ANNUAL INFORMATION FORM DATED MARCH 5, 2010

SUNCOR ENERGY

ANNUAL INFORMATION FORM

TABLE OF CONTENTS

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.

Barrel of oil equivalent (boe)

Suncor converts natural gas to barrels of oil equivalent (boe) at a 6 thousand cubic feet:1 barrel ratio. BOEs may be misleading, particularly if used in isolation. The boe conversion ratio of 6 thousand cubic feet:1 barrel is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a 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, 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.

Dry hole

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

Feedstock

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

Finding costs

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

Gross wells/Land holdings

Total number of wells or acres, as the case may be, in which Suncor has an interest.

Heavy fuel oil

Residue from refining of conventional crude oil that remains after lighter products such as gasoline, petrochemicals and heating oils have been extracted. This product traditionally sells at less than the cost of crude oil.

In-situ

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

Lifting costs

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

MD&A

Suncor's Management's Discussion and Analysis dated February 26, 2010, accompanying its audited consolidated financial statements, notes and auditors' report, as at and for the three years in the period ended December 31, 2009.

MMbbls

Millions of barrels.

MMbtu

Millions of British Thermal Units.

MMcf

Millions of cubic feet.

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.

Net wells/Land holdings

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

Overburden

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

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.

Synthetic crude oil (SCO)

A mixture of hydrocarbons derived by upgrading (thermal cracking and purification) of crude bitumen from oil sands which 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"; 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

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.

CONVERSION TABLE

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

Notes:

(1) Conversion using the above factors on rounded numbers appearing in this 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

The information contained in this AIF is dated as at December 31, 2009, unless otherwise indicated. All references in this AIF to dollar amounts are in Canadian 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 its experience and its perception of historical trends.

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 (including in respect of our planned sales of certain natural gas assets)

- anticipated construction and repair activities
- anticipated turnarounds at upgraders, refineries and other facilities
- anticipated refining margins
- future oil and natural gas production levels 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 our experience. Our actual results may differ materially from those expressed or implied by our forward-looking statements and you are cautioned not to place undue reliance on them.

The risks, uncertainties and other factors, 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 debt capital markets at acceptable rates; availability of third-party bitumen; success of our hedging strategies; maintaining a desirable debt to cash flow ratio; risks associated with the integration of the business of Petro-Canada following completion of the merger; changes in the general economic, market and business conditions; fluctuations in supply and demand for our products; commodity prices, interest rates and currency exchange rates; our ability to respond to changing markets, and to receive timely regulatory approvals; the successful and timely implementation of capital projects including growth projects and regulatory projects; the accuracy of cost estimates, some of which are provided at the conceptual or other preliminary stage of projects and prior to commencement of the detailed engineering needed to reduce the margin of error or level of accuracy; the integrity and reliability of our capital assets; the cumulative impact of other resource development; the cost of compliance with existing and future environmental laws; the accuracy of Suncor's reserve, resource and future production estimates and our success at exploration and development drilling and related activities; the maintenance of satisfactory relationships with unions, employee associations and joint venture partners; changes in refining and marketing margins; competitive actions of other companies, including increased competition from other oil and gas companies and from companies that provide alternative sources of energy; labour and material shortages; uncertainties resulting from potential delays or changes in plans with respect to projects or capital expenditures; actions by governmental authorities including the imposition of taxes or changes to fees and royalties; changes in environmental and other regulations (for example, the Government of Alberta's review of the unintended consequences of the proposed Crown royalty regime, and the Government of Canada's current review of greenhouse gas emission regulations); international political events and actions by foreign governments in jurisdictions in which we operate (including OPEC production quotas); the ability and willingness of parties with whom we have material relationships to perform their obligations to us; and the occurrence of unexpected events such as fires, blowouts, freeze-ups, equipment failures and other similar events affecting us or other parties whose operations or assets directly or indirectly affect us. These important factors are not exhaustive.

Many of these risk factors and other specific risks and uncertainties are discussed in further detail 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 112 - 4th Avenue S.W., Calgary, Alberta, T2P 2V5, by calling 1-800-558-9071, or by email request to info@suncor.com or by referring to SEDAR at www.sedar.com or by referring to EDGAR at www.sec.gov. Information contained in or otherwise accessible through our website does not form a part of this AIF, and is not incorporated into this AIF by reference.

NON-GAAP FINANCIAL MEASURES

Certain financial measures referred to in this AIF are not prescribed by Canadian generally accepted accounting principles (GAAP), namely operating earnings, cash flow from operations, return on capital employed (ROCE), and cash and total operating costs per barrel. These non-GAAP financial measures do not have any standardized meaning and therefore are unlikely to be comparable to similar measures presented by other companies. Suncor includes these non-GAAP financial measures because investors may use this information to analyze operating performance, leverage and liquidity. The additional information should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP. For more information with respect to financial measures which have not been defined by GAAP, see the "Non-GAAP Financial Measures" section of the MD&A.

ACCOUNTING MATTERS

References to our "2009 Consolidated Financial Statements" mean Suncor's audited consolidated financial statements prepared in accordance with GAAP, the notes and the auditors' report, as at and for the three years in the period ended December 31, 2009.

On August 1, 2009, Suncor completed its merger with Petro-Canada. All closing conditions were satisfied, including approvals from shareholders, the Alberta Court of Queen's Bench, and the Competition Bureau of Canada. Under the terms of the merger, Petro-Canada shareholders received 1.28 Suncor common shares for each Petro-Canada common share held. 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 reflect solely the 2007 and 2008 results of legacy Suncor. For further information with respect to the merger transaction, please refer to note 2 of our 2009 Consolidated Financial Statements.

Certain amounts in prior years have been reclassified to enable comparison with 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 International Financial Reporting Standards, 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 (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 principal office is located at 112 - 4th Avenue, S.W. Calgary, Alberta, T2P 2V5.

Intercorporate Relationships

Material operating subsidiaries, each of which were owned 100%, directly or indirectly, by the company as at December 31, 2009 are as follows:

Name	Jurisdiction	Purpose
Suncor Energy Oil Sands Limited Partnership	Canada	A subsidiary of Suncor Energy Inc. that holds certain oil sands assets.
Suncor Energy Products Inc.	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 business 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 Marketing Inc. holds a 50% interest in Sun Petrochemicals Company, a petrochemical products joint venture.
Suncor Energy (U.S.A) Inc.	United States	A subsidiary of Suncor Energy Inc., through which our U.S. refining and marketing operations are conducted.
Suncor Energy Oil & Gas Partnership	Canada	A subsidiary of Suncor Energy Inc. through which certain of our upstream Canadian oil and gas operations are conducted and through which our 12% interest in the Syncrude joint venture is held.
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 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.

Individually, the company's remaining subsidiaries accounted for (i) less than 10% of the company's consolidated assets as at December 31, 2009, and (ii) less than 10% of the company's consolidated sales and operating revenues for the fiscal year ended December 31, 2009. In the 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 buying and selling futures contracts and other derivative instruments based on the commodities we produce.

Our operating business units are composed of Oil Sands, Natural Gas, East Coast Canada, International 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 third-party energy trading activities.

Suncor completed its merger with Petro-Canada on August 1, 2009, resulting in Suncor becoming Canada's largest energy company by market capitalization. After completion of the merger with Petro-Canada, Suncor's total upstream production during the final five months of 2009 averaged 635,200 barrels of oil equivalent (boe) per day.

The table below outlines the various Suncor businesses as at December 31, 2009:

Oil Sands
- Mining
- In-Situ (Firebag and MacKay River)
- Syncrude (12% Interest) – mining
- Fort Hills (60% Interest) – mining

Natural Gas
- Western Canada
  - *Alberta Foothills*
  - *Southeast Alberta/Southwest Saskatchewan*
  - *West Central Alberta*
  - *Northeast British Columbia (B.C.)*
- U.S. Rockies
- Northwest Territories (NWT)/Nunavut
- Alaska/Arctic Islands

East Coast Canada
- Hibernia (20% Interest)
- Terra Nova (34%[1] Interest)
- White Rose (27.5%[2] Interest)
- Hebron (22.7% Interest)
- Discovery Licences and Exploration Acreage
- Hibernia South Extension (19.5%[3] Interest)
- White Rose North Amethyst and West White Rose Extensions (26.125% Interest)

International
- North Sea
  - *Buzzard (29.9% Interest)*
  - *Triton Area*
  - *Scott/Telford Area*
  - *De Ruyter (54.07% Interest)*
  - *Hanze (45% Interest)*
  - *Other Exploration Acreage*
- Other International
  - *Libya Exploration Production Sharing Agreements (EPSAs) (50% Interest)*
  - *Syria Ebla Natural Gas Project (100% Interest)*
  - *Trinidad and Tobago North Coast Marine Area 1 (NCMA-1) (17.3% Interest)*
  - *Other Exploration Acreage*

Refining and Marketing
- Edmonton Refinery
- Montreal Refinery
- Sarnia Refinery
- Commerce City (Colorado) Refinery
- St. Clair Ethanol Plant
- Sun Petrochemicals Company (50% Interest)

Sales and Marketing
- Retail Operations
- Wholesale Operations

Lubricants
- Mississauga Lubricants Plant

Corporate, Energy Trading and Eliminations
- Energy Trading activities
- Ripley Wind Farm (50% Interest)
- Chin Chute Wind Farm (33.3% Interest)
- Magrath Wind Farm (33.3% Interest)
- SunBridge Wind Farm (50% Interest)

(1) Under the Terra Nova Development and Operating Agreement, a re-determination of working interests is required following payout. The owners have been working through a process to re-determine what the future working interests will be. This process is ongoing.

(2) Suncor's working interest in the White Rose North Amethyst and West White Rose Extensions is 26.125% after the Newfoundland and Labrador Energy Corporation (NALCOR) acquired its 5% working interest effective with the signing of the final project agreements in February 2009. There is no change to the White Rose 27.5% working interest for the original field development as NALCOR is not a partner.

(3) This interest was 21.7% prior to signing the Hibernia South extension agreement with NALCOR on February 16, 2010.

Three-Year History

On August 1, 2009, Suncor Energy Inc. completed its merger with Petro-Canada. The amounts ending December 31, 2009 reflect results of the post-merger Suncor from August 1, 2009 together with results of legacy Suncor only from January 1 through July 31, 2009. Comparative figures from prior years reflect solely results of legacy Suncor. For further information with respect to the merger, please refer to note 2 to the December 31, 2009 Consolidated Financial Statements.

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 by-products. 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.

Over the past three years we have continued to advance our multi-phased growth strategy to increase production capacity. Key milestones and significant events that have affected our Oil Sands business during this time period include the following:

- Operational Issues – Oil Sands had two recent upgrader fires which negatively impacted production. In December 2009 there was a fire at our Upgrader 2 facility and in February 2010 there was a fire at our Upgrader 1 facility. Upgrader 2 was repaired and operational in early 2010, while the damage to Upgrader 1 is currently being repaired and is expected to return to production in April 2010.
- 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 development (a steam-assisted gravity drainage (SAGD) operation), 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 included historically in Suncor's reported production from January 1, 2009 to July 31, 2009 as volumes processed by Suncor under a processing fee arrangement.
- 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. Safe mode is defined as deferring the projects and keeping the equipment and facilities in a safe manner in order to expedite remobilization. As a result of placing the company's Oil Sands projects into safe mode, pre-tax costs of $380 million were incurred in 2009.
- Tailings Reduction Operations (TRO) – Suncor is seeking approval from Alberta regulators to convert from its current Consolidated Tailings (CT) tailings management process to Tailings Reduction Operations (TRO). TRO is a new "dry tailings" process in which mature fine tails (MFT) are dried, rather than mixed with sand and other materials to form CT. The processing rate for TRO is expected to be more efficient and effective than CT. If we receive timely approval to proceed, we believe that TRO will allow Suncor to meet the requirements of the new Tailings Directive issued by Alberta's Energy Resources Conservation Board (ERCB) last year. Major construction on this project is expected in mid-2010 following Board approval, assuming regulatory approvals are received.
- North Steepbank Extension (NSE) – The NSE is currently under construction and is expected to begin production in 2012. The NSE was approved in early 2007 as an extension to Suncor's mining activities east of the Athabasca River. Conditions contained within the government's approval of the NSE relating to Suncor's tailings management performance are expected to be satisfied or waived if the TRO application is approved. During its peak production years, it is currently expected that the NSE will produce approximately half the total bitumen ore mined within the overall Millennium Mine/NSE mining operations.
- Firebag Stage 3 – in-situ oil sands expansion – This project was approximately 50% complete before being deferred due to market conditions in early 2009. The project has restarted and Suncor expects the project to begin production in the second quarter of 2011, with volumes then beginning to ramp up toward design capacity of approximately 68,000 barrels per day (bpd) of bitumen over a period of approximately 18 months.
- Steepbank Extraction Plant – This project was completed on schedule and on budget during the third quarter of 2009. After commissioning, the plant began operations in late September 2009 and has resulted in improved reliability and productivity within our Oil Sands business.
- Firebag Sulphur Plant – This project was also completed on schedule and on budget during the third quarter of 2009. The plant is currently ready to operate and is expected to support sulphur emissions reductions for existing and planned in-situ development at Firebag, including Firebag Stage 3.
- Royalties – In January 2008, we entered into the Suncor Royalty Amending Agreement (Amending Agreement) with the government of Alberta, which modifies the rates under the Government of Alberta's New Royalty Framework (New Royalty Framework) that applies to our in-situ operations and would otherwise apply to our base mining operations. Under the Amending Agreement, prior to January 1, 2010, we would pay a royalty in respect of our base operations at 25% of the difference between a project's annual gross revenues net of reasonable quality adjustments and related allowable transportation costs (R), less allowable costs (C) including allowable capital expenditures (the R – C Royalty). This is subject to

a minimum royalty of 1% of revenues should allowable costs exceed revenues as determined using the R-C Royalty formula. Under the New Royalty Framework enacted in December 2008, royalty rates move to a sliding scale royalty of 25% – 40% of R – C, subject to a minimum royalty of 1% – 9%, depending on oil price. In both cases, the sliding scale royalty would move with an increase in WTI prices from Cdn$55/bbl to the maximum rate at Cdn$120/bbl. From 2010 through 2015, royalty rates on our base mining operations are those in the New Royalty Framework, with a cap of 30% of R – C and a minimum royalty of 1.0% to a cap of 1.2% of R. In 2016 and subsequent years, the royalty rates for all of our Oil Sands operations (our base mining project and our in-situ projects) will be the rates prescribed under the New Royalty Framework, unless it is amended or superseded prior to that time.

- Coker Unit – A $2.3 billion expansion to one of our two oil sands upgraders was completed in 2008. This new set of cokers is intended to increase our design capacity by 90,000 bpd to a total of 350,000 bpd at our Oil Sands facilities.
- Voyageur South Extension of Mine – In July 2007, Suncor filed a regulatory application for the Voyageur South extension of the mine. Bitumen produced at the proposed project is expected to provide additional feedstock flexibility once operational.
- Operating Permit – We were issued a new 10-year operating approval in connection with our Oil Sands business in August 2007.
- Firebag Cogeneration – A capital project expanding Firebag Stages 1 and 2 in conjunction with the addition of a cogeneration facility was completed in 2007.
- Emissions – In September 2007, high emissions at our Firebag in-situ operations resulted in orders being issued by both Alberta Environment and the Alberta Energy and Utilities Board that capped production. The production cap was lifted on July 22, 2008, after Suncor demonstrated the ability to meet emissions restrictions. This enforcement action was closed in March 2010. In December 2007, high emissions recorded at our base oil sands plant resulted in an order being issued by Alberta Environment. Emissions at the oil sands plant exceeded air quality standards, and accordingly, we are upgrading our emission control equipment and reducing discharges to the tailings ponds. In addition, we have introduced processing changes and are undertaking a more comprehensive monitoring program.

The following changes to our Oil Sands business have occurred, or are expected to occur, in 2010:

- Approximately $950 million in growth spending will be directed toward Firebag Stages 3 and 4 in-situ oil sands expansion. Firebag Stage 3 was approximately 50 per cent complete before being deferred in early 2009 due to market conditions. Production from Firebag Stage 3 is expected to begin in the second quarter of 2011, with volumes then beginning to ramp up toward design capacity of approximately 68,000 bpd of bitumen over a period of approximately 18 months. Subject to Board approval, first bitumen for Firebag Stage 4 is targeted in the fourth quarter of 2012. Firebag Stage 4 also has a design capacity of 68,000 bpd.

Natural Gas

Our Natural Gas business, based in Calgary, Alberta, explores for, acquires, develops and produces natural gas, natural gas liquids, oil and by-products from reserves primarily in western Canada and the U.S. Rockies. This business also has established resources in Alaska, the Northwest Territories (NWT) and the Arctic Islands. The sale of natural gas production offsets natural gas purchased for internal consumption at our North American operations.

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

- 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 established resources in Alaska, the NWT and the Arctic Islands.
- Offshore Permit – In September 2008, Suncor, together with a partner, successfully bid for a large offshore parcel in the Newfoundland and Labrador Offshore Area. This land is adjacent and complementary to an existing holding in the Bjarni area and provides Suncor with a long-term option for future potential natural gas growth. In order to retain the lands, the exploration license requires Suncor to commit to exploration spending of $30 million on the lands within six years. Subsequent to the merger, these licenses are now managed by our East Coast Canada business.
- Acquisition – In March 2007, we acquired developed and undeveloped lands in British Columbia for approximately $160 million.

The following changes to our Natural Gas business have occurred or are expected to occur, in 2010:

- Planned divestitures – As part of its strategic business alignment, Suncor announced its intention to divest of a number of non-core natural gas assets. The proposed divestments identified to date include certain natural gas assets in Western Canada and the U.S. Rockies. On February 9, 2010, Suncor announced it has entered into an agreement to sell certain natural gas properties in northeastern British Columbia for proceeds of approximately $390 million. The sale is expected to close in the first quarter of 2010 and is subject customary to closing conditions and regulatory approvals. On December 31, 2009, Suncor entered into an agreement to sell substantially all of its oil and gas producing assets in the U.S. Rockies for proceeds of $517 million (US$494 million). The sale closed March 1, 2010.

East Coast Canada

Our East Coast Canada business comprises exploration and production activity offshore Newfoundland and Labrador. The company has a strong position in every major producing oil development off Canada's east coast. The company holds a 20% interest in Hibernia, a 19.5% (1) interest in Hibernia Southern Extension, a 27.5% interest in White Rose, a 26.125% interest in White Rose North Amethyst and West White Rose extensions, a 22.7% interest in Hebron and is the operator of Terra Nova with a 34% interest. The company also holds a number of exploration licenses and significant discovery licenses in the region.

Key milestones and significant events that have affected our East Coast Canada business during the past three years include the following:

- Hibernia South – Production from Hibernia South is expected later in the first quarter of 2010 with the completion of the first oil producer/water injector well pair. Final fiscal agreements were made between co-venturers and the Government of Newfoundland and Labrador in February 2010.
- Terra Nova – In 2009, Terra Nova was negatively impacted by planned and unplanned downtime for maintenance. In 2008, there were mechanical failures on the Terra Nova Floating Production, Storage and Offloading (FPSO) vessel and Terra Nova had a 16-day maintenance turnaround.
- White Rose – White Rose was negatively impacted by planned downtime for maintenance and the tie-in of the North Amethyst extension in the second half of 2009. Additionally, pack ice at the White Rose field in the second quarter of 2008 caused production deferrals and drilling delays.
- Hibernia – In 2007, Hibernia had a 30-day maintenance turnaround.

International

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 U.K., The Netherlands, Norway, Trinidad and Tobago, Libya and Syria.

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

North Sea

- As part of our strategic business alignment, we plan to divest of certain non-core North Sea assets, including all assets in The Netherlands.
- Completed our first operated exploration well in January 2010 in Norway and encountered hydro-carbon; further appraisal is required to determine the potential size of this discovery. The company is committed to participating in other non-operated drilling in Norway.
- After completion of the shutdown at the Buzzard development in the third quarter of 2009, production did not return to full production capacity as quickly as planned, but this development was back operating at expected capacity by year-end.
- In 2008, there was a non-operated oil discovery, located in Block 20/1 North, called Pink. The Pink block is located in the Outer Moray Firth approximately 110 kilometres northeast of Aberdeen. Our working interest is 33%.
- In the Netherlands sector of the North Sea, the company, as operator with a 50% working interest, drilled a successful exploration well in 2008, named van Ghent. The company drilled two successful exploration wells in 2007, van Nes and van Brakel, as an operator with a 50% and 60% working interest, respectively. Both van Nes and van Brakel were suspended as gas discoveries. In the third quarter of 2008, the company completed a sale and purchase agreement with Bayerngas Norge AS for the sale of all the company's interests in Denmark for net proceeds of $140 million, resulting in a $107 million ($82 million after-tax) gain on the sale of these assets.
- In 2008, the company was awarded four additional production licences in the 2007 Awards in Predefined Areas round in Norway. Suncor is operator of five of the 17 licences in Norway.
- In the U.K. sector of the North Sea, the Buzzard development, in which the company has a 29.9% interest, achieved first oil in January 2007.

Libya

- In the five months ended December 31, 2009, Suncor's production in Libya averaged 32,600 bpd (net to Suncor). During this period, gross production from our Libya Exploration Production Sharing Agreements (EPSAs) was restricted initially to 82,000 bpd and then to 50,000 bpd from September to the end of the year. In January 2010, the Libya National Oil Company (NOC) advised the company that production from Suncor's Libya EPSAs will be limited to 70,000 bpd gross (35,000 bpd net to Suncor) due to the quota agreed to by OPEC producers.

(1) This interest was 21.7% prior to signing the Hibernia South extension agreement with NALCOR on February 16, 2010.

- Work on the exploration program progressed, with seven seismic surveys completed during 2009 and two seismic crews continue to acquire data in the country. At the end of 2009, the seismic program was approximately 75% complete. The company expects to begin drilling Suncor's first operated exploration well in early 2010.
- In the final five months of 2009, eight development wells were completed in the producing fields in Libya, consisting of six production wells and two injection wells. A further three development wells were drilling at year end. In 2008, 12 development wells were completed in the producing fields in Libya, consisting of 11 production wells and one injection well. Additionally, one appraisal well was drilled.
- In 2008, the company completed 2D and 3D seismic acquisitions.

Syria

- The Ebla gas project remains on plan with first gas delivery currently expected in mid-2010. The project was 90% complete at the end of 2009. Five gas wells have been completed and are ready for production. The 3D seismic acquisition of the Cherrife field was completed at the end of the third quarter of 2009 and is currently being interpreted. The 3D seismic survey of the Ash Shaer field that was completed during the second quarter of 2009 is also now being interpreted.
- In 2008, the company completed front-end engineering and design (FEED) and undertook 2D and 3D seismic operations for the Ebla gas project.

Trinidad and Tobago

- As part of its strategic business alignment, Suncor announced its plans to divest a number of non-core assets, including all Trinidad and Tobago assets.
- In 2008, there was maintenance at the Atlantic liquefied natural gas (LNG) plant, rebalancing of mutual aid production among producers to the Atlantic LNG plant and several brief shutdowns of the North Coast Marine Area (NCMA-1) asset to prepare for the startup of the new Poinsettia field. Development of the Poinsettia field, with a platform and pipeline tie-back to the Hibiscus platform, was carried out on schedule during 2008.
- In 2008, the company completed its eight-well exploration program in Block 22 and Block 1a/1b, which yielded four material discoveries (two on Block 22 and two on Block 1a).

Other International

- A 2D seismic survey was completed in Morocco in 2009 and is currently being interpreted.
- In July 2008, the company converted its existing reconnaissance licence in southern Morocco to an exploration permit. The company's partners in the exploration licence include a German company called RWE AG and the Moroccan National Office of Hydrocarbons.

The following changes to our International business have occured or are expected to occur, in 2010:

- On February 25, 2010, Suncor entered into an agreement to sell its assets in Trinidad and Tobago for proceeds of $396 million (US$380 million). The sale is expected to close in March 2010 and is subject to customary closing conditions, Trinidad and Tobago government approval and other regulatory approvals.

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.A. into a broad range of petroleum and petrochemical products for sale to retail, commercial and industrial customers. This operating business also includes our plant in St. Clair, Ontario that produces ethanol for blending into fuels and our lubricants plant in Mississauga, Ontario that produces specialty lubricants and waxes.

In Canada, our retail businesses are managed through Petro-Canada® and Sunoco®-branded and joint venture operated retail networks. In Colorado, our retail businesses are managed through Phillips 66® and Shell® – branded sites. We also transport crude oil through our wholly-owned pipelines in Eastern and Western Canada, Wyoming and Colorado. In conjunction with the merger, the Canadian Competition Bureau required Suncor to divest of 104 retail sites in Ontario and provide 1.1 billion litres of terminal and distribution capacity to an unrelated party in the Greater Toronto Area for ten years.

In 2009, our Refining and Marketing business sold approximately 345,300 bpd or 54,900 m^3 per day of refined products nationwide in Canada and in Colorado, as well as into other parts of the United States and in Europe.

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

- Merger – On August 1, 2009, Suncor merged with Petro-Canada, resulting in the addition of two refineries, one in Edmonton, Alberta and one in Montreal, Quebec, with a total daily rated capacity of 255,000 bpd or 40,500 m^3 per day, 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 the merger, as requested by the Canadian Competition Bureau, Suncor entered into terminalling agreements with Ultramar Ltd. to provide 1.1 billion litres of terminal and distribution capacity in the Greater Toronto Area for 10 years.
- Retail Site divestiture – In conjunction with the merger, the Canadian Competition Bureau required Suncor to divest 104 retail sites in Ontario. On December 8, 2009, Suncor agreed to sell 98 sites with expected closing dates commencing in the first half of 2010. Agreements are also now in place to meet the full divestiture requirement and we expect to complete the divestitures in 2010.
- Edmonton Refinery Conversion – The Edmonton refinery completed its refinery conversion project to process oil-sands feedstock in 2008.
- Sarnia and Denver Refining Capacities – The observed performance of our Sarnia refinery in 2008, after completion of our diesel desulphurization and oil sands integration project in 2007, has enabled us to upwardly revise our nameplate capacity to 85,000 bpd from the previously disclosed 70,000 bpd. Starting January 1, 2009, refinery utilization was calculated using the 85,000 bpd capacity. The Commerce City, Colorado refining capacity was also increased from 90,000 bpd to 93,000 bpd effective January 1, 2009.
- Diesel Desulphurization and Oil Sands Integration – In November 2007, Suncor completed a multiphase three-year $950 million project at the Sarnia refinery with a 120-day shutdown to complete the tie-ins. The project increased the amount of oil sands crude oil the refinery can upgrade, improved the facility's environmental performance, and commencing in 2006, enabled the production of ultra low sulphur diesel fuel. In 2006, Suncor additionally completed diesel desulphurization and Oil Sands integration at the Commerce City refinery. This enabled the refinery to process up to 15,000 bpd of oil sands sour crude oil and increased the refinery's ability to process a broader slate of synthetic crude oil.

The following changes to our Refining and Marketing have occured or are expected to occur, in 2010:

- Edmonton Refining Capacity – The observed performance of our Edmonton refinery in 2009, after improvements completed in previous years, has enabled us to upwardly revise our nameplate capacity to 135,000 bpd from the previously disclosed 125,000 bpd. Starting January 1, 2010, refinery utilization will be calculated using the 135,000 bpd capacity.

Other

Renewable Energy

Suncor's renewable energy interests include four wind power plants and Canada's largest ethanol plant by production volume.

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

- Suncor re-commenced construction of $120 million St. Clair Ethanol Expansion Project in the fourth quarter of 2009, following a slow down of capital spending in the fourth quarter of 2008 and placement into safe mode in January 2009. In addition, we submitted a project application to the Alberta Utilities Commission (AUC) for the 88 megawatt (MW) Wintering Hills Wind Farm, located in Alberta.
- In 2008, approval was obtained to expand our existing St. Clair Ethanol Plant, located in Ontario, from a capacity of 200 million litres to 400 million litres.
- Suncor completed construction and commissioned our 76 MW Ripley Wind Farm, located in Ontario, in 2007.

Significant Acquisition in 2009

Pursuant to 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. In respect of the Arrangement, we filed a Business Acquisition Report on Form 51-102F4 on October 2, 2009, which can be found under the company's SEDAR profile at www.sedar.com.

Forward-Looking Information

The preceding paragraphs describing the general development of our business contain forward looking information. The material factors used to develop target completion dates and cost estimates and expected results are: current capital spending plans, the current status of procurement, design and engineering phases of the projects, updates from third parties on delivery of services and goods associated with the project, and estimates from major project teams on completion of future phases of the project. We have assumed that commitments from third parties will be honored and that material delays and increased costs related will not be encountered. For additional information on risks, uncertainties and other factors that could cause actual results to differ, please see "Forward Looking Information" and "Major Projects" in the Risk Factors section of this AIF.

NARRATIVE DESCRIPTION OF THE BUSINESS

Oil Sands

Suncor produces a variety of refinery feedstock, diesel fuel and by-products by developing our resource leases in the Athabasca oil sands in northeastern Alberta and upgrading the bitumen extracted at our plant near Fort McMurray, Alberta. The company also has a 12% ownership interest in the Syncrude oil sands mining and upgrading joint venture, also located near Fort McMurray. Our Oil Sands operations represent a significant portion[(1)] of our 2009 cash flow from operations[(1)] (36%), net earnings (52%) and capital employed[(1)] excluding major projects in progress (55%).

Operations

Our integrated oil sands business involves four operations located near Fort McMurray, Alberta.

(1) Bitumen is supplied from a combination of open pit mining operations, in-situ operations and third-party supply.

(2) Primary extraction facilities recover the bitumen from the mined oil sands ore. In in-situ operations, primary extraction occurs in the ground. All mined and some in-situ bitumen also undergo Oil Sands secondary extraction processes in preparation for upgrading.

(3) Heavy oil upgrading converts bitumen into crude oil products. Since late 2005, we have upgraded bitumen from Firebag, with only a small portion of non-upgraded production being strategically sold directly into the market. Since 2007, we have upgraded bitumen from MacKay River, originally pursuant to a processing agreement with Petro-Canada, and subsequent to the merger as proprietary bitumen. A portion of that bitumen production is also strategically sold directly into the market.

(4) Required 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.

Mining/Extraction – The first step of the open pit mining operation is to remove the overburden with trucks and shovels to access the oil sands – a mixture of sand, clay and bitumen. Oil sands ore is then excavated and either transported to fixed sizing and extraction plants or fed directly to a mobile sizing and extraction operation at the mine face. In the primary extraction process, bitumen is separated from the oil sands ore using a hot water process. After the final removal of impurities and minerals during secondary extraction, naphtha is added to dilute the bitumen to facilitate transportation to upgrading.

In-Situ – Our in-situ operations (Firebag and MacKay River) use an extraction technology called Steam Assisted Gravity Drainage (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 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 upgrading. At our MacKay River operation (and in future with Firebag Stage 4), a heated pipeline is used instead of naphtha dilution for transport.

Upgrading – 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 as sour SCO or is further upgraded into sweet SCO by removing the sulphur and nitrogen using a hydrogen treating process. Four separate streams of refined crude oil are produced: diesel, naphtha, kerosene and gas oil.

We continue to explore and develop improved and alternative technologies to facilitate increased efficiency within our operations. For example, in the past three years, we have tested new mining technology and processes for potential use in our future mine development plans.

While there is virtually no finding costs associated with oil sands resources, delineation of the resources, costs associated with production including mine development and drilling wells for SAGD operations, and 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 and, as a result, operating costs per unit are largely dependent on levels of production. Natural gas is used in the production of SCO, particularly in SAGD production at our Firebag and MacKay River operations, and accordingly, natural gas prices are a key variable component of SCO production costs.

In the normal course of our operations, we regularly conduct planned maintenance shutdowns of our Oil Sands facilities. These shutdowns are scheduled, and provide both preventative maintenance and capital replacement, which are expected to improve our operational efficiency. In July 2007, a scheduled maintenance shutdown of Upgrader 2 occurred to facilitate the tie-in of new coker units, an important milestone in the capital expansion project to increase oil sands production capacity to 350,000 bpd in the second half of 2008. In May 2008, a planned shutdown of Upgrader 1 was undertaken to provide both

(1) Refer to "Non-GAAP Financial Measures" on page 5 of this AIF. Percentages have been determined excluding amounts related to Corporate, Energy Trading and Eliminations.

preventative maintenance and capital replacement to improve operational efficiency. During September and October 2009, a planned maintenance shutdown of a vacuum unit at Upgrader 1 occurred, and was completed ahead of schedule. We have planned turnarounds scheduled for Upgrader 2 for approximately 45 days during the second quarter of 2010 and approximately 35 days during the third quarter of 2010.

Syncrude – Commercial operations commenced at Syncrude in 1978. Two mines, the North mine and the Aurora mine, are currently in operation at Syncrude. Mine operations are carried out using truck, shovel and hydro-transport 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 the five months ended December 31, 2009, Syncrude production averaged 38,500 bpd (net to Suncor).

Principal Products

Sales of light sweet SCO and diesel represented 48% of Oil Sands consolidated operating revenues in 2009, compared to 45% in 2008. The other significant component of our revenues were light sour SCO and bitumen sales of 49% (2008 – 46%). Set forth below is information on daily sales volumes and the corresponding percentage of Oil Sands operating revenues by product for each of the last two years:

Product:	2009		2008	
	(thousands of barrels per day)	(% of operating revenues)	(thousands of barrels per day)	(% of operating revenues)
Light sweet crude oil/diesel	144.9	48	96.8	45
Light sour crude oil/bitumen	147.5	49	130.2	46
Total	292.4		227.0	

Principal Markets

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

Transportation

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

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 that went into service on June 1, 2008. Under this 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. Under this agreement, our current pipeline commitment is 75,000 bpd for the transportation of SCO and diluted bitumen from Cheecham to Edmonton, Alberta. Following the Petro-Canada merger, we additionally assumed a short-haul commitment from Fort McMurray to Cheecham for 58,000 bpd on the Enbridge Athabasca pipeline, a lateral transportation agreement from MacKay River to the Athabasca Tank Terminal for 40,000 bpd and contracted storage facilities of 250,000 bbls for a remaining 24-year term. We also assumed contracted storage facilities at Edmonton for 500,000 bbls with a remaining nine-year term.

Suncor has 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. Linefill on the Keystone pipeline is expected to occur in early 2010, with transportation of crude oil expected to commence in the summer of 2010. Our capacity on this pipeline in 2010 will be 25,000 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 million barrels of storage and for fixed five-year terms. On January 1, 2009, Suncor contracted storage facilities for an additional 1.2 million barrels at Nederland, Texas, for a fixed five-year term.

In 2008, we entered into new 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). We continue to evaluate additional pipeline agreements to support planned increases in production capacity.

Periodically, we also enter into strategic short-term cargo transport 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. It extends approximately 300 kilometres south of the Oil Sands plant and is connected to TransCanada Pipeline's Alberta intra-provincial pipeline system. The Albersun pipeline had the capacity to move in excess of 100 mmcf/day 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/day 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 Firebag current road access in 2010. An East Athabasca Highway (EAH) is under construction and is expected to be available for use in 2010. This highway is owned equally by Suncor, Husky Energy Inc. and Imperial Oil Ltd.

Competitive Conditions

For a discussion of the competitive conditions affecting our Oil Sands operations, refer to "Strategic Risks — 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.

Sales of SCO and Diesel

Aside from on-site fuel use, all of our Oil Sands production is sold to, and subsequently marketed by Suncor Energy Marketing Inc. Primary markets for our crude oil products include refining operations in Alberta, Ontario, the U.S. Midwest and the U.S. Rocky Mountain region. Diesel products are sold primarily in western Canada.

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 (approximately 10% of our average 2009 total production (2008 – 13%)) 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 to 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. During 2009, our refineries processed the following portion of our total Oil Sands crude sales:

Refinery	2009 (thousands of barrels per day)	2009 (% total Oil Sands sales)[1]	2008 (thousands of barrels per day)	2008 (% total Oil Sands sales)
Edmonton[2]	58	25	—	—
Sarnia	44	18	37	18
Montreal[2]	—	—	—	—
Commerce City	9	4	9	4

There were no customers that represented 10% or more of our consolidated revenues in 2009 or 2008.

Environmental Compliance

For a discussion of environmental risks at our Oil Sands operations, refer to the "Legal and Regulatory Risks" in the Risk Factors section of this AIF.

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

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

Natural Gas

Our Natural Gas business explores for, develops and produces natural gas, natural gas liquids, crude oil and by-products primarily in Western Canada, supplying markets throughout North America. The sale of this production provides a natural price hedge for natural gas purchased for internal consumption at our North American operations.

Our exploration program is primarily focused on multiple geological zones throughout Western Canada. The business is structured with the following core asset areas: Unconventional (northeast British Columbia and southeast Alberta), Foothills (western Alberta and portions of northeast British Columbia), Conventional (Western Canada) and Alaska.

Marketing, Pipeline and Other Operations

In Western Canada, Suncor operates 15 natural gas processing plants, with total licensed capacity of approximately 1,273 million cubic feet/day (MMcf/d), of which the company's share is approximately 764 MMcf/d. The following table shows Suncor's working interest ownership and the licensed capacity of operated processing plants as at December 31, 2009.

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	46.07	382.0	176.0
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
Wildcat Hills	65.78	125.0	82.2
Bearberry	100.00	94.9	94.9
Ferrier	99.37	120.0	119.2
Gilby East	100.00	52.4	52.4
South Rosevear	60.53	90.5	54.8
Pine Creek	51.46	19.5	10.0
Progress	38.46	44.0	16.9
Simonette	37.50	150.0	56.3
Total		**1 272.9**	**763.9**

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 197.8 MMcf/d of licensed capacity.

Approximately 74% of our natural gas production in 2009 was sold to Suncor Energy Marketing Inc. (SEMI) and then marketed under direct sales arrangements to our customers. Approximately 25% of our natural gas production was marketed directly to customers related to legacy Petro-Canada production from August to November 2009. Starting December 2009, this production was marketed through SEMI. Contracts for these direct sales arrangements are of varied terms, with a majority having terms of one year or less, and incorporate pricing which is either fixed over the term of the contract or determined on a monthly basis in relation to a specified market reference price. Under these contracts, we are responsible for transportation arrangements to the point of sale.

Approximately 1% of our natural gas production in 2009 was sold under existing contracts to aggregators ("system sales"). Proceeds received by producers under these system sales arrangements are determined on a netback basis, whereby each producer receives revenue equal to its proportionate share of sales less regulated transportation charges and a marketing fee. Most of our system sales volumes are contracted to Pan-Alberta Gas Ltd.

To provide exposure to the Pacific Northwest and California markets, we have a long-term gas pipeline transportation contract on the TCPL Gas Transmission Northwest Pipeline. Our contract expires in 2023 and is for 68,000 million british thermal units (MMBtu) per day.

We do not typically enter long-term supply arrangements for our conventional crude oil production. Instead, our conventional crude oil production is generally sold under spot contracts or under contracts that can be terminated on relatively short notice. Our conventional crude oil production is shipped on pipelines operated by independent pipeline companies. We currently have no pipeline commitments related to the shipment of conventional crude oil.

As part of its strategic business alignment, Suncor announced its intention to divest of a number of non-core natural gas assets. The proposed divestments identified to date include certain natural gas assets in Western Canada and the U.S. Rockies. On December 31, 2009, Suncor entered into an agreement to sell substantially all of its oil and gas producing assets in the U.S. Rockies for proceeds of $517 million (US$494 million). The sale closed March 1, 2010. On February 9, 2010, Suncor announced it has entered into an agreement to sell certain natural gas properties in northeast British Columbia for proceeds of approximately $390 million. The sale is expected to close in the first quarter of 2010 and is subject customary to closing conditions and regulatory approvals.

Principal Products

Sales of natural gas represented 76% (2008 – 81%) of the Natural Gas business segment's consolidated operating revenues in 2009, with 23% (2008 – 11%) comprised of sales of natural gas liquids and crude oil. The remaining 1% (2008 – 8%) is related mainly to sales of sulphur by-product. Set forth below is information on average daily sales volumes and the corresponding percentage of Natural Gas's operating revenues by product for the last two years.

Product:	2009		2008	
	(mmcf equivalent per day)	(% of operating revenues)	(mmcf equivalent per day)	(% of operating revenues)
Natural gas	398	76	202	81
Crude oil and natural gas liquids	48	23	18	11
Total	446		220	

Product:	Five months ended December 31, 2009*	
	(mmcf equivalent per day)	(% of operating revenues)
Natural gas	677	72
Crude oil and natural gas liquids	90	28
Total	767	

* Reflects operations subsequent to the Petro-Canada merger on August 1, 2009

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 the "Legal and Regulatory Risks" outlined in the Risk Factors section of this AIF.

East Coast Canada

Our East Coast Canada business explores for, develops and produces crude oil offshore Newfoundland and Labrador. Suncor has a strong position in every major producing oil development off Canada's east coast, holding a 20% interest in Hibernia, a 19.5%(1) interest in Hibernia Southern Extension, a 27.5% interest in White Rose, a 26.125%(2) interest in White Rose North Amethyst and West White Rose extensions, a 22.7% interest in Hebron and is the operator of Terra Nova with a 34%(3) interest. The company also holds interests in a number of exploration licenses and significant discovery licenses in the region including 47 significant discovery licenses and 7 exploration licenses offshore in Newfoundland and Labrador.

Our East Coast Canada strategy is to deliver reliable and profitable production well into the next decade, leveraging the existing infrastructure while pursuing profitable exploration and development opportunities.

(1) This interest was 21.7% prior to signing the Hibernia South extension agreement with NALCOR on February 16, 2010.

(2) Suncor's working interest in the White Rose North Amethyst and West White Rose Extensions is 26.125% after the Newfoundland and Labrador Energy Corporation (NALCOR) acquired its 5% working interest effective with the signing of the final project agreements in February 2009. There is no change to the White Rose 27.5% working interest for the original field development as NALCOR is not a partner.

(3) Under the Terra Nova Development and Operating Agreement, a re-determination of working interests is required following payout. The owners have been working through a process to re-determine what the future working interests will be. This process is ongoing.

Marketing, Pipeline and Other Operations

Hibernia

The Hibernia oilfield is approximately 315 kilometres southeast of St. John's, Newfoundland and Labrador, and was the first field to be developed in the Jeanne d'Arc Basin offshore on the Grand Banks of Newfoundland. The production system is a fixed Gravity Base Structure (GBS), which sits on the ocean floor. The GBS has a production capacity of 230,000 bpd gross and storage capacity of 1.3 million barrels (MMbbls) gross. Actual production levels are lower, however, reflecting current reservoir capability and natural decline. Hibernia commenced production in November 1997. The Hibernia oilfield, encompassing the Hibernia and Ben Nevis Avalon reservoirs, is estimated to have a remaining production life of 23 to 27 years at current rates.

In the second quarter of 2009, co-venturers in the ExxonMobil operated Hibernia South project signed a non-binding Memorandum of Understanding (MOU) with the Government of Newfoundland and Labrador establishing the key fiscal, equity and operational principles for the development of the Hibernia Southern Extension satellite (Suncor's working interest is 19.5%). Production from Hibernia South is expected later in the first quarter of 2010 with the completion of the first oil producer/water injector well pair. Final fiscal agreements were signed between co-venturers and the Government of Newfoundland and Labrador in February 2010.

At December 31, 2009, there were 33 producing oil wells, 17 water injection wells and six gas injection wells in operation. Field production is transported by shuttle tanker either from the platform to either a transshipment terminal on the Avalon Peninsula 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 the five months ended December 31, 2009, Hibernia production averaged 27,200 bpd (net to Suncor).

Terra Nova

The Terra Nova oilfield, which is approximately 350 kilometres southeast of St. John's, Newfoundland and Labrador, was discovered by Petro-Canada in 1984. Located about 35 kilometres southeast of Hibernia, it is the second oilfield to be developed offshore Newfoundland and Labrador. The Suncor-operated production system uses a Floating Production Storage and Offloading (FPSO) vessel, which is a ship moored on location. Terra Nova was the first harsh environment development in North America to use a FPSO vessel. It has a production capacity of 180,000 bpd gross, of which we have a 34% interest, and a storage capacity of 960,000 bbls gross; however, actual production levels reflect 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.

Under the Terra Nova Operating Agreement, a redetermination of operating interests is required following payout. This process is ongoing.

At December 31, 2009, 15 producing oil wells, nine water injection wells and three gas injection wells were in operation. Terra Nova uses the same system of shuttle tankers and transshipment terminal that are used for Hibernia, and also transports its crude oil to markets in Eastern Canada and the U.S.

In the five months ended December 31, 2009, Terra Nova production averaged 20,800 bpd (net to Suncor) with production negatively impacted by planned and unplanned maintenance during August, September and early October.

White Rose

White Rose, the third development offshore Newfoundland and Labrador, is about 350 kilometres southeast of St. John's and approximately 50 kilometres northeast of Hibernia and Terra Nova. Operated by Husky Energy Inc., White Rose uses a FPSO vessel similar to Terra Nova, which had an initial design production capacity of 100,000 bpd gross and a storage capacity of 940,000 bbls gross. Production is offloaded to chartered tankers that go directly to markets in Eastern Canada and the U.S. 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.

At December 31, 2009, eight producing oil wells and 10 water injection wells were in operation. Effective June 1, 2007, White Rose was granted regulatory approval to increase the daily oil production rate on the SeaRose FPSO to 140,000 bpd gross (38,500 bpd net) and to increase the annual oil production rate to 50 MMbbls. In the five months ended December 31, 2009, White Rose production averaged 10,000 bpd (net to Suncor) with production negatively impacted by planned downtime for maintenance and the tie-in of the North Amethyst extension during August, September and early October. Production rates have been slow to recover from these outages due to high water cuts in production wells.

In September 2007, the Government of Newfoundland and Labrador approved the Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) recommendation to permit development of the South White Rose extension. Subsequently, the White Rose partners reached an agreement in principle with the province on fiscal and other terms for the White Rose extensions development, incorporating the South White Rose Extension, North Amethyst and West White Rose satellite fields. In December 2007, the partners signed a formal agreement with the Province of Newfoundland and Labrador for the development of these oilfields. Development drilling has commenced and installation of subsea infrastructure is complete for the North Amethyst portion of the White Rose extensions, with the project on schedule to deliver first oil in the second quarter of 2010. The West White Rose development will be divided into two stages. Stage 1 was approved in the second quarter of 2009, and development drilling and subsea installation of this stage will take place in 2010. Results of Stage 1, combined with ongoing evaluation, will help define the scope of Stage 2.

Other Offshore Exploration and Development

In addition to existing East Coast Canada developments, Suncor also holds interests in a number of discoveries, including a 22.7% interest in the Hebron/Ben Nevis oilfield discoveries located 340 kilometres southeast of St. John's. In 2005, Chevron Canada Resources (as operator) and the other joint venture participants signed a unitization and joint operating agreement to advance the joint evaluation of the Hebron/Ben Nevis and West Ben Nevis oilfields offshore Newfoundland and Labrador. In August 2007, the Hebron partners signed a non-binding MOU with the Government of Newfoundland and Labrador related to the fiscal and other terms for the future development of the Hebron/Ben Nevis offshore oilfield. In August 2008, the Hebron partners reached an agreement with the Government of Newfoundland and Labrador on commercial terms that will allow development activities to proceed for Hebron. The transfer of operatorship from Chevron Canada Resources to ExxonMobil Canada Properties (ExxonMobil) was effective in the fourth quarter of 2008. Pre-front-end engineering and design (pre-FEED) activities continued during the 2009 and ExxonMobil opened a Hebron project office in April 2009.

Sales of Conventional Crude Oil

We do not typically enter long-term supply arrangements for our East Coast Canada conventional crude oil production. Instead, our conventional crude oil production is generally sold under spot contracts or under contracts that can be terminated on relatively short notice. Our conventional crude oil production is shipped on pipelines operated by independent pipeline companies. We currently have no pipeline commitments related to the shipment of conventional crude oil.

Principal Products

The East Coast Canada business unit produces crude oil exclusively. Set forth below is information on daily sales volumes for 2009, subsequent to August 1, 2009, the date that the East Coast Canada assets were acquired under the merger with Petro-Canada.

Product:	Five months ended December 31, 2009*	
	(thousands of barrels per day)	(% of operating revenues)
Crude oil	58	100

* Reflects operations subsequent to the Petro-Canada merger on August 1, 2009

Competitive Conditions

For a discussion of the competitive conditions affecting the East Coast Canada business unit, refer to "Competition" in the Risk Factors section of this AIF.

Seasonal Impacts

The primary East Coast Canada seasonal impacts are caused by winter storms, pack ice, icebergs and fog. During the winter storm season (October – 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 (April – June) 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 East Coast Canada operations, refer to the "Legal and Regulatory Risks" outlined in the Risk Factors section of this AIF.

International

Our International business explores for, develops and produces crude oil and natural gas in the North Sea (United Kingdom, The Netherlands and Norway), Trinidad and Tobago, Libya, and Syria. For reporting purposes, Suncor consolidates its International activities into two core areas: the North Sea (U.K., The Netherlands and Norway sectors) and Other International areas (Libya, Syria and offshore Trinidad and Tobago). As part of its strategic business alignment, Suncor plans to divest all Trinidad and Tobago assets and certain non-core North Sea assets, including all assets in The Netherlands.

Marketing, Pipeline and Other Operations

North Sea

In the North Sea, the company focuses its business around core production areas in the U.K. and the Netherlands sectors, with exploration activities extending into Norway. Total North Sea production averaged 76,500 boe per day for the final five months of 2009. As part of its strategic business alignment, Suncor plans to divest certain non-core North Sea assets, including all assets in The Netherlands.

The company's U.K. position is built around three core production hubs: Triton, Buzzard and Scott/Telford. Triton comprises the Guillemot West and Northwest fields (90% owned by Suncor), the Bittern field (4.7% owned by Suncor), the Pict field (100% owned and operated by Suncor), the Clapham field (100% owned and operated by Suncor) and the Saxon field (100% owned and operated by Suncor). All of the Triton areas are produced into the Triton FPSO. Suncor is a 33.1% owner of the Triton FPSO (operated by Hess Corporation). The crude oil gathered at Triton is shipped via tanker, while natural gas is delivered through the SEGAL system to the U.K.

The second core hub in the U.K. North Sea is the Buzzard oilfield, located in the Outer Moray Firth. Buzzard achieved first oil in January 2007 and the company has a 29.9% interest in the field operated by Nexen Inc. The field ramped up to peak production in the middle of 2007. Buzzard is supported by three bridge-linked platforms supporting wellhead facilities, production facilities, living quarters and utilities. Crude oil is transported via the Forties pipeline system to shore in Scotland and natural gas is transported to the St. Fergus gas terminal in Scotland via the Frigg pipeline in the U.K. A fourth platform is being installed to remove higher than expected levels of hydrogen sulphide (H_2S) in the oil production from some segments of the field. This new platform is on budget and on schedule for start-up in late 2010 or early 2011.

The company's third core production hub, in the U.K. North Sea, Scott/Telford, is also located in the Outer Moray Firth and consists of a 20.6% interest in the Scott oilfield and production platform and a 9.4% interest in the Telford oilfield. The Telford oilfield produces through a subsea tie-back to the Scott platform. Both the Scott and Telford oilfields are operated by Nexen Inc. Crude oil from Scott and Telford is transported to shore via the Forties pipeline system. Associated natural gas is transported to the St. Fergus gas terminals via the Scottish Area Gas Evacuation pipeline system.

In The Netherlands sector of the North Sea, oil production comes from the Suncor-operated Hanze and De Ruyter platforms. The company has a 45% working interest in Hanze and a 54.07% working interest in De Ruyter. De Ruyter came on-stream in late September 2006. Oil from the Hanze and De Ruyter platforms is exported by a dedicated tanker and the cargoes are marketed on a spot basis into Northwest Europe. Natural gas production from Hanze is exported to shore via the Northern Offshore Gas Transport (NOGAT) pipeline and natural gas from De Ruyter is exported via the Noord Gas Transport (NGT) pipeline system. Production in The Netherlands sector of the North Sea was 13,200 boe per day for the final five months of 2009.

The major source of natural gas production in the Netherlands is from the L5b-L8b non-operated natural gas area, where Suncor has a working interest of approximately 30%. L5b-C, a non-operated asset in this area, achieved first natural gas in November 2006. The company has a 30% working interest in L5b-C. The produced natural gas is transported to shore by pipeline and sold to NV Nederlandse Gasunie under long-term delivery and off-take contracts. Suncor also holds a 12% interest in the onshore Bergen gas storage facility development operated by TAQA, the Abu Dhabi national energy company, and has exploration activities extending into Norway.

As noted above, Suncor plans to divest certain non-core North Sea assets including all of its assets in the Netherlands.

Other International

Crude oil production comes from interests principally in Libya, with natural gas production from assets offshore Trinidad and Tobago. A natural gas development is also underway in Syria. Total Other International production averaged 44,300 boe per day during the final five months of 2009.

Libya

The company conducts its Libyan operations pursuant to exploration and production sharing agreements (EPSAs) signed with the Libya National Oil Company (NOC). The EPSAs will run until 2033 (a five-year extension may be granted if there is commercial production for the last three years of the agreements and the extension is technically and commercially viable for

Suncor and the Libyan state) and enable the company and the NOC to jointly design and implement the redevelopment of the existing fields in the Sirte Basin. Suncor and the NOC will each pay one-half of development expenditures that are expected to total up to US$7 billion gross over the term of the licenses and to double existing production to 100,000 bpd net to Suncor. Under the agreements, the company is the exploration operator and has committed to fully fund 100% of an exploration program at an estimated cost of US$460 million over a five-year period. Suncor is also committed to EPSA signing bonus payments of approximately US$500 million payable from 2010 to 2013.

Work has now commenced on implementing the projects associated with the Libya EPSAs, with a focus on preparing the EPSA field development programs and initiating the new exploration program. Work on the exploration program is progressing, with seven seismic surveys completed during 2009 and two seismic crews continuing to acquire data in the country. At the end of 2009, the seismic program was approximately 75% complete. The company expects to begin drilling its first operated exploration well in early 2010. Suncor pays all of the exploration expenditures.

In the five months ended December 31, 2009, Suncor's production in Libya averaged 32,600 bpd (net to Suncor). During this period, gross production from our Libya EPSAs was restricted initially to 82,000 bpd and then to 50,000 bpd from September to the end of the year. In January 2010, the NOC advised the company that production from Suncor's Libya EPSAs will be limited to 70,000 bpd gross (35,000 bpd net to Suncor) due to the quota agreed to by OPEC producers.

In the final five months of 2009, eight development wells were completed in the producing fields in Libya, consisting of six production wells and two injection wells. A further three development wells were drilling at year end.

Syria

Suncor is 100% operator in a Production Sharing Contract (PSC) in the Ebla gas project. The company pays 100% of the costs which it recovers out of 40% of production. The remaining 60% of production is split between the company and the Syrian state depending on volume. Under the PSC, Suncor expects to spend approximately $1 billion to develop and produce an estimated 80 MMcf/d of natural gas from the Ash Shaer and Cherrife natural gas fields, with first gas currently expected in the second quarter of 2010. The majority of this spending ($1.1 billion) had been incurred by the end of 2009. The development includes uncapped take or pay contracts for the gas, the price of which is tied to Mediterranean heavy fuel oil prices. Overall, the Ebla gas project remains on plan and was 90% complete at the end of 2009. Five wells have been completed and are ready for production. The 3D seismic survey of the Cherrife field was completed at the end of the second quarter of 2009 and is currently being interpreted. The 3D seismic survey of Ash Shaer field that was completed in the second quarter of 2009 is also now being interpreted.

Trinidad and Tobago

On February 25, 2010, Suncor entered into an agreement to sell its assets in Trinidad and Tobago for proceeds of $396 million (US$380 million). The sale is expected to close in March 2010 and is subject to customary closing conditions, Trinidad and Tobago government approval and other regulatory approvals.

The company holds a 17.3% working interest in the NCMA-1 offshore natural gas development project operated by BG Group p.l.c. Natural gas production is delivered by pipeline to the Atlantic liquefied natural gas (LNG) facility operated by Atlantic LNG at Point Fortin for liquefaction and subsequent sale into U.S. and other international markets. Suncor has Production Sharing Contracts (PSCs) with the Trinidad and Tobago Ministry of Energy and Energy Industries for offshore exploration Blocks 1a, 1b and 22. These blocks cover a total of 4,258 square kilometres. A number of exploration wells have been drilled to date on these blocks.

In the five months ended December 31, 2009, Suncor's Trinidad and Tobago offshore gas production averaged 70.3 MMcf per day, with high demand from the Atlantic LNG terminal in the period. The company has certain minimum annual commitments to either deliver gas or reimburse the marketing company, BG Gas Marketing, a variable value as determined under the terms of the Trinidad LNG Sales Contract. Current production levels are sufficient to meet the near-term committed volumes.

Principal Products

For the five months ended December 31, 2009, sales of crude oil and natural gas liquids represented 95% of the International business unit's consolidated operating revenues, with 5% comprised of sales of natural gas. Set forth below is information on daily sales volumes and the corresponding percentage of our International business unit's operating revenues by product for the final five months of 2009.

Product:	Five months ended December 31, 2009*	
	(thousands of boe per day)	(% of operating revenues)
Crude oil and natural gas liquids	101.5	95
Natural gas	19.3	5
Total	120.8	

* Reflects operations subsequent to the Petro-Canada merger on August 1, 2009

Competitive Conditions

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

Environmental Compliance

For a discussion of environmental risks for our International operations, refer to the "Legal and Regulatory Risks" outlined in the Risk Factors section of this AIF.

Refining and Marketing

The Refining and Marketing business operates refineries in Edmonton, Alberta, Montreal, Quebec and Sarnia, Ontario in Canada and Commerce City, Colorado in the United States with a total capacity of 443,000 bpd, as well as a lubricants plant that is the largest producer of lubricant-base stocks in Canada. The Refining and Marketing business unit 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. Assets also include the 480-kilometre Rocky Mountain pipeline system, the 140-kilometre Centennial pipeline system, thirteen major refined products terminals in Canada and two product terminals in Colorado, U.S.A. In addition, Refining and Marketing holds interests in two refined product pipelines, as well as interests in the Portland-Montreal Pipeline and a joint venture interest in one major refined products terminal.

Canada – General

Our Edmonton refinery produces light oils and currently has the potential to run entirely on oil sands-based feedstocks. The refinery primarily produces gasoline and distillates, the majority of which are distributed in Western Canada. The observed performance of our Edmonton refinery in 2009, after improvements completed in previous years, enabled us to upwardly revise our nameplate capacity to 135,000 bpd from 125,000 bpd. Starting January 1, 2010, refinery utilization will be calculated using the 135,000 bpd capacity.

Our Montreal refinery has a current crude oil capacity of 130,000 bpd. It is supplied with imported crude oil primarily through the Portland-Montreal pipeline and has a flexible configuration that allows processing of a variety of crude oils, including heavy grades, and intermediate feedstocks. The refinery produces gasoline, distillates, asphalts, heavy fuel oil, petrochemicals, solvents and feedstock for our lubricants plant. Products produced at the Montreal refinery are primarily distributed across Quebec and Ontario.

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/year of paraxylene, which is used to manufacture polyester textiles and plastic bottles. ParaChem also produces benzene, hydrogen and heavy aromatics.

Our refinery in Sarnia, Ontario, has a current crude oil capacity of 85,000 bpd, up from previous capacity of 70,000 bpd as a result of improvements made with the completion of our diesel desulphurization and oil sands integration project in 2007. The plant refines petroleum feedstock from oil sands and other sources into gasoline, distillates, and petrochemicals with the majority of these refined products distributed in Ontario. We also distribute product purchased from third parties.

Our ethanol plant in St. Clair, Ontario produces ethanol from corn. This ethanol is used for blending into our fuels and is also sold to third parties and has a capacity of 200 million litres per year. In 2009, Suncor announced its plans to double the capacity of its St. Clair Ethanol plant to 400 million litres per year. The construction of this expansion project is underway, and is expected to be completed by late 2010 or early 2011.

Our lubricants plant in Mississauga, Ontario 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.

Suncor's retail service station network operates nationally under the Petro-Canada® brand and includes sites in Ontario under the Sunoco® brand and joint venture operated outlets. Suncor's owned and operated Sunoco®-branded retail and cardlock sites will be re-branded to Petro-Canada® brand starting 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, the Canadian Competition Bureau required Suncor to divest 104 retail sites in Ontario. On December 8, 2009, Suncor agreed to sell 98 sites with expected closing dates commencing in the first half of 2010. Agreements are also now in place to meet the full divestiture requirement and we expect to complete the divestitures in 2010. In conjunction with the merger, as requested by the Canadian Competition Bureau, Suncor also entered into terminalling agreements with Ultramar Ltd. to provide 1.1 billion litres of terminal and distribution capacity in the Greater Toronto Area for 10 years.

As of December 31, 2009, our retail service station network consisted of 1,813 outlets across Canada which attracted a 21% share of the national retail market with annual sales of petroleum product averaging 4.1 million litres per site. Suncor also generates non-petroleum revenues from convenience stores, car washes, and automotive repair and maintenance services.

Retail Sites:	Years ended December 31,	
	2009	2008
Petro-Canada®-branded retail service stations	1 318	—
Sunoco®-branded retail service stations	280	276
Total branded retail service stations	1 598	276
Joint venture operated retail service stations	215	211
Total retail service stations	1 813	487

Suncor also sells petroleum products into farm, home heating, paving, small industrial, commercial and truck markets. We are the leading national marketer to the commercial road transport segment in Canada through our PETRO-PASS network. We also sell large volumes of petroleum products directly to large industrial and commercial customers and independent marketers. Sun Petrochemicals Company, a joint venture between a Suncor subsidiary and a Toledo, Ohio-based refinery, also contributed to sales in this channel.

Wholesale Sites:	Years ended December 31,	
	2009	2008
Petro-Canada®-branded cardlock sites (PETRO-PASS)	235	—
Joint venture operated bulk distribution facilities for rural and farm fuels	10	11
Sunoco®-branded Fleet Fuel Cardlock sites	49	47
	294	58

We continue to enter into reciprocal buy/sell or exchange arrangements with other refining companies from time to time as a means of minimizing transportation costs, balancing product availability and leveraging our assets. We also purchase refined products in order to meet customer requirements.

Average Daily Sales of Petroleum Products in Canada

Set forth below are the daily sales volumes and corresponding percentages of Refining and Marketing's operating revenues for the last two years.

Product:	2009		2008	
	(thousands of cubic meters per day)	(% of operating revenues)	(thousands of cubic meters per day)	(% of operating revenues)
Gasoline (1)	19.0	48	7.9	55
Middle distillates (2)	12.9	31	5.2	37
Other (3)	6.4	21	2.4	8
Total	38.3		15.5	

(1) Includes motor and aviation gasoline.

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

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

Product:	Five months ended December 31, 2009*	
	(thousands of cubic meters per day)	(% of operating revenues)
Gasoline (1)	33.6	46
Middle distillates (2)	23.5	31
Other (3)	11.7	23
Total	68.8	

* Reflects operations subsequent to the Petro-Canada merger on August 1, 2009

(1) Includes motor and aviation gasoline.

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

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

United States – General

Our U.S.-based Refining and Marketing business includes a refining facility, a retail network, and a pipeline transportation business primarily in Colorado and Wyoming. Our Commerce City, Colorado refining facility has a current combined crude distillation capacity of 93,000 bpd. The majority of the refined products from the Commerce City refinery are distributed to industrial, commercial, wholesale, and refining customers in Colorado. The remainder of our production was sold through a distribution network in Colorado that sells gasoline and diesel fuel to retail customers. Asphalt sales comprised the remaining refined product sales volumes for 2009. As of December 31, 2009, our retail service station network consisted of 37 Shell® and 7 Phillips 66® branded-outlets (44 in 2008) across Colorado. We additionally have supply agreements with 191 additional Phillips 66® branded retail sites (200 in 2008) throughout Colorado.

Average Daily Sales of Petroleum Products in United States

Set forth below is the daily sales volumes and corresponding percentage of refining and marketing's operating revenues for the last two years.

Product:	2009		2008	
	(thousands of cubic meters per day)	(% of operating revenues)	(thousands of cubic meters per day)	(% of operating revenues)
Gasoline (1)	8.5	54	8.0	49
Middle distillates (2)	5.3	35	5.6	42
Other (3)	2.7	11	2.4	9
Total	16.5		16.0	

(1) Includes motor and aviation gasoline.

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

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

Procurement of Feedstocks

Canada – General

Our Edmonton refinery has the ability to process SCO. The refinery has the ability to directly upgrade an Athabasca blend feed of 35,000 bpd (comprised of 25,000 bpd of bitumen and 10,000 bpd of diluent) and process 45,000 bpd of sour synthetic crude oil. The refinery can also process 55,000 bpd of sweet SCO through its synthetic train. The crude refined at the Edmonton refinery is supplied from our Oil Sands operations and third parties under month-to-month contracts.

Our Montreal refinery processes primarily foreign, conventional crude oil. The majority of the refinery's crude is procured from third parties under month-to-month contracts and delivered through the Portland-Montreal pipeline. We have not made any firm capacity commitments to the associated pipeline systems. Other feedstocks, procured under month-to-month contracts, are primarily delivered via marine movements. Crude oil is procured from the market on a spot basis or under contracts which can be terminated on short notice.

Our Sarnia refinery processes both SCO and conventional crude oil. In 2009, 56,000 bpd of the crude oil refined at the Sarnia Refinery was SCO, of which 43,700 bpd was supplied from our Oil Sands operations. The balance of the refinery's SCO, as well as its conventional and condensate feedstocks, were purchased from third parties under month-to-month contracts.

We procure conventional crude oil feedstock for our Sarnia refinery primarily from western Canada. This is supplemented periodically with crude oil from the United States and other countries. Foreign crude oil is delivered to Sarnia via pipeline from the United States Gulf Coast or via the Enbridge Pipeline from Montreal. We have not made any firm capacity commitments on these pipeline systems. Crude oil is procured from the market on a spot basis or under contracts which can be terminated on short notice. In 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.

Feedstock for our lubricants facility comes from our Montreal refinery and other purchase contracts.

United States – General

Our Commerce City refining operation processes both conventional crude oil and SCO. Approximately 19% of the refinery's crude oil is purchased from Canadian sources with the remainder supplied from sources in the United States, primarily from the Rocky Mountain region.

The refinery's crude oil purchase contracts have terms ranging from month-to-month to multi-year. In the event of a significant disruption in the supply of crude oil, the refinery has the flexibility to substitute other sources of sweet or sour crude oil on a spot purchase basis.

With the completion of our diesel desulphurization and oil sands integration projects, we are now capable of processing of up to 15,000 bpd of oil sands sour crude oil at our U.S. refining operation.

The below table summarizes the crude feedstock and utilizations for the refineries, for the year-ended December 31, 2009.

Refinery	Average Daily Crude Input (thousands of bpd)*					
	Average Daily Crude Input	Conventional	Synthetic	Oil Sands Synthetic	Other	(% Utilization)
Edmonton	115.6	20.4	36.8	58.4	—	92
Montreal	110.6	110.6	—	—	—	85
Sarnia	75.3	18.8	12.3	43.7	0.5	89
Commerce City	95.3	86.0	—	9.3	—	103

* Reflects August 1, 2009 to December 31, 2009 for legacy Petro-Canada assets (Edmonton and Montreal) and January 1, 2009 to December 31, 2009 for legacy Suncor assets (Sarnia and Commerce City).

Transportation and Distribution

Our Refining and Marketing business has interests in two crude oil pipelines, two refined product pipelines, the Portland-Montreal Pipeline and a joint venture interest in one major refined products terminal. Our Refining and Marketing business owns and operates thirteen major refined products terminals in Canada and two product terminals in Colorado, U.S.A.

Canada – General

Our Refining and Marketing business owns and operates petroleum transportation, terminal and dock facilities across Canada.

The Edmonton refinery primarily uses the Alberta Products Pipe Line Inc., in which Suncor has a 35% ownership interest, and the Trans-Mountain Pipelines Inc. as its major modes of transporting gasoline and diesel to core markets in western Canada. In addition, the Enbridge pipeline, rail movement and trucking are used to move product in the west.

The pipelines used by the Montreal refinery for transporting its gasoline and middle distillates are the Montreal Pipeline Limited, in which Suncor has a 24% ownership interest and Trans-Northern Pipeline, in which Suncor has a 33% ownership interest.

For our Sarnia refinery, the Sun-Canadian pipeline, which is 55% owned by Suncor, serves as the major mode of transporting gasoline, diesel, jet fuel and heating fuels from this refinery to its core markets in Ontario. The pipeline operates as a private facility for its owners, serving terminal facilities in Toronto, Hamilton and London.

We also have pipeline access to petroleum markets in the Great Lakes region of the United States by way of a pipeline system in Sarnia operated by a U.S.-based refiner. This link to the U.S. allows Refining and Marketing's Sarnia and Montreal operations to move products to market or obtain feedstocks/products when market conditions are favorable in the Michigan and Ohio markets and is subject to pipeline availability constraints.

United States – General

For our U.S. operations, approximately 60% of crude oil processed at our Commerce City refining operation is transported via pipeline, with the remainder supplied via truck. We own and operate the Rocky Mountain Crude pipeline system, which runs from Guernsey, Wyoming to Denver, Colorado. This is a common carrier pipeline that transports crude for the Denver refinery as well as for other shippers. We also own and operate the Centennial pipeline, which transports crude from Guernsey, Wyoming to Cheyenne, Wyoming.

The Rocky Mountain Crude system had a capacity of 38,000 bpd in 2009 for the Guernsey to Cheyenne leg of the pipeline and 73,500 bpd for the Cheyenne to Denver leg of the pipeline. In 2009, it utilized approximately 53% (2008 – 43%) of its capacity with average throughput of 20,000 bpd (2008 – 16,500 bpd) in the Guernsey to Cheyenne leg of the pipeline, and utilized approximately 87% (2008 – 85%) with average throughput of 64,000 bpd (2008 – 62,200 bpd) in the higher capacity Cheyenne to Denver leg. During the same period, the Centennial pipeline utilized approximately 57% (2008 – 46%) of capacity, with an average throughput of approximately 36,000 bpd (2008 – 29,400 bpd).

Our U.S. operations have both truck and rail loading racks at the Commerce City refining facility with product loading capacity in excess of 30,000 bpd, a one-mile long 7,000 bpd jet fuel pipeline that connects to a common carrier pipeline system for deliveries to the Denver International Airport, and a four-mile long 14,000 bpd diesel pipeline that delivers diesel product directly to the Union Pacific railroad yard in Denver, Colorado.

In both our Canadian and U.S. operations, we believe our own storage facilities, and those under long-term contractual arrangements with other parties, are sufficient to meet our current and foreseeable storage and distribution needs.

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 the "Legal and Regulatory Risks" in the Risk Factors section of this AIF.

Corporate, Energy Trading and Eliminations

The Corporate, Energy Trading and Eliminations area includes third-party energy trading activity, our renewable energy business and other activities not directly attributable to an operating segment.

RESERVES ESTIMATES

General

As a Canadian issuer, Suncor is subject to the reporting requirements of the Canadian Securities Administrators (CSA), including the reporting of our reserves in accordance with National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* (NI 51-101). In order to harmonize its oil and gas disclosure in both Canada and the United States, Suncor applied for, and received, an exemption from Canadian securities regulatory authorities permitting Suncor to report its reserves in accordance with the rules and regulations of the United States Securities and Exchange Commission (SEC). See "Reliance on Exemptive Relief" in this AIF. The SEC has updated its oil and gas disclosure requirements with the issuance of its final rule, Modernization of Oil and Gas Reporting, on December 31, 2008. Under the new SEC rule, disclosure of probable reserves is now permitted in addition to proved reserves. Disclosure of oil sands mining and upgrading as oil and gas activities is also permitted. Suncor's 2009 reserves disclosure includes both proved and probable reserves for all of our oil and gas operations including our oil sands areas and associated upgrading facilities.

Differences in the estimates of the reserves between U.S. disclosure requirements and NI 51-101 methodology can be material mainly due to differences in the stipulated product prices to be used for reserves evaluations. U.S. disclosure requirements mandate the use of an average of first day of the month price for the 12 months prior to the end of the reporting period, while the CSA requires a forecasted price. However this difference in pricing methodologies did not have a material impact on Suncor's 2009 reserves disclosure.

Additional differences between U.S. disclosure requirements and NI 51-101 methodology include the following:

- SEC registrants apply SEC reserves definitions and prepare their reserves estimates in accordance with SEC requirements and generally accepted industry practices in the U.S. whereas NI 51-101 requires adherence to the definitions and standards promulgated by the COGE Handbook;
- the SEC mandates disclosure of reserves by country or geographic area and sales product whereas NI 51-101 requires disclosure of more reserve categories and product types;
- the SEC prescribes certain information about proved and probable undeveloped reserves and future development costs whereas NI 51-101 requirements are different; and
- the SEC does not allow proved and probable reserves to be aggregated whereas NI 51-101 requires aggregate disclosure.

The foregoing is a general description of the principal differences only. The differences between SEC requirements and NI 51-101 may be material.

In addition to reporting our reserves in accordance with U.S. disclosure requirements, we are also providing voluntary additional disclosure (which does not conform to U.S. disclosure requirements). Our voluntary additional disclosure will differ from our required U.S. disclosure in the following ways:

- Disclosure of reserves on a gross basis (before royalty) voluntarily, as well as the required net basis (after royalty) under U.S. disclosure requirements.
- Disclosure of voluntary addition of proved and probable reserve totals on a gross basis (before royalty) together, in addition to reporting them separately as required under U.S. disclosure requirements.
- Disclosure of contingent resources and remaining recoverable resources on a gross basis (before royalty) following NI 51-101 requirements (disclosure of resources is not recognized under U.S. disclosure requirements).

The majority of Suncor's proved reserves and probable reserves are in Canada, in the Athabasca oil sands, conventional type plays in Western Canada and offshore on the east coast of Canada. Suncor also has other North American proved and probable reserves in the United States and international proved and probable reserves in the North Sea, Libya, Syria, Trinidad and Tobago.

Reserves Evaluation Process and Controls

GLJ Petroleum Consultants Ltd. (GLJ) and Sproule Associates Limited (Sproule) evaluated or reviewed all of our North American reserves and RPS Energy Plc (RPS) evaluated or reviewed all of our International reserves. All three independent petroleum consultants are industry recognized qualified reserves evaluators. For the year ended December 31, 2009, 95% of Suncor's proved and 94% of its probable reserves volumes were externally evaluated. The third party evaluations were reviewed internally by Suncor's Business Units, the Reserve Steering Committee (a management committee) and the Audit Committee of the Board of Directors prior to disclosure. Suncor's Audit Committee includes independent Board members who reviewed the qualifications and approved the appointment of the qualified independent reserve evaluators. The Audit Committee also reviewed the procedures and process for providing information to the evaluators.

Suncor's mining lease interests, Firebag in-situ lease interests, legacy Petro-Canada's Syncrude mining lease interests and nearly all of legacy Suncor's North American onshore interests have been evaluated as at December 31, 2009 by independent petroleum consultants, GLJ. Legacy Suncor North American onshore leases not evaluated by GLJ were reviewed by GLJ. In the "GLJ Summary Reserves Report" (Schedule "E") dated March 5, 2010 GLJ provides a summary of their proved and probable reserves evaluations and reviews pursuant to U.S. disclosure requirements. GLJ also evaluated the contingent resources associated with the legacy Suncor mining leases, the Firebag In-situ leases and legacy Petro-Canada's Syncrude mining lease interests.

Legacy Petro-Canada's North American onshore interests, East Coast Canada lease interests and MacKay River in-situ lease interests have been evaluated as at December 31, 2009 by independent petroleum consultants, Sproule. In the "Sproule Summary Reserves Report" (Schedule "F") dated March 5, 2010, Sproule provides a summary of their proved and probable reserves evaluations, pursuant to U.S. disclosure requirements. Sproule has also audited legacy Petro-Canada's Fort Hills contingent resources.

Approximately 45% of legacy Petro-Canada reserves related to our International operations have been evaluated as at December 31, 2009 by independent petroleum consultants, RPS. The legacy Petro-Canada international interests not evaluated by RPS were reviewed by RPS. In the "RPS Summary Reserves Report" (Schedule "G") dated March 5, 2010. RPS provides a summary of their proved and probable reserves evaluations and reviews, pursuant to U.S. disclosure requirements.

There are many uncertainties inherent in estimating quantities of oil and natural gas reserves, including many factors beyond the company's control. Estimates of economically recoverable oil and natural gas reserves are based upon a number of variables and assumptions. These include geoscientific interpretation, commodity prices, operating and capital costs and historical production from properties. These estimates have some degree of uncertainty. For these reasons, estimates of the economically recoverable oil and natural gas reserves attributed to properties and classification of reserves based on recovery risk may vary substantially. Actual production, revenues, royalties, taxes and development and operating expenditures related to reserves may vary materially from estimates.

Definitions and Notes to Reserves Data Tables

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

1. "Gross" means:
   (a) in relation to our interest in production and reserves, our interest (operating and non-operating) before deduction of royalties and without including any of our royalty interests;
   (b) in relation to wells, the total number of wells in which we have an interest; and
   (c) in relation to properties, the total area of properties in which we have an interest.
2. "Net" means:
   (a) in relation to our interest in production and reserves, our interest (operating and non-operating) after deduction of royalties obligations, plus our royalty interest in production or reserves (see royalty discussion below);
   (b) in relation to wells, the number of wells obtained by aggregating our working interest in each of our gross wells; and
   (c) in relation to our interest in a property, the total area in which we have an interest multiplied by the working interest we own.
3. "SCO" means synthetic crude oil.
4. Columns may not add due to rounding.
5. The oil, natural gas liquids and natural gas reserves estimates presented in the third party evaluators' reports are based on the SEC definitions and guidelines. A summary of certain of those definitions is set forth below. The SCO reserves include our Oil Sands diesel volume.
6. See "Industry Conditions – Royalties and Incentives" in this AIF and the "Royalties" section of our MD&A for a discussion of the applicable royalties. These assumptions reflect market and regulatory conditions, as required, at December 31, 2009, which could differ significantly from other points in time throughout the year, or future periods. Changes in market and regulatory conditions and assumptions can materially impact the estimation of net reserves.

Reserves Categories (SEC definitions)

Reserves. Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Proved oil and gas reserves. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

Probable oil and gas reserves. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

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

Developed oil and gas reserves. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Undeveloped oil and gas reserves. Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. In addition:

(i) Reserves on undrilled acreage are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

(iii) Under no circumstances are estimates for undeveloped reserves to be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology establishing reasonable certainty.

Resource Categories (NI 51-101 COGEH definitions; do not conform to U.S. disclosure requirements).

Contingent Resources. 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.

Contingencies may include factors such as economic, legal, environmental, political, and regulatory matters or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage.

Contingent Resource 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 prepared independent of the risks associated with achieving commercial production.

Remaining recoverable resources (unrisked). The arithmetic sum of proved and probable reserves and best estimate contingent resources. Suncor has not quantified potentially recoverable volumes from either undiscovered accumulations or its carbonate leases. The contingent resources have not been adjusted for risk based on the chance of development. It is not an estimate of volumes that may be recovered. Actual recovery may be less.

Discussion on Changes to Reserve Estimates

Changes related to revised SEC reserves disclosure requirements. With the issuance of SEC final rule, Modernization of Oil and Gas Reporting, on December 31, 2008, disclosure of oil sands mining is now considered an oil and gas activity and quantities of oil and gas that are to be upgraded and sold as SCO can now be disclosed as SCO volumes. As a result, oil sands mining reserves are now included in the reserve tables and those bitumen volumes that are to be upgraded and sold as SCO are reported as SCO volumes. To show the change of reporting bitumen only volumes to the current requirements in the SEC rule, a one line adjustment has been made to show the 2008 closing balances as if the rule took effect on December 31, 2008.

Merger of Suncor and Petro-Canada. Effective August 1, 2009, legacy Suncor and legacy Petro-Canada amalgamated to form a single corporation continuing under the name "Suncor Energy Inc." The addition of the Petro-Canada properties is shown as a purchase by Suncor. In determining the purchased volumes, Petro-Canada's 2008 closing reserve balances were used and adjusted for 2009 production volumes and any purchases or sales of assets prior to August 1, 2009. A total of 752 MMbbls of proved oil volumes on a net basis (after royalty) and 1179 Bcf of proved natural gas volumes on a net basis (after royalty) were added to Suncor's proved reserves base as a result of the merger.

Production

Production shown in the tables reflects full year production for the legacy Suncor properties but only represents production for the last five months of the year for the legacy Petro-Canada properties.

Bitumen Reserves

As a portion of Suncor's in-situ bitumen production will be sold directly to the market rather than being upgraded and sold as SCO, approximately one-third of our proved in-situ reserves are now shown as bitumen volumes.

In-Situ

Over 80% of our proved undeveloped reserves and over 75% of our probable undeveloped reserves are associated with our in-situ properties. These reserves are well delineated by core hole drilling, are included in our corporate business plans, and have the appropriate regulatory approvals in place. These are long life projects and new production is expected to be brought on stream throughout the majority of the project life as capacity becomes available at existing processing facilities or when new facilities are constructed. In 2009 approximately 28 MMbbls were moved from the proved undeveloped category to proved developed as a result of ongoing development work.

Mining

As a result of continued development of our North Steepbank extension, approximately 500 MMbbls of reserves were moved out of the probable undeveloped reserves category with approximately 330 MMbbls moved into proved developed reserves and the remainder moved into the probable developed reserves category.

International

A significant amount of our Other International proved and probable undeveloped gas reserves are associated with the development of the Ebla field in Syria. The majority of these reserve quantities are currently expected to be moved to the proved developed reserves category after the field commences production operations in 2010.

REQUIRED U.S. OIL AND GAS DISCLOSURE

The table below shows Suncor's 2009 year-end balances for proved and probable reserves, and was prepared in accordance with SEC standards for oil and gas activities:

Summary of Oil and Gas Reserves After Royalties (1)(2)(3)(5)

Reserve category	Reserves: Oil & NGL (MMbbls)	Reserves: Natural Gas (BCF)	Reserves: SCO (MMbbls)	Reserves: Bitumen (MMbbls)
PROVED				
Developed				
North Sea (4)	72	29	—	—
Other International (6)(7)	38	93	—	—
North America Onshore	35	1229	—	—
East Coast Canada	41	—	—	—
Oil Sands – In-situ	—	—	152	22
Oil Sands – Mining (8)	—	—	1899	—
Total Developed	**186**	**1351**	**2051**	**22**
Undeveloped				
North Sea (4)	69	—	—	—
Other International (6)(7)	6	294	—	—
North America Onshore	7	48	—	—
East Coast Canada	26	—	—	—
Oil Sands – In-situ	—	—	514	389
Oil Sands – Mining (8)	—	—	—	—
Total Undeveloped	**108**	**342**	**514**	**389**
TOTAL PROVED	**294**	**1693**	**2565**	**411**

Reserve category	Reserves: Oil (MMbbls)	Reserves: Natural Gas (BCF)	Reserves: SCO (MMbbls)	Reserves: Bitumen (MMbbls)
PROBABLE				
Developed				
North Sea (4)	36	23	—	—
Other International (6)(7)	30	42	—	—
North America Onshore	6	282	—	—
East Coast Canada	39	—	—	—
Oil Sands – In-situ	—	—	69	8
Oil Sands – Mining (8)	—	—	287	—
Total Developed	**111**	**347**	**356**	**8**
Undeveloped				
North Sea (4)	36	50	—	—
Other International (6)(7)	31	222	—	—
North America Onshore	9	211	—	—
East Coast Canada	60	—	—	—
Oil Sands – In-situ	—	—	507	1336
Oil Sands – Mining (8)	—	—	237	—
Total Undeveloped	**136**	**483**	**744**	**1336**
TOTAL PROBABLE	**247**	**830**	**1100**	**1344**

(1) Numbers in the above table are rounded to the nearest 1 MMbbls or 1 Bcf and may not add due to rounding.

(2) The reserves data are based upon evaluations by GLJ, Sproule, RPS and Suncor with an effective date of December 31, 2009 and does not account for any planned divestiture after the effective date. GLJ, Sproule, and RPS summary reserve reports are contained in Schedules "E", "F", "G" to this AIF.

(3) Proved reserves before royalties are Suncor's working interest reserves before the deduction of Crown or other royalties. Such royalties are subject to change by legislation or regulation and can also vary depending on production rates, selling prices and timing of initial production. Reserve quantities after royalty also reflect net overriding royalty interests paid and received.

(4) Reserves in the North Sea are subject to a conventional royalty and tax regime. No royalty is payable on reserves in the U.K. sector. Royalty is payable on onshore reserves in the Netherlands.

(5) Proved reserves include quantities of crude oil and natural gas, which will be produced under arrangements, which involve the company or its subsidiaries in upstream risks and rewards, but which do not transfer title of the product to those companies.

(6) In Suncor's exploration and production sharing contracts (PSCs), after royalty proved reserves have been determined using the economic interest method and includes the company's share of future production entitlement calculated using the contract's cost recovery and profit oil terms. The entitlement reserves are then adjusted to include reserves relating to income tax payable. Under this method, reported reserves will increase as oil prices decrease (and vice versa), since the bbls necessary to achieve cost recovery change with the prevailing oil prices.

(7) All reserves reported in "Other International" (which include reserves in Libya, Syria, and Trinidad and Tobago) are calculated as per footnote 5.

(8) Due to the SEC rule change in respect to reporting mining as an oil and gas activities, Suncor has included oil sands mining reserves which would have been previously reported under Mining Guide 7. For more information, refer to page 30.

The following tables are provided in accordance with the provisions of the Financial Accounting Standards Board's, Topic 932 Extractive Industries – Oil and Gas.

Proved Developed and Undeveloped Reserves After Royalties

	Total By Products				Oil Activities (1)(2)(3)(5)(11)(12)						
					International		North America				
									Oil Sands – In-Situ		
	Total	Oil & NGL	SCO	Bitumen	North Sea (4) Oil & NGL	Other International (6)(7) Oil & NGL	North America Onshore Oil & NGL	East Coast Canada Oil & NGL	SCO	Bitumen	Oil Sands – Mining SCO (10)
	(MMbbls)	(MMbbls)	(MMbbls)	(MMbbls)	(MMbbls)	(MMbbls)	(MMbbls)	(MMbbls)	(MMbbls)	(MMbbls)	(MMbbls)
Beginning of year 2007	**910**	**7**	**—**	**903**	**—**	**—**	**7**	**—**	**—**	**903**	**—**
Revisions of previous estimates (8)	68	—	—	68	—	—	—	—	—	68	—
Purchase of reserves in place	—	—	—	—	—	—	—	—	—	—	—
Discoveries, extensions and improved recovery	99	—	—	99	—	—	—	—	—	99	—
Production (net)	(14)	(1)	—	(13)	—	—	(1)	—	—	(13)	—
Sale of reserves in place	—	—	—	—	—	—	—	—	—	—	—
End of year 2007	**1063**	**6**	**—**	**1057**	**—**	**—**	**6**	**—**	**—**	**1057**	**—**
Revisions of previous estimates (8)	—	—	—	—	—	—	—	—	—	—	—
Purchase of reserves in place	—	—	—	—	—	—	—	—	—	—	—
Discoveries, extensions and improved recovery	35	—	—	35	—	—	—	—	—	35	—
Production net	(14)	(1)	—	(13)	—	—	(1)	—	—	(13)	—
Sale of reserves in place	—	—	—	—	—	—	—	—	—	—	—
End of year 2008	**1084**	**5**	**—**	**1079**	**—**	**—**	**5**	**—**	**—**	**1079**	**—**
SEC rule change adjustment (9)	1218	—	2254	(1036)	—	—	—	—	833	(1036)	1421
Opening of year 2009	**2302**	**5**	**2254**	**43**	**—**	**—**	**5**	**—**	**833**	**43**	**1421**
Revisions of previous estimates (8)	(8)	34	(411)	369	6	4	5	19	(330)	369	(81)
Purchase of Petro-Canada reserves	752	264	488	—	145	36	34	49	178	—	310
Purchase of other reserves in place	—	—	—	—	—	—	—	—	—	—	—
Discoveries, extensions and improved recovery	343	13	330	—	1	6	1	5	—	—	330
Production net	(118)	(21)	(96)	(1)	(11)	(2)	(3)	(5)	(15)	(1)	(81)
Sale of reserves in place	(1)	(1)	—	—	—	—	—	(1)	—	—	—
End of year 2009	**3270**	**294**	**2565**	**411**	**141**	**44**	**42**	**67**	**666**	**411**	**1899**
Proved developed reserves											
Beginning of 2009	1565	5	1560	—	—	—	5	—	139	—	1421
End of 2009	**2259**	**186**	**2051**	**22**	**72**	**38**	**35**	**41**	**152**	**22**	**1899**
Proved undeveloped reserves											
Beginning of 2009	738	—	695	43	—	—	—	—	695	43	—
End of 2009	**1011**	**108**	**514**	**389**	**69**	**6**	**7**	**26**	**514**	**389**	**—**

(1) Numbers in the above table are rounded to the nearest 1 MMbbls or 1 Bcf and may not add due to rounding.

(2) The reserves data are based upon evaluations by GLJ, Sproule, RPS and Suncor with an effective date of December 31, 2009 and does not account for any planned divestiture after the effective date. GLJ, Sproule, and RPS summary reserve reports are contained in Schedules "E", "F", "G" to this AIF.

(3) Proved reserves before royalties are Suncor's working interest reserves before the deduction of Crown or other royalties. Such royalties are subject to change by legislation or regulation and can also vary depending on production rates, selling prices and timing of initial production. Reserve quantities after royalty also reflect net overriding royalty interests paid and received.

(4) Reserves in the North Sea are subject to a conventional royalty and tax regime. No royalty is payable on reserves in the U.K. sector. Royalty is payable on onshore reserves in the Netherlands.

(5) Proved reserves include quantities of crude oil and natural gas, which will be produced under arrangements, which involve the company or its subsidiaries in upstream risks and rewards, but which do not transfer title of the product to those companies.

(6) In Suncor's exploration and production sharing contracts (PSCs), after royalty proved reserves have been determined using the economic interest method and includes the company's share of future production entitlement calculated using the contract's cost recovery and profit oil terms. The entitlement reserves are then adjusted to include reserves relating to income tax payable. Under this method, reported reserves will increase as oil prices decrease (and vice versa), since the bbls necessary to achieve cost recovery change with the prevailing oil prices.

(7) All reserves reported in "Other International" (which include reserves in Libya, Syria, and Trinidad and Tobago) are calculated as per footnote 5.

(8) Revisions include changes in previous estimates, either upward or downward, resulting from new information (except an increase in acreage) normally obtained from drilling or production history or resulting from a change in economic factors.

(9) Due to the SEC rule change in respect to reporting final product sold, Suncor has in-situ reserve volumes that were previously reported as bitumen that now are to be reported as SCO. In addition, oil sands mining has also been added. This line shows the impact of that reporting change.

(10) Due to the SEC rule change in respect to reporting mining as oil and gas activities, Suncor has included a mining opening balance which would have been previously reported under Mining Guide 7. For more information, see page 30.

(11) The 2008 reserve data for legacy Suncor assets has been re-stated per SEC guidelines, this information was previously disclosed under NI 51-101.

(12) The production data in the 2009 reserve tables are estimates from the third party evaluators, and may not exactly match production shown else where in this AIF. Any variance in the production numbers is deemed not material in the disclosure of these reserves.

Proved Developed and Undeveloped Reserves After Royalties (Natural Gas)

	Natural Gas Activities [1][2][3][5][9][10]			
		International		North America
	Total	North Sea [4] Gas	Other International [6][7] Gas	North America Onshore Gas
	(BCF)	(BCF)	(BCF)	(BCF)
Beginning of year 2007	**426**	**—**	**—**	**426**
Revisions of previous estimates [8]	4	—	—	4
Purchase of reserves in place	19	—	—	19
Discoveries, extensions and improved recovery	33	—	—	33
Production net	(53)	—	—	(53)
Sale of reserves in place	(1)	—	—	(1)
End of year 2007	**428**	**—**	**—**	**428**
Revisions of previous estimates [8]	42	—	—	42
Purchase of reserves in place	0	—	—	—
Discoveries, extensions and improved recovery	25	—	—	25
Production net	(54)	—	—	(54)
Sale of reserves in place	—	—	—	—
End of year 2008	**441**	**—**	**—**	**441**
Revisions of previous estimates [8]	(39)	(4)	15	(50)
Purchase of Petro Canada reserves	1179	40	153	986
Purchase of other reserves in place	—	—	—	—
Discoveries, extensions and improved recovery	248	1	229	18
Production net	(134)	(8)	(10)	(116)
Sale of reserves in place	(2)	—	—	(2)
End of year 2009	**1693**	**29**	**387**	**1277**
Proved developed reserves				
Beginning of 2009	412	—	—	412
End of 2009	**1351**	**29**	**93**	**1229**
Proved undeveloped reserves				
Beginning of 2009	28	—	—	28
End of 2009	**342**	**—**	**294**	**48**

(1) Numbers in the above table are rounded to the nearest 1 MMbbls or 1 Bcf and may not add due to rounding.

(2) The reserves data are based upon evaluations by GLJ, Sproule, RPS and Suncor with an effective date of December 31, 2009 and does not account for any planned divestiture after the effective date. GLJ, Sproule, and RPS summary reserve reports are contained in Schedules "E", "F", "G" to this AIF.

(3) Proved reserves before royalties are Suncor's working interest reserves before the deduction of Crown or other royalties. Such royalties are subject to change by legislation or regulation and can also vary depending on production rates, selling prices and timing of initial production. Reserve quantities after royalty also reflect net overriding royalty interests paid and received.

(4) Reserves in the North Sea are subject to a conventional royalty and tax regime. No royalty is payable on reserves in the U.K. sector. Royalty is payable on onshore reserves in the Netherlands.

(5) Proved reserves include quantities of crude oil and natural gas, which will be produced under arrangements, which involve the company or its subsidiaries in upstream risks and rewards, but which do not transfer title of the product to those companies.

(6) In Suncor's exploration and production sharing contracts (PSCs), after royalty proved reserves have been determined using the economic interest method and includes the company's share of future production entitlement calculated using the contract's cost recovery and profit oil terms. The entitlement reserves are then adjusted to include reserves relating to income tax payable. Under this method, reported reserves will increase as oil prices decrease (and vice versa), since the bbls necessary to achieve cost recovery change with the prevailing oil prices.

(7) All reserves reported in "Other International" (which include reserves in Libya, Syria, and Trinidad and Tobago) are calculated as per footnote 5.

(8) Revisions include changes in previous estimates, either upward or downward, resulting from new information (except an increase in acreage) normally obtained from drilling or production history or resulting from a change in economic factors.

(9) The 2008 reserve data for legacy Suncor assets has been re-stated per SEC guidelines, this information was previously disclosed under NI 51-101. For more information, see page 30.

(10) The production data in the 2009 reserve tables are estimates from the third party evaluators, and may not exactly match production shown else where in this AIF. Any variance in the production numbers is deemed not material in the disclosure of these reserves.

VOLUNTARY ADDITIONAL DISCLOSURE (does not conform to U.S. disclosure requirements):

Proved Reserves Before Royalties (1)(2)(3)(5)(11)

	Oil and Gas Activities											
	International				North America						Totals	
	North Sea (4)		Other International (6)(7)		North America Onshore		East Coast Canada	Oil Sands – In-Situ		Oil Sands – Mining (9)		
	Crude Oil & NGL	Natural Gas	Crude Oil & NGL	Natural Gas	Crude Oil & NGL	Natural Gas	Crude Oil & NGL	SCO	Bitumen	SCO	Crude Bitumen, SCO & NGL	Total Natural Gas
	(MMbbls)	(BCF)	(MMbbls)	(BCF)	(MMbbls)	(BCF)	(MMbbls)	(MMbbls)	(MMbbls)	(MMbbls)	(MMbbls)	(BCF)
End of Year 2008 (10)	**—**	**—**	**—**	**—**	**7**	**532**	**—**	**860**	**45**	**1571**	**2483**	**532**
Revisions of previous estimates (8)	6	(4)	11	12	8	(67)	25	(318)	406	(23)	115	(59)
Sale of reserves in place	—	—	—	—	—	(2)	(1)	—	—	—	(1)	(2)
Purchase of reserves in place	145	40	117	155	39	1158	65	201	—	360	927	1353
Discoveries, extensions and improved recovery	1	1	9	351	—	22	8	—	—	383	401	374
Production	(11)	(8)	(5)	(11)	(4)	(146)	(8)	(16)	(1)	(88)	(133)	(165)
End of Year 2009	**141**	**29**	**132**	**507**	**50**	**1497**	**89**	**727**	**450**	**2203**	**3792**	**2033**
Proved Undeveloped Reserves												
End of year 2009	**69**	**—**	**9**	**414**	**9**	**57**	**35**	**564**	**427**	**—**	**1113**	**471**

(1) Numbers in the above table are rounded to the nearest 1 MMbbls or 1 Bcf and may not add due to rounding.

(2) The reserves data are based upon evaluations by GLJ, Sproule, RPS and Suncor with an effective date of December 31, 2009 and does not account for any planned divestiture after the effective date. GLJ, Sproule, and RPS summary reserve reports are contained in Schedules "E", "F", "G" to this AIF.

(3) Proved reserves before royalties are Suncor's working interest reserves before the deduction of Crown or other royalties. Such royalties are subject to change by legislation or regulation and can also vary depending on production rates, selling prices and timing of initial production. Reserve quantities after royalty also reflect net overriding royalty interests paid and received.

(4) Reserves in the North Sea are subject to a conventional royalty and tax regime. No royalty is payable on reserves in the U.K. sector. Royalty is payable on onshore reserves in the Netherlands.

(5) Proved reserves include quantities of crude oil and natural gas, which will be produced under arrangements, which involve the company or its subsidiaries in upstream risks and rewards, but which do not transfer title of the product to those companies.

(6) In Suncor's exploration and production sharing contracts (PSCs), after royalty proved reserves have been determined using the economic interest method and includes the company's share of future production entitlement calculated using the contract's cost recovery and profit oil terms. The entitlement reserves are then adjusted to include reserves relating to income tax payable. Under this method, reported reserves will increase as oil prices decrease (and vice versa), since the bbls necessary to achieve cost recovery change with the prevailing oil prices.

(7) All reserves reported in "Other International" (which include reserves in Libya, Syria, and Trinidad and Tobago) are calculated as per footnote 5.

(8) Revisions include changes in previous estimates, either upward or downward, resulting from new information (except an increase in acreage) normally obtained from drilling or production history or resulting from a change in economic factors.

(9) Due to the SEC rule change in respect to reporting mining as oil and gas activities, Suncor has re-stated its mining opening balance which would have been previously reported under Mining Guide 7. For more information, see page 30.

(10) The 2008 reserve data for legacy Suncor assets has been re-stated per SEC guidelines, this information was previously disclosed under NI 51-101.

(11) The production data in the 2009 reserve tables are estimates from the third party evaluators, and may not exactly match production shown else where in this AIF. Any variance in the production numbers is deemed not material in the disclosure of these reserves.

VOLUNTARY ADDITIONAL DISCLOSURE (does not conform to U.S. disclosure requirements):

Proved and Probable Reserves Before Royalties (1)(2)(3)(5)(11)

	Oil and Gas Activities											
	International				North America						Company Totals	
	North Sea (4)		Other International (6)(7)		North America Onshore		East Coast Canada	Oil Sands – In-Situ		Oil Sands – Mining (9)		
	Crude Oil & NGL	Natural Gas	Crude Oil & NGL	Natural Gas	Crude Oil & NGL	Natural Gas	Crude Oil & NGL	SCO	Bitumen	SCO	Crude Bitumen, SCO & NGL	Total Natural Gas
	(MMbbls)	(BCF)	(MMbbls)	(BCF)	(MMbbls)	(BCF)	(MMbbls)	(MMbbls)	(MMbbls)	(MMbbls)	(MMbbls)	(BCF)
End of Year 2008 (10)	**—**	**—**	**—**	**—**	**9**	**734**	**—**	**2565**	**148**	**2316**	**5038**	**734**
Revisions of previous estimates (8)	6	(18)	6	247	15	(52)	16	(1587)	1863	(72)	247	177
Sale of reserves in place	—	—	—	—	—	(6)	(3)	—	—	—	(3)	(6)
Purchase of reserves in place	215	98	276	618	47	1498	213	437	—	638	1826	2214
Discoveries, extensions and improved recovery	3	29	9	352	1	52	7	—	—	—	20	433
Production	(11)	(8)	(5)	(11)	(4)	(146)	(8)	(16)	(1)	(88)	(133)	(165)
End of Year 2009	**213**	**101**	**286**	**1206**	**68**	**2080**	**225**	**1399**	**2010**	**2794**	**6995**	**3387**
Proved & Probable Undeveloped Reserves												
End of year 2009	**105**	**50**	**89**	**1065**	**19**	**309**	**114**	**1160**	**1977**	**264**	**3728**	**1424**

(1) Numbers in the above table are rounded to the nearest 1 MMbbls or 1 Bcf and may not add due to rounding.

(2) The reserves data are based upon evaluations by GLJ, Sproule, RPS and Suncor with an effective date of December 31, 2009 and does not account for any planned divestiture after the effective date. GLJ, Sproule, and RPS summary reserve reports are contained in Schedules "E", "F", "G" to this AIF

(3) Proved reserves before royalties are Suncor's working interest reserves before the deduction of Crown or other royalties. Such royalties are subject to change by legislation or regulation and can also vary depending on production rates, selling prices and timing of initial production. Reserve quantities after royalty also reflect net overriding royalty interests paid and received.

(4) Reserves in the North Sea are subject to a conventional royalty and tax regime. No royalty is payable on reserves in the U.K. sector. Royalty is payable on onshore reserves in the Netherlands.

(5) Proved reserves include quantities of crude oil and natural gas, which will be produced under arrangements, which involve the company or its subsidiaries in upstream risks and rewards, but which do not transfer title of the product to those companies.

(6) In Suncor's production sharing contracts (PSCs), after royalty proved reserves have been determined using the economic interest method and includes the company's share of future production entitlement calculated using the contract's cost recovery and profit oil terms. The entitlement reserves are then adjusted to include reserves relating to income tax payable. Under this method, reported reserves will increase as oil prices decrease (and vice versa), since the bbls necessary to achieve cost recovery change with the prevailing oil prices.

(7) All reserves reported in "Other International" (which include reserves in Libya, Syria, and Trinidad and Tobago) are calculated as per footnote 5.

(8) Revisions include changes in previous estimates, either upward or downward, resulting from new information (except an increase in acreage) normally obtained from drilling or production history or resulting from a change in economic factors.

(9) Due to the SEC rule change in respect to reporting mining as oil and gas activities, Suncor has re-stated its mining opening balance which would have been previously reported under Mining Guide 7. For more information, see page 30.

(10) The 2008 reserve data for legacy Suncor assets has been re-stated per SEC guidelines, this information was previously disclosed under NI 51-101.

(11) The production data in the 2009 reserve tables are estimates from the third party evaluators, and may not exactly match production shown else where in this AIF. Any variance in the production numbers is deemed not material in the disclosure of these reserves.

REMAINING RECOVERABLE RESOURCES (does not conform to U.S. disclosure requirements)

In addition to Suncor's proved plus probable reserve holdings, we also have considerable contingent resources (see table below). GLJ prepared the estimates for legacy Suncor and Syncrude mining leases as well as the Firebag in-situ leases. Sproule audited the Fort Hills estimate. Estimates for the remainder of our contingent resources were prepared internally by qualified reserves evaluators.

Remaining Recoverable Resources Before Royalties:

As at December 31, 2009 (1)(6)	Conventional	Oil Sands – Mining	Oil Sands – In-Situ	Total
	(MMboes)	(MMboes)	(MMboes)	(MMboes)
Total Proved	751	2203	1177	4131
Total Probable	606	591	2232	3429
Total Proved Plus Probable Reserves	1357	2794	3409	7560
Contingent Resources (2)(5)(6) – Best Estimate (3)	2935	6080	10881	19896
Remaining Recoverable Resources (unrisked) (4)	4292	8874	14290	27456

(1) Numbers in the above table are rounded to the nearest 1 million boe. MMboe means millions of barrels of oil equivalent and is comprised of all liquids: 1 mmbbl = 1 mmboe and natural gas: 6 Bcf = 1 MMboe.

(2) 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.

(3) 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.

(4) Remaining recoverable resources (unrisked) are the arithmetic sum of proved and probable reserves and best estimate contingent resources. Suncor has not quantified potentially recoverable volumes from either undiscovered accumulations or its carbonate leases. The contingent resources have not been adjusted for risk based on the chance of development. It is not an estimate of volumes that may be recovered. Actual recovery may be less.

(5) Our contingent resources are composed primarily of resources from: (i) (in-situ) Firebag, Lewis, Meadow and Chard; (ii) (mining) Voyager South, Audette (North Leases), Fort Hills and Syncrude; and (iii) (conventional) Arctic Islands and MacKenzie corridor, Libya, Hebron/BenNevis, Labrador, White Rose, Hibernia, Terra Nova, Trinidad and Tobago and the North Sea.

(6) All mining and in-situ contingent resources are stated in SCO.

Remaining recoverable resources were 27,456 millions of barrels of oil equivalent at December 31, 2009. The increase in 2009 was primarily due to the merger with Petro-Canada.

Approximately 85% of our contingent resources are associated with our long term mining and in-situ growth projects. The remaining contingent resources are associated with our frontier North America and International assets. Contingent resources may require additional delineation drilling, future corporate approval to proceed with development, additional regulatory approvals and other commercial factors to be put in place.

Remaining recoverable resources are the best estimate of Suncor's total resource assets, which form the basis of our long term business plans and production growth. Management believes that this metric is also useful in comparing Suncor's resource base to that of our competitors. Readers are cautioned that the manner in which remaining recoverable resources are calculated may differ across companies and for that reason, direct comparisons may not be possible in some instances.

Estimates of contingent resources have not been adjusted for risk based on the chance of development. Such estimates are not estimates of volumes that may be recovered and actual recovery is likely to be less and may be substantially less or zero. There is no certainty as to the timing of such development.

There is no certainty that all or any portion of the contingent resource will be commercially viable to produce any portion of the resources. 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.

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Gas Reserves

The following disclosures on Standardized Measure of discounted cash flows and changes therein relating to proved oil and natural gas reserves are presented in accordance with the U.S. FASB Topic 932, *Disclosures About Oil and Gas Producing Activities*. The future cash flows are calculated by applying a 12-month average price for the year, or prices provided by contractual arrangements, net of royalties, to year-end quantities of proved crude oil, natural gas liquids, and natural gas reserves. Future production, development and asset retirement costs are based on year-end costs and estimated future income taxes are based on legislated future income tax rates. The resulting future net cash flows are discounted at 10% per annum. The calculation does not represent a fair market value of the company's crude oil, natural gas liquids and natural gas reserves or of the future net cash flows. No consideration is given to the value of exploration properties or probable reserves. The following benchmark commodity prices and exchange rates were used as at December 31, 2009 in deriving the Standardized Measure:

		2009 12 month average	2008 Year-end
Dated Brent	USD/BBL	60.67	36.55
WTI @ Cushing	USD/BBL	61.04	44.60
Edmonton Light (Par) @ Edmonton	CAD/BBL	63.55	52.96
Condensate @ Edmonton	CAD/BBL	66.66	59.70
Syncrude/OSA @ Edmonton	CAD/BBL	69.36	59.52
WCS FOB @ Hardisty	CAD/BBL	56.60	43.53
Henry Hub Gas Price	USD/MMBTU	3.82	5.62
CIG US Rockies Gas Price	USD/MMBTU	3.30	4.61
AECO-C Canadian Gas Price	CAD/GJ	3.81	6.04
Propane @ Edmonton	CAD/BBL	36.45	37.36
Butane @ Edmonton	CAD/BBL	44.27	23.05
Canadian Dollar to US Dollar	CAD/USD	1.15	1.22
Canadian Dollar to Euro	CAD/EURO	1.52	N/A
Canadian Dollar to British Pound	CAD/GBP	1.79	N/A

Present Value of Estimated Future Net Cash Flows (millions of Canadian dollars)

	North America Onshore			Oil Sands – Mining [1]			Oil Sands – In-Situ		
	2009	2008 [2]	2007 [2]	2009	2008 [2]	2007 [2]	2009	2008 [2]	2007 [2]
Future cash flows	**7,452**	3,186	3,341	**121,231**	—	—	**59,853**	35,486	27,886
Future production costs	**(3,400)**	(1,119)	(827)	**(61,740)**	—	—	**(33,947)**	(17,749)	(15,136)
Future development costs	**(451)**	(182)	(202)	**(31,567)**	—	—	**(12,634)**	(8,084)	(7,800)
Asset retirement and other	**(1,773)**	(465)	(528)	**(3,265)**	—	—	**(373)**	(238)	(214)
Future income taxes	**(77)**	(199)	(268)	**(6,205)**	—	—	**(1,922)**	(1,053)	(1,935)
Future net cash flows	**1,751**	1,221	1,516	**18,454**	—	—	**10,977**	8,362	2,801
10% annual discount for estimated timing of cash flows	**(248)**	(474)	(601)	**(11,152)**	—	—	**(7,541)**	(5,989)	(3,206)
Discounted future net cash flows	**1,503**	747	915	**7,302**	—	—	**3,436**	2,373	(405)

	East Coast Canada			North Sea			Other International		
	2009	2008 [2]	2007 [2]	2009	2008 [2]	2007 [2]	2009	2008 [2]	2007 [2]
Future cash flows	**4,711**	—	—	**9,778**	—	—	**5,610**	—	—
Future production costs	**(1,863)**	—	—	**(3,096)**	—	—	**(1,191)**	—	—
Future development costs	**(678)**	—	—	**(470)**	—	—	**(411)**	—	—
Asset retirement and other	**(213)**	—	—	**(696)**	—	—	**(463)**	—	—
Future income taxes	**(343)**	—	—	**(2,958)**	—	—	**(1,461)**	—	—
Future net cash flows	**1,614**	—	—	**2,558**	—	—	**2,084**	—	—
10% annual discount for estimated timing of cash flows	**(374)**	—	—	**(682)**	—	—	**(887)**	—	—
Discounted future net cash flows	**1,240**	—	—	**1,876**	—	—	**1,197**	—	—

	Total		
	2009	2008 [2]	2007 [2]
Future cash flows	**208,635**	38,672	31,227
Future production costs	**(105,237)**	(18,868)	(15,963)
Future development costs	**(46,211)**	(8,266)	(8,002)
Asset retirement and other	**(6,783)**	(703)	(742)
Future income taxes	**(12,966)**	(1,252)	(2,203)
Future net cash flows	**37,438**	9,583	4,317
10% annual discount for estimated timing of cash flows	**(20,884)**	(6,463)	(3,807)
Discounted future net cash flows	**16,554**	3,120	510

(1) US FASB Topic 932 disclosures for mining operations were effective December 31, 2009, therefore prior year comparative numbers for Oil Sands mining have not been disclosed.

(2) The amalgamation with Petro-Canada was effective August 1, 2009, hence comparative figures do not include the operations of Petro-Canada.

Summary of Changes in Present Value of Estimated Future Cash Flows (millions of Canadian dollars)

	2009	2008 (1)	2007 (1)
Balance at beginning of year	**3,120**	510	3,369
Changes result from:			
Sales and transfers of oil and gas produced, net of production costs	**(2,263)**	(677)	(483)
Net changes in prices, production costs and royalties (2)	**442**	1,560	(3,226)
Extensions, discoveries, additions and improved recoveries	**1,470**	248	72
Changes in estimated future development costs	**(2,837)**	(2,494)	(2,151)
Development costs incurred during the year	**1,675**	2,389	1,459
Revisions of previous quantity estimates	**1,679**	293	(4)
Accretion of discount	**342**	93	472
Purchase and sale of reserves in place (3)	**9,371**	—	35
Net change in income tax (3)	**(3,600)**	130	934
Changes in timing and other	**(147)**	1,068	33
Net change	**6,132**	2,610	(2,859)
Addition of future cash flows from Oil Sands – Mining (4)	**7,302**	—	—
Balance at end of year	**16,554**	3,120	510

(1) The amalgamation with Petro-Canada was effective August 1, 2009, hence comparative figures do not include the operations of Petro-Canada.

(2) Due to the SEC rule change in respect to reporting final product sold, Suncor has reserve In-situ volumes that were previously reported as Bitumen that now are to be reported as SCO. The impact of this change on the future cash flows of In-Situ has been reflected in this line item.

(3) Petro-Canada future cash flows as at August 1, 2009, including sales, production costs, development costs, asset retirement, and other expenses are reflected in "purchase and sale of reserves in place". Changes to cash flows subsequent to August 1, 2009 are presented in the respective line items. The associated tax impacts are reflected in "net change in income tax".

(4) US FASB Topic 932 disclosures for mining operations were effective December 31, 2009, therefore prior year numbers for Oil Sands mining have not been disclosed. Oil Sands mining cash flows are reflected as a cash flow addition for purposes of this table.

Capitalized Costs Relating to Oil & Gas Producing Activities (3)

Suncor's aggregate capitalized costs relating to its oil and natural gas activities are summarized in the following table.

	As at December 31,		
(millions of Canadian dollars)	2009	2008 (1)(2)	2007 (1)(2)
Oil and gas properties	56,079	10,171	6,971
Accumulated depreciation, depletion, and amortization, and valuation allowances	(6,234)	(1,608)	(1,306)
Net capitalized costs	49,845	8,563	5,665

(1) US FASB Topic 932 disclosures for mining operations were effective December 31, 2009, therefore prior year numbers for mining are not disclosed.

(2) The amalgamation with Petro-Canada was effective August 1, 2009, hence comparative figures do not include the operations of Petro-Canada.

(3) Includes work in progress, development assets, assets under construction which are currently not being depreciated or depleted.

Costs Incurred in Oil and Gas Property Acquisition Exploration and Development

Suncor's costs incurred on acquisition, exploration, and development, whether capitalized or expensed at the time they are incurred, are summarized in the following table.

	For the years ended December 31,		
(millions of Canadian dollars)	2009 (2)	2008 (2)	2007 (2)
Exploration			
North America Onshore	**100**	120	141
Oil Sands – Mining (1)	**2**	—	—
Oil Sands – In-Situ	**13**	13	1
East Coast Canada	**41**	—	—
North Sea	**150**	—	—
Other International	**71**	—	—
Total Exploration	**377**	133	142
Development			
North American Onshore	**239**	216	230
Oil Sands – Mining (1)	**1,561**	—	—
Oil Sands – In-Situ	**988**	2,182	1,228
East Coast Canada	**83**	—	—
North Sea	**131**	—	—
Other International	**252**	—	—
Total Development	**3,254**	2,398	1,458
Property acquisitions			
North America Onshore	**3,103**	19	172
Oil Sands – Mining (1)	**5,024**	—	—
Oil Sands – In-Situ	**1,779**	—	—
East Coast Canada	**4,701**	—	—
North Sea	**5,895**	—	—
Other International	**2,434**	—	—
Total Property Acquisitions	**22,936**	**19**	**172**
Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development	**26,567**	**2,550**	**1,772**

(1) US FASB Topic 932 disclosures for mining operations were effective December 31, 2009, therefore prior year numbers for mining are not disclosed.

(2) The amalgamation with Petro-Canada was effective August 1, 2009. Hence comparative figures do not include the operations of Petro-Canada. Current year figures include the acquisition cost of Petro-Canada assets based on the fair values assigned on the amalgamation date and post-acquisition expenditures incurred on Petro-Canada properties.

Abandonment and Reclamation Costs

The company's upstream future asset retirement costs are estimated based on current costs and technology in accordance with existing legislation and industry practice. As of December 31, 2009, the total of these future costs was estimated to be $8.3 billion undiscounted, as disclosed in the 2009 annual MD&A, or $2.6 billion discounted at 10%. We expect to spend approximately $318 million, $254 million and $214 million in the next three years, respectively, for future asset retirement costs in our upstream operations.

Productive Wells(1)(2)

Suncor's total gross and net productive wells by product are summarized in the following table.

	Crude Oil Wells		Natural Gas Wells		Total Wells	
As at December 31, 2009	Gross (3)	Net (4)	Gross (3)	Net (4)	Gross (3)	Net (4)
North America Onshore	1,446	1,253	6,239	4,206	7,685	5,459
Oil Sands – In-Situ	96	96	—	—	96	96
East Coast Canada	101	25	—	—	101	25
North Sea	80	29	29	5	109	34
Other International	146	73	11	2	157	75
Total productive wells	1,869	1,476	6,279	4,213	8,148	5,689

(1) Wells with multiple completions are counted as one well.

(2) Well data not applicable to oil sands mining operations.

(3) Gross wells include the interests of others.

(4) Net wells exclude the interests of others.

Oil and Natural Gas Rights

Suncor's oil and natural gas rights are summarized in the following table. Landholdings are subject to government regulation.

	Developed Lands [1]				Undeveloped Lands [1]				Total			
	2009		2008 [5]		2009		2008 [5]		2009		2008 [5]	
(thousands of acres)	Gross [2]	Net [3]	Gross [2]	Net [3]	Gross [2]	Net [3]	Gross [2]	Net [3]	Gross [2]	Net [3]	Gross [2]	Net [3]
North America Onshore [4]	**3,096**	**1,688**	700	410	**13,673**	**9,213**	1,780	880	**16,769**	**10,901**	2,480	1,290
Oil Sands – Mining	**181**	**98**	87	87	**474**	**288**	127	127	**655**	**386**	214	214
Oil Sands – In-Situ	**85**	**85**	40	40	**1,085**	**1,085**	402	402	**1,170**	**1,170**	442	442
East Coast Canada	**113**	**29**	—	—	**1,844**	**643**	—	—	**1,957**	**672**	—	—
North Sea	**78**	**40**	—	—	**2,211**	**788**	—	—	**2,289**	**828**	—	—
Other International	**551**	**243**	—	—	**9,718**	**5,639**	—	—	**10,269**	**5,882**	—	—
Total	**4,104**	**2,183**	827	537	**29,005**	**17,656**	2,309	1,409	**33,109**	**19,839**	3,136	1,946

(1) Developed lands are areas capable of production, while undeveloped lands are areas with rights to explore.

(2) Gross acres include the interests of others.

(3) Net acres exclude the interests of others.

(4) Figures do not include option acreage in the Alaska Foothills.

(5) The merger with Petro-Canada was effective August 1, 2009. Hence comparative figures do not include the operations of Petro-Canada.

Land Expiries

The following table summarizes the land area by region for which Suncor's rights to explore for or develop hydrocarbons will expire in 2010.

(millions of acres)	Gross [1]	Net [2]
North America Onshore	1.2	0.8
Oil Sands – In-Situ	—	—
Oil Sands – Mining	—	—
East Coast Canada	0.3	0.2
North Sea	—	—
Other International	1.5	1.4
Total land expiries in 2010	3.0	2.4

(1) Gross acres include the interests of others.

(2) Net acres exclude the interests of others.

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. Suncor has made the following commitments in regard to the lands it holds. Work commitments as at December 31, 2009 are summarized below.

(millions of Canadian dollars)	Suncor Share of Total Work Commitments	Suncor Share of Total Work Commitments to be Incurred in 2010 [1]
North America Onshore	9	8
Oil Sands – Mining	—	—
Oil Sands – In-Situ	—	—
East Coast Canada	64	17
North Sea	199	31
Other International	428	132
Total work commitments	700	188

(1) Capital expenditure plan for 2010 includes provisions for these work commitments.

Drilling Activity

The following table shows Suncor's drilling activity during the years indicated.

Exploration and Development Wells Drilled as at December 31, [6]

	2009		2008 [7]		2007 [7]	
	Gross [1]	Net [2]	Gross [1]	Net [2]	Gross [1]	Net [2]
North America Onshore						
Exploration wells [3]						
Oil	**—**	**—**	—	—	—	—
Natural gas	**4**	**2**	7	5	10	7
Dry [4]	**8**	**6**	7	4	6	4
Subtotal	**12**	**8**	14	9	16	11
Development wells [5]						
Oil	**26**	**26**	—	—	—	—
Natural gas	**68**	**31**	25	17	29	14
Dry	**1**	**1**	7	5	2	1
Subtotal	**95**	**58**	32	22	31	15
Total North America Onshore	**107**	**66**	46	31	47	26
Total North America Onshore – In progress [8]	**32**	**32**				
Oil Sands – In-Situ						
Development wells [5]						
Bitumen	**20**	**20**	24	24	26	26
Total Oil Sands – In-Situ	**20**	**20**	24	24	26	26
Total Oil Sands – In-Situ – In progress [8]	**—**	**—**				
East Coast Canada						
Exploration wells [3]	**—**	**—**	—	—	—	—
Oil	**—**	**—**	—	—	—	—
Dry [4]	**—**	**—**	—	—	—	—
Subtotal	**—**	**—**	—	—	—	—
Development wells [5]			—	—	—	—
Oil	**6**	**2**	—	—	—	—
Dry	**—**	**—**	—	—	—	—
Subtotal	**6**	**2**	—	—	—	—
Total East Coast Canada	**6**	**2**	—	—	—	—
Total East Coast Canada – In progress [8]	**2**	**1**	—	—	—	—
International						
Exploration wells [3]						
Oil						
North Sea	**11**	**4**	—	—	—	—
Other International	**—**	**—**	—	—	—	—
Natural gas						
North Sea	**1**	**1**	—	—	—	—
Other International	**—**	**—**	—	—	—	—
Dry [4]						
North Sea	**3**	**1**	—	—	—	—
Other International	**—**	**—**	—	—	—	—
Subtotal	**15**	**6**	—	—	—	—
Development wells [5]						
Oil						
North Sea	**10**	**4**	—	—	—	—
Other International	**27**	**15**	—	—	—	—
Natural gas						
North Sea	**1**	**1**	—	—	—	—
Other International	**6**	**4**	—	—	—	—
Dry [4]						
North Sea	**4**	**2**	—	—	—	—
Other International	**1**	**1**	—	—	—	—
Subtotal	**49**	**27**	—	—	—	—
Total International	**64**	**33**	—	—	—	—
Total International – In progress [8]	**8**	**5**	—	—	—	—
Total wells drilled	**197**	**121**	70	55	73	52

(1) Gross wells (excluding all service wells) include the interests of others. This includes gross overriding royalty (GOR) wells.
(2) Net wells exclude the interests of others. Net wells exclude GOR wells.
(3) Exploration wells are wells drilled to discover crude oil or natural gas in an unproven area previously not known to contain hydrocarbons
(4) A dry hole is an exploration or development well determined to be incapable of producing either crude oil or natural gas in sufficient economic quantities to justify completion as a crude oil or natural gas well.
(5) Development wells are wells drilled in an oil or natural gas reservoir to the depth of a stratigraphic horizon previously known to be productive.
(6) Table does not include drilling activity for oil sands mining operations. For information on oil sands mining exploration and development activities, see page 8 and 9 of this AIF.
(7) The amalgamation with Petro-Canada was effective August 1, 2009. Hence comparative figures do not include the operations of Petro-Canada. Current year figures include post-acquisition drilling activity related to Petro-Canada properties.
(8) Wells in progress at December 31, 2009.

Results of Operations for Oil and Gas Producing Activities[3]

Suncor's Results of Operations for oil and gas producing activities is shown below by geographic area:

	North America Onshore			Oil Sands[1]			East Coast Canada		
(millions of Canadian dollars)	2009	2008[2]	2007[2]	2009	2008[2]	2007[2]	2009	2008[2]	2007[2]
Revenues									
Sales to unaffiliated customers	**527**	521	416	**3,490**	—	—	**282**	—	—
Transfers to other operations	**154**	58	9	**2,609**	713	496	**159**	—	—
	681	579	425	**6,099**	713	496	**441**	—	—
Expenses									
Purchases of crude oil and products	**—**	—	—	**325**	—	—	**33**	—	—
Operating, selling and general	**322**	160	128	**3,898**	326	280	**49**	—	—
Transportation costs	**58**	17	30	**248**	1	8	**19**	—	—
Depreciation, depletion and amortization	**448**	225	180	**922**	87	83	**184**	—	—
Exploration	**127**	73	93	**10**	17	—	**4**	—	—
Gain on disposal of assets	**(20)**	(22)	14	**70**	—	—	**—**	—	—
Other related assets	**22**	8	1	**162**	19	—	**4**	—	—
Operating profits before income taxes	**(276)**	118	(21)	**464**	263	125	**148**	—	—
Related income taxes	**77**	(29)	41	**(47)**	(70)	(40)	**(18)**	—	—
Results of operations	**(199)**	89	20	**417**	193	85	**130**	—	—

	North Sea			Other International			Total		
	2009	2008[2]	2007[2]	2009	2008[2]	2007[2]	2009	2008[2]	2007[2]
Revenues									
Sales to unaffiliated customers	**949**	—	—	**218**	—	—	**5,466**	521	416
Transfers to other operations	**—**	—	—	**—**	—	—	**2,922**	771	505
	949	—	—	**218**	—	—	**8,388**	1,292	921
Expenses									
Purchases of crude oil and products	**—**	—	—	**—**	—	—	**358**	—	—
Operating, selling and general	**198**	—	—	**20**	—	—	**4,487**	486	408
Transportation costs	**30**	—	—	**3**	—	—	**358**	18	38
Depreciation, depletion and amortization	**359**	—	—	**40**	—	—	**1,953**	312	263
Exploration	**59**	—	—	**36**	—	—	**236**	90	93
Gain on disposal of assets	**—**	—	—	**—**	—	—	**50**	(22)	14
Other related assets	**10**	—	—	**6**	—	—	**204**	27	1
		—	—		—	—			
Operating profits before income taxes	**293**	—	—	**113**	—	—	**742**	381	104
Related income taxes	**(136)**	—	—	**(85)**	—	—	**(210)**	(99)	1
Results of operations	**157**	—	—	**28**	—	—	**532**	282	105

(1) US FASB Topic 932 disclosures for mining operations was effective December 31, 2009. Therefore prior year numbers for mining are not disclosed.

(2) The amalgamation with Petro-Canada was effective August 1, 2009. Hence comparative figures do not include the operations of Petro-Canada. Current year figures include post-acquisition results of Petro-Canada properties.

(3) Results from operations may not agree to the operating segment results reported in the 2009 Annual Report, as the above figures have been calculated in accordance with US FASB Topic 932 requirements not Canadian Generally Accepted Accounting Principles.

Upstream Production and Prices

Average Daily Production before Royalties and Sale Prices for Crude Oil, NGL, Bitumen, Synthetic Crude Oil and Natural Gas

Production information stated before royalties does not conform to SEC standards and is supplemental general information. Refer to page 32 of this AIF for annual after royalty production as computed by third party evaluators in accordance with SEC standards. Daily production figures below are consistent with the information presented in the 2009 Annual Report and may differ in relation to the before royalty figures computed by third party evaluators reported on page 34 of this AIF.

	Twelve months ended December 31**		
	2009	2008	2007
OIL SANDS (INCLUDING IN-SITU)			
Production (1)(a)			
Total production (excluding Syncrude)	**290.6**	228.0	235.6
Firebag (h)	**49.1**	37.4	36.9
MacKay River (h)	**29.7****	—	—
Syncrude	**38.5****	—	—
Sales (a) (excluding Syncrude)			
Light sweet crude oil	**99.6**	77.0	101.7
Diesel	**29.1**	19.8	25.0
Light sour crude oil	**135.7**	128.7	102.3
Bitumen	**11.8**	1.5	5.7
Total sales	**276.2**	227.0	234.7
Average sales price (2)(b)(excluding Syncrude)			
Light sweet crude oil*	**67.26**	98.66	78.03
Other (diesel, light sour crude oil and bitumen) *	**64.18**	95.14	70.86
Total *	**65.29**	96.33	74.01
Total	**61.26**	95.96	74.07
Syncrude average sales price (2)(b)	**77.36**	—	—
NORTH AMERICA ONSHORE			
Gross production			
Natural gas (d)			
Western Canada	**374**	202	196
U.S. Rockies	**24**	—	—
Natural gas liquids and crude oil (a)			
Western Canada	**6.4**	3.1	3.1
U.S. Rockies	**1.7**	—	—
Total gross production (f)			
Western Canada	**412**	220	215
U.S. Rockies	**34**	—	—
Average sales price (2)			
Natural gas (g)			
Western Canada	**3.70**	8.23	6.32
U.S. Rockies	**3.93**	—	—
Natural gas (g)*			
Western Canada	**3.68**	8.25	6.27
U.S. Rockies	**3.93**	—	—
Natural gas liquids and crude oil (b)			
Western Canada	**52.97**	70.89	56.64
U.S. Rockies	**71.62**	—	—

	Twelve months ended December 31**		
	2009	2008	2007
EAST COAST CANADA			
Production [(a)]			
Terra Nova	**20.8**	—	—
Hibernia	**27.2**	—	—
White Rose	**10.0**	—	—
Total production	**58.0**	—	—
Average sales price [(2)]	**76.86**	—	—
NORTH SEA			
Production [(e)]			
Buzzard	**47.8**	—	—
Other U.K.	**15.5**	—	—
The Netherlands sector of the North Sea	**13.2**	—	—
Total production	**76.5**	—	—
Average sales price [(2)] **– crude oil and NGL**	**74.99**	—	—
Average sales price [(2)] **– natural gas**	**6.89**	—	—
Total average sales price [(i)]	**71.63**	—	—
OTHER INTERNATIONAL			
Production [(e)]			
Libya	**32.6**	—	—
Trinidad & Tobago	**11.7**	—	—
Total production	**44.3**	—	—
Average sales price [(2)] **– crude oil and NGL**	**78.05**	—	—
Average sales price [(2)] **– natural gas**	**2.42**	—	—
Total average sales price [(i)]	**61.25**	—	—

Please refer to footnotes on Page 47 of this AIF.

Average Production Costs for Crude Oil, NGL, Bitumen, Synthetic Crude Oil and Natural Gas

	Twelve months ended December 31		
	2009	2008	2007
OIL SANDS (c)			
(Excluding Syncrude)			
Cash costs	**31.50**	31.45	24.15
Natural gas	**2.40**	5.25	3.55
Imported bitumen	**0.05**	1.80	0.10
Cash operating costs (3)	**33.95**	38.50	27.80
Project start-up costs	**0.45**	0.40	0.95
Total cash operating costs (4)	**34.40**	38.90	28.75
(Including Syncrude)			
Cash costs	**29.60**	—	—
Natural gas	**2.90**	—	—
Cash operating costs (3)	**32.50**	—	—
Project start-up costs	**—**	—	—
Total cash operating costs (4)	**32.50**	—	—
IN-SITU (c)			
Cash costs	**10.90**	13.00	10.85
Natural gas	**5.70**	12.30	9.90
Cash operating costs (5)	**16.60**	25.30	20.75
In-situ start-up costs	**1.30**	0.65	—
Total cash operating costs (6)	**17.90**	25.95	20.75
NATURAL GAS (g)			
Western Canada			
Average price realized (8)	**4.58**	9.35	6.88
Royalties	**(0.49)**	(2.17)	(1.56)
Operating costs (7)	**(1.79)**	(1.60)	(1.41)
Operating netback	**2.30**	5.58	3.91
U.S. Rockies			
Average price realized (8)	**6.35**	—	—
Royalties	**(1.01)**	—	—
Operating costs (7)	**(1.82)**	—	—
Operating netback	**3.52**	—	—
Total Natural Gas			
Average price realized (8)	**4.71**	9.35	6.88
Royalties	**(0.53)**	(2.17)	(1.56)
Operating costs (7)	**(1.79)**	(1.60)	(1.41)
Operating netback	**2.39**	5.58	3.91
EAST COAST CANADA (b)			
Average price realized (8)	**79.07**	—	—
Royalties	**(23.82)**	—	—
Operating costs (7)	**(9.76)**	—	—
Operating netback	**45.49**	—	—
NORTH SEA (b)			
Average price realized (8)	**71.63**	—	—
Operating costs (7)	**(9.78)**	—	—
Operating netback	**61.85**	—	—
OTHER INTERNATIONAL (b)			
Average price realized (8)	**61.35**	—	—
Royalties	**(30.43)**	—	—
Operating costs (7)	**(3.38)**	—	—
Operating netback	**27.54**	—	—

Definitions

(1) Total operations production	—	Total operations production includes total production from both mining and in-situ operations.
(2) Average sales price	—	This operating statistic is calculated before royalties (where applicable) and net of related transportation costs and excludes the realized impact of hedging activities unless stated.
(3) Cash operating costs	—	Include cash costs that are defined as operating, selling and general expenses (excluding inventory changes), accretion expense, transportation costs, taxes other than income taxes 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 for total operations (excluding Syncrude), see page 53 of our 2009 annual MD&A.
(4) 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.
(5) Cash operating costs – In-situ bitumen production	—	Include cash costs that are defined as operating, selling and general expenses (excluding inventory changes), accretion expense and taxes other than income taxes. 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) Operating costs	—	Include lifting costs and related transportation costs.
(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 twelve months ended December 31, 2009, operating summary information reflects results of operations since the merger with Petro-Canada on August 1, 2009.

(a) thousands of barrels per day
(b) dollars per barrel
(c) dollars per barrel rounded to the nearest $0.05
(d) millions of cubic feet per day
(e) thousands of barrels of oil equivalent per day
(f) millions of cubic feet equivalent per day
(g) dollars per thousand cubic feet equivalent
(h) thousands of barrels of bitumen per day
(i) dollars per barrel of oil equivalent

Metric conversion

Crude oil, refined products, etc. 1 m^3 (cubic metre) = approx. 6.29 barrels

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. 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 contracts directly with oil purchasers, with the result that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand. The specific price depends 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 with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (NEB). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an 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.

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 must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m^3/day), must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity requires an 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.

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 reserve 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 which govern land tenure, royalties, production rates, environmental protection, and other matters. The royalty regime is a significant factor in the profitability of crude oil, natural gas liquids, 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 working interest owner's 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. However, the trend in recent years has been for provincial governments to revise existing incentive programs and royalty structures, which have generally resulted in increases to the amounts of royalties ultimately payable.

The Canadian federal corporate income tax rate levied on taxable income is 19% effective January 1, 2009 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 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. Prior to the New Royalty Framework, the amount of conventional oil royalties that were payable was influenced by the oil production, density of the oil, and the vintage of the oil (the "Generic Regime"). Originally, the vintage classified oil was "new oil" and "old oil" depending on when the oil pools were discovered. If the pool was discovered prior to March 31, 1974 it was considered "old oil", and if it was discovered after March 31, 1974 and before September 1, 1992, it was considered "new oil". The Alberta government introduced in 1992 a Third Tier Royalty with a base rate of 10% and a rate cap of 25% for oil pools discovered after September 1, 1992. The new oil royalty reserved to the Crown had a base rate of 10% and a rate cap of 30%. The old oil royalty reserved to the Crown had a base rate of 10% and a rate cap of 35%. The New Royalty Framework eliminates this classification and establishes new royalty rates for conventional oil, natural gas and oil sands. As at January 1, 2009, the new royalty rates for conventional oil are set by a single sliding rate formula which is applied monthly and increases the old royalty from 30%-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 per barrel. The sliding rate formula includes 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 are set by a single sliding rate formula ranging from 5% to 50% with a rate cap once the price of natural gas reaches Cdn$16.59/Gigajoule. The New Royalty Framework determined rate is 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 2,500 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, which program became effective January 1, 2009. Under this new program 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 in December 31, 2013. Following this period, all new wells drilled will automatically be subject to the New Royalty Framework.

Oil sands projects are now subject to the New Royalty Framework, and regulated by, among others, 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. In December 2008, the Government of Alberta enacted 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, subject to 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 Amending Agreement) and assessed on the R – C royalty 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 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 costs and related capital costs; (c) from January 1, 2010 through December 31, 2015, pursuant to our January 2008 royalty amending agreement with the Government of Alberta, the New Royalty Framework rates described above will apply to the bitumen royalty for current production levels, subject to a cap of 30% of R – C, and a royalty cap of

1.2% of R. In addition, the Suncor Amending Agreement provides Suncor with a level of guidance for various matters, including the bitumen valuation methodology (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 Bitumen Valuation Methodology (Ministerial) Regulations effective January 1, 2009. These interim regulations determine the valuation of bitumen for 2009 and 2010. The final regulations are being developed by the Crown that will establish the bitumen valuation methodology for future years. For Suncor's mining operations, the bitumen valuation methodology is based on the terms of Suncor's Amending Agreement, which we believe places certain limitations on the interim bitumen valuation methodology. 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 Amending Agreement. Royalty payments to the Crown for our mining operations were determined in accordance with Suncor's Royalty Amending Agreement and royalty expense was recorded under the Crown's interim bitumen valuation methodology, representing a negative difference of approximately $200 million. Suncor's Royalty Amending Agreement provides for an arbitration procedure failing an agreed settlement of these issues. See also, "Risk Factors – Legal and Regulatory Risks – Risks that affect our ability to comply with regulatory and statutory requirements under applicable law – Alberta Crown Royalties" in 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 Amending Agreement). 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. For the year 2009, 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 Amending Agreement.

On April 10, 2008, the Government of Alberta introduced two new royalty programs to encourage the development of deep oil and gas reserves, and these are: (a) a five-year oil program for exploration wells over 2,000 metres that will provide royalty adjustments to offset higher drilling costs and provide a greater incentive for producers to continue to pursue new, deeper oil plays (these oil wells will qualify for up to $1 million or 12 months of royalty offsets, whichever comes first); and (b) a five-year natural gas deep drilling program that will replace the existing program in order to encourage continued deep gas exploration for wells deeper than 2,500 metres (the program will create a sliding scale of royalty credit according to depth, of up to $3,750 per metre).

Regulations made pursuant to the *Mines and Minerals Act* (Alberta) provided various incentives for exploring and developing oil reserves in Alberta. However, the Alberta Government announced in August of 2006 that four royalty programs were to be amended, a new program was to be introduced and the Alberta Royalty Tax Credit Program was to be eliminated, effective January 1, 2007. The programs affected by this announcement were: (i) Deep Gas Royalty Holiday; (ii) Low Productivity Well Royalty Reduction; (iii) Reactivated Well Royalty Exemption; and (iv) Horizontal Re-Entry Royalty Reduction. The program introduced was the Innovative Energy Technologies Program (IETP) which has a stated objective of promoting the producers' investment in research, technology and innovation for the purposes of improving environmental performance while creating commercial value. The IETP provides royalty reductions which are presumed to reduce financial risk. Alberta Energy decides which projects qualify and the level of support that will be provided. The deadline for the IETP's final round of applications was September 20, 2008. The successful applicants for the first two rounds have been announced, and those for the third round were announced in the first half of 2009. The technical information gathered from this program is to be made public once a two-year confidentiality period expires.

The New Royalty Framework includes a policy of "shallow rights reversion". The Government of Alberta stated that it will implement this policy in order to maximize the development of currently undeveloped resources, which is consistent with the Government of Alberta's objective of maximizing recovery of known gas resources, while increasing royalty revenues. The policy's stated objective is for the mineral rights to shallow gas geological formations that are not being developed to revert back to the government and be made available for resale, and in the event of non-productive shallow wells, to sever the rights from shallow zones and encourage increased production from up-hole zones. In December 2008, the Government of Alberta proclaimed an amendment to the *Mines and Minerals Act* (Alberta) with respect to shallow rights reversion. This amendment affects leases issued after January 1, 2009, with phased-in application for leases entered into prior to January 1, 2009.

On March 3, 2009, as result of depressed energy commodity prices and the global economic slowdown, the Government of Alberta announced a three-point incentive program to encourage additional activity in the province's conventional oil and gas sectors. The incentive program included: (i) a drilling royalty credit which offered $200 in royalty credits per meter drilled on new conventional oil and natural gas wells; (ii) a new well incentive program which provided a maximum five-per-cent royalty rate for all new wells that begin producing conventional oil and natural gas between April 1, 2009 and March 31, 2010; and (iii) $30 million in investment by the Province of Alberta in the reclamation and abandonment of old oil and gas well sites.

East Coast Canada

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. Hibernia royalty and net profits interest averaged 35% of gross revenue for the 5 month period ending December 31, 2009. An agreement has been reached with the Province of Newfoundland and Labrador on the eligibility of transportation costs for royalty deductibility.

The Terra Nova royalty regime 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. Terra Nova royalty averaged 31% of gross revenue for the 5 month period ending December 31, 2009.

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. The total royalty payable in 2009 is expected to equate to a rate of between 20% and 25% of gross revenue, depending on crude oil prices. White Rose royalty averaged 20% of gross revenue for the 5 month period ending December 31, 2009.

See also, "Risk Factors – Legal and Regulatory Risks – Risks that affect our ability to comply with regulatory and statutory requirements under applicable law – Offshore Royalties" in this AIF.

United States

In the U.S., production is from federal, state and freehold lands. Production from federal and state lands is subject to a fixed royalty rate plus a payment to the surface landowner. Freehold royalty rates are determined by negotiations with the freehold mineral rights owner.

Other International

Reserves in the North Sea are subject to a conventional royalty and tax regime. No royalty is payable on reserves in the U.K. sector. Royalty is payable on onshore reserves in the Netherlands.

See also, "Risk Factors – Legal and Regulatory Risks – Risks that affect our ability to comply with regulatory and statutory requirements under applicable law – International Royalties" in this AIF.

Land Tenure

In Canada, crude oil and natural gas located in the western provinces is 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 from two years, 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.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation requires that well and facility sites be abandoned and reclaimed 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 licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties.

Environmental legislation in the Province of Alberta relating to oil and gas activities has been primarily consolidated into the *Environmental Protection and Enhancement Act* (Alberta) (EPEA), which came into force on September 1, 1993, and the *Oil and Gas Conservation Act* (Alberta) (OGCA). In 2006, the Alberta Government enacted regulations pursuant to the EPEA to specifically target sulphur oxide and nitrous oxide emissions from industrial operations including the oil and gas industry.

In 2007, the Alberta government introduced the *Climate Change and Emissions Management Amendment Act* (Alberta), which places intensity (emissions per unit of production) limits on facilities emitting more than 100,000 tonnes of carbon dioxide equivalent per year. Suncor's Oil Sands business are subject to this legislation. The Act calls for intensity reductions of 12% commencing July 1, 2007.

In compliance with this new legislation, Suncor filed applications in December 2007 to establish baseline intensities for our Oil Sands facility. In March 2010, Suncor must file compliance reports that show what actions the company took during the year to demonstrate that each facility either met its intensity target for 2009 or took action to offset its emissions intensity. Compliance options available to Suncor include emission reductions, utilizing offset projects or contributing to a government climate change emission management fund at a present cost of $15/tonne.

For the compliance period of January 1 to December 31, 2009, the compliance costs to Suncor post-merger are estimated at between $3 million and $5 million. Final costs for 2009 will be determined when the company files its compliance report with the Province of Alberta in March 2010.

On April 26, 2007, the Federal Government released its Action Plan to Reduce Greenhouse Gases and Air Pollution (the Action Plan) also known as ecoACTION which includes the regulatory framework for air emissions. This Action Plan covers not only large industry, but regulates the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy using products.

The Government of Canada and the Province of Alberta released on January 31, 2008 the final report of the Canada-Alberta ecoENERGY Carbon Capture and Storage Task Force, which recommends among other things: (i) incorporating carbon capture and storage into Canada's clean air regulations; (ii) allocating new funding into projects through competitive process; and (iii) targeting research to lower the cost of technology.

On March 10, 2008, the Government of Canada released "Turning the Corner – Taking Action to Fight Climate Change" (the Updated Action Plan) which provides some additional guidance with respect to the Government's plan to reduce Canada's 2006 greenhouse gas emissions levels by 20% by 2020 and by 60% to 70% by 2050.

The Updated Action Plan is primarily directed towards industrial emissions from certain specified industries including the oil sands, oil and gas and refining. The Updated Action Plan is intended to create a carbon emissions trading market, including an offset system, to provide an incentive to reduce greenhouse gas emissions and establish a market price for carbon. For the oil sands, its proposed application will be process-specific; oil sands plants built in 2012 and later, those which use heavier hydrocarbons, up-graders and in-situ production will have mandatory standards in 2018 that will be based on carbon capture and storage.

The Updated Action Plan is proposed to apply only to facilities exceeding a minimum annual emissions threshold: (i) 50,000 tonnes of CO_2 equivalent per year for natural gas pipelines; (ii) 3,000 tonnes of CO_2 equivalent per upstream oil and gas facility; and (iii) 10,000 boe/d/company. These proposed thresholds are significantly stricter than the current Alberta regulatory threshold of 100,000 tonnes of CO_2 equivalent per year per facility.

Subsequent to the introduction of the Updated Action Plan, the Canadian federal government committed to implement a North American cap and trade system with the United States, and therefore it is currently not certain that the Updated Action Plan will be implemented as proposed or at all.

The United States federal and the Ontario provincial and Colorado state governments are also in various stages of developing greenhouse gas management legislation and regulation. At this time, no such legislation has been tabled in these jurisdictions and any potential impacts are unknown. The uncertainty and delay surrounding greenhouse gas management legislation in the U.S. has had a direct impact on Canadian greenhouse gas legislation. The Canadian government has gone on record as saying that they will delay implementing any specific greenhouse gas emissions legislation until after the U.S. implements its legislation, and that Canada is committed to having Canadian greenhouse gas legislation integrated and consistent with the U.S. legislation.

Additionally, in the United Kingdom, Phase II of the European Union Emissions Trading Scheme ('EU ETS') began in 2008 and will run until 2012. The EU ETS requires that member states 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 begins in 2013 and will run until 2020. The legislation has not been finalized but the emissions caps will likely be reduced under Phase III. Also, a review of regulations in the UK is currently underway which may impact the disposal of naturally occurring radioactive material (NORM). This review is currently in the consultation stages and, at this time, no such legislation has been tabled and any potential impacts are unknown.

At the end of 2009, the United Nations Climate Change Conference, commonly known as the Copenhagen Summit, was held in Copenhagen, Denmark. While an accord that endorses, among other things, the continuation of the Kyoto Protocol and the need for global emissions reductions was generally accepted by the member countries at the Copenhagen Summit, the accord is generally viewed as not being legally binding and does not contain any binding commitments for reducing carbon dioxide emissions. Canada subsequently committed to reducing its greenhouse gas emissions by 17% below 2005 levels by 2020, although it has not indicated how it will achieve gas reduction.

In addition, a number of frameworks and proposals were issued in 2009 by the various Canadian provincial regulators that oversee oil sands development. These relate to tailings management, water use and land use, to name a few. While the financial implications of such directives 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 regulations and directives as they apply to the company's operations.

In general, 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. 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 such as carbon capture and sequestration.

RISK FACTORS

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

We are continually working to mitigate the impact of potential risks to our 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.

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

Operating Hazards and Other Uncertainties. Each of our principal operating businesses, Oil Sands, Natural Gas, East Coast Canada, International 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, 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. 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 is susceptible to loss of production, slowdowns, shutdowns or restrictions on our ability to produce higher value products due to the interdependence of its component systems. 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, delineation of 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 and, as a result, operating costs per unit are largely dependent on levels of production.

There are risks and uncertainties associated with 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, blow-outs, equipment failures and other accidents, sour gas releases, uncontrollable flows of crude oil, natural gas or well fluids, adverse weather conditions, pollution and other environmental risks.

Our 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 could have a material adverse effect on our business, financial condition, results of operations and cash flow.

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 the U.S. or Canada. 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.

The company has operations in Libya, which is a member of OPEC, and may operate in other OPEC-member countries in the future. Production in those countries may be constrained by OPEC quotas.

Major Projects. 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.

Insurance. Our involvement in the exploration for and development of oil and natural gas properties may result in the company becoming subject to liability for pollution, blow-outs, property damage, personal injury or other hazards. 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.

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

2) Financial Risks – Risks that directly affect our business and financial condition.

Capital Markets. The market events and conditions witnessed over the past two financial years, including disruptions in the 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. While there have been recent signs which may suggest the beginning of a global economic recovery, there can be no certainty regarding the timing or extent of a potential 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 ability to make future capital expenditures 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 lending capacity of many financial institutions has diminished and risk premiums have increased. As future capital expenditures will be financed out of cash generated from operations and borrowings, our ability to do so 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, 2009, we had approximately $4.2 billion of unused credit available under bank credit facilities. In addition, we have announced a planned divesture program which is expected to generate $2-4 billion in proceeds. Based on current funds available and expected cash from operations and the planned divesture program, we believe that we have sufficient funds available to fund our currently projected capital expenditures in 2010. If cash flow from operations is lower than expected or 2010 capital expenditures exceed current estimates, or if we incur major unanticipated expenses related to development or maintenance of our existing properties, 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. 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. Neither the company's articles nor its by-laws 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 effect 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 $7.5 billion in syndicated credit facilities with 19 banks expiring in 2013 and a bilateral credit facility of $61 million expiring in 2010 and approximately $13.9 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 favorable terms, if at all or any restrictions imposed on our borrowings under these facilities due to covenant breaches or otherwise 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.

Uncertainty of Reserve and Resource Estimates. The reserves 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 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 reserve and resource estimate is a matter of engineering interpretation and judgment and is a function of the quality and quantity of available data, which may have been gathered over time. In the oil sands business unit, reserve and resource estimates are based upon a geological assessment, including drilling and laboratory tests. 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 resource estimates are based upon a geological assessment of data gathered from evaluation drilling, the testing of core samples and seismic operations and demonstrated commercial success of the in-situ process. Our actual production, revenues, royalties, taxes and development and operating expenditures with respect to our reserves will vary from such estimates and such variances could be material. Production performance subsequent to the date of the estimate may justify revision, either upward or downward, 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 reserve evaluations, and such variations could be material. The reserve 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 reserve evaluations will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluations. The reserve evaluations are effective as of a specific effective date and has not been updated, and thus does not reflect changes in our reserves since that date.

Volatility of Crude Oil and Natural Gas Prices. Our future financial performance is closely linked to crude oil prices, and to a lesser extent, natural gas prices. The prices of these commodities can be influenced by global and regional supply and demand factors. Worldwide economic growth, political developments, compliance or non-compliance with quotas imposed upon members of the Organization of the Petroleum Exporting Countries and weather, among other things, can affect world oil supply and demand. Our natural gas price realizations 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 and prices may remain at depressed levels in the near term and beyond. A prolonged period of low crude oil and natural gas prices could affect the value of our crude oil and gas properties and the level of spending on growth projects, and could result in curtailment of production on some properties. Accordingly, low crude oil prices in particular could have a material adverse effect on our business, financial condition, results of operations and cash flow. A key component of our business strategy is to target production of sufficient natural gas to meet or exceed internal demands for natural gas purchased for consumption in our oil sands operations, creating a natural price hedge which reduces our exposure to gas price volatility. However, there are no assurances that we will be able to continue to increase production to keep pace with growing internal natural gas demands.

We conduct an assessment of the carrying value of our assets to the extent required by Canadian generally accepted accounting principles. If crude oil and natural gas prices decline further or remain at low levels, the carrying value of our assets could be subject to downward revisions, and our earnings could be materially adversely affected.

Volatility of Downstream Margins. Our downstream business is sensitive to wholesale and retail margins for its refined products, including gasoline, diesel and asphalt. Margin volatility is influenced by, among other things, overall marketplace competitiveness, weather, the cost of crude oil (see "Volatility of Crude Oil and Natural Gas Prices" above) and fluctuations in supply and demand for refined products. We expect that margin and price volatility and overall marketplace competitiveness, including the potential for new market entrants, will continue. As a result, our operating results for our refining and marketing business unit can be expected to fluctuate and may be materially adversely affected.

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 otherwise 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, 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.

Exchange Rate Fluctuations. Our 2009 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, but 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 operations and cash flow.

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.

Interest Rate Risk. We are exposed to fluctuations in short-term Canadian interest rates as a result of the use of floating rate debt. We maintain a substantial portion of our debt capacity in revolving / floating rate bank facilities and commercial paper, with the remainder issued in fixed rate borrowings, 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.

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 fulfill 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 fulfill their contractual obligations may have material adverse effect on our business, financial condition, results of operations and cash flow.

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

Environmental Regulation and Risk. The company is subject to environmental regulation under a variety of Canadian, U.S., United Kingdom 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 licenses and permits in order to operate and impose certain standards and controls on activities relating to mining, oil and gas exploration, development and production, and the refining, distribution and marketing of petroleum products and petrochemicals. Environmental assessments and regulatory approvals are generally required before initiating most new major projects or undertaking significant changes to existing operations. In addition to these specific, known requirements, we expect future changes to environmental legislation, including anticipated legislation for air pollution (Criteria Air Contaminants) and greenhouse gases that will impose further requirements on companies operating in the energy industry. 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 lifecycle 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 clean up costs and damages and the loss of important licenses and permits, which may in turn, have a material adverse effect on our business, financial condition, results of operations and cash flow.

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so called "greenhouse gases". Our exploration and production facilities and other operations and activities emit greenhouse gases and may require us to comply with the new regulatory framework announced as part of the Updated Action Plan which is intended to force large industries to reduce emissions of greenhouse gases, in addition to the Federal Government's proposed *Clean Air Act* (Alberta) of 2006 and Action Plan and Alberta's recently enacted *Climate Change and Emissions Management Act* and *Specified Gas Emitters Regulation*. However, subsequent to the introduction of the Updated Action Plan, the Canadian federal government committed to implement a North American cap and trade system with the United States. More recently, the Canadian federal government has committed to aligning its greenhouse gas legislation with U.S. legislation and therefore it is currently not certain that Updated Action Plan will be implemented as proposed or at all. See "Industry Conditions – Environmental Regulation" in this AIF. Although it is too early to predict the exact costs of compliance, it is likely that compliance costs will increase. The direct or indirect costs of these regulations may have a material adverse effect on our business, financial condition, results of operations and cash flow.

A new reclamation liability management program is under review by the Province of Alberta. The new program would involve increased reporting of progressive reclamation, an asset/liability based risk assessment and consideration of reserve life. Partial security could be required if reclamation targets are not met and full security may eventually be required. On October 15, 2009, Suncor applied to the Energy Resources Conservation Board (ERCB) and Alberta Environment (AENV) for permission to amend its existing and/or approved operations east of the Athabasca River to move from the currently adopted tailings management system, being the use of a consolidated tailings (CT) process to consolidate mature fine tailings (MFT), to Suncor's new Tailings Reduction Operations (TRO) strategy, based on MFT drying. This application is currently pending ERCB and AENV approval.

In addition, over the past few years legislation has been passed in Canada and the United States to reduce allowable levels of sulphur in transportation fuels. For a discussion of projects completed at our refining and marketing operations, see the information under Refining and Marketing in the "Three-Year History" section of this AIF. Projects to retrofit existing facilities to comply with these standards are subject to all risks inherent in large capital projects, and to the additional risk that failure to meet legislated deadlines could have a material impact on the company's ability to market its products, or subject the company to fines and penalties potentially having a material adverse effect on our business, financial condition, results of operations and cash flow.

Our Refining and Marketing business' U.S. operations are subject to Consent Decrees with the United States Environmental Protection Agency, the United States Department of Justice and the State of Colorado. The company is subject to the risk that failure to meet remaining obligations or the deadlines under these Consent Decrees could have a material impact on our ability to market our products, potentially having a material adverse effect on our business, financial condition, results of operations and cash flow.

In addition, our business could be materially adversely affected by the potential for lawsuits against greenhouse gas emitters, based on links drawn between greenhouse gas emissions and climate change. The company is also subject to the environmental laws in the international jurisdictions in which it operates and the costs of compliance with these laws and any changes to such laws could also materially adversely affect the company's results from operations. See "Industry Conditions – Environmental Regulation" in this AIF.

Governmental 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 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. 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.

U.S. Policies. The U.S. government has passed legislation that may be interpreted as limiting the purchase of oil and related refined products by governmental agencies to oil and related refined products produced from conventional sources, rather than oil from the oil sands. Although we continue to focus on mitigating our business impact to air, water and land, current and future U.S. environmental laws, regulations and policies may impact or limit our current business plans and/or reduce demand for our products. As a result, our business, financial condition, results of operations and cash flow could be adversely affected.

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.

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

- The Alberta government enacted new Bitumen Valuation Methodology (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 and 2010. The final regulations are being developed by the Crown that will establish the bitumen valuation methodology for future years. For Suncor's mining operations, the bitumen valuation methodology is based on the terms of Suncor's Amending Agreement, which we believe places certain limitations on the interim bitumen valuation methodology as recently enacted. 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 Amending Agreement. A similar non-compliance notice has been filed by Syncrude 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 Royalty Amending Agreement, and the similar agreement entered into by Syncrude, determine the royalty obligation through 2015 for the 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; and

- 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.

See "Industry Conditions – Royalties and Incentives" in this AIF.

East Coast Canada Royalties. The government of Newfoundland and Labrador and Suncor 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, 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 could impact royalty payments to the Crown.

See "Industry Conditions – Royalties and Incentives" in this AIF.

International Royalties. 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. See "Industry Conditions – Royalties and Incentives" in this AIF.

Control Environment. Based on their evaluation as of December 31, 2009, 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, 2009, there were no changes in our internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) – 15d-15(f)) that occurred during the year ended December 31, 2009 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.

Management continues to integrate 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 management does not yet know whether these changes will materially affect the company's internal control over financial reporting. Management expects this integration process to be completed during 2010.

Based on their inherent limitations, disclosure control 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.

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

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 Oil Sands business will further increase our dependence on the Oil Sands business. For example, in 2009, the Oil Sands business accounted for approximately 67% of our upstream production (2008 – 86%), 52% of our net earnings (2008 – 95%) and 36% of our cash flow from operations (2008 – 86%). Refer to "Non-GAAP Financial Measures" on page 5 of the AIF. These percentages have been determined excluding the Corporate, Energy Trading and Eliminations information and include twelve months of Suncor-legacy operations and five months of Petro-Canada-legacy operations.

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

In February 2009, the Energy Resources Conservation Board (ERCB) released a directive, Tailings Performance Criteria and Requirements for Oil Sands Mining Schemes. The directive establishes performance criteria for CT operations, a requirement for specific approval and monitoring of CT ponds, a requirement for reporting tailings plans, and changes to the ERCB annual mine plan requirements and approval process to regulate tailings operations. We are currently assessing the impact of the directive.

On October 15, 2009, the company applied to the ERCB and Alberta Environment (AENV) for permission to amend its existing and/or approved operations east of the Athabasca River to move from the currently approved tailings management system, being the use of CT technology to consolidate mature fine tailings (MFT), to the company's new planned Tailings Reduction Operations (TRO) strategy, based on MFT drying. This application is currently pending ERCB and AENV approval.

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.

Interdependence of Oil Sands Systems. 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.

Need to Replace Conventional Reserves. Future conventional oil and natural gas reserves and production from our East Coast, International and Natural Gas business unit are highly dependent on our successful discovery or acquisition of additional reserves and exploitation of our current reserve base. Without conventional oil and natural gas reserve 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 cash flow from operations(1) 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.

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 chemicals. We compete in virtually every aspect of our business with other energy companies. The petroleum industry also competes with other industries in supplying energy, fuel and related products to consumers. We believe the primary competition for our crude oil production are 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. While this activity has declined with the corresponding decline in economic conditions, it is expected to resume once there is more market certainty. 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. The Canadian Association of Petroleum Producers estimates that Canada's production of bitumen and upgraded SCO could increase from approximately 1.2 million bpd in 2007 to approximately 3 million bpd by 2020(2). 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.

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 skilled labour ability is and the supply 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 "Major Projects" above.

Constraints. 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. See "Industry Conditions – Pipeline Capacity".

---

(1) Refer to "Non GAAP Financial Measures" on page 5 of this AIF.

(2) Canadian Association of Petroleum Producers' Canadian Crude Oil Forecast and Market Outlook, 5 June 2009.

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.

In-Situ Recovery. Current steam-assisted gravity drainage (SAGD) technologies for in-situ recovery of heavy oil and bitumen are energy intensive, requiring significant consumption of natural gas and other fuels in the production of steam which is used in the recovery process. The amount of steam required in the production process can also vary and impact costs. The performance of the reservoir can also impact the timing and levels of production using this technology. 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.

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.

Labour Relations. Hourly employees at our Oil Sands facility near Fort McMurray, Alberta, our London, Ontario terminal operation, our Sarnia, Ontario refinery, our Commerce City, Colorado refinery, our Montreal refinery, our Terra Nova FPSO, 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. Approximately 87% of our unionized employees are members of the Communications Energy and Paperworkers Union (CEP). Three-year collective bargaining agreements with most CEP locals will expire in 2010. Negotiations are ongoing. 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.

DIVIDENDS

Our Board of Directors has established a policy of paying dividends on a quarterly basis. We review our policy from time to time in light of our financial position, financing requirements for growth, cash flow and other factors which our Board of Directors considers relevant. Our Board of Directors approved an increase in the quarterly dividend to $0.10 per share* from $0.05 per share* in the third quarter of 2009 and an increase in the quarterly dividend to $0.05 per share* from $0.04 per share* in the second quarter of 2007.

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

	Year Ended December 31,		
	2009	2008	2007
Common shares			
Cash dividends**	$0.30	$0.20	$0.19
Dividends paid in common shares	—	—	—

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

** Petro-Canada declared dividends in an aggregate amount of $0.40 per share for the first two quarters of 2009, which amount is not included in the above table.

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, 2009, there were 1,559,778,481 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 fulfill 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 table shows the ratings issued by the rating agencies noted therein as of December 31, 2009. 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)

Dominion Bond Rating Service's (DBRS) credit ratings are on a long-term debt rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. A rating of A (low) by DBRS is the third highest of ten 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 catagories.

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.

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

S&P's commercial paper credit ratings are on a short-term debt rating scale that ranges from A-1 (High) to D, which represent 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 obliger'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 OUR SECURITIES

Price Range and Trading Volume of Common Shares

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

Toronto Stock Exchange

	Price Range ($Cdn)		
	High	Low	Trading Volume (000's)
2009			
January	29.78	22.00	104,250
February	27.25	21.15	112,120
March	34.22	23.50	192,482
April	32.17	27.44	117,944
May	39.98	30.87	121,417
June	40.13	31.84	122,525
July	36.84	29.90	115,715
August (1)	37.30	33.38	108,182
September	39.84	32.76	115,893
October	40.79	34.66	94,602
November	39.24	34.72	100,098
December	39.50	35.33	83,079

New York Stock Exchange

	Price Range ($Cdn)		
	High	Low	Trading Volume (000's)
2009			
January	25.31	17.37	229,625
February	22.34	16.95	207,281
March	27.92	18.21	341,981
April	26.44	21.61	188,623
May	36.53	25.96	275,432
June	36.93	27.56	233,009
July	34.09	25.51	240,720
August (1)	35.05	30.41	135,886
September	37.31	29.60	164,879
October	39.62	31.84	160,307
November	37.37	32.18	153,070
December	37.80	33.38	123,552

(1) The merger with Petro-Canada occurred August 1, 2009

Prior Sales

Except as disclosed herein and other than the approximately 1,568,322,051 common shares issued pursuant to the merger of Suncor and Petro-Canada on August 1, 2009 (actual number subject to rounding), no securities of the company were issued in 2009. Approximately 621,141,900 common shares were issued to former Petro-Canada shareholders and approximately 937,180,151 common shares were issued to former (pre-merger) Suncor shareholders.

During the twelve months prior to the date of this AIF, Suncor issued common shares pursuant to the exercise of outstanding options and pursuant to Suncor's dividend reinvestment plan. For information in respect of such issuances, see Note 15 to Suncor's audited annual consolidated financial statements for the year ended December 31, 2009, which are incorporated by reference into this AIF.

DIRECTORS AND EXECUTIVE OFFICERS

Directors

The following individuals are directors of Suncor.

Name and Jurisdiction of Residence	Period Served and Independence	Principal Occupations During Past Five Years
Mel E. Benson [3][4] 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 a director of Tenax Energy Inc., a director of Winalta Homes 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 [1][4] 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 [1][2] 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 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 [2][3] 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. Mr. George is also a director of the Swiss offshore and onshore drilling company Transocean Ltd. 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.

Name and Jurisdiction of Residence	Period Served and Independence	Principal Occupations During Past Five Years
Paul Haseldonckx (1)(4) Essen, Germany	Director since 2002 (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 the ubiquitous 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 (3)(4) Texas, USA	Director since 1998 Independent	John Huff is chairman of Oceaneering International Inc., an oilfield services company. He also serves as director of BJ Services Company and KBR Inc.
Jacques Lamarre (3)(4) Quebec, Canada	Director since 2009 Independent	Jacques Lamarre was the president and chief executive officer of SNC-Lavalin from 1996 to 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 P3 Canada and as a member of the Engineering Institute of Canada, Engineers Canada and the Ordre des ingénieurs du Québec. 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 and the University of Moncton.
Brian MacNeill (1)(2) Alberta, Canada	Director since 1995 (Petro-Canada 1995 to July 31, 2009) Independent	Brian MacNeill was a director and chairman of the board of Petro-Canada and is a Chartered Accountant, a Certified Public Accountant and holds a Bachelor of Commerce. 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 (3)(4) Alberta, Canada	Director since 2004 (5) (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 (1)(2) 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 (2)(3) California, USA	Director since 2004 (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.

Name and Jurisdiction of Residence	Period Served and Independence	Principal Occupations During Past Five Years
Eira M. Thomas[(1)(2)] 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) Audit Committee
(2) Governance Committee
(3) Human Resources and Compensation Committee
(4) Environment, Health, Safety and Sustainable Development Committee
(5) As chairman, by standing invitation, Mr. Ferguson is considered an ex-officio member of all committees

Corporate Officers

The following individuals are the executive officers of Suncor.

Name and Jurisdiction of Residence	Office[(1)]
Richard L. George Alberta, Canada	President and Chief Executive Officer
Ron A. Brenneman Alberta, Canada	Executive Vice Chairman
Steve W. Williams Alberta, Canada	Chief Operating Officer
Bart Demosky Alberta, Canada	Chief Financial Officer
Kirk Bailey Alberta, Canada	Executive Vice President, Oil Sands
Neil J. Camarta Alberta, Canada	Executive Vice President, Natural Gas
Boris Jackman Ontario, Canada	Executive Vice President, Refining and Marketing
Kevin D. Nabholz Alberta, Canada	Executive Vice President, Major Projects
Jay Thornton Alberta, Canada	Executive Vice President, Energy Supply, Trading and Development
Terrence J. Hopwood Alberta, Canada	Senior Vice President and General Counsel
Sue Lee Alberta, Canada	Senior Vice President, Human Resources and Public Affairs
Mark Little Alberta, Canada	Senior Vice President, International and Offshore
Mike MacSween Alberta, Canada	Senior Vice President, In-Situ
Harry Roberts Alberta, Canada	Senior Vice President, Integration
Andrew Stephens Alberta, Canada	Senior Vice President, Business Services
Eric Axford Alberta, Canada	Senior Vice President, Operations Support
Janice B. Odegaard Alberta, Canada	Corporate Secretary

Notes:
(1) This information reflects the positions of officers as at December 31, 2009.

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

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;

  (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 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 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,	
	2009[3]	2008
Oil Sands	4,616	3,903
Natural Gas	786	198
International & East Coast Canada	582	—
Refining and Marketing	3,347	1,112
Corporate [1]	3,647	1,585
Total [2]	12,978	6,798

Notes:

(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.

(3) Includes employees added as a result of the merger with Petro-Canada.

Approximately 35% of the company's employees were covered by collective bargaining agreements in 2009.

The Communications, Energy and Paperworkers Union (CEP) Local 707 represent approximately 2,900 Oil Sands employees. A new collective agreement with the union was entered into effective May 1, 2007. The terms of the agreement include a wage increase of 7% in the first year and 6% in each of the following two years, as well as an initial lump sum payment. Approximately 22% of legacy Petro-Canada's employees were covered by collective bargaining agreements in 2009. Approximately 1,100 employees of legacy Petro-Canada's unionized employees (8% of the company's employees) were members of the CEP in 2009, which represents refinery, marketing, gas plant and offshore production workers. Three-year collective bargaining agreements with most CEP locals will expire in 2010.

Employee associations represent approximately 230 of Refining and Marketing's Sarnia refinery, London terminal and Sun-Canadian Pipe Line Company employees. In 2008, a four-year agreement that will be renegotiated in 2012 was signed with the Sarnia employee association. In 2006, a three-year agreement was signed with the Canadian Auto Workers Union (CAW) at the London terminal, and expired March 1, 2009. In January 2009, management received formal notification from CAW of its intention to bargain. The agreement with the employee association of Sun-Canadian Pipe Line Company was signed in 1993, and is renewed automatically each year unless terminated by written notice by either party at least 60 days prior to the anniversary date of the agreement. No notice has been received or given to date, and management believes the agreement will be automatically renewed on its anniversary. A collective agreement at legacy Petro-Canada's Montreal refinery was reached in December 2008, following a 13-month company-initiated work stoppage.

The United Steel Workers Union (USW) represents approximately 250 employees at Refining and Marketing's Commerce City, Colorado refining facilities. In February 2009, USW ratified a three-year contract which will expire in January 2012. Negotiations between legacy Petro-Canada and the union representing employees on the Terra Nova FPSO commenced well in advance of the contract expiry and a tentative agreement was reached in early 2009.

RELIANCE ON EXEMPTIVE RELIEF

We report our oil and gas reserves data in accordance with, and are relying on, the terms of the following Dual Decision Document: In the Matter of the Securities Legislation of Alberta and In the Matter of the Process for Exemptive Relief Applications in Multiple Jurisdictions and In the Matter of Suncor Energy Inc., November 16, 2009 which came into effect on December 28, 2009 (the "Decision Document").

Our reserves data consists of net proved working interest oil and gas reserve quantities relating to oil and gas operations, estimated as at December 31, 2009, using constant dollar cost and pricing assumptions for the first day of each month for the previous 12 months, and the related standardized measure.

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

- the information required by the United States Financial Accounting Standards Board, including Topic 932;
- the information required by Subpart 1200 of Regulation S-K as promulgated by the SEC under the SEC final rule Modernization of Oil and Gas Reporting (December 31, 2008); and

- certain other information required in accordance with US disclosure practices.

If we had been reporting our reserves data in accordance with NI 51-101 and had not been relying on the terms of the Decision Document, we would have been required to report the following:

- proved and probable working interest oil and gas reserve quantities relating to oil and gas operations, gross and net, using forecast prices and costs for each of proved developed producing reserves, proved developed non-producing reserves, proved undeveloped reserves, proved reserves (in total), probable reserves (in total) and proved plus probable reserves (in total); and
- future net revenue attributable to the reserves categories referred to above, estimated using forecast prices and costs, before and after deducting future income tax expenses, calculated without discount and using discount rates of 5%, 10%, 15% and 20% on an aggregate and certain per unit value basis (10% discount), as well as certain elements of future net revenue calculation without discount.

AUDIT COMMITTEE INFORMATION

Audit Committee Mandate

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

Fees Paid to Auditors

Fees payable to PricewaterhouseCoopers LLP in 2009 and 2008 are detailed below:

($)	2009	2008
Audit Fees	4,307,000	1,600,000
Audit-Related Fees	807,000	442,000
Tax Fees	—	7,000
All other Fees	164,000	13,000
Total	5,278,000	2,062,000

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.

Tax Fees

Tax fees were paid for international tax planning, advice and compliance.

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.

None of the services described under the captions "Audit-related Fees", "Tax Fees" and "All Other Fees" were approved by the Audit Committee pursuant to paragraph (c)(7)(i)(C) of Rule 2-01 of Regulation S-X.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

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

Other than the arrangement agreement entered into between Suncor Energy Inc. and Petro-Canada on March 22, 2009, of which a full summary of the particulars was included in the Joint Information and Proxy Circular of Suncor Energy Inc. and Petro-Canada dated April 29, 2009 (the Information Circular), as filed on SEDAR at www.sedar.com, described under the heading "*The Arrangement – The Arrangement Agreement*" on pages 60 to 67 of the Information Circular, which section of the Information Circular is incorporated by reference into this AIF, during the year ended December 31, 2009, 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.

INTERESTS OF EXPERTS

Reserve and resource estimates contained in this AIF are based upon reports prepared by GLJ Petroleum Consultants Ltd, Sproule Associates Ltd. and RPS Energy Plc., Suncor's Independent Reserve Engineering Evaluators. The 2009 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, Sproule or RPS, 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 New York Stock Exchange (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, 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 2009 Consolidated Financial Statements and MD&A for our most recently completed financial year.

Further information about Suncor, filed with Canadian securities commissions and the SEC, including periodic quarterly and annual reports and the Annual Information Form (AIF/40-F) is available online on SEDAR at www.sedar.com and www.sec.gov. In addition, our Standards of Business Conduct Code is available online at www.suncor.com. Information contained in or otherwise accessible through our website does not form part of this AIF, and is not incorporated into the AIF by reference.

SCHEDULE "A"

Approved and Accepted April 28, 2004

SUNCOR ENERGY INC.
POLICY AND PROCEDURES FOR PRE-APPROVAL OF AUDIT AND NON-AUDIT SERVICES

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

I. STATEMENT OF POLICY

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

II. RESPONSIBILITY

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

III. DEFINITIONS

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

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

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

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

   ii) the performance of domestic and foreign statutory audits;

   iii) Attest services required by statute or regulation;

   iv) Internal control reviews; and

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

* * *

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 "B"

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 & Sustainable Development 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 Director, Internal Audit, and annually review a summary of the remuneration and performance of the Director, Internal Audit.

12. Review the Internal Audit Department Charter, and the plans, activities, organizational structure and qualifications of the Internal Auditors, and monitor the department's performance and independence.

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

Financial Reporting and other Public Disclosure

14. Review 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.

16. 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.

17. 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.

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

19. Review any change in the Corporation's accounting policies.

20. 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

27. Conduct any independent investigations into any matters which come under its scope of responsibilities.
28. Review any recommended appointees to the office of Chief Financial Officer.
29. Review and/or approve other financial matters delegated specifically to it by the Board of Directors.

Reporting to the Board

30. 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 August 1, 2009. (1)

(1) Previously revised on February 25, 2009

SCHEDULE "C"

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

Form 51-101F3, as modified in accordance with exemptions from National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101") contained in Suncor Energy Inc., Re, 2009 ABASC 571 dated effective December 28, 2009, *In the Matter of Suncor Energy Inc.* (the "Decision Document").

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

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

(a) proved and probable oil and gas reserve quantities relating to oil and gas operations, estimated as at December 31, 2009 using an average constant dollar cost and pricing assumptions as of the first day of each calendar month in 2009, and the related standardized measure; and

(b) the Standardized Measure of Discounted Future Net Cash Flows relating to proved and probable oil and gas reserves.

GLJ Petroleum Consultants Ltd., Sproule Associates Limited and RPS Energy Inc., independent qualified reserves evaluators, have evaluated the company's reserves data. The report of the independent qualified reserves evaluators will be filed with securities regulatory authorities concurrently with this report.

The Audit Committee of the Board of Directors of the company has:

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

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

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

The Audit Committee of the Board of Directors has reviewed the company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on the recommendation of the Audit Committee, approved:

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

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

(c) the content and filing of this report.

Reserves data are estimates only and are not exact quantities. Because reserves data are based on judgments regarding future events, actually results will vary and such 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 5, 2010

SCHEDULE "D"

MODIFIED FORM 51-101F2
REPORT ON RESERVES DATA
BY
INDEPENDENT QUALIFIED RESERVES
EVALUATORS

Report on Reserves Data

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

To: The Board of Directors of Suncor Energy Inc. (the "Company")

Re: Form 51-101F2, as modified in accordance with exemptions from National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101") contained in Suncor Energy Inc., Re, 2009 ABASC 571 dated effective December 28, 2009, *In the Matter of Suncor Energy Inc.* (the "Decision Document")

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

We have evaluated and reviewed the Company's reserves data as at December 31, 2009. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2009, estimated using constant prices and costs.

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 or 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) modified to the extent necessary to reflect the terminology and standards of US Disclosure Requirements.

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

The following tables sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved and proved plus probable reserves, estimated using constant 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 for the year ended December 31, 2009, and identifies the respective portions thereof that we have evaluated or reviewed and reported on to the Company's Board of Directors:

Proved Reserves						
			Net Present Value of Future Net Revenue (before income taxes, 10% discount rate) ($ millions)			
Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Audit/Evaluation/Review Report	Location of Reserves (Country or Foreign Geographic Area)	Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants Ltd.	December 31, 2009	Canada	—	14,258	18	14,276
Sproule Associates Limited	December 31, 2009	Canada & United States	—	4,438	—	4,438
RPS Energy Ltd.	December 31, 2009	International	—	3,480	1,476	4,938
Totals			—	22,176 (93.7%)	1,494 (6.3%)	23,652 (100%)

Proved plus Probable Reserves						
			Net Present Value of Future Net Revenue (before income taxes, 10% discount rate) ($ millions)			
Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Audit/Evaluation/Review Report	Location of Reserves (Country or Foreign Geographic Area)	Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants Ltd.	December 31, 2009	Canada	—	18,879	20	18,899
Sproule Associates Limited	December 31, 2009	Canada & United States	—	7,601	—	7,601
RPS Energy Ltd.	December 31, 2009	International	—	5,687	3,038	8,725
Totals			—	32,167 (91.3%)	3,058 (8.7%)	35,225 (100%)

In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined by, and are in accordance with, the COGE Handbook as modified to the extent necessary to reflect the terminology and standards of US Disclosure Requirements. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

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

Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Executed as to our report referred to above:

GLJ Petroleum Consultants Ltd.

"Dana B. Laustsen"

Dana B. Laustsen, P.Eng
Executive Vice-President
March 5, 2010

Sproule Associates Limited

"R. Keith MacLeod"

R. Keith MacLeod, P.Eng
President
March 5, 2010

RPS Energy Plc

"Dr. Graeme Simpson"

Dr. Graeme Simpson
Director, Advisory
March 5, 2010

SCHEDULE "E"

REPORT OF GLJ PETROLEUM CONSULTANTS LTD.

GLJ Petroleum Consultants

Principal Officers:

Harry Jung, P. Eng.
President, C.E.O.
Dana B. Laustsen, P. Eng.
Executive V.P., C.O.O.
Keith M. Braaten, P. Eng.
Executive V.P.

Officers / Vice Presidents:

Terry L. Aarsby, P. Eng.
Jodi L. Anhorn, P. Eng.
Neil I. Dell, P. Eng.
David G. Harris, P. Geol.
Myron J. Hladyshevsky, P. Eng.
Bryan M. Joa, P. Eng.
John H. Stilling, P. Eng.
Douglas R. Sutton, P. Eng.
James H. Willmon, P. Eng.

March 5, 2010

Project 1099570

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

Dear Board Members:

Re: Third Party Report on Reserves

This report was prepared to satisfy requirements contained in Item 1202(a)(8) of U.S. Securities and Exchange Commission Regulation S-K and to provide the qualifications of the technical persons responsible for overseeing the reserve estimation process.

The numbering of items below corresponds to the requirements set out in Item 1202(a)(8) of Regulation S-K. Terms to which a meaning is ascribed in *Regulation S-K* and *Regulation S-X* have the same meaning in this report.

i. We have prepared an independent evaluation of certain reserves of Suncor Energy Inc. (the "Company") for the management and the board of directors of the Company. The primary purpose of our evaluation report was to provide estimates of reserves information in support of the Company's year-end reserves reporting requirements under U.S. and Canadian securities laws, specifically Regulation S-K, and for other internal business and financial needs of the Company.

ii. We have evaluated and reviewed certain reserves of the Company as at December 31, 2009. The completion (transmittal) date of our report is March 5, 2010.

iii. The attached table sets forth the total net after royalty reserves under constant prices and costs covered by our report by geographic area, and the proportion of the Company covered. All of the Company reserves covered by our report are located in Western Canada. We evaluated essentially all of the Company reserves covered by our report. We express no opinion on the portion of the Company's reserves that we did not evaluate

iv. Our report covered approximately 81% of the Company's total proved and total probable oil equivalent reserves, respectively. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") with the necessary modifications to reflect definitions and standards under the U.S. Financial Accounting Standards Board policies (the "FASB Standards") and the legal requirements under the U.S. Securities and Exchange Commission ("SEC requirements").

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

The royalty obligations on the oil sands mining and in-situ properties are determined on a bitumen project basis. Where subsequent upgrading of the bitumen is recognized in the reserves, the synthetic crude oil (SCO) reserves reflect both the yield on bitumen and product value differences. As a consequence of differences in revenue, the royalty percent is lower on an SCO basis than it is on bitumen.

The economic evaluations were prepared on a before income tax basis and only consider a portion of the Company's abandonment and reclamation obligations associated with the properties we evaluated. Costs relating to greenhouse gas (GHG) emissions were included for the Syncrude operation; they were not included for Suncor operated oil sands properties, in recognition of the level at which such costs have been reported and budgeted.

Data used in our evaluation were obtained from regulatory agencies, public sources and from Company personnel and Company files. In the preparation of our report we have accepted as presented, and have relied, without independent verification, upon a variety of information furnished by the Company such as interests and burdens, recent production, product transportation and marketing and sales agreements, historical revenue, capital costs, operating expense data, budget forecasts, capital cost estimates and well data for recently drilled wells. If in the course of our evaluation, the validity or sufficiency of any material information was brought into question, we did not rely on such information until such concerns were satisfactorily resolved.

The Company has warranted in a representation letter to us that, to the best of the Company's knowledge and belief, all data furnished to us was accurate in all material respects, and no material data relevant to our evaluation was omitted.

A field examination of all the evaluated properties was not performed nor was it considered necessary for the purposes of our report.

In our opinion, estimates provided in our report have, in all material respects, been determined in accordance with the applicable industry standards, and results provided in our report and summarized herein are appropriate for inclusion in filings under U.S. and Canadian securities laws, specifically Regulation S-K.

v. As required under SEC Regulation S-K, reserves are those quantities of oil and gas that are estimated to be economically producible under existing economic conditions. As specified, in determining economic production, constant product reference prices have been based on a 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the effective date of our report. In our economic analysis, operating and capital costs are those costs estimated as applicable at the effective date of our report, with no future escalation. Where deemed appropriate, the capital costs and revised operating costs associated with the implementation of committed projects designed to modify specific field operations in the future may be included in economic projections.

vi. Our report has been prepared assuming the continuation of existing regulatory and fiscal conditions subject to the guidance in the COGE Handbook and SEC regulations. Notwithstanding that the Company currently has regulatory approval to produce the reserves identified in our report, there is no assurance that changes in regulation will not occur; such changes, which cannot reliably be predicted, could impact the Company's ability to recovery the estimated reserves.

vii. Oil and gas reserves estimates have an inherent degree of associated uncertainty the degree of which is affected by many factors. Reserves estimates will vary due to the limited and imprecise nature of data upon which the estimates of reserves are predicated. Moreover, the methods and data used in estimating reserves are often necessarily indirect or analogical in character rather than direct or deductive. Furthermore, the persons involved in the preparation of reserves estimates and associated information are required, in applying geosciences, engineering and evaluation principles, to make numerous unbiased judgments based upon their educational background, professional training, and professional experience. The extent and significance of the judgments to be made are, in themselves, sufficient to render reserves estimates inherently imprecise. Reserves estimates may change substantially as additional data becomes available and as economic conditions impacting oil and gas prices and costs change. Reserves estimates will also change over time due to other factors such as knowledge and technology, fiscal and economic conditions, and contractual, statutory and regulatory provisions.

viii. In our opinion, the reserves information evaluated by us have, in all material respects, been determined in accordance with all appropriate industry standards, methods and procedures applicable for the Company's filing of reserves information under U.S. and Canadian securities laws, specifically Regulation S-K.

ix. A summary of the Company reserves evaluated by us for item iii is attached.

GLJ is a private firm established in 1972 whose business is the provision of independent geological and engineering services to the petroleum industry. GLJ is among the largest evaluation firms in North America with approximately 70 professional engineering and geoscience personnel. GLJ evaluate the reserves of the four producing oil sands mining operations for various owners, and also prepare in-situ evaluations for a significant number of owners. Mr. Laustsen and Mr. Willmon were responsible for overseeing GLJ's reserves estimation process, with Mr. Laustsen addressing the In-Situ reserves, and Mr. Willmon addressing the Mining and North America Conventional Onshore reserves. Both responsible individuals are qualified, independent reserves evaluators as defined in COGEH, are registered Practicing Professional Engineers in the Province of Alberta, have in excess of 32 years of practical experience in petroleum engineering, and have been employed at GLJ as evaluators/auditors since 1982.

We trust this meets your current requirements.

Yours truly,

GLJ PETROLEUM CONSULTANTS LTD.

"James H. Willmon"

James H. Willmon, P. Eng.
Vice President

"Dana B. Laustsen"

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

Suncor Energy Inc.
SEC Net After Royalty Reserves Covered by GLJ Petroleum Consultants
Effective December 31, 2009

	Total Proved Reserves				
Location	**Oil & NGL MMbbl**	**SCO[1] MMbbl**	**Bitumen[2] MMbbl**	**Natural Gas Bcf**	**Oil Equivalent[3] MMbbl**
Mining		1,899			1,899
In Situ		506	411		917
NACO[4]	4			363	65
Total GLJ Coverage	4	2,405	411	363	2,881
Total Company Reserves[5]	294	2,565	411	1,692	3,552
Portion of Total Covered by GLJ	1%	94%	100%	21%	81%

	Total Probable Reserves				
Location	**Oil & NGL MMbbl**	**SCO[1] MMbbl**	**Bitumen[2] MMbbl**	**Natural Gas Bcf**	**Oil Equivalent[3] MMbbl**
Mining		524			524
In Situ		397	1,344		1,741
NACO[4]	2			117	22
Total GLJ Coverage	2	921	1,344	117	2,287
Total Company Reserves[5]	246	1,100	1,344	830	2,828
Portion of Total Covered by GLJ	1%	84%	100%	14%	81%

Notes:

1. Synthetic Crude Oil; liquid sales volumes after upgrading
2. portion of the in-situ bitumen production not forecast to be upgraded
3. Oil equivalence factors: Oil& NGL, SCO and Bitumen 1 bbl/bbl, Natural Gas 6 Mcf/bbl
4. North America Conventional Onshore; 97% evaluated, with balance reviewed
5. supplied by the company to derive portion of total covered by GLJ

SCHEDULE “F”

REPORT OF SPROULE ASSOCIATES LIMITED

Ref.: 0468.17530

March 5, 2010

The Board of Directors of Suncor Energy Inc.
Suncor Energy Inc.
P.O. Box 38
112 Fourth Avenue SW
Calgary AB T2P 2V5

**Re: Evaluation of Certain Petroleum & Natural Gas Reserves of Suncor Energy Inc.
(As of December 31, 2009)**

Dear Sirs:

At your request, we have independently evaluated certain proved and probable oil, natural gas, and natural gas liquids reserves of Suncor Energy Inc. ("Suncor"), as of December 31, 2009, in the properties located in the following regions:

East Coast, Canada;
North America Conventional Onshore; and
In Situ, Canada.

The purpose of this report is to summarize the results of our independent evaluations, to be included as an exhibit for Suncor's annual filings in accordance with U.S. and Canadian security laws and pursuant to the Securities and Exchange Commission ("SEC"), Modernization of Oil and Gas Reporting; Final Rule, December 31, 2008.

Summary of Conclusions

Our evaluation of these reserves was conducted during the period of September 2009 through January 2010. The results of our work are summarized in Table 1.

**Table 1
Summary of Reserves Evaluated by Sproule
As of December 31, 2009**

Geographical Area	Company Net Proved Reserves (After Royalty)					
	Oil & NGLs	SCO	Natural Gas	Total BOE	Portion Evaluated	Portion Reviewed
	MMbbl	MMbbl	Bcf	MMbbl	%	%
East Coast	67	0	0	67	100	0
North America Conventional Onshore	38	0	913	190	100	0
In Situ	0	160	0	160	100	0
Total	**105**	**160**	**913**	**417**		
Grand Total Suncor*	**294**	**2565**	**1692**	**3552**		
Proportion of Total Suncor Reserves	**36%**	**6%**	**54%**	**12%**		

Geographical Area	Company Net Probable Reserves (After Royalty)					
	Oil & NGLs	SCO	Natural Gas	Total BOE	Portion Evaluated	Portion Reviewed
	MMbbl	MMbbl	Bcf	MMbbl	%	%
East Coast	99	0	0	99	100	0
North America Conventional Onshore	13	0	376	76	100	0
In Situ	0	179	0	179	100	0
Total	**112**	**179**	**376**	**354**		
Grand Total Suncor*	**246**	**1100**	**830**	**2828**		
Proportion of Total Suncor Reserves	**46%**	**16%**	**45%**	**13%**		

* provided by Suncor

Assumptions, Data, Methods & Procedures

This report has been prepared by Sproule Associates Limited ("Sproule") using current geological and engineering knowledge, techniques and computer software. It has been prepared within the Code of Ethics of the Association of Professional Engineers, Geologists and Geophysicists of Alberta ("APEGGA"). For this evaluation, Sproule used the reserves evaluation model, Value Navigator (ValNav). This report adheres, in all material aspects, to the SEC, Modernization of Oil and Gas Reporting; Final Rule, December 31, 2008. Sproule used the methods and procedures that it considered necessary to prepare this report, as follows:

Reserves and Production

The oil and natural gas reserves were estimated volumetrically, from production decline curve analyses, using analogy techniques, or by material balance methods. Volumetric reserves were estimated using the net pay encountered at the wellbore and an assigned drainage area, or, where sufficient well data were available, using reservoir volumes calculated from isopach maps of net pay. Reservoir rock and fluid property data were obtained from available core analyses, well logs, PVT data, gas analyses, and published information, either from the pool in question or from a similar reservoir producing from the same zone. Reservoir pressures were derived from drillstem and AOF test data, pressure surveys, and published reports. Recovery factors for oil reserves were selected either from the results of detailed reservoir analyses, or by comparing the reservoir under study with similar reservoirs that have more firmly established recovery factors from extended production histories. Recovery factors for gas reserves were estimated by taking into consideration well depths, deliverability characteristics, product prices, and operating cost information.

The solution gas reserves were estimated based on current producing gas-oil ratios (GORs) and estimates of future oil production or volumetric calculations. Similarly, the natural gas by-product reserves were based on current recoveries and estimates of future gas production.

Forecasts of net revenue were prepared by predicting annual production from the reserves, and product prices. Annual production was forecast taking into account historical production trends of Suncor's producing wells, applicable regulatory conditions, existing or anticipated contract rates, and by comparison with other wells in the vicinity producing from similar reservoirs.

Historical Data, Interests and Burdens

All historical production, revenue and expense data, product prices actually received, and other data that were obtained from Suncor or from public sources, were accepted as represented, without any further investigation by Sproule Associates Limited.

Property descriptions, details of interests held, and well data, as supplied by Suncor, were accepted as represented. No investigation was made into either the legal titles held or any operating agreements in place relating to the subject properties.

Lessor and overriding royalties and other burdens were obtained from Suncor. No further investigation was undertaken by Sproule Associates Limited.

Operating Expenses

Suncor provided Sproule with recent revenue statements to determine certain economic parameters.

Capital Expenses

Capital expenses were based the capital program provided by Suncor, or on estimates by Sproule.

Abandonment

Well abandonment and disconnect costs were included for the North American Conventional Onshore and the In Situ properties. For these areas, our evaluation does not include well-site or facility reclamation costs. No abandonment costs were incorporated by Sproule for the East Coast property.

Economic Assumptions

This evaluation utilized constant prices and costs which were consistent with the new SEC guidance, which incorporates a twelve month average pricing mechanism. The prices used were supplied by Suncor, reviewed by Sproule for reasonableness and were accepted as represented.

Regulatory Considerations

In the conduct of our evaluation, we reviewed the ability of the booked reserves to be developed, produced and/or recovered based on current regulations existing in the jurisdictions where the assets reside. This review yielded no concerns with respect to Suncor's ability to develop, produce and/or recover the reserves as booked in the selected entities reported and reviewed. Down-spacing requirements or plans have already been approved or have significant offsetting precedents to indicate that such down-spacing requirements have a high degree of certainty to be approved when applied for.

Uncertainties of Forward-Looking Statements & Reserves Estimates

This report contains forward-looking statements including or incorporating expectations of future production revenues and capital expenditures. Information concerning reserves may also be deemed to be forward-looking as estimates involve the implied assessment that the reserves described can be profitably produced in future. These statements are based on current expectations that involve a number of risks and uncertainties, which could cause actual results to differ from those anticipated. These risks include, but are not limited to: the underlying risks of the oil and gas industry (i.e., corporate commitment, regulatory approval, operational risks in development, exploration and production); potential delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of reserves estimations; the uncertainty of estimates and projections relating to production; costs and expenses; health, safety and environmental factors; commodity prices; and exchange rate fluctuation.

The analysis of individual entities and properties as reported herein was conducted within the context and scope of an evaluation of a unique group of properties in aggregate. Use of this report outside of this scope may not be appropriate.

Actual future production may require that estimated trends be significantly altered. Reserve estimates from volumetric calculations and from analogies are often less certain than reserve estimates based on well performance obtained over a period during which a substantial portion of the reserves was produced.

The accuracy of reserves estimates and associated economic analysis is, in part, a function of the quality and quantity of available data and of engineering and geological interpretation and judgment. Given the data provided at the time this report was prepared, the estimates presented herein are considered reasonable. However, they should be accepted with the understanding that reservoir and financial performance subsequent to the date of the estimates may necessitate revision. These revisions may be material.

No limitations and/or restrictions were placed upon Sproule by the officials of Suncor in our independent reserves evaluation.

Sproule has no responsibility to update this evaluation for events and circumstances occurring after the date of this report.

Suncor provided all technical data, revenue and expense statements, budget and development strategy prior to December 31, 2009. Any information with a date of occurrence after December 31, 2009 was not considered in the evaluation.

Evaluator's Qualifications

The people primarily responsible for the evaluation were Doug W.C. Ho, P.Eng., VP Engineering – Unconventional; Matthew J. O'Blenes, P.Eng, Senior Associate – Canada; Scott W. Pennell, P.Eng., Supervisor – Unconventional Gas; and Cameron P. Six, P.Eng., Manager Engineering – Canada. Sproule's executive endorsement of the Report was provided by R. Keith MacLeod, P.Eng., President. The persons responsible for the preparation of the report are qualified reserves evaluators and auditors and are completely independent from Suncor in accordance with National Instrument 51-101.

Exclusivity

This report is solely for the information of Suncor and for the information and assistance of its independent public accountants in connection with their review of, and report upon, the financial statements of Suncor. Also, Sproule hereby provides permission for this report to be included as an exhibit for Suncor's annual filings in accordance with applicable U.S. and Canadian securities laws. This report should not be used, circulated or quoted for any other purpose without the express written consent of the undersigned or except as required by law. Our work papers and data are in our files and available for review upon request.

If you have any questions regarding the above, or if we can be of further assistance, please call us.

Certification

Report Preparation

The report entitled "Evaluation of Certain Reserves of Suncor Energy Inc., (As of December 31, 2009)" was prepared by the following Sproule personnel:

"Doug W. C. Ho"

Doug W. C. Ho, P.Eng.
Vice-President, Engineering – Unconventional
05 / 03 /2010 dd/mm/yr

"Matthew J. O'Blenes"

Matthew J. O'Blenes, P.Eng.
Senior Associate
05 / 03 /2010 dd/mm/yr

"Scott W. Pennell"

Scott W. Pennell, P.Eng.
Supervisor, Unconventional Gas
05 / 03 /2010 dd/mm/yr

"Cameron P. Six"

Cameron P. Six, P.Eng.
Manager, Engineering – Canada
05 / 03 /2010 dd/mm/yr

Sproule Executive Endorsement

This report has been reviewed and endorsed by the following Executive of Sproule:

"R. Keith MacLeod"

R. Keith MacLeod, P.Eng.
President
05 / 03 /2010 dd/mm/yr

Permit to Practice

Sproule Associates Limited is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta and our permit number is P00417.

Enclosure(s)
MJO-RKM
P:\Suncor 17530 WC 2009\Report – SEC summary all Regions\Suncor 2009 Summary for SEC March 5 2010.doc

SCHEDULE "G"

REPORT OF RPS ENERGY LTD.

RPS Energy

Goldsworth House, Denton Way, Goldsworth Park, Woking, Surrey, GU2I 3LG, United Kingdom
T +44 (0)1483 746500 **F** +44 (0)1483 746505 **E** rpsenergy@rpsgroup.com **W** www.rpsgroup.com

March 5, 2010 Project Ref: ECV1516

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

To: The Board of Directors of Suncor Energy Inc.

INDEPENDENT EVALUATION AND REVIEW OF SUNCOR ENERGY'S RESERVES AS OF DECEMBER 31, 2009

At the request of Suncor Energy Inc. ("Suncor"), RPS Energy ("RPS") evaluated Suncor's reserves of oil, natural gas and natural gas liquids (NGLs), in selected "International" oil and gas properties, as of 31st December, 2009. In addition, RPS carried out a review of Suncor's estimates of its reserves of oil, natural gas and natural gas liquids (NGLs) in its remaining "International" oil and gas properties. This letter summarizes the context, performance and findings of the RPS evaluation and review.

Context of Evaluation and Review

Suncor is a Canadian company which has securities that are traded on the Toronto Stock Exchange (TSX) and on the New York Stock Exchange (NYSE). Therefore, it must comply with Canadian securities laws, and is also subject to securities laws of the United States.

Canada's National Instrument 51-101 (NI 51-101), "Standards for Disclosure for Oil and Gas Activities", sets out Suncor's reserves reporting requirements. Suncor has applied for an exemption and received approval to disclose reserves in accordance with US Securities and Exchange Commission (SEC) rules (effective December 28, 2009; in effect for 1 year):

- Citation: Suncor Energy Inc., Re. 2009 ABASC 571 Date: 20091116

Although Suncor uses its own staff to prepare some of its reserves estimates, its internal corporate governance practices require that independent qualified reserves evaluators or auditors must be used to confirm the quality of the company's reserves evaluation policies, practices and procedures. The objective of these activities is to provide the management and directors of Suncor with assurance that the reserves which have been estimated internally are materially correct.

Suncor has specified that for the year ending December 31, 2009 three of its "International" fields would be evaluated by an independent qualified reserves evaluator; for the remainder of its "International" fields the reserves have been evaluated by Suncor, with the results being reviewed by the independent qualified reserves evaluator. It is in this context, that RPS was retained by Suncor to evaluate the company's reserves in the selected properties, as of December 31, 2009, and to review the company's own estimates of reserves in the remaining"International" properties.

Suncor's "International"properties fall into two Geographical Areas ("North Sea" which covers the UK and Netherlands and "Other International"; which covers Libya, Syria and Trinidad & Tobago), and we understand from Suncor Energy that these properties represent approximately 7% of Suncor Energy's Net After Royalty reserves (when expressed as barrels of oil equivalent).

Applicable Reserves Definitions

As of the 1st of January 2010 the SEC has issued new rules governing reporting oil and gas producing activities for companies with a financial year ending on or after December 31, 2009. RPS has used the following documents to interpret these rules and referenced collectively as SEC Rules 2009:

a) Modernization of Oil and Gas Reporting (29/12/08)
http://www.sec.gov/rules/final/2008/33-8995.pdf

b) Compliance and Disclosure Interpretations (26/10/09)
http://www.sec.gov/divisions/corpfin/guidance/regs-kinterp.htm

c) Staff Accounting Bulletin No 113 (29/10/09)
http://www.sec.gov/interps/account/sab113.htm

The reported reserve volumes evaluated by RPS have been estimated in accordance with the standards set out in those documents.

The reported reserve volumes evaluated by Suncor have been reviewed by RPS against the same standards, and the reserves are determined in a manner and standard consistent with RPS practice.

Reserve Information

Suncor provided RPS with (i) access to basic data and documentation pertaining to the "International" oil and gas properties being evaluated by RPS (ii) all Reserve Information prepared by Suncor in respect of its "International" oil and gas fields being reviewed by RPS, and (iii) access to Suncor personnel who might have information relevant to the evaluation or review of such basic data, documentation and Reserve Information.

Conduct of the Evaluation and Review

For the purpose of this Evaluation and Review, RPS's Primary Evaluators were Roy Wikramaratna and Graeme Simpson, whose qualifications are as follows:

- Roy Wikramaratna is a Principal Advisor and manager of the specialist reservoir engineering group at RPS's Winfrith office, with over 30 years experience in oil reservoir engineering and groundwater resource evaluation. He is a Member of the Energy Institute (MEI) and a Chartered Engineer (registration 569043) registered with the Engineering Council, UK.

- Graeme Simpson is a Director of RPS, with over 30 years of experience in exploration and production geoscience, with a major operator, in academia and through consultancy. He has a PhD in Geology. He is a Certified Petroleum Geologist (number 5926) with the American Association of Petroleum Geologists and a Chartered Geologist. He is a member of the SPEE, and chairs the SPEE European Chapter.

RPS carried out its evaluation and reviews in accordance with generally accepted petroleum engineering and evaluation principles as set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers ("SPE Standards"). The evaluations undertaken by RPS used a mix of performance based and volumetric methods as judged appropriate for each particular accumulation for the purposes of this report.

Our examination included such tests and procedures as we considered necessary under the circumstances to render the opinion set forth herein.

We are independent with respect to Suncor Energy as provided in the SPE Standards.

It should be understood that the RPS evaluation and review does not constitute a complete reserve study of the oil and gas properties of Suncor Energy. In the conduct of our report, we have not independently verified the accuracy and completeness of information and data furnished by Suncor Energy with respect to ownership interests, oil and gas production, costs of operation and development, product prices, and agreements relating to current and future operations and sales of production.

If, in the course of our examination the validity or sufficiency of any of information or data was brought into question, we did not rely on such information or data until we had satisfactorily resolved our concerns thereto or had independently verified such information or data.

Throughout its work, RPS endeavoured to reconcile with Suncor any differences of opinion that it may have held with Suncor on the estimates of reserves.

Key Findings of Evaluation and Review

RPS have carried out independent evaluations of proved reserves and probable reserves for three of Suncor's "International" fields, and have undertaken reviews of Suncor's internal evaluations for the remaining Suncor "International" fields. The results of these evaluations and reviews are summarised in Table 1 (for Net After Royalty Reserves), which show the resulting proved reserves and probable reserves (for Oil and NGL combined and for Gas) by geographic area. The proved reserves and probable reserves for each of the individual fields evaluated by RPS have been evaluated in accordance with the SEC Guidance detailed above under "Applicable Reserves Definitions"; reviews carried out by RPS for fields evaluated by Suncor have been undertaken against the same SEC Guidance. The estimated reserves for the individual fields have been summed arithmetically within each geographic area, in accordance with SEC guidance, to give the numbers that have been quoted in Table 1. The percentages of Suncor Energy's total proved reserves (which sum to 3552 MMboe) and probable reserves (which sum to 2828 MMboe), expressed as barrels of oil equivalent, that were evaluated and reviewed by RPS in each category are also shown in Table 1. It should be noted that due to the effects of rounding, the numbers shown in Table 1 might not add up exactly in all cases.

In respect of the fields where the reserves were reviewed, RPS has conducted a high-level assessment of reserves data and information provided by Suncor, supplemented by detailed discussions with Suncor reserves management and other staff, and concluded that the final reserves data were plausible (in the sense defined in the COGE Handbook, Volume 1, section 12.2).

Requested Warranties

In addition to providing the findings of its evaluation and review, RPS makes the following warranties, which were requested of it by Suncor.

(a) Neither RPS, nor its Shareholders and Officers have or have had any direct or indirect interest, nor do they expect to receive any direct or indirect interest in any securities of Suncor.

(b) No limitations and/or restrictions were placed upon RPS by officials of Suncor in its independent evaluations and reviews of the International and Offshore Business Unit Reserves Reported Volumes of Suncor.

(c) There has been no information obtained by RPS from January 1, 2010 to the date of this letter that would have material effect on the various amounts and classifications of reserves reported upon.

(d) RPS consents to this summary report being filed with Suncor's Annual Disclosure Requirements.

Very truly yours,

"Dr. Graeme Simpson"
Dr. Graeme Simpson
Director, Advisory

Attachment

Table 1
Summary of Reserves Evaluated and Reviewed by RPS Energy
(as of December 31, 2009)

Geographical Area	Company Net Proved Reserves (After Royalty)					
	Oil & NGLs	SCO	Natural Gas	Total BOE*	Portion Evaluated	Portion Reviewed
	MMbbl	MMbbl	Bcf	MMbbl	%	%
North West Europe	141	0	29	146	79%	21%
Other International	45	0	387	109	16%	84%
Total	**185**	**0**	**415**	**255**	**52%**	**48%**
Grand Total Suncor**	**294**	**2565**	**1692**	**3552**		
Proportion of Total Suncor Reserves	**63%**	**0%**	**25%**	**7%**		

Geographical Area	Company Net Probable Reserves (After Royalty)					
	Oil & NGLs	SCO	Natural Gas	Total BOE*	Portion Evaluated	Portion Reviewed
	MMbbl	MMbbl	Bcf	MMbbl	%	%
North West Europe	73	0	72	85	71%	29%
Other International	60	0	265	105	8%	92%
Total	**133**	**0**	**337**	**189**	**36%**	**64%**
Grand Total Suncor**	**246**	**1100**	**830**	**2828**		
Proportion of Total Suncor Reserves	**54%**	**0%**	**41%**	**7%**		

* Conversion factors to barrels of oil equivalent: all liquids 1bbl/boe; natural gas 6Mcf/boe=6Bcf/MMboe

** Data provided by Suncor