OF INDEPENDENT AUDITOR

We hereby consent to inclusion in this Annual Report on Form 40-F for the year ended December 31, 2010 and the incorporation by reference in the registration statements on Form S-8 (File No. 333-87604), Form S-8 (File No. 333-112234), Form S-8 (File No. 333-118648), Form S-8 (File No. 333-124415), Form S-8 (File No. 333-149532), Form S-8 (File No. 333-161021) and Form S-8 (File No. 333-161029), of Suncor Energy Inc., of our report dated February 24, 2011 relating to the consolidated financial statements and the effectiveness of internal control over financial reporting, which appears in the Annual Report.

We also consent to reference to us under the heading "Interests of Experts" in the Annual Information Form incorporated by reference in this Annual Report on Form 40-F which is incorporated by reference in the Registration Statements referred to above.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta
March 3, 2011

QuickLinks

EXHIBIT 99-3

Consent of PricewaterhouseCoopers LLP

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EXHIBIT 99-4

Consent of GLJ Petroleum Consultants Ltd.

LETTER OF CONSENT

TO: Suncor Energy Inc.
The Securities and Exchange Commission
The Securities Regulatory Authorities of Each of the Provinces of Canada

Dear Sirs

Re: Suncor Energy Inc.

We refer to the following reports (the "Reports") prepared by GLJ Petroleum Consultants Ltd. ("GLJ"):

- Reserves Assessment and Evaluation of In Situ Oil Sands Properties — Corporate Summary; and
- Reserves Evaluation and Resources Assessment of Oil Sands Mining Properties — Summary.

which provide GLJ's reports on proved and probable reserves evaluations pursuant to Canadian disclosure requirements of Suncor Energy Inc.'s Canadian mining and in-situ leases that were evaluated as at December 31, 2010.

We hereby consent to the use of our name, reference to and excerpts from the said Reports by Suncor Energy Inc. in its Annual Report on Form 40-F and the incorporation by reference in the registration statements on Form S-8 (File No. 333-87604), Form S-8 (File No. 333-112234), Form S-8 (File No. 333-118648), Form S-8 (File No. 333-124415), Form S-8 (File No. 333-149532), Form S-8 (File No. 333-161021) and Form S-8 (File No. 333-161029) of Suncor Energy Inc., of our Reports. In addition, we also consent to the use of our name, reference to and excerpts from the said Reports in Suncor Energy Inc.'s 2010 annual report to be filed with the securities regulatory authorities of each of the provinces of Canada.

We have read Suncor Energy Inc.'s Annual Information Form dated March 3, 2011 and the Form 40-F dated March 3, 2011 and have no reason to believe that there are any misrepresentations in the information contained therein that is derived from our Reports or that are within our knowledge as a result of the services which we performed in connection with the preparation of the Reports.

Yours very truly,

GLJ PETROLEUM CONSULTANTS LTD.

"GLJ PETROLEUM CONSULTANTS LTD."

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

Dated: March 3, 2011
Calgary, Alberta
CANADA

QuickLinks

EXHIBIT 99-4

Consent of GLJ Petroleum Consultants Ltd.
LETTER OF CONSENT

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EXHIBIT 99-5

Consent of Sproule Associates Limited and Sproule International Limited

LETTER OF CONSENT

TO: Suncor Energy Inc.
The Securities and Exchange Commission
The Securities Regulatory Authorities of Each of the Provinces of Canada

Dear Sirs:

Re: Suncor Energy Inc.

We refer to the following reports (the "Reports") prepared by Sproule Associates Limited ("Sproule Associates") and Sproule International Limited ("Sproule International"):

- Evaluation of the P&NG Reserves of Suncor Energy Inc. in the Newfoundland Offshore Areas;
- Evaluation of the P&NG Reserves of Suncor Energy Inc. in the Canada Conventional Onshore Business Unit;
- Evaluation/Review of the P&NG Reserves of Suncor Energy Inc., North Sea Business Unit; and
- Evaluation of the P&NG Reserves of Suncor Energy Inc., Other International Business Unit

which provide Sproule Associates' and Sproule International's reports on proved and probable reserves evaluations and reviews pursuant to Canadian disclosure requirements of Suncor Energy Inc.'s Canadian onshore and offshore conventional assets and international operations that were evaluated or reviewed as at December 31, 2010.

We each hereby consent to the use of our name, reference to and excerpts from the said Reports by Suncor Energy Inc. in its Annual Report on Form 40-F and the incorporation by reference in the registration statements on Form S-8 (File No. 333-87604), Form S-8 (File No. 333-112234), Form S-8 (File No. 333-118648), Form S-8 (File No. 333-124415), Form S-8 (File No. 333-149532), Form S-8 (File No. 333-161021) and Form S-8 (File No. 333-161029) of Suncor Energy Inc., of our Reports. In addition, we each also consent to the use of our name, reference to and excerpts from the said Reports in Suncor Energy Inc.'s 2010 annual report to be filed with the securities regulatory authorities of each of the provinces of Canada.

We each have read Suncor Energy Inc.'s Annual Information Form dated March 3, 2011 and the Form 40-F dated March 3, 2011 and have no reason to believe that there are any misrepresentations in the information contained therein that is derived from our Reports or that are within our knowledge as a result of the services which we performed in connection with the preparation of the Reports.

Sincerely,

Sproule Associates Limited and
Sproule International Limited

"Sproule Associates Limited" and
"Sproule International Limited"

R. Keith MacLeod, P.Eng.
President

Dated: March 3, 2011
Calgary, Alberta, Canada

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EXHIBIT 99-5

Consent of Sproule Associates Limited and Sproule International Limited
LETTER OF CONSENT

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EXHIBIT 99-6

CERTIFICATION

I, RICHARD L. GEORGE, certify that:

1. I have reviewed this annual report on Form 40-F of the Issuer;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this annual report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

/s/ RICHARD L. GEORGE

Richard L. George
President and Chief Executive Officer

DATE: March 3, 2011

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EXHIBIT 99-6

CERTIFICATION

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EXHIBIT 99-7

CERTIFICATION

I, BART DEMOSKY, certify that:

1. I have reviewed this annual report on Form 40-F of the issuer;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this annual report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

/s/ BART DEMOSKY

Bart Demosky
Chief Financial Officer

DATE: March 3, 2011

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EXHIBIT 99-7

CERTIFICATION

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EXHIBIT 99-8

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ENACTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the annual report of Suncor Energy Inc. (the "Company") on Form 40-F for the fiscal year ending December 31, 2010 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, RICHARD L. GEORGE, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ RICHARD L. GEORGE

Richard L. George
President and Chief Executive Officer
Suncor Energy Inc.

DATE: March 3, 2011

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EXHIBIT 99-8

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350, AS ENACTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

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EXHIBIT 99-9

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ENACTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the annual report of Suncor Energy Inc. (the "Company") on Form 40-F for the fiscal year ending December 31, 2010 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, BART DEMOSKY, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ BART DEMOSKY

Bart Demosky
Chief Financial Officer
Suncor Energy Inc.

DATE: March 3, 2011

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EXHIBIT 99-9

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350, AS ENACTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002