SUNCOR ENERGY INC
Form 40-F
March 01, 2012

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SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 40-F

(Check One)

o Registration statement pursuant to Section 12 of the Securities Exchange Act of 1934
or
ý Annual report pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934

For fiscal year ended:	December 31, 2011
Commission File Number:	No. 1-12384

SUNCOR ENERGY INC.
(Exact name of registrant as specified in its charter)

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

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

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

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

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

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

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

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

None

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

None

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

ý	Annual Information Form	ý	Annual Audited Financial Statements

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

Common Shares	**As of December 31, 2011 there were 1,558,636,368 Common Shares issued and outstanding**
Preferred Shares, Series A	**None**

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

Yes ý No o

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

Yes o No o

ANNUAL INFORMATION FORM DATED MARCH 1, 2012

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ADVISORIES

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. On August 1, 2009, Suncor completed its merger with Petro-Canada, referred to in this document as the "merger". References to the "Board of Directors" or the "Board" mean the Board of Directors of Suncor Energy Inc., unless the context otherwise requires.

All financial information is reported in Canadian dollars, unless otherwise noted. Production volumes are presented on a working-interest basis, before royalties, unless otherwise noted. Certain amounts in prior years may have been reclassified to conform to the current year's presentation.

References to our 2011 audited Consolidated Financial Statements mean Suncor's audited Consolidated Financial Statements prepared in accordance with Canadian generally accepted accounting principles (GAAP), the notes and the auditors' report, as at and for each year in the two-year period ended December 31, 2011. References to our MD&A mean Suncor's Management's Discussion and Analysis, dated February 23, 2012.

Unless otherwise noted, all financial information has been prepared in accordance with Canadian GAAP, which is within the framework of International Financial Reporting Standards (IFRS).

This AIF contains forward-looking information based on Suncor's current expectations, estimates, projections and assumptions. This information is subject to a number of risks and uncertainties, including those discussed in this document in the Risk Factors section, many of which are beyond the company's control. Users of this information are cautioned that actual results may differ materially. Refer to the Advisory Forward-Looking Information section of this AIF for information on other risk factors and the material assumptions underlying our forward-looking information.

Information contained in or otherwise accessible through Suncor's website www.suncor.com does not form a part of this AIF, and is not incorporated into the AIF by reference.

GLOSSARY OF TERMS AND ABBREVIATIONS

Common Industry Terms

Products

Hydrocarbons are solids, liquids or gas made up of compounds of carbon and hydrogen, in varying proportions.

Crude oil is a mixture of pentanes (lighter hydrocarbons) and heavier hydrocarbons that exists in the liquid phase in reservoirs and remains liquid at atmospheric pressure and temperature. Crude oil may contain small amounts of sulphur and other non-hydrocarbons, but does not include liquids obtained in the processing of natural gas.

> **Bitumen or heavy crude oil** is a naturally occurring viscous mixture, consisting mainly of pentanes and heavier hydrocarbons, which may not be recoverable at a commercial rate in its naturally occurring viscous state through a well without using enhanced recovery methods. After it is extracted, bitumen or heavy crude oil may be upgraded into crude oil and other petroleum products.
>
> **Conventional crude oil** is crude oil produced through wells by standard industry recovery methods.
>
> **Oil sands** are naturally occurring deposits of sand or sandstone, or other sedimentary rocks that contain bitumen.
>
> **Synthetic crude oil** (SCO) is a mixture of hydrocarbons derived by upgrading bitumen from oil sands. SCO 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 synthetic crude oil**, while SCO with higher sulphur content is referred to as **sour synthetic crude oil**.
>
> **West Texas Intermediate** is a type of crude oil used as a benchmark in oil pricing, and is the underlying commodity of futures contracts on the New York Mercantile Exchange (NYMEX).

Natural gas is a mixture of lighter hydrocarbons, which at atmospheric conditions of temperature and pressure is in a gaseous state.

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

Non-associated gas is an accumulation of natural gas in a reservoir where there is no crude oil. **Associated gas** is the gas cap overlying a crude oil accumulation in a reservoir.

Solution gas is natural gas dissolved in crude oil in a reservoir.

Natural gas liquids (NGLs) are 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.

Oil and gas exploration and development processes

Development costs are costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from reserves.

Exploration costs are costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves.

Field is a defined geographical area consisting of one or more pools containing hydrocarbons.

Glory hole is an excavation into the sea floor designed to protect wellhead equipment from icebergs, and which typically contains multiple wellheads.

Reservoir is 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.

Wells:

Development wells are 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.

Dry wells are exploratory or development wells found to be incapable of producing either oil or gas in sufficient quantities to justify the completion as an oil or gas well.

Exploratory wells are drilled in a territory without existing proved reserves, with the intention to discover commercial reservoirs or deposits of crude oil and/or natural gas. Exploratory wells include **appraisal wells**, which are drilled to measure the commercial potential (i.e. size and quality) of a hydrocarbon discovery. Before development, an offshore discovery is likely to need several appraisal wells.

Service wells are drilled or completed for the purpose of supporting production in an existing field, such as wells drilled for observation or wells drilled for the injection of gas or water.

Stratigraphic wells are drilling efforts, geologically directed, to obtain information pertaining to a specific geologic condition, such as **core hole drilling** on oil sands leases, and are usually drilled without the intention of being completed for production.

Production processes

Capacity is the annual average output that may be achieved from a processing facility, such as an upgrader, refinery or natural gas processing plant, under ideal operating conditions and in accordance with current design specifications.

Downstream refers to the refining of crude oil or synthetic crude oil and the selling and distribution of refined products in retail and wholesale channels.

Feedstock generally refers either to i) the bitumen required in the production of synthetic crude oil for the company's oil sands operations; or ii) crude oil and/or other components required in the production of refined products for the company's downstream operations.

In situ or "in place" refers to methods of extracting bitumen or heavy crude oil from deep deposits of oil sands by means other than surface mining.

Overburden is the material overlying oil sands that must be removed before mining, which consists of muskeg, glacial deposits and sand.

Production Sharing Contracts (PSC) are a common type of contract signed between a government and a resource extraction company that states how much of the resource produced each party will receive and which parties are responsible for the development and operation of the resource. An **Exploration and Production Sharing Agreement (EPSA)** is a form of Production Sharing Contract, which also states which parties are responsible for exploration activities.

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

Steam-to-oil ratio (SOR) is a metric used to quantify the efficiency of an in situ oil recovery process, which measures the cubic metres of steam required to produce one cubic metre of oil. The lower the ratio, the higher the efficiency of the use of steam.

Utilization is the average use of capacity, and includes the impact of planned and unplanned facility outages and maintenance. More specifically, **refinery utilization** is the amount of crude oil and natural gas plant liquids run through crude distillation units, expressed as a percentage of the capacity of these units.

Upgrading is the two-stage process by which bitumen or heavy crude oil is converted into synthetic crude oil.

> **Primary upgrading,** also referred to as coking or thermal cracking, heats the bitumen in coke drums to remove excess carbon. The superheated hydrocarbon vapours are sent to fractionators where they condense into naphtha, kerosene and gas oil. Carbon residue, or coke, is removed from the coke drums on short intervals and later sold as a byproduct.
>
> **Secondary upgrading,** a purification process also referred to as hydrotreating, adds hydrogen to, and reduces the sulphur of, primary upgrading output to create sweet synthetic crude oil and diesel.

Upstream refers to the exploration, development and production of conventional crude oil, bitumen or natural gas.

Reserves and resources

Please refer to the Definitions for Reserves Data Tables section of the Statement of Reserves Data and Other Oil and Gas Information in this AIF.

Common Abbreviations

The following is a list of abbreviations that may be used in this AIF:

Measurement		Places and Currencies	
bbl(s)	barrel(s)	U.S.	United States
bbls/d	barrels per day	U.K.	United Kingdom
mbbls/d	thousands of barrels per day	B.C.	British Columbia
mmbbls	millions of barrels		
		$ or Cdn$	Canadian dollars
boe	barrels of oil equivalent	US$	United States dollars
boe/d	barrels of oil equivalent per day	£	Pounds sterling
mboe	thousands of barrels of oil equivalent	€	Euros
mboe/d	thousands of barrels of oil equivalent per day		
mmboe	millions of barrels of oil equivalent		
mcf	thousands of cubic feet of natural gas	Products, Markets and Processes	
mcf/d	thousands of cubic feet of natural gas per day		
mcfe	thousands of cubic feet of natural gas equivalent	WTI	West Texas Intermediate
mmcf	millions of cubic feet of natural gas	WCS	Western Canadian Select
mmcf/d	millions of cubic feet of natural gas per day	NGL(s)	natural gas liquid(s)
mmcfe	millions of cubic feet of natural gas equivalent	LPG	liquefied petroleum gas
mmcfe/d	millions of cubic feet of natural gas equivalent per day	SCO	synthetic crude oil
bcf	billions of cubic feet of natural gas	NYMEX	New York Mercantile Exchange
GJ	gigajoule	TSX	Toronto Stock Exchange
mmbtu	millions of British thermal units	NYSE	New York Stock Exchange
m^3	cubic metres	SAGD	steam-assisted gravity drainage
m^3/d	cubic metres per day	PSC	production sharing contract

km	kilometres	EPSA	exploration and production sharing agreement
MW	megawatts		

Suncor converts certain crude oil and NGL volumes to mmcfe or mmcfe/d on the basis of one bbl to six mcf, and certain natural gas volumes to boe, mboe, mmboe or mboe/d on the same basis. Any figure presented in mcfe, mmcfe, mmcfe/d, boe, boe/d, mboe, mmboe or mboe/d may be misleading, particularly if used in isolation. A conversion ratio of one bbl of crude oil or NGL to six mcf of natural gas is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Conversion Table [1][2]

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

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

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

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 further 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 the issued and outstanding shares on a two-for-one basis.

Pursuant to an arrangement (the Arrangement), which was completed effective August 1, 2009, Suncor amalgamated with Petro-Canada 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 common shares of the continuing Suncor entity for each Petro-Canada common share held and Suncor shareholders received one common share of the continuing Suncor entity for each common share held.

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

Intercorporate Relationships

Material subsidiaries, each of which was owned 100%, directly or indirectly, by the company as at December 31, 2011 are as follows:

Name	Jurisdiction where organized	Description
Canadian operations		
Suncor Energy Oil Sands Limited Partnership	Canada	This partnership holds most of the company's oil sands assets.
Suncor Energy Ventures Partnership	Canada	This partnership was created in 2011 and holds the company's interest in the Syncrude joint venture.
Suncor Energy Products Partnership	Canada	This partnership holds substantially all of the company's Canadian refining and marketing assets.
Suncor Energy Oil & Gas Partnership	Canada	This partnership holds certain upstream Canadian oil and gas assets.
Suncor Energy Joslyn Partnership	Canada	This partnership holds our working interest in the Joslyn joint venture.
Suncor Energy Products Inc.	Canada	A subsidiary of Suncor Energy Inc. that holds interests in the company's energy marketing and renewable energy businesses, and which is a partner of Suncor Energy Products Partnership.

Name	Jurisdiction where organized	Description
Suncor Energy Marketing Inc.	Canada	A subsidiary of Suncor Energy Products Inc. through which the products produced by our upstream North American businesses are marketed. Through this subsidiary, we also administer Suncor's energy trading activities, market certain third-party products, procure crude oil feedstocks and natural gas for our downstream business, and procure and market NGLs and LPG for our downstream business.

Name	Jurisdiction where organized	Description
U.S. operations		
Petro-Canada U.S. Holdings Ltd.	U.S.	A subsidiary of Suncor Energy Inc. that holds the majority of our U.S. interests.
Suncor Energy (U.S.A.) Inc.	U.S.	A subsidiary of Suncor Energy Inc. through which our U.S. refining and marketing operations are conducted.
International operations		
3908968 Canada Inc.	Canada	A subsidiary of Suncor Energy Inc. that holds certain of our international interests.
Suncor Energy UK Holdings Ltd.	U.K.	A subsidiary of 3908968 Canada Inc. that holds certain of our U.K. interests. Formerly Petro-Canada U.K. Holdings Limited.
Suncor Energy UK Limited	U.K.	A subsidiary of Suncor Energy UK Holdings Ltd. through which certain of our operations are conducted in the U.K. Formerly Petro-Canada U.K. Limited.
Petro-Canada Cooperative Holding U.A.	The Netherlands	A subsidiary of 3908968 Canada Inc. that holds certain of our international interests.
Petro-Canada (International) Holdings B.V.	The Netherlands	A subsidiary of Petro-Canada Cooperative Holding UA that holds certain of our international interests.
Petro-Canada Palmyra B.V.	The Netherlands	A subsidiary of Petro-Canada (International) Holdings BV that holds the majority of our interests in Syria.
Petro-Canada Germany GmbH [(1)]	Germany	A subsidiary of Petro-Canada (International) Holdings BV that holds the majority of our interests in Libya.
Petro-Canada Oil (North Africa) GmbH [(2)]	Germany	A subsidiary of Petro-Canada Germany GmbH through which the majority of our Libya operations are conducted.

(1) Subsequent to December 31, 2011, Petro-Canada Germany GmbH changed its name to Suncor Energy Germany GmbH.

(2) Subsequent to December 31, 2011, Petro-Canada Oil (North Africa) GmbH changed its name to Suncor Energy Oil (North Africa) GmbH.

Individually, the company's remaining subsidiaries accounted for (i) less than 10% of the company's consolidated assets as at December 31, 2011, and (ii) less than 10% of the company's consolidated sales and operating revenues for the fiscal year ended December 31, 2011. In aggregate, the remaining subsidiaries accounted for less than 20% of each of (i) and (ii) described above.

GENERAL DEVELOPMENT OF THE BUSINESS

Overview

Suncor is an integrated energy company, with corporate headquarters in Calgary, Alberta, Canada. We are strategically focused on developing one of the world's largest petroleum resource basins Canada's Athabasca oil sands. In addition, we explore for, acquire, develop, produce and market crude oil and natural gas in Canada and internationally, and we transport and refine crude oil, and market petroleum and petrochemical products primarily in Canada. Periodically, we market third-party petroleum products. We also carry on energy trading activities focused principally on the marketing and trading of crude oil, natural gas, refined products and byproducts.

Suncor has classified its operations into the following segments:

OIL SANDS

Suncor's Oil Sands segment, with assets located in northeast Alberta, recovers bitumen from mining and in situ operations and upgrades the majority of this production into refinery feedstock, diesel fuel and byproducts. The Oil Sands segment includes:

Oil Sands operations refers to Suncor's wholly owned and operated mining, extraction, upgrading and in situ assets in the Athabasca oil sands region. Oil Sands activities consist of:

Oil Sands Base operations include the Millennium and Steepbank (including the North Steepbank Extension) mining and extraction operations, two integrated upgrading facilities known as Upgrader 1 and Upgrader 2, and the associated infrastructure for these assets including utilities, energy and reclamation facilities, such as Tailings Reduction Operations (TRO_{TM}) assets.

In Situ operations include oil sands bitumen production from Firebag and MacKay River and supporting infrastructure, such as central processing facilities and cogeneration units. The majority of In Situ production is upgraded by Oil Sands Base; however, the company's marketing plan includes sales of bitumen when marketing conditions are favourable or as operating conditions at Oil Sands Base require.

Oil Sands Ventures includes the company's interests in significant growth projects, including two where Suncor is the operator the Fort Hills mining (40.8%) and the Voyageur upgrader (51%) projects, and one where Total E&P Canada Ltd. (Total E&P) is the operator the Joslyn mining project (36.75%). Oil Sands Ventures also includes the company's 12% interest in the Syncrude oil sands mining and upgrading joint venture.

EXPLORATION AND PRODUCTION

In January 2011, Suncor combined its International and Offshore and Natural Gas segments into the Exploration and Production segment, which consists of offshore operations off the east coast of Canada and in the North Sea, and onshore operations in North America, Libya and Syria.

East Coast Canada operations include Suncor's 37.675% working interest in Terra Nova, for which Suncor is the operator. Suncor also holds a 20% interest in the Hibernia base project and a 19.5% interest in the Hibernia Southern Extension Unit (HSEU), a 27.5% interest in the White Rose base project and a 26.125% interest in the White Rose Extensions, and a 22.729% interest in Hebron, all of which are operated by other companies.

International operations include Suncor's 29.89% working interest in Buzzard and a 26.69% interest in the Golden Eagle Area Development (Golden Eagle) both of which are operated by another company in the U.K. portion of the North Sea. Suncor also holds interests in several North Sea licences offshore the U.K. and Norway. Suncor owns, pursuant to a Production Sharing Contract, an interest in the Ebla gas development in the Ash Shaer and Cherrife areas in Syria. Suncor also owns, pursuant to Exploration and Production Sharing Agreements, working interests in the exploration and development of oilfields in the Sirte Basin in Libya.

Due to recent unrest in both countries, the company has declared force majeure under its contractual obligations in Libya and Syria. Operations in Libya are in the process of restarting, while operations in Syria have been suspended indefinitely.

North America Onshore operations include Suncor's interests in a number of assets in Western Canada, which primarily produce natural gas.

REFINING AND MARKETING

Suncor's Refining and Marketing segment consists of two primary operations:

Refining and Product Supply operations refine crude oil into a broad range of petroleum and petrochemical products. Eastern North America operations include refineries located in Montreal, Quebec and Sarnia, Ontario, and a lubricants business located in Mississauga, Ontario that manufactures, blends and markets products worldwide. Western North America operations include refineries located in Edmonton, Alberta and Commerce City, Colorado. Other assets include interests in a petrochemical plant, pipelines and product terminals in Canada and the U.S.

Downstream **Marketing** operations sell refined petroleum products and lubricants to retail, commercial and industrial customers through a combination of company-owned, branded-dealer and other retail stations in Canada and Colorado, a nationwide commercial road transport network in Canada, and a bulk sales channel in Canada.

CORPORATE, ENERGY TRADING AND ELIMINATIONS

The grouping **Corporate, Energy Trading and Eliminations** includes the company's investments in renewable energy projects, results related to energy supply and trading activities, and other activities not directly attributable to any other operating segment.

Renewable Energy interests include six operating wind power projects and the St. Clair ethanol plant in Ontario.

Energy Trading activities primarily involve the marketing and trading of crude oil, natural gas, refined petroleum products and byproducts and the use of midstream infrastructure and financial derivatives to optimize related trading strategies.

Corporate includes stewardship of Suncor's debt and borrowing costs, expenses not allocated to the company's businesses, and the company's captive insurance activities that self-insure a portion of the company's asset base.

Intersegment revenues and expenses are removed from consolidated results in **Group Eliminations**. Intersegment activity includes the sale of feedstock by the Oil Sands and Exploration and Production segments to the Refining and Marketing segment, the sale of fuels and lubricants by the Refining and Marketing segment to the Oil Sands segment, the sale of ethanol by the Renewable Energy business to the Refining and Marketing segment, and the provision of insurance for a portion of the company's operations by the Corporate captive insurance entity.

Three-Year History

2009

Economic downturn leads to "safe mode" for key growth projects. In the first quarter of 2009, Suncor placed a number of oil sands projects into safe mode as a result of the downturn in the global economy. Safe mode is the deferral of projects and maintenance of equipment and facilities in a safe manner in order to expedite remobilization when appropriate. The placement and maintenance of projects in safe mode resulted in significant operating expenses in 2009 and 2010, and the ensuing changes to project scheduling resulted in increased capital expenditures when projects were eventually remobilized. As a result of the merger and an improvement in the economy, in 2010, Firebag Stage 3, Firebag Stage 4 and the Millennium Naphtha Unit (MNU) projects were all taken out of safe mode. The Voyageur upgrader project began remobilizing in 2011.

Merger with Petro-Canada. On August 1, 2009, Suncor merged with Petro-Canada, adding approximately 375 mboe/d of upstream production at that time, which included the MacKay River in situ bitumen project, a 12% ownership interest in the Syncrude joint venture, interests in all of the major producing fields offshore Newfoundland and Labrador, interests in several offshore fields in the U.K. and the Netherlands portions of the North Sea, including Buzzard, interests in foreign operations pursuant to PSCs in Syria and Libya, and significant natural gas assets in Western Canada and the U.S. Rockies. Growth assets acquired included the Fort Hills oil sands mining project, other extensive oil sands acreage considered prospective for in situ development of bitumen resources, and interests in other North Sea fields that would eventually become known as Golden Eagle. Downstream assets acquired included the Edmonton and Montreal refineries, a lubricants plant, and the Petro-Canada$_{TM}$ branded network of retail service stations and wholesale cardlock sites. In addition, responsibilities for crude marketing and procurement activities related to Petro-Canada assets were assumed by Suncor's existing Energy Trading business.

Steepbank extraction plant completed. To reduce the distance to the mine face, a new bitumen extraction plant on the east side of the Athabasca River was completed, resulting in improved reliability and bitumen recovery.

Fires at Suncor's upgrading facilities. In December 2009, there was a fire at the company's Upgrader 2 facilities, which were repaired and returned to normal operations in February 2010. In February 2010, there was a fire at our Upgrader 1 facilities, which were repaired and returned to full operations by April 2010.

2010

Disposition of non-core assets. Subsequent to the merger, the company undertook a strategic initiative to sell non-core assets. Throughout 2010, the company completed or entered into agreements for the disposition of non-core assets representing approximately 60 mboe/d of production. This included assets in the U.S. Rockies, the Netherlands portion of the

North Sea, Trinidad and Tobago, the Scott, Telford and Guillemot areas in the U.K. portion of the North Sea, and numerous natural gas packages in Western Canada. Some of these disposals closed in 2011. Additional disposals of non-core North America Onshore assets representing approximately 5.9 mboe/d of 2010 production occurred in 2011.

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

Tailings Reduction Operations (TRO$_{TM}$). Suncor received approval from Alberta regulators to convert from the Consolidated Tailings (CT) management process to TRO$_{TM}$, a process in which mature fine tailings are dried, rather than mixed with sand and other materials to form CT. Suncor expects that TRO$_{TM}$ will allow the company to significantly reduce the area required for tailings management, increase the speed at which it is able to reclaim its tailings ponds and meet the requirements of the Tailings Directive approved by Alberta's Energy Resources Conservation Board (ERCB) in 2009.

Production commences in Syria. Suncor achieved commercial production of natural gas from the Ebla project in April. First oil was later achieved from Ebla in December.

First oil from the White Rose Extensions. In the second quarter, first oil was achieved from the North Amethyst portion of the White Rose Extensions.

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

Transformation of downstream Marketing operations. Suncor rebranded 158 Sunoco$_{TM}$ retail sites to consolidate its post-merger Canadian downstream marketing operations under the Petro-Canada$_{TM}$ brand. Suncor divested 104 retail sites in Ontario to comply with Canadian Competition Bureau requirements relating to the merger.

Suncor announced plans to grow production to one million barrels of oil equivalent per day. In December, Suncor announced that it had entered into agreements with Total E&P. Concurrent with this announcement, Suncor introduced its long-term growth strategy to increase production to over one million boe/d by 2020. Key components of the plan included arrangements with Total E&P for the restart of construction of the Voyager upgrader, and the joint development of the Fort Hills and Joslyn mining projects with the respective joint venture owners of these projects. Other key components of the ten-year growth strategy included continued development of the company's Firebag and MacKay River in situ projects, and investments in, and ongoing production from, international and offshore operations.

2011

Exploration and Production segment created. In January, Suncor announced organizational changes that included the International and Offshore and Natural Gas business divisions merging into a single organization primarily focused on conventional production, which includes both onshore and offshore operations.

Ethanol plant expansion completed. In January, Suncor completed the expansion of its ethanol plant in Ontario that doubled production capacity to 400 million litres per year, making it Canada's largest biofuels production facility.

Operations in Libya temporarily suspended. In response to political unrest and sanctions in Libya in the first quarter, the joint venture operator shut in production, while Suncor suspended all exploration activities and declared force majeure under its EPSAs. The uncertainty about the company's future in Libya caused by these events at that time resulted in the company recording an impairment charge against the company's assets. Sanctions in Libya were eventually lifted upon the transition to a new government, and the joint venture operator was able to restart production from all major producing fields by early January 2012.

Transactions with Total E&P close. After receiving the necessary regulatory approvals, Suncor and Total E&P completed their previously announced transactions. In exchange for net proceeds of $1.820 billion (after closing adjustments) and a 36.75% interest in the Joslyn project, Suncor sold to Total E&P a 49% interest in the Voyageur upgrader and a 19.2% interest in the Fort Hills project.

Largest turnaround in Suncor history. During the second quarter, the company completed safely and on time a turnaround at its Upgrader 2 facilities.

New wind farms commissioned. In May, the eight-turbine, 20-MW Kent Breeze wind power project in southwest Ontario commenced operations. In November, Suncor completed construction of, and initiated full production from, the 55-turbine, 88-MW Wintering Hills project in southern Alberta.

First oil at Firebag Stage 3. In July, Suncor achieved first oil from the first of three well pads at the Firebag Stage 3 expansion. With the ramp up of production from the Stage 3 expansion and the addition of infill wells at Firebag, Suncor's In Situ production surpassed 100,000 bbls/d of bitumen for the first time in the fourth quarter.

Development of Golden Eagle approved. In the third quarter, the field development plan for Golden Eagle was approved. The company anticipates first production late in 2014 or early 2015.

North Steepbank Extension. In December, the company started mining ore from the North Steepbank Extension (NSE) at its Oil Sands Base operations. The opening of this new mine extension enables Suncor to access additional oil sands ore, decrease overall haul distances and decrease mine congestion.

Operations in Syria suspended. In December, sanctions were introduced that resulted in Suncor declaring force majeure under its contractual obligations and suspending its operations in Syria. Consequently, the company has ceased recording all production and revenue associated with its Syrian assets.

Systems integration project completed. During the year, the company integrated Exploration and Production and Refining and Marketing assets acquired in the merger onto a common information systems platform. Oil Sands and Corporate assets were integrated during 2010.

2012

Chief Executive Officer Rick George to retire. Suncor's long-standing chief executive officer (CEO) announced his plan to retire after more than 20 years leading the company. Steve Williams, Suncor's chief operating officer (COO), was appointed president and a member of the company's Board of Directors, and will assume the role of CEO upon Mr. George's retirement in May 2012.

NARRATIVE DESCRIPTION OF SUNCOR'S BUSINESSES

Oil Sands

For a discussion of environmental and other regulatory conditions, and competitive conditions and seasonal impacts affecting our Oil Sands segment, refer to the Industry Conditions and Risk Factors sections of this AIF.

Oil Sands Base Operations

Our integrated Oil Sands Base operations, located near Fort McMurray, Alberta, involve numerous activities:

Mining and Extraction

After overburden is removed, open-pit mining operations use shovels to excavate the oil sands bitumen ore, which is trucked to sizers and breaker units that reduce the size of the ore, then create a slurry of hot water, rock, sand and bitumen. The slurry is delivered via a hydrotransport pipeline to extraction plants. The raw bitumen is separated from the slurry using a hot water process that creates a bitumen froth. Naphtha is added to the bitumen froth to form a diluted bitumen, which is subsequently sent to a centrifuge plant that removes most of the remaining impurities and minerals.

Upgrading

After the diluted bitumen is transferred to upgrading facilities, the naphtha is removed and recycled to be used again as diluent. Bitumen is upgraded through a coking and distillation process. The upgraded product, referred to as sour SCO, is either sold directly to customers or upgraded further into sweet SCO by removing sulphur and nitrogen using a hydrotreating process. In addition to sweet and sour SCO, upgrading processes also produce diesel, naphtha, kerosene and gas oil.

Utilities

Process water is used in extraction processes and then recycled. Steam and electricity are generated through facilities on site. Steam required for operations is generated by a cogeneration unit or coke-fired boilers. Electricity is generated by turbine generators, some of which are part of the cogeneration unit. Excess energy produced is sold back to the power grid; however, during peak periods, Suncor purchases additional electricity from the grid.

Maintenance

In the normal course of our operations, we regularly conduct planned maintenance events at our facilities. Large planned maintenance events, which require units to be taken offline to be completed, are often referred to as turnarounds. Turnaround maintenance provides opportunities for both preventive maintenance and capital replacement, which are expected to improve reliability and operational efficiency. Planned maintenance events generally occur on routine cycles, determined by historical operating performance, recommended usage factors or regulatory requirements. A turnaround typically involves shutting down the unit, inspecting it for wear or other damage, repairing or replacing components, and then restarting the unit.

Reclamation

Mining processes disturb areas of land that must be reclaimed. Land reclamation activities involve monitoring soil salvage and replacement, wetlands research, fish, waterfowl and other wildlife protection, and re-vegetation.

The extraction process produces tailings that are a mixture of water, clay, sand and residual bitumen. Suncor has developed a new tailings management approach, known as TRO$_{TM}$, which involves converting tailings more rapidly into a solid landscape suitable for reclamation. In this process, mature fine tailings are mixed with a polymer flocculent and then deposited in thin layers on shallow slopes. The resulting product is a dry material that is capable of being reclaimed in place or moved to another location for final reclamation. The new process is expected to eliminate the need for new tailings ponds at existing mining operations, improve tailings management going forward and, in the years ahead, reduce the number of tailings ponds presently in operation.

Oil Sands Base Assets

Mining and Extraction

Suncor pioneered the commercial development of the Athabasca oil sands beginning in 1962. The original mining area is essentially depleted, and, for several years, bitumen has been mined almost exclusively from the Millennium area, which began production in 2001. During 2011, the company mined approximately 160 million tonnes from Millennium, and started mining ore from the NSE.

Suncor currently operates two extraction plants, the second of which was brought into service during 2009. The original extraction plant on the west side of the Athabasca River is operated only as required to support reclamation activities. During 2011, Suncor averaged processing 289,000 bbls/d of mined bitumen ore in its extraction facilities.

Upgrading

Suncor's upgrading facilities consist of two upgraders Upgrader 1, which has a primary upgrading capacity of 110,000 bbls/d of SCO, and Upgrader 2, which has a primary upgrading capacity of 240,000 bbls/d of SCO. When the MNU is fully commissioned, Suncor's secondary upgrading facilities will consist of three hydrogen plants, three naphtha hydrotreaters, two gas oil hydrotreaters and two diesel hydrotreaters.

During 2011, Suncor averaged 279,700 bbls/d of upgraded bitumen (SCO) production and an additional 25,000 bbls/d of non-upgraded bitumen production (2010 251,400 bbls/d upgraded, 31,600 bbls/d non-upgraded).

Other Mining Leases

Suncor owns several other oil sands leases, including those known as Voyageur South and Audet, which it believes can be developed using mining techniques and on which it undertakes modest exploratory drilling programs on a year-to-year basis.

In Situ Operations

Suncor's In Situ operations, Firebag and MacKay River, use SAGD technology to separate bitumen from oil sands deposits that are too deep to be mined economically and primarily provide additional bitumen to Oil Sands Base upgrading facilities.

The SAGD process

The SAGD process drills pairs of horizontal wells with one located above the other. To help reduce land disturbance and improve cost efficiency, well pairs are drilled from central multi-well pads. Steam is injected into the upper well to create a high-temperature steam chamber underground. This process reduces the viscosity of the thick bitumen, allowing heated bitumen and condensed steam to drain into the bottom well and flow up to the surface aided by subsurface pumps or circulating gas. Typically, it takes 18 to 24 months for the steam chamber to reach conditions that support peak production levels.

Central processing facilities

The bitumen and water mixture is pumped to separation units at central processing facilities, where the water is removed from the bitumen, treated and recycled for use in steam generation. To facilitate transportation of viscous bitumen, In Situ operations add diluent (naphtha) or use an insulated (referred to as "hot") bitumen pipeline.

Steam generation

Gas vapours recovered at central processing facilities are treated and used as fuel to power Once Through Steam Generators. Cogeneration units are energy efficient systems, which use natural gas combustion to power turbines that generate electricity and steam.

Maintenance and feedstock supply

Central processing facilities, steam generation units and well pads are all subject to routine inspection and maintenance cycles.

SAGD production volumes are impacted by reservoir quality and the capacity of central processing facilities and steam generation units to process liquids and generate steam. As with conventional oil and gas properties, SAGD wells will experience natural production declines after several years. Suncor strives to maintain bitumen supply by drilling new wells from existing well pads or by developing new well pads.

New technologies

Suncor is involved in numerous pilot projects, both operated and non-operated. These pilot projects evaluate potential enhancements to existing SAGD operations or potential new technologies targeted at improving capital efficiency and lowering SORs.

<u>In Situ Assets</u>

Firebag

Initial development of Suncor's Firebag operations included two well pads, each with ten well pairs, and central processing facilities for each of Firebag Stage 1 and Stage 2, with production commencing in 2004 and 2006, respectively. A cogeneration unit was added in 2007. The combined processing capacity of these initial Firebag operations was approximately 95,000 bbls/d of bitumen at design SORs of 2.0 to 2.5; however, actual SORs for Firebag have been higher than the design specifications, largely due to geological heterogeneity (inconsistent quality throughout the reservoir). Prior to first oil from the Stage 3 expansion, production averaged between 50,000 to 60,000 bbls/d for 2010 and 2011. As at December 31, 2011, the cumulative SOR at Firebag was 3.3. As production from the Stage 3 expansion increases, the Firebag SOR is expected to decrease.

During 2011, the company completed its Firebag Stage 3 expansion, which added three well pads, two cogeneration units and a central processing facility. Commissioning of the cogeneration units is expected to be completed in the first quarter of 2012. The Firebag Stage 4 expansion, scheduled for completion during 2013, includes two well pads, an additional central processing facility and two more cogeneration units. The design capacity for both of the Stage 3 and Stage 4 expansions is 62,500 bbls/d of bitumen. Actual production may vary from this capacity based on steaming and ramp-up periods, scheduled and unscheduled maintenance, reservoir conditions and other factors. Suncor designed the Stage 3 and Stage 4 expansions with the goal of integrating the entire Firebag operation. Steam and electricity generated at one facility or unit can be used at any well pad. Central processing facilities have been designed to be flexible as to which well pads supply bitumen.

Suncor has received regulatory approval for further expansion of Firebag beyond Stage 4 for an aggregate of 368,000 bbls/d of bitumen.

During 2011, Firebag operations averaged production of 59,500 bbls/d of bitumen (2010 53,600 bbls/d), approximately 90% of which was upgraded by Oil Sands Base operations.

MacKay River

Production from MacKay River commenced in 2002 from two well pads with 25 well pairs, and subsequent expansion phases added four more well pads with 31 producing well pairs. Starting in June 2011, a new phase of 22 well pairs was initiated, with production coming on-stream in the fourth quarter of 2011 and continuing to build throughout 2012. Central processing facilities have a nameplate capacity of approximately 30,000 bbls/d of bitumen. A third party owns and operates the on-site cogeneration unit in return for a fee and natural gas fuel being purchased by Suncor. As at December 31, 2011, the cumulative SOR at MacKay River was 2.5.

Suncor has regulatory approval for 73,000 bbls/d of bitumen production from MacKay River and is currently evaluating an expansion to add a second central processing facility. Suncor has approval to include its Dover properties in the MacKay River project area, and has submitted an application to develop a portion of these lands.

During 2011, MacKay River operations averaged production of 30,000 bbls/d of bitumen (2010 31,500 bbls/d), approximately 30% of which was upgraded by Oil Sands Base operations.

Other In Situ Leases

Suncor owns several other oil sands leases, including those known as Meadow Creek, Lewis, Chard and Kirby, which it believes can be developed using in situ techniques, and on which it may undertake modest exploratory drilling programs on a year-to-year basis.

Oil Sands Ventures Assets and Operations

Syncrude

Suncor holds a 12% interest in the Syncrude joint venture, also located near Fort McMurray, which includes operations at the Mildred Lake North and Aurora North oil sands mines. Syncrude also has regulatory approval to develop the Aurora South oil sands mining leases.

Syncrude began producing in 1978 and is operated by Syncrude Canada Ltd. (SCL). In 2006, SCL entered into a comprehensive management services agreement with Imperial Oil Resources (Imperial Oil) to provide operational, technical and business management services. This agreement has an initial term of ten years and includes renewal provisions.

Syncrude mining operations use truck, shovel and hydrotransport systems, similar to those at Oil Sands Base. Extraction and upgrading technologies at Syncrude are also similar to those used at Oil Sands Base, except that Syncrude uses a fluid coking process that involves the continuous thermal cracking of the heaviest hydrocarbons, as opposed to a delayed coking process. At Mildred Lake, electricity is provided by a utility plant fuelled by off-gas from upgrading operations and natural gas. At Aurora North, Syncrude operates two 80-MW gas turbine power plants. The gross design capacity for Syncrude facilities is approximately 375,000 bbls/d, but when allowances are made for scheduled and unscheduled downtime the gross productive capacity of the facilities is approximately 350,000 bbls/d.

Syncrude primarily produces a single sweet synthetic light crude product. Marketing of this product is the responsibility of the individual joint venture owners.

Land reclamation activities are similar to those at Oil Sands Base; however, tailings management processes are different. Syncrude's ERCB-approved tailings plan uses the following: freshwater capping, a composite tails mixture of fine tails and gypsum, and plans for centrifuge technology that separates water from tailings.

In 2011, Suncor's share of Syncrude production averaged 34,600 bbls/d (2010 35,200 bbls/d).

Voyageur Upgrader, Fort Hills and Joslyn

Oil Sands Ventures also includes assets important to Suncor's long-term growth strategy. During the first quarter of 2011, Suncor completed transactions with Total E&P, which brought Total E&P into the Voyageur upgrader project, increased their working interest in the Fort Hills oil sands mining project and brought Suncor into the Joslyn oil sands mining project.

Fort Hills is the oil sands mining project comprising leases on the east side of the Athabasca River, north of Oil Sands Base operations. Preliminary designs for Fort Hills plan for 164,000 bbls/d of bitumen production (gross). Suncor originally acquired a 60% working interest in Fort Hills as a result of the merger, and then agreed to a partial disposition of 19.2% as part of transactions with Total E&P. Suncor now holds a 40.8% working interest in the Fort Hills project. Suncor Energy Operating Inc., a wholly owned subsidiary of Suncor, is the contract operator for the Fort Hills project. Prior to the merger, the joint venture owners of Fort Hills had completed design basis memorandum engineering in 2008, but deferred a final investment decision as a result of the economic downturn. Subsequent to completing the transactions with Total E&P, the Fort Hills project has restarted design basis memorandum engineering. Total E&P holds a 39.2% working interest in the Fort Hills project and Teck Resources Limited holds the remaining 20%.

Joslyn is the oil sands mining project comprising leases southwest of the Fort Hills project and on the west side of the Athabasca River. Preliminary designs for the Joslyn North mine project plan for 100,000 bbls/d of bitumen production (gross). Suncor acquired a 36.75% working interest in this asset as a result of transactions with Total E&P. Under this joint venture agreement, Total E&P is scheduled to act as operator, holding a 38.25% interest, while Occidental Oil and Gas Corporation (15%) and Inpex Canada Ltd. (10%) hold the remaining interests.

Suncor anticipates that the majority of bitumen production from the Fort Hills and Joslyn projects will be upgraded into SCO and other products by the Voyageur upgrader. Suncor began design work for the Voyageur upgrader in 2004. The original Voyageur program received approval from the Board of Directors in January 2008. The Voyageur upgrader project was placed into safe mode in January 2009 as a result of the economic downturn, at which time construction was approximately 15% complete. Subsequent to the transactions with Total E&P in December 2010, the Voyageur upgrader project team has engaged in activities such as remobilizing personnel and assessing the condition of assets. Preliminary design plans are for 200,000 bbls/d (gross) of upgrading capacity.

The development of each of these projects is still subject to approval by Suncor's Board of Directors and the joint venture owners for each respective project.

Sales of Principal Products

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

For bitumen production from In Situ operations, Suncor's marketing strategy allows it to take advantage of changes in market conditions by either: a) upgrading the bitumen directly at our Oil Sands Base facilities; b) upgrading the bitumen at Suncor's refineries; or c) selling diluted bitumen directly to third parties. Direct bitumen sales may also be required during outages of upgrading facilities or interruptions in pipeline systems. During 2011, 73% (2010 63%) of In Situ bitumen production was processed by Oil Sands Base upgrading facilities.

In 2011, sales of light sweet SCO and diesel represented 44% and sales of light sour SCO and bitumen represented 45% of total Oil Sands segment operating revenues. There were no individual customers that represented 10% or more of Suncor's consolidated revenues in 2011 or 2010.

Operating revenues include sales of non-proprietary volumes purchased from third parties. These volumes are typically transacted when Oil Sands Base or third-party refinery capacities are constrained, in conjunction with a corresponding sales agreement, which allow Suncor and the third party to optimize their logistics. These volumes may also include purchases of third-party diluent to support sales of bitumen, required when the company is unable to meet diluent demands internally.

Information on average daily sales volumes and the corresponding percentage of Oil Sands segment operating revenues by product for each of the last two years are as follows:

Sales Volumes and Operating Revenues Principal Products	2011		2010	
	mbbls/d	% operating revenues	mbbls/d	% operating revenues
Light sweet SCO and diesel (including Syncrude)	144.4	44	137.9	43
Light sour SCO and bitumen	194.6	45	176.6	46
Non-proprietary, byproducts and other operating revenues	n/a	11	n/a	11
	339.0		314.5	

In the normal course of business, Suncor enters into long-term strategic supply agreements for its proprietary sour SCO, which contain varying terms with respect to pricing, volume, expiry and terminations.

Distribution of Products

Production from Oil Sands Base operations is gathered from our Fort McMurray facilities at the Athabasca Terminal, which is operated by Enbridge Inc. (Enbridge). Suncor has various arrangements with Enbridge at this facility to store SCO, diluted bitumen and diesel. Production from Firebag is transported to the Athabasca Terminal via a pipeline that is operated by Suncor, while production from MacKay River is transported to the Athabasca Terminal via an insulated pipeline.

Product moves from the Athabasca Terminal in the following ways:

SCO is sent to Edmonton via the Oil Sands pipeline, which is owned by Suncor and operated by the Refining and Marketing segment. At Edmonton, the product is sold to local refiners or transferred onto the Enbridge Mainline system.

- SCO and diluted bitumen is transported to Hardisty, Alberta via Cheecham, Alberta on the Enbridge Athabasca Pipeline.
- SCO also reaches Edmonton via the Waupisoo pipeline, which is owned and operated by Enbridge. This pipeline begins from the Enbridge Athabasca Pipeline at Cheecham.

From Hardisty, where Suncor has storage capacity under contract, Suncor has various options for delivering product to customers:

- SCO reaches Suncor's Commerce City refinery via the Express and Platte pipelines. Suncor owns and operates a pipeline that is connected to the Commerce City refinery, which originates from the Guernsey, Wyoming station that is part of the Platte pipeline.
- SCO reaches Suncor's Sarnia refinery on the Enbridge Mainline and Lakehead systems.

From Hardisty, which is also connected to the Enbridge Mainline pipeline from Edmonton, crude can reach most major refining hubs via the Enbridge Mainline, Express/Platte and Keystone pipeline systems.

Natural gas is used in the production of SCO, particularly in our SAGD operations. Natural gas is delivered to Oil Sands Base and In Situ facilities via the Nova Gas Transmission Limited (NGTL) regulated pipeline system. Suncor also transports natural gas to our Oil Sands Base facilities on the company-owned and operated Albersun Pipeline, which has a capacity of 46 mmcf/d and extends approximately 300 km south of the Oil Sands Base facilities and is connected to the NGTL.

Oil Sands Base facilities are readily accessible by public road. MacKay River facilities are accessible by a combination of public and private roads. Firebag facilities are currently accessible by air and private road. In 2010, the East Athabasca Highway was constructed to provide access to the Firebag site. This highway is owned by Suncor, Husky Energy Inc. and Imperial Oil Ltd., and was constructed to provide each company with access to its oil sands operations in the area.

Royalty Agreements

New oil sands projects are subject to the New Royalty Framework issued by the Government of Alberta, and regulated by the *Oil Sands Royalty Regulation 2009* (OSRR 2009), and supporting regulations, which were approved on December 10, 2008.

In 2011, Oil Sands royalties (excluding Syncrude) were approximately 7% (2010 7%) of Oil Sands operating revenues before royalties, and excluding non-proprietary sales and sales of byproducts. In 2011, Suncor incurred royalties on Syncrude operations averaging approximately 8% of Syncrude gross revenue (2010 9%).

Oil Sands Base and Syncrude

As part of the New Royalty Framework, Suncor negotiated and entered into the Suncor Royalty Amending Agreement (Suncor RAA) with the Government of Alberta in January 2008 for royalties pertaining to its Oil Sands Base operations. Prior to the New Royalty Framework, Suncor exercised its option to transition to a bitumen-based royalty from an SCO-based royalty, which became effective January 1, 2009. Royalty rates for 2009 remained at 25% of net revenue. For the period from January 1, 2010 to December 31, 2015, royalty rates are based on a sliding scale (depending on the Canadian dollar equivalent for WTI) from 25% to 30% of R-C (Revenue-Cost), where R is gross revenues, net of bitumen quality adjustments and transportation costs, and C is allowable costs including allowable capital expenditures, which excludes substantially all operating and capital expenditures associated with upgrading facilities. The minimum royalty rate is 1.0% to 1.2% of R. In 2011 and 2010, Suncor incurred royalties on Oil Sands Base mining operations at a rate of 30% of R-C because of high prices for WTI.

In November 2008, the Alberta government and the joint owners of the Syncrude joint venture reached an agreement for the implementation of the New Royalty Framework for the Syncrude project (similar to the Suncor RAA). Under the new terms, Syncrude would continue paying the greater of 1% gross revenue, or 25% of net revenue, until the end of 2015. For 2011, the royalty rate was 25% of net revenue. As part of its agreement, Syncrude also exercised its option to transition to a bitumen-based royalty from an SCO-based royalty. As such, the upgrader facility at the Syncrude project is no longer considered a part of the royalty project. The Syncrude joint venture owners agreed to pay an additional royalty of $975 million over a six-year period starting in 2010, which is contingent on achieving certain production levels.

As part of the implementation of the New Royalty Framework, the Alberta government enacted new Bitumen Valuation Methodology (BVM) regulations effective January 1, 2009. These interim BVM regulations determine the valuation of bitumen for 2009 to 2011. Final regulations to establish the BVM calculation for future years are still to be developed by the Crown. For the year 2009, Suncor filed a non-compliance notice with the Crown, citing that reasonable adjustments were not considered by the Crown in the determination of bitumen value as permitted by the Suncor RAA. In December 2010, the Minister of Energy notified Suncor of a modification to the Suncor BVM, permitting adjustments for bitumen quality and transportation. Suncor filed its second non-compliance notice with the Crown, for the years 2009 and 2010, related to the quality adjustment made by the Minister, which Suncor believes is not reasonable. Pursuant to the OSRR 2009, Suncor provided replacement royalty reports for 2009 and 2010 and remitted, under protest, the balance of royalty payable at the end of January 2011. For 2011, Suncor continued to remit royalty payments based on its view of reasonable quality adjustments; however, royalty expense was calculated based on the Minister's quality adjustment. The Suncor RAA provides for an arbitration procedure failing settlement of these issues. Suncor filed a Notice of Commencement of Arbitration with the Crown on January 29, 2011.

The joint venture owners of Syncrude have 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 the Suncor RAA.

Beginning on January 1, 2016, Suncor's Oil Sands Base and Syncrude operations will be subject to the generic royalty regime under OSRR 2009 that is currently in place for all other oil sands royalty projects in Alberta, including Suncor's In Situ operations, as described below.

In Situ

Under the New Royalty Framework, royalties on Suncor's Firebag and MacKay River projects are based on a sliding-scale rate of 25% to 40% of R-C, subject to a minimum royalty of 1% to 9% of R, depending on oil prices for WTI from Cdn$55/bbl to the maximum rate at a WTI price of Cdn$120/bbl. A project remains subject to the minimum royalty (the pre-payout phase) until the project's cumulative gross revenue exceeds its cumulative costs, including an annual investment allowance (the post-payout phase). In 2011, Suncor incurred royalties at a rate of 34% of R-C for MacKay River, which reached the post-payout phase in November 2010, and royalties averaging 6% of R for Firebag, which continues in the pre-payout phase.

Exploration and Production

For a discussion of the environmental and other regulatory conditions, competitive conditions, foreign operations and seasonal impacts affecting our Exploration and Production segment, refer to the Industry Conditions and Risk Factors sections of this AIF.

East Coast Canada Assets and Operations

Based in St. John's, Newfoundland and Labrador, this business focuses on high-volume production from three existing fields, interests in future developments and expansions, and exploration drilling for new opportunities. Suncor holds a unique position as the only company with interests in all current producing fields.

Terra Nova

The Terra Nova oilfield is approximately 350 km southeast of St. John's, Newfoundland. Terra Nova was discovered by Petro-Canada in 1984, and was the second oilfield to be developed offshore Newfoundland and Labrador. Operated by Suncor, the production system uses a Floating Production, Storage and Offloading (FPSO) vessel that is moored on location, and has gross production capacity of 180,000 bbls/d and oil storage capacity of 960,000 bbls. Terra Nova was the first harsh environment development in North America to use a FPSO vessel. Actual production levels are lower than production capacity, reflecting current reservoir capability. Production from Terra Nova began in January 2002. At December 31, 2011, there were 28 wells in operation: 16 oil wells, nine water injection wells and three gas injection wells. Two of the oil wells have been shut in due to hydrogen sulphide (H_2S) flow line restrictions. In 2011, Suncor's share of Terra Nova production averaged 16,200 bbls/d (2010 23,200 bbls/d).

H_2S was detected in several oil wells in the fourth quarter of 2010. Wells and facilities directly and indirectly impacted by H_2S have been shut in while the company implements its mitigation plan to safely address the situation. In the fourth quarter of 2011, the company replaced a flow line that has remediated some of the H_2S issues. Remaining H_2S remediation is anticipated to be completed as part of the dockside maintenance program scheduled to commence in the third quarter of 2012. The dockside maintenance program also includes replacement of the FPSO swivel.

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

Field production is transported by shuttle tanker from the FPSO and either delivered directly to customers (if tanker schedules permit) or to the Newfoundland transshipment terminal in Placentia Bay, where it is subsequently loaded onto tankers for transport to markets in Eastern Canada or the U.S. Suncor has a 14% ownership interest in the transshipment facility and is part of a group of companies that share the operation of marine transportation assets for East Coast Canada.

Hibernia and the Hibernia Southern Extension Unit (HSEU)

The Hibernia oilfield, encompassing the Hibernia and Ben Nevis Avalon reservoirs, is approximately 315 km southeast of St. John's and was the first field to be developed in the Jeanne d'Arc Basin. Operated by Hibernia Management and Development Company Ltd., the production system is a fixed gravity base structure (GBS) that sits on the ocean floor, and has gross production capacity of 230,000 bbls/d and oil storage capacity of 1.3 mmbbls. Actual production levels are lower, reflecting current reservoir capability and natural declines. Hibernia commenced production in November 1997. At December 31, 2011, there were 64 wells in operation: 35 oil wells, 23 water injection wells and six gas injection. In 2011, Suncor's share of Hibernia production averaged 30,900 bbls/d (2010 30,900 bbls/d). Hibernia uses the same transshipment terminal and system of shuttle tankers that are used for Terra Nova.

Final fiscal agreements were signed between the Hibernia joint venture owners and the Government of Newfoundland and Labrador in 2010 that established the fiscal, equity and operational principles for the development of the HSEU. During 2011, the first two development wells were completed and are producing oil. Current development plans include drilling up to two additional producing wells and five water injection wells in a subsea, excavated drill centre, known as a glory hole. The number of producing and injection wells required may be revised as the development proceeds and uncertainties about reservoir capability are resolved.

White Rose and the White Rose Extensions

White Rose, the third oilfield development offshore Newfoundland, is about 350 km southeast of St. John's. Operated by Husky Oil Operations Limited, White Rose uses a FPSO vessel and has gross production capacity of 140,000 bbls/d and oil storage capacity of 940,000 bbls. Production from White Rose began in November 2005. At December 31, 2011, there were 25 wells in operation: twelve oil wells and 13 water injection wells. In 2011, Suncor's share of White Rose production averaged 18,500 bbls/d (2010 14,500 bbls/d). White Rose uses the same transshipment terminal and the same system of shuttle tankers that are used for Hibernia and Terra Nova.

In 2007, the White Rose joint venture owners signed a formal agreement with the Province of Newfoundland and Labrador for the development of the White Rose Extensions, which include the South White Rose Extension, North Amethyst and West White Rose satellite fields. In May 2010, first oil was achieved in North Amethyst, and development drilling is ongoing. Development of the West White Rose Extension will be divided into two stages. The first stage was approved in 2009 and first oil was achieved during the third quarter of 2011 with the completion of the first production well. A water injection well to support this initial production is expected to be completed in the second quarter of 2012. Results of the first stage, combined with other ongoing evaluation, will help define the scope of the second stage.

An extended, 18-week off-station maintenance program is scheduled to commence in the second quarter of 2012 for the White Rose FPSO, primarily to address issues with the FPSO propulsion system.

Hebron

Discovered in 1980, the Hebron oilfield is located 340 km southeast of St. John's. In 2008, the Hebron joint venture owners reached an agreement with the Government of Newfoundland and Labrador on commercial terms allowing development activities to proceed. The project is operated by ExxonMobil Canada Properties.

Development of the Hebron project anticipates the construction of a concrete GBS that supports an integrated topsides deck to be used for production, drilling and accommodations. Development plans include 1.2 mmbbls of oil storage capacity and 52 well slots with a gross oil production capacity of 150,000 bbls/d.

The contract for the front-end engineering and design of topsides, procurement and construction was awarded in September 2010. Initial construction on the GBS began in September 2011 in Newfoundland and Labrador. The decision from the joint venture owners of Hebron to sanction the development of Hebron is anticipated in late 2012, with initial production anticipated in late 2017.

Other Assets

The Ballicatters discovery well, located 22 km northeast of Hibernia, was completed earlier in 2011 and is comprised of gas and oil. Suncor and its partner are currently evaluating potential options to commercialize the discovery.

Suncor continues to pursue opportunities offshore Newfoundland and Labrador. The company holds interests in 48 other significant discovery licences and six other exploration licences offshore Newfoundland and Labrador.

International Assets and Operations

Buzzard North Sea

The Buzzard oilfield is located in the Outer Moray Firth, 95 km northeast of Aberdeen, Scotland. Operated by Nexen Petroleum U.K. Limited, the Buzzard facilities have gross installed production capacity of approximately 220,000 bbls/d of oil and 80 mmcf/d of natural gas. Oil production rates at Buzzard are currently limited to a maximum of approximately 215,000 bbls/d due to restrictions on third-party pipeline systems. Work is ongoing with the pipeline operator to increase the maximum production rate closer to the gross oil production capacity. Buzzard commenced production in January 2007. Buzzard consists of four bridge-linked platforms supporting wellhead facilities, production facilities, living quarters and utilities, and sulphur handling. In 2011, commissioning was completed for the fourth platform, which was installed to remove H_2S from oil production from some segments of the field. At December 31, 2011, there were 40 wells in operation: 29 oil and gas wells and 11 water injection wells. In 2011, Suncor's share of Buzzard production averaged 42,900 boe/d (2010 55,500 boe/d).

Crude oil is transported via the third-party operated Forties Pipeline System to the Kinneil terminal in Scotland. Natural gas is transported via the third-party operated Frigg pipeline to the St. Fergus gas terminal in Scotland.

Golden Eagle North Sea

During 2011, the Golden Eagle Area Development received regulatory approval from the U.K. Department of Energy and Climate Change. This development is approximately 70 km from the Aberdeen shore and consists of the unitization of the Pink, Hobby and Golden Eagle discoveries completed from 2007 to 2009. The development plan incorporates a combined production, utilities and accommodation platform, linked to a separate wellhead platform, with an initial gross production rate of 70,000 boe/d (gross) from 20 development wells. The operator, Nexen Petroleum U.K. Limited, estimates that the gross development cost will be £2 billion (Cdn$3.3 billion). First production is expected late in 2014 or early 2015. The joint venture owners of Golden Eagle also hold adjacent exploration licences and continue to explore the region.

Beta North Sea

In the Norway portion of the North Sea, Suncor is the operator of the Beta discovery. Suncor has a 65% working interest in this field, which is currently under evaluation. The company completed the first exploration well in early 2010, encountering hydrocarbons. An appraisal well was drilled and tested later in 2010 with positive results. Suncor has secured a rig to drill a third appraisal well, which is scheduled to commence in the second quarter of 2012.

Other Assets North Sea

During 2011, the operator for the PL405 licence (in the Norway portion of the North Sea) in which Suncor has a 30% interest, drilled an exploration well resulting in a discovery, referred to as the Butch prospect. A sidetrack well subsequently drilled at this prospect was abandoned early in 2012, due to well instability, before reaching its intended depth. In the U.K. portion of the North Sea, Suncor, as operator, has secured a rig and expects to drill a joint exploration well for the Romeo joint venture prospect (Block 30/11c). The joint well is to be drilled to comply with work commitments for two adjacent licences, one held by Suncor and its co-venturers, and the other by Total E&P U.K. Limited.

In late 2010 and early 2011, the company disposed of non-core assets in the U.K portion of the North Sea, including its working interests in production from the Guillemot and Scott/Telford areas. Also, in August 2010, the company disposed of non-core assets in the Netherlands portion of the North Sea.

Syria

Located in the Central Syrian Gas Basin, the Ebla project includes all hydrocarbons in the Ash Shaer and Cherrife development areas, which cover more than 300,000 acres. Suncor conducts its Syrian operations pursuant to a PSC, under which the company is a joint owner of the Ebla project with the General Petroleum Corporation (GPC). Under the PSC, the company pays 100% of the development costs and recovers these costs from a 40% share of production after deduction for royalties of 12.5%. This petroleum revenue is referred to as Cost Recovery petroleum. The amount by which Cost Recovery petroleum exceeds recoverable cost is referred to as Excess Cost Recovery petroleum; 50% of this amount is due to the GPC and the remaining 50% is shared between Suncor and the GPC according to a profit-sharing schedule. The Ebla PSC expires in April 2035, but includes a five-year extension subject to GPC approval. First commercial gas production from Ebla was achieved in April 2010 and first oil was achieved in December 2010. In 2011, Suncor's share of production in Syria averaged 17,600 boe/d (2010 11,600 boe/d).

The Ebla development comprises six natural gas producing wells in the Ash Shaer field, a gas gathering and compression station, approximately 80 km of pipeline, and a gas treatment plant. The facility is designed to produce 97 mmcf/d of natural gas, along with related LPG and condensate volumes. Natural gas is delivered into the Syrian national gas grid for domestic consumption. The Ebla development also includes three wells producing crude oil, which is sold to the GPC.

In December 2011, amid continuing unrest in Syria, sanctions were introduced and Suncor declared force majeure under its contractual obligations and suspended its operations in the country. Suncor withdrew its expatriate staff and undertook measures to maintain support for its Syrian employees. Consequently, the company has ceased recording all production and revenue associated with its Syrian assets.

Libya

In Libya, Suncor acts pursuant to several EPSAs that enable Suncor and the Libya National Oil Corporation (NOC) to jointly design and implement the redevelopment of existing fields in the Sirte Basin. Existing reserves are associated with five separate agreements (EPSAs I through V), which contain five primary production fields. Under the EPSAs, the company pays 100% of the exploration costs, 50% of the development and 12% of the operating costs, and recovers these costs from a 12% share of production, also referred to as Cost Recovery. Any petroleum remaining after Cost Recovery is referred to as Excess Petroleum, and is shared between Suncor and the NOC based on a profit-sharing schedule affected by several factors, with Suncor's share of profit ranging from 4% to 12%. The EPSAs expire on December 31, 2032, but include an initial five-year extension through the end of 2037. In 2011, Suncor's share of production in Libya averaged 12,100 bbls/d (2010 35,200 bbls/d). Libya is a member of the Organization of Petroleum Exporting Countries (OPEC) and is subject to quotas that can affect the company's production in Libya.

For most of the period from March to September 2011, the operator for the joint venture, Harouge Oil Operations BV (Harouge) shut in production as a result of political unrest that began earlier in the year. Sanctions prohibiting the purchase of oil from Libya, among other things, were also introduced by many governments. In March 2011, Suncor declared force majeure under its EPSAs. Beginning late in the third quarter of 2011, a new governing authority was formed in Libya and sanctions were lifted. By January 2012, Harouge had successfully restarted production from all major producing fields and work continues to stabilize production levels. Net production exiting December 2011 was approximately 30,000 bbls/d. Suncor remains optimistic about a gradual return to full operations in Libya and is working to remove its ESPAs from force majeure, where possible.

As a result of the merger, the company assumed the remaining US$500 million obligation for a signature bonus relating to Petro-Canada's ratification of the EPSAs in 2008. As at December 31, 2011, the undiscounted value of Suncor's remaining obligation is US$347 million, payable in several instalments through 2013. In addition, as part of its contractual obligations under the EPSAs, Suncor is the exploration operator and has committed to fully fund an exploration program, at an estimated remaining cost of US$360 million. As at December 31, 2011, Suncor is still under condition of force majeure with respect to its EPSAs and has re-engaged Harouge to discuss current operations and future plans, including contractual obligations.

North America Onshore Assets and Operations

The North America Onshore business includes the assets and operations previously reported under Suncor's Natural Gas segment, which is now part of the Exploration and Production segment. This business explores for, develops and produces natural gas, NGLs, crude oil and byproducts in Western Canada. After the merger with Petro-Canada, this business implemented a strategy with greater emphasis on liquids-rich and unconventional sources, and, as a result, disposed of a number of non-core assets throughout 2010 and 2011.

Given the vast amount of natural gas brought on-stream in North America by recent advances in shale gas technology, coupled with the economic downturn in 2008 and 2009, natural gas producers in North America continue to face relatively low gas prices. In light of this environment, Suncor has implemented a strategy to make its operations in this region more profitable. One component of that strategy involved selling assets that were no longer deemed core to Suncor's business strategy. As market conditions for such divestitures worsened, Suncor has started to focus more on another component of its strategy becoming more profitable in this region, primarily by increasing activity in tight oil projects. The company is also assessing and pursuing activities to grow the unconventional side of its North America Onshore operations.

In 2011, Suncor's share of production from its North America Onshore properties was 388 mmcfe/d (2010 575 mmcfe/d) with approximately 21 mmcfe/d of production in 2011 coming from assets that were disposed throughout the year (2010 143 mmcfe/d). Natural gas represented 92% of production in 2011 (2010 91%), with crude oil and NGL production representing the remainder. North America Onshore also sells sulphur, a byproduct of processing operations.

Operations are primarily focused on multiple geological zones throughout Western Canada. The business is structured with the following asset areas:

Zone / Area	Primary Focus	2011 mmcfe/d
Northeast B.C.	Montney, Triassic and Slave Point	113
Southeast Alberta	Sweet, dry gas	70
Foothills western Alberta, portions of northeast B.C.	Mississippian sour gas	161
Plains western Alberta	Cardium oil, Cretaceous gas	44
		388

In addition, Suncor holds assets that could allow the company to eventually explore long-term supply opportunities in northern frontier areas.

Natural gas extracted from the wellhead requires further processing. In Western Canada, Suncor operates several natural gas processing plants, with total licensed capacity of 772 mmcf/d, of which the company's share is 470 mmcf/d. Capacity not utilized by the company's own production is optimized through processing agreements with third-party producers. Suncor also has varying working interests in other natural gas processing plants and field gathering facilities operated by other oil and natural gas companies. The company's aggregate share from such interests is 91.5 mmcf/d of licensed capacity. The following table shows Suncor's working interest ownership and the licensed capacity of operated processing plants as at December 31, 2011.

Suncor Operated Natural Gas Processing Plants	Zone / Area	Working Interest Ownership %	Gross Licensed Capacity mmcf/d	Net Licensed Capacity mmcf/d
Hanlan Sour	Foothills	49.86	382.0	190.5
Hanlan Sweet	Foothills	40.73	44.2	18.0
Ferrier	Plains	100.00	120.0	120.0
Gilby East	Plains	100.00	52.4	52.4

Wilson Creek	Plains	52.17	34.6	18.1
Progress	Northeast B.C.	38.01	42.6	16.2
Boundary Lake Sour	Northeast B.C.	50.00	46.0	23.0
Boundary Lake Sweet	Northeast B.C.	100.00	20.0	20.0
Parkland 1	Northeast B.C.	43.98	18.1	8.0
Parkland 2	Northeast B.C.	34.75	11.7	4.1
Total			771.6	470.3

Natural gas production from Alberta is typically sold at the Nova Inventory Transfer point (NIT), which is one of the largest natural gas trading hubs in North America. Natural gas at NIT generally receives a daily or monthly average AECO (Alberta) spot price. Natural gas production from B.C. is typically sold at Station 2, part of the Spectra B.C. transmission system, and receives the Station 2 Gas Daily Index price, but can also be moved on the Alliance Pipeline system to its terminus in Illinois. To provide diversity in access to markets, Suncor holds firm capacity on the Alliance Pipeline system and the TransCanada PipeLines Gas Transmission Northwest Pipeline (GTN). The GTN firm capacity enables Suncor to deliver natural gas to the Pacific Northwest and California markets.

Conventional crude oil production from North America Onshore assets is shipped on pipelines operated by independent pipeline companies. We currently have no pipeline commitments related to the shipment of conventional crude oil. In most sale arrangements, Suncor is responsible for transportation to the point of sale.

Sales of Principal Products

Oil and gas production from East Coast Canada and the North Sea, and substantially all production from North America Onshore, are sold to our Energy Trading business, which then markets the products to customers under direct sale arrangements. Suncor does not typically enter into long-term supply arrangements to sell its production from its Exploration and Production segment. Contracts for these direct sales arrangements are of varied terms, with a majority having terms of one year or less, and incorporate pricing that is generally determined on a daily or monthly basis in relation to a specified market reference price.

In Syria, the company entered into purchase and sale agreements with the Syrian government for all hydrocarbon production from the Ebla project. In Libya, hydrocarbon production is marketed by the Libyan government on behalf of Suncor.

For each of Exploration and Production's operations, and for Exploration and Production in total, the following table provides information on average sales volumes for principal products and the corresponding percentage of operating revenues for 2011 and 2010:

Sales Volumes	2011		2010	
	mboe/d	% operating revenues	mboe/d	% operating revenues
East Coast Canada [(1)]				
Crude oil	52.3	42	54.2	29
International				
Crude oil and NGLs	62.4	34	111.1	46
Natural gas	14.0	4	21.5	4
North America Onshore				
Crude oil and NGLs	5.1	3	8.8	4
Natural gas	59.6	8	87.0	13
Total Exploration and Production				
Crude oil and NGLs	119.8	79	174.2	79
Natural gas	73.6	12	108.5	17

(1) Operating revenues for East Coast Canada include crude oil marketed on behalf of our partner in White Rose.

Royalty Agreements

East Coast Canada

The Terra Nova royalty consists of a sliding-scale, basic royalty payable throughout the project's life, with two tiers of incremental royalties, which became payable upon the achievement of specified levels of profitability that included an additional return allowance. The basic royalty is now capped at 10% of gross field revenue, based on the project reaching a specified cumulative production level. The tier one royalty is the greater of the basic royalty or 30% of net revenue, and became payable in 2005. Net revenue is gross revenue adjusted for eligible operating and capital costs. The tier two royalty, equal to 12.5% of net revenue, became payable in 2008. During 2011, Terra Nova royalty expense averaged

32% of gross revenue (2010   35%).

The Hibernia royalty agreement for production from the original oilfields and the AA Block consists of a sliding-scale gross royalty, two tiers of incremental royalty, and an additional net profits interest (NPI). The basic royalty is now capped at 5% of gross revenue, as the project has reached a specified cumulative production level. The tier one royalty, which became payable in 2009, is the greater of the gross royalty or 30% of net revenue. The tier two royalty is 12.5% of net revenue, but has not yet been triggered. Production from the AA Block, which commenced in late 2009, attracts an additional super royalty of 12.5% of net revenue. The NPI, which also became payable in 2009, is an additional 10% of net revenue.

Limited production from the HSEU began in 2011. The HSEU has a similar royalty structure (gross, tier one and tier two) to that described above for Hibernia. Currently, Suncor is only subject to a 5% gross royalty. HSEU production will be subject to an additional super royalty that ranges between 2.5% and 7.5% of net revenue, depending on the price for WTI. The HSEU super royalty will coincide with the triggering of the tier one net royalty. During 2011, Hibernia (including the HSEU) royalty expense and net profits interest combined to average 37% of gross revenue (2010 38%).

The White Rose royalty for the base project consists of a sliding-scale basic royalty payable throughout the project's life, with two tiers of incremental royalties, which became payable upon the achievement of specified levels of profitability that included an additional return allowance. The basic royalty is now capped at 7.5% of gross field revenue, based on the base project reaching a specified cumulative production level. The tier one royalty is the greater of the basic royalty or 20% of net revenue, and became payable in 2007. Net revenue adjusts gross revenue for eligible operating and capital costs. The tier two royalty, equal to 10% of net revenue, became payable in 2008. The White Rose Extensions royalty is similar to the base project, except that there is a tier three royalty, equal to 6.5% of net revenue, which is payable if WTI is greater than Cdn$50/bbl. None of the tier royalties have been triggered for the White Rose Extensions. During 2011, total White Rose royalty expense averaged 14% of gross revenue (2010 25%).

International

There are no royalties on oil and gas production from the North Sea; however, in the U.K., oil and gas profits are subject to a 62% income tax rate. For operations in Libya and Syria, all government interests, except for income taxes, are presented as royalties.

North America Onshore

Royalties for Suncor's North America Onshore production in Alberta are regulated by the *Natural Gas Royalty Regulation 2009*, introduced as part of the New Royalty Framework, which came into effect on January 1, 2009, but was later modified by changes that came into effect on January 1, 2011. Royalties for natural gas and conventional oil production are set by a sliding-scale formula ranging from 5% to 36% for natural gas and 0% to 40% for conventional crude oil that is dependent on factors such as well depth, production rate, and the price and quality of natural gas and crude oil. The maximum rates of 36% and 40% for the sliding-scales became effective on January 1, 2011 and were both reduced from 50%. NGLs have royalty rates of 30% for propane and butane and 40% for pentanes.

In response to the drop in commodity prices experienced during the second half of 2008, the provincial government introduced the New Well Royalty Reduction Program with the intent of promoting new drilling. New wells drilled after April 1, 2009 are subject to an initial 5% royalty for the first twelve months of production, subject to a 500 mmcfe or 50 mboe volume cap. After May 1, 2010, new wells that started producing exclusively from shale formations qualify for a maximum 5% royalty on all production for the first 36 months of production, and are not subject to volume caps.

The Alberta government's Natural Gas Deep Drilling Program also provides royalty relief for wells drilled beyond 2000 metres (true vertical depth). The maximum royalty rate for these wells is 5%, which applies for five years after the finished drilling date, and is subject to dollar caps that are determined based on total depth and whether the well is exploratory or developmental.

Operating and capital costs for gathering, compressing and processing facilities, and processing costs on a fee-for-service basis are allowable costs for deduction from gas and natural gas liquids gross royalties payable.

Royalties for Suncor's North America Onshore production in British Columbia are regulated primarily by the Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation. Royalty rates for natural gas production are subject to different formulas based on the date the well was drilled. Wells drilled before June 1998 attract a rate starting at 15%. Wells drilled after June 1998 attract a royalty starting at 9% or 12%, depending on whether wells were completed within five years of the date drilling rights were issued, and are subject to a sliding scale with a maximum royalty rate of 27% as prices increase. Similar to Alberta, royalty programs exist in British Columbia to provide relief for deep drilling, lower production rates, and unique production methods. Royalties on NGLs are assessed at a flat rate of 20% of sales.

Expenses for field gathering, compression and field processing are allowed as cost of services deductions from gross royalties, and royalty clients who use producer-owned processing facilities or distribution systems are also entitled to operating and capital cost deduction for these facilities.

During 2011, royalty expense for North America Onshore production averaged 11% of gross revenue (2010 14%).

Refining and Marketing

For a discussion of the environmental and other regulatory conditions, and competitive conditions and seasonal impacts affecting our Refining and Marketing segment, refer to the Industry Conditions and Risk Factors sections of this AIF.

Operations   Refining and Product Supply

Eastern North America

Effective January 1, 2012, the Montreal refinery had a crude oil capacity of 137,000 bbls/d. The observed performance of the refinery, after improvements in reliability and operations, enabled the nameplate capacity to be upwardly revised from the previously reported capacity of 130,000 bbls/d.

The refinery processes primarily foreign conventional crude oil, with a flexible configuration that allows processing of light, sour and heavy grades of crude oil, as well as intermediate feedstocks. Crude oil is procured from the market on a spot basis or under contracts that can be terminated on short notice. Crude oil for the refinery is largely supplied by the Portland-Montreal Pipeline.

Production yield from the Montreal refinery includes gasoline, distillates, asphalts, heavy fuel oil, petrochemicals and solvents, which are distributed primarily across Quebec and Ontario. The Montreal refinery also produces feedstock for our lubricants plant. Refined products are delivered to distribution terminals in Ontario via the Trans-Northern Pipeline and delivered to customers directly by truck, rail and marine vessel.

The Sarnia refinery has a crude oil capacity of 85,000 bbls/d, processing both SCO supplied by the company's Oil Sands operations and conventional crude oil purchased from third parties on a spot basis or under contracts that can be terminated on short notice. Crude oil is supplied to the Sarnia refinery primarily via the Enbridge pipelines system. Suncor procures conventional crude oil feedstock primarily from Western Canada, but periodically supplements supply with purchases from the U.S. and other countries. Foreign crude oil is delivered to Sarnia via the Enbridge pipeline system from Montreal.

Production yield from the Sarnia refinery includes gasoline, distillates and petrochemicals, which are primarily distributed in Ontario. Refined products are delivered to distribution terminals in Ontario via the Sun-Canadian Pipeline, or delivered to customers directly via marine vessel and rail. The Sarnia refinery also has limited access to pipelines delivering refined product into the U.S.

To meet the demands of Suncor's marketing network in Eastern North America, the company also imports gasoline and distillates from refiners in Europe. Suncor enters into reciprocal exchange arrangements with other refiners in Eastern North America, primarily for gasoline and distillates, as a means of minimizing transportation costs and balancing product availability. Specialty products, such as asphalts and petrochemicals, are also exported to customers in the U.S.

Suncor holds a 51% interest in ParaChem Chemicals L.P. (ParaChem), which owns and operates a petrochemicals plant located adjacent to the Montreal refinery. Feedstock for the plant includes xylene and toluene produced by the Montreal and Sarnia refineries. The plant primarily produces up to 350,000 metric tons per year of paraxylene, which is used by customers to manufacture polyester textiles and plastic bottles. ParaChem also produces benzene, hydrogen and heavy aromatics. Benzene production is delivered back to the Montreal refinery to be marketed with production from that facility.

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

Western North America

The Edmonton refinery has a crude oil capacity of 135,000 bbls/d and has the potential to run entirely on feedstocks sourced from oil sands and heavy crude oil from Alberta. Feedstock is supplied from Suncor's Oil Sands Base operations, Syncrude operations (including volumes purchased by Suncor from other joint venture owners' share of production) and other producers from the Athabasca and Cold Lake regions of Alberta. The refinery can process directly 35,000 bbls/d of blended feedstock (comprised of 25,000 bbls/d of bitumen and 10,000 bbls/d of diluent) and process 45,000 bbls/d of sour SCO. The refinery can also process 55,000 bbls/d of sweet SCO through its synthetic train. Crude oil is supplied to the refinery via third-party pipelines.

Production yield from the Edmonton refinery includes primarily gasoline and distillates, which are delivered to distribution terminals across Western Canada via the Alberta Products Pipeline, the TransMountain Pipeline and the Enbridge pipeline system, as well as via truck and rail.

Effective January 1, 2012, the Commerce City refinery had a crude oil capacity of 98,000 bbls/d. The observed performance of the refinery, after improvements in reliability and operations, enabled the nameplate capacity to be upwardly revised from the previously reported capacity of 93,000 bbls/d.

The refinery processes primarily conventional crude oil, but also has the capability of processing up to 15,000 bbls/d of sour SCO from Suncor's Oil Sands Base operations. A majority of crude feedstock is supplied from sources in the U.S., primarily the Rocky Mountain region, while the remainder is purchased from Canadian sources. Crude oil purchase contracts have terms ranging from month-to-month to multi-year. Approximately 60% of crude oil supplied to the refinery is transported via pipeline, with the remainder transported via truck.

Production yield from the Commerce City refinery includes primarily gasoline, diesel and asphalt. The majority of the refined products from the refinery are sold to commercial and wholesale customers in Colorado and Wyoming, and a retail network in Colorado. Refined products are distributed by truck, rail, and pipeline.

To support supply and demand balance in the Vancouver area, Suncor imports and exports finished products through its Burrard distribution terminal on the west coast of Canada. Suncor also enters into reciprocal exchange arrangements with other refiners in Western North America as a means of minimizing transportation costs and balancing product availability.

Refinery Throughputs, Utilizations and Yields

The following table summarizes the crude feedstock and utilizations for Suncor's refineries for the years ended December 31, 2011 and 2010. Refinery utilizations for 2011 include the impacts of planned maintenance events at the Sarnia, Edmonton and Commerce City refineries, and the impacts of a month-long disruption to third-party hydrogen supply at Edmonton.

Average Daily Crude Throughput	Montreal		Sarnia		Edmonton		Commerce City	
(mbbls/d, except as noted)	2011	2010	2011	2010	2011	2010	2011	2010
Oil Sands Base sweet synthetic			11.4	14.1	12.3	11.4		0.1
Oil Sands Base sour synthetic			25.2	17.4	41.2	42.5	7.7	9.4
Other synthetic			12.6	17.0	41.9	39.6		
East Coast Canada light conventional [1]	23.0	41.5						
Other light conventional	82.3	54.7	3.2	3.0		2.4	67.0	72.0
Sour conventional	10.2	6.4	18.6	19.3				
Heavy conventional	15.3	19.2			20.4	22.7	16.0	17.5
Total	130.8	121.8	71.0	70.8	115.8	118.6	90.7	99.0
Utilization [2] (%)	101	94	83	83	86	88	98	106

(1) Includes purchases of Suncor and third-party shares of production from East Coast Canada oilfields.

(2) Utilization rates for Montreal and Commerce City are determined based on refinery capacities in effect prior to January 1, 2012.

Refined petroleum production yield mix	Montreal		Sarnia		Edmonton		Commerce City	
(%)	2011	2010	2011	2010	2011	2010	2011	2010
Gasoline	40	42	44	53	46	42	51	51
Distillates	34	32	42	35	50	54	36	36
Other	26	26	14	12	4	4	13	13

Distribution Terminals and Pipelines

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

Suncor has ownership interests in the following pipelines:

Pipeline	Ownership	Type	Origin	Destinations
Portland-Montreal Pipeline	23.8%	Crude oil	Portland, Maine	Montreal, Quebec
Trans-Northern Pipeline	33.3%	Refined product	Montreal, Quebec	Ontario Ottawa, Toronto, Oakville
Sun-Canadian Pipeline	55.0%	Refined product	Sarnia, Ontario	Ontario Toronto, London, Hamilton
Alberta Products Pipeline	35.0%	Refined product	Edmonton, Alberta	Calgary, Alberta
Rocky Mountain Crude Pipeline	100.0%	Crude oil	Guernsey, Wyoming	Denver, Colorado
Centennial Pipeline	100.0%	Crude oil	Guernsey, Wyoming	Cheyenne, Colorado

Operations Marketing

Suncor's retail service station network operates nationally in Canada under the Petro-Canada$_{TM}$ brand. As at December 31, 2011, Suncor's branded retail service station network consisted of 1,465 outlets across Canada. Most of Suncor's owned and operated Sunoco$_{TM}$-branded retail sites were re-branded to the Petro-Canada$_{TM}$ brand in 2010. In addition to marketing through proprietary retail outlets, petroleum product is marketed through independent dealers and joint arrangements. Suncor's network had annual sales of gasoline motor fuels averaging approximately 4.9 million litres per site in 2011 (2010 5.1 million litres per site) and attracted an estimated 18% share (2010 19% share) of the national retail market (based on data available from Statistics Canada for the period from January to August 2011). The decline in market share in 2011 primarily reflects the loss of volume associated with the disposal of numerous retail sites in 2010 as mandated by the Canadian Competition Bureau as a result of the merger.

Suncor's Colorado retail network consists of 44 owned outlets. Suncor has product supply agreements with an additional 195 Shell®-branded sites and 62 Phillips 66®-branded sites in Colorado.

Marketing activities also generate non-petroleum revenues from convenience stores and car washes.

Suncor's wholesale operations sell petroleum products into farm, home heating, paving, small industrial, commercial and truck markets. Through its PETRO-PASS network, Suncor is the leading national marketer to the commercial road transport segment in Canada. Suncor also sells large volumes of petroleum products directly to large industrial and commercial customers and independent marketers.

The following tables summarize the locations comprising Suncor's retail and wholesale network and the daily sales volumes and corresponding percentages of Refining and Marketing's operating revenues for the years ended December 31, 2011 and 2010.

Locations	As at December 31 2011	2010
Retail Service Stations Canada		
Petro-Canada$_{TM}$-branded	1 456	1 447
Sunoco$_{TM}$-branded	9	10
	1 465	1 457
Retail Service Stations Colorado		
Shell®-branded retail service stations	38	37
Phillips 66®-branded retail service stations	6	7
	44	44
Wholesale Cardlock Sites Canada		
Petro-Canada$_{TM}$-branded cardlock sites (PETRO-PASS)	245	249

Sales Volumes	2011		2010	
	thousands of m^3/d	% operating revenues	thousands of m^3/d	% operating revenues
Gasoline (includes motor and aviation gasoline)				
Eastern North America	20.9		22.2	
Western North America	18.8		18.9	
	39.7	45	41.1	48
Distillates (includes diesel and heating oils, and aviation jet fuels)				
Eastern North America	12.8		12.4	
Western North America	17.6		18.0	
	30.4	41	30.4	37
Other (includes heavy fuel oil, asphalts, lubricants, petrochemicals, other)				
Eastern North America	9.8		10.7	
Western North America	3.2		5.1	
	13.0	14	15.8	15
	83.1		87.3	

Sales volumes for specific products are somewhat impacted by seasonal cycles: gasoline sales are typically higher during the summer driving season; heating oil sales are typically higher during the winter season; diesel sales are typically higher during the drilling season at the beginning of the year in Western Canada, and during agricultural planting and harvest seasons in early spring and late summer, respectively; and asphalt sales are typically higher during the summer construction paving period. Suncor has the flexibility to modify refinery inputs and outputs to match production yields with anticipated product demands.

Sales volumes can also be impacted when refineries undergo planned maintenance events, which reduce production. Suncor is able to partially mitigate this impact through its integrated facilities: the Edmonton refinery and Oil Sands Base upgrading facilities in Western North America, and the Sarnia and Montreal refineries in Eastern North America. In addition, Suncor may purchase refined products from third-party suppliers.

Other Suncor Businesses

Energy Trading

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

The Energy Trading business supports the company's Oil Sands production by optimizing price realizations, managing inventory levels during unplanned outages at Suncor's facilities and managing the impacts of external market factors, like pipeline disruptions or outages at refining customers. The Energy Trading business has entered into arrangements for other midstream infrastructure, such as pipeline and storage capacity, to optimize delivery of existing and future growth production, while generating trading earnings on select strategies and opportunities.

The Energy Trading business continues to evaluate additional pipeline agreements to support planned increases in production capacity. Until the company completes its Oil Sands growth projects, Suncor's Energy Trading business expects to optimize the capacities associated with existing arrangements.

Renewable Energy

Suncor's renewable energy interests include a corn-based ethanol facility in southwest Ontario and six wind power projects in operation. Suncor is a Canadian pioneer in wind power with its investments in wind farms, which have a gross generating capacity of 255 MW and reduce carbon dioxide (CO_2) emissions by approximately 470,000 tonnes each year, compared with traditional power generation sources. We continue to evaluate new opportunities to build our renewable energy portfolio, and have a number of potential wind power project sites in various stages of evaluation.

Wind Farm		Ownership Interest (%)	Size (MW)	Turbines	Commissioned
Operated by Suncor					
Wintering Hills	Drumheller, Alberta	70.0	88	55	2011
Kent Breeze	Thamesville, Ontario	100.0	20	8	2011
Non-operated					
Ripley	Ripley, Ontario	50.0	76	38	2007
Chin Chute	Taber, Alberta	33.3	30	20	2006
Magrath	Magrath, Alberta	33.3	30	20	2004
SunBridge	Gull Lake, Saskatchewan	50 .0	11	17	2002

Since 2006, Suncor has invested in Canada's emerging biofuels industry. Suncor operates Canada's largest ethanol facility, the St. Clair Ethanol Plant in the Sarnia-Lambton region of Ontario. Our ethanol plant had an original production capacity of 200 million litres per year, which has since doubled with the completion of the plant expansion in January 2011. In 2011, the plant produced 381.5 million litres of ethanol (2010 206.0 million litres).

SUNCOR EMPLOYEES

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

As of December 31	2011	2010
Oil Sands	5 464	4 753
Exploration and Production	768	898
Refining and Marketing	3 161	3 151
Corporate, Energy Trading and Renewable Energy	3 633	3 274
Total	13 026	12 076

Corporate includes employees from our Major Projects group, which supports the business units. In addition to our employees, the company also uses independent contractors to supply a range of services.

Approximately 36% of the company's employees were covered by collective bargaining agreements at the end of 2011. The Communications, Energy and Paperworkers Union (CEP) represented the majority of the company's unionized employees. A collective agreement with CEP Local 707 representing approximately 3,200 Oil Sands employees is in force and expires in May 2013. Collective agreements that will expire in January 2013 are also in place with the CEP for approximately 1,000 employees in the company's refinery, lubricants, natural gas, and terminal operations. A collective agreement with the CEP representing approximately 65 employees for the Terra Nova facility was renewed in 2011 and will expire in September 2013.

A collective agreement with the United Steel Workers Union representing approximately 260 employees at the Commerce City refinery was recently renewed and will expire in January 2015. An independent union, the Suncor Employee Bargaining Association, represents approximately 200 employees at the Sarnia refinery under an agreement that will expire in May 2012.

SIGNIFICANT POLICIES

Suncor has a Standards of Business Conduct Code (the Code), which applies to Suncor's directors, officers, employees and contractors. The Code requires strict compliance with legal requirements and sets Suncor's standards for the ethical conduct of our business. Topics addressed in the Code include competition, conflict of interest, the protection and proper use of corporate assets and opportunities, confidentiality, disclosure of material information, trading in shares and securities, communications to the public, improper payments, fair dealing in trade relations, and accounting, reporting and business controls. The Code is supported by detailed policy guidance and standards and a Code compliance program, under which every Suncor director, officer, employee and contract worker is required to annually read a summary of the Code and affirm that he or she has reviewed the summary, affirm that he or she understands the requirements of the Code, and provide confirmation of his or her compliance with the Code during the preceding year. Compliance is then reported to the Audit Committee.

Suncor has a Human Rights Policy, which affirms Suncor's responsibility to respect human rights and ensures that Suncor is not complicit in human rights abuses. Suncor is subject to the laws of the countries in which it operates and is committed to complying with all such laws while honouring the spirit of international human rights principles, such as those described in the Universal Declaration of Human Rights and the Voluntary Principles on Security and Human Rights. The policy includes principles committed to a harassment-free and violence-free working environment, which respects the cultures, customs and values of the communities in which we operate. The policy makes it clear that the scope of Suncor's human rights due diligence includes its own operations and, where we can influence our third-party business relationships, the operations of others.

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

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

Suncor has an Environment, Health and Safety (EH&S) policy, which affirms Suncor's aspirations to be a sustainable energy company by meeting or exceeding the environmental, social and economic expectations of our current and future stakeholders. The policy reflect Suncor's beliefs that our EH&S efforts are complementary and interdependent with our economic and social performance. The policy makes it clear that Suncor management is responsible for ensuring that employees under their direction are competent to manage their EH&S responsibilities and knowledgeable of the hazards and risks associated with their jobs, and that all Suncor employees and contractors are accountable for compliance with relevant acts, codes, regulations, standards and procedures, and for their own personal safety and the safety of their co-workers.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Date of Statement

The statement of reserves data and other oil and gas information outlined below is dated March 1, 2012, with an effective date of December 31, 2011. The preparation date of the information is as of February 16, 2012.

Disclosure of Reserves Data

As a Canadian issuer, Suncor is subject to the reporting requirements of Canadian securities regulatory authorities, including the reporting of our reserves in accordance with National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* (NI 51-101).

The reserves data set forth in this section of the AIF for Suncor's Mining (includes Oil Sands Base and Syncrude, unless otherwise noted) and In Situ operations is based upon evaluations conducted by GLJ Petroleum Consultants Ltd. (GLJ) with an effective date of December 31, 2011, contained in their reports (the GLJ Reports). The reserves data set forth below for all other reserves, which includes Suncor's interests in its conventional natural gas assets primarily located in Western Canada (North America Onshore), conventional assets offshore Newfoundland and Labrador (East Coast Canada), conventional assets offshore the U.K. (North Sea), and conventional assets in Syria and Libya (collectively, Other International), is based upon evaluations conducted by Sproule Associates Limited or Sproule International Limited (collectively, Sproule) with an effective date of

December 31, 2011 contained in their reports (the Sproule Reports). Each of GLJ and Sproule (collectively, the Evaluators) are independent qualified reserves evaluators as defined in NI 51-101. All factual data supplied to the Evaluators was accepted as presented. For general interest purposes, GLJ conducted field tours of Suncor's Millennium mine and the Syncrude Aurora North mine. No other field inspections were deemed necessary by the Evaluators.

The reserves data summarizes Suncor's SCO, bitumen, light and medium oil, NGL and natural gas reserves and the net present values of future net revenue for these reserves using forecast prices and costs (unless otherwise indicated) prior to provision for interest, and general and administrative expenses. Net present values of future revenues include the impact of certain abandonment costs. For more information on abandonment costs, see the Future Net Revenues Tables and Notes Abandonment and Reclamation Costs section of this AIF.

Future net revenues are presented on before-tax and after-tax bases. The reserves data conforms to the requirements of NI 51-101. See also the Notes to Reserves Data Tables and the Definitions for Reserves Data Tables discussions presented subsequently in this section of the AIF.

Advisories Future Net Revenues

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. There is no guarantee that the estimates for SCO, bitumen, light and medium oil, NGL and natural gas reserves provided herein will be recovered. Actual SCO, bitumen, light and medium oil, NGL and natural gas reserves may be greater than or less than the estimates provided herein. Readers should review the definitions and information contained in the Notes to Reserves Data Tables, Definitions for Reserves Data Tables and Notes to Future Net Revenues Tables discussions in conjunction with the following notes and tables.

Significant Factors or Uncertainties Affecting Reserves Data

The evaluation of reserves is a continuous process, one that can be significantly impacted by a variety of internal and external influences. Revisions are often required as a result of newly acquired technical data, technology improvements, or changes in historical performance, pricing, economic conditions, market availability, and regulatory requirements. Additional technical information regarding geology, reservoir properties, reservoir fluid properties and well performance are obtained through seismic programs, drilling programs, updated reservoir performance studies and analysis, and production history, and may result in upward or downward revisions to reserves. Pricing, market availability and economic conditions affect the profitability of reserves exploitation. Depending on the current business environment, higher commodity prices may result in higher reserves by making more projects economically viable and extending their economic life, while lower commodity prices may result in lower reserves, although this generally does not result for assets under Production Sharing Contracts. Regulatory changes, including royalty regimes and environmental regulations, cannot be predicted but may have positive or negative effects on reserves. Future technology improvements would be expected to have a favourable impact on the economics of reserves development and exploitation, and therefore result in an increase to reserves.

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

In 2011, the company's assets in Syria were impacted by political unrest. As a result of the current situation in Syria, reserves previously reported as proved developed producing and probable developed producing have been reclassified to the respective non-producing categories. In addition, estimated 2012 production from Syria has not been included as reserves, but has been reflected as contingent resources, as current sanctions prohibit Suncor from receiving payment for any production that may occur during the force majeure period.

For more information as to the risks involved when estimating reserves and resources, see the Risk Factors Uncertainty of Reserves and Resources Estimates section in this AIF.

Disclosure of Resources Data

GLJ conducted an independent evaluation of Best Estimate contingent resources volumes for all of Suncor's Mining properties and for Suncor's In Situ properties for which they also evaluated reserves. For Suncor's In Situ properties without attributed reserves, GLJ audited Suncor's internal evaluation of Best Estimate contingent resources volumes. Best Estimate contingent resources for conventional properties were prepared by Suncor's qualified reserves evaluators in accordance with the Canadian Oil and Gas Evaluation (COGE) Handbook. For more information on contingent resources, see the discussion in the Additional Information Relating to Reserves Data Contingent Resources section of this AIF.

Oil and Gas Reserves Tables and Notes

Summary of Oil and Gas Reserves [1][2][3]
as at December 31, 2011
(forecast prices and costs)

	SCO		Bitumen		Light & Medium Oil		Natural Gas		NGLs		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	bcf	bcf	mmbbls	mmbbls	mmboe	mmboe
Proved Developed Producing												
Mining	2 022.5	1 722.1									2 022.5	1 722.1
In Situ	203.0	191.0	47.7	39.4							250.7	230.4
East Coast Canada					48.1	38.2					48.1	38.2
North America Onshore					11.2	9.2	805.7	688.8	6.3	4.6	151.7	128.6
Total Canada	2 225.5	1 913.1	47.7	39.4	59.3	47.4	805.7	688.8	6.3	4.6	2 473.0	2 119.3
North Sea					71.5	71.5	3.3	3.3	0.3	0.3	72.3	72.3
Other International					96.0	35.7					96.0	35.7
Total Proved Developed Producing	**2 225.5**	**1 913.1**	**47.7**	**39.4**	**226.8**	**154.6**	**809.0**	**692.1**	**6.6**	**4.9**	**2 641.3**	**2 227.3**
Proved Developed Non-Producing												
Mining												
In Situ												
East Coast Canada												
North America Onshore					0.1	0.1	40.5	31.3	0.2	0.1	7.0	5.4
Total Canada					0.1	0.1	40.5	31.3	0.2	0.1	7.0	5.4
North Sea					21.4	21.4	1.1	1.1	0.1	0.1	21.6	21.6
Other International					36.6	14.3	334.5	206.9	11.9	7.0	104.2	55.8
Total Proved Developed Non-Producing					**58.1**	**35.8**	**376.1**	**239.3**	**12.2**	**7.2**	**132.8**	**82.8**
Proved Undeveloped												
Mining												
In Situ	502.0	430.0	661.1	572.4							1 163.1	1 002.4
East Coast Canada					26.6	20.7					26.6	20.7
North America Onshore					0.3	0.3	78.7	72.8	0.1		13.5	12.4
Total Canada	502.0	430.0	661.1	572.4	26.9	21.0	78.7	72.8	0.1		1 203.2	1 035.5
North Sea					43.3	43.3	2.7	2.7	0.1	0.1	43.8	43.8
Other International					5.8	2.4					5.8	2.4
Total Proved Undeveloped	**502.0**	**430.0**	**661.1**	**572.4**	**76.0**	**66.7**	**81.4**	**75.5**	**0.2**	**0.1**	**1 252.8**	**1 081.7**
Proved												
Mining	2 022.5	1 722.1									2 022.5	1 722.1
In Situ	705.0	621.0	708.8	611.8							1 413.8	1 232.8
East Coast Canada					74.7	58.9					74.7	58.9

North America Onshore					11.5	9.6	924.9	792.9	6.6	4.7	172.3	146.4
Total Canada	2 727.5	2 343.1	708.8	611.8	86.2	68.5	924.9	792.9	6.6	4.7	3 683.3	3 160.2
North Sea					136.2	136.2	7.1	7.1	0.5	0.5	137.9	137.9
Other International					138.4	52.4	334.5	207.1	11.9	7.0	206.1	93.9
Total Proved	**2 727.5**	**2 343.1**	**708.8**	**611.8**	**360.8**	**257.1**	**1 266.5**	**1 007.1**	**19.0**	**12.2**	**4 027.3**	**3 392.0**
Probable												
Mining	552.7	478.4									552.7	478.4
In Situ	1 271.9	1 061.2	693.9	552.0							1 965.8	1 613.2
East Coast Canada					275.3	201.0					275.3	201.0
North America Onshore					5.0	4.1	320.4	262.8	2.9	2.1	61.3	50.0
Total Canada	1 824.6	1 539.6	693.9	552.0	280.3	205.1	320.4	262.8	2.9	2.1	2 855.1	2 342.6
North Sea					36.1	36.1	2.9	2.9	0.1	0.1	36.7	36.7
Other International					104.9	40.3	405.5	168.8	14.5	7.0	187.0	75.4
Total Probable	**1 824.6**	**1 539.6**	**693.9**	**552.0**	**421.3**	**281.5**	**728.8**	**434.5**	**17.5**	**9.2**	**3 078.8**	**2 454.7**
Proved Plus Probable												
Mining	2 575.2	2 200.5									2 575.2	2 200.5
In Situ	1 976.9	1 682.2	1 402.7	1 163.8							3 379.6	2 846.0
East Coast Canada					350.0	259.9					350.0	259.9
North America Onshore					16.5	13.7	1 245.3	1 055.7	9.5	6.8	233.6	196.5
Total Canada	4 552.1	3 882.7	1 402.7	1 163.8	366.5	273.6	1 245.3	1 055.7	9.5	6.8	6 538.4	5 502.9
North Sea					172.3	172.3	10.0	10.0	0.6	0.6	174.5	174.5
Other International					243.3	92.7	740.0	375.9	26.4	14.0	393.0	169.3
Total Proved Plus Probable	**4 552.1**	**3 882.7**	**1 402.7**	**1 163.8**	**782.1**	**538.6**	**1 995.3**	**1 441.6**	**36.5**	**21.4**	**7 105.9**	**5 846.7**

Please see Notes (1) through (3) at the end of the reserves data section for important information about volumes in this table.

Summary of Oil and Gas Reserves [(1)(2)(3)]
as at December 31, 2011
(constant prices and costs)

	SCO		Bitumen		Light & Medium Oil		Natural Gas		NGLs		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	bcf	bcf	mmbbls	mmbbls	mmboe	mmboe
Proved Developed Producing												
Mining	2 022.5	1 718.2									2 022.5	1 718.2
In Situ	202.9	194.0	47.7	40.2							250.6	234.2
East Coast Canada					48.1	37.2					48.1	37.2
North America Onshore					11.2	9.6	731.8	640.1	6.1	4.4	139.2	120.7
Total Canada	2 225.4	1 912.2	47.7	40.2	59.3	46.8	731.8	640.1	6.1	4.4	2 460.4	2 110.3
North Sea					71.7	71.7	3.3	3.3	0.3	0.3	72.5	72.5
Other International					96.3	36.4					96.3	36.4
Total Proved Developed Producing	**2 225.4**	**1 912.2**	**47.7**	**40.2**	**227.3**	**154.9**	**735.1**	**643.4**	**6.4**	**4.7**	**2 629.2**	**2 219.2**
Proved Developed Non-Producing												
Mining												
In Situ												
East Coast Canada												
North America Onshore					0.1	0.1	18.3	14.7	0.2	0.1	3.3	2.6
Total Canada					0.1	0.1	18.3	14.7	0.2	0.1	3.3	2.6
North Sea					21.7	21.7	1.1	1.1	0.1	0.1	22.0	22.0
Other International					36.7	14.3	338.6	199.0	12.0	6.7	105.1	54.2
Total Proved Developed Non-Producing					**58.5**	**36.1**	**358.0**	**214.8**	**12.3**	**6.9**	**130.4**	**78.8**
Proved Undeveloped												
Mining												
In Situ	502.0	446.5	661.1	584.0							1 163.1	1 030.5
East Coast Canada					26.6	20.2					26.6	20.2
North America Onshore					0.3	0.3	11.5	10.5			2.2	2.1
Total Canada	502.0	446.5	661.1	584.0	26.9	20.5	11.5	10.5			1 191.9	1 052.8
North Sea					43.9	43.9	2.7	2.7	0.1	0.1	44.4	44.4
Other International					5.8	2.4					5.8	2.4
Total Proved Undeveloped	**502.0**	**446.5**	**661.1**	**584.0**	**76.6**	**66.8**	**14.2**	**13.2**	**0.1**	**0.1**	**1 242.1**	**1 099.6**
Proved												
Mining	2 022.5	1 718.2									2 022.5	1 718.2
In Situ	704.9	640.5	708.8	624.2							1 413.7	1 264.7
East Coast Canada					74.7	57.4					74.7	57.4
North America Onshore					11.5	10.0	761.6	665.3	6.3	4.5	144.7	125.4

Total Canada	2 727.4	2 358.7	708.8	624.2	86.2	67.4	761.6	665.3	6.3	4.5	3 655.6	3 165.7
North Sea					137.3	137.3	7.1	7.1	0.5	0.5	138.9	138.9
Other International					138.8	53.1	338.6	199.0	12.0	6.7	207.3	93.0
Total Proved	**2 727.4**	**2 358.7**	**708.8**	**624.2**	**362.3**	**257.8**	**1 107.3**	**871.4**	**18.8**	**11.7**	**4 001.8**	**3 397.6**
Probable												
Mining	552.7	480.0									552.7	480.0
In Situ	1 271.9	1 114.5	693.9	566.0							1 965.8	1 680.5
East Coast Canada					275.3	197.1					275.3	197.1
North America Onshore					5.0	4.3	227.4	197.1	2.3	1.6	45.2	38.8
Total Canada	1 824.6	1 594.5	693.9	566.0	280.3	201.4	227.4	197.1	2.3	1.6	2 839.0	2 396.4
North Sea					35.6	35.6	2.9	2.9	0.1	0.1	36.2	36.2
Other International					104.5	37.7	401.4	157.0	14.4	6.6	185.8	70.5
Total Probable	**1 824.6**	**1 594.5**	**693.9**	**566.0**	**420.4**	**274.7**	**631.7**	**357.0**	**16.8**	**8.3**	**3 061.0**	**2 503.1**
Proved Plus Probable												
Mining	2 575.2	2 198.2									2 575.2	2 198.2
In Situ	1 976.8	1 755.0	1 402.7	1 190.2							3 379.5	2 945.2
East Coast Canada					350.0	254.5					350.0	254.5
North America Onshore					16.5	14.3	989.0	862.4	8.6	6.1	189.9	164.2
Total Canada	4 552.0	3 953.2	1 402.7	1 190.2	366.5	268.8	989.0	862.4	8.6	6.1	6 494.6	5 562.1
North Sea					172.9	172.9	10.0	10.0	0.6	0.6	175.1	175.1
Other International					243.3	90.8	740.0	356.0	26.4	13.3	393.1	163.5
Total Proved Plus Probable	**4 552.0**	**3 953.2**	**1 402.7**	**1 190.2**	**782.7**	**532.5**	**1 739.0**	**1 228.4**	**35.6**	**20.0**	**7 062.8**	**5 900.7**

Please see Notes (1) through (3) at the end of the reserves data section for important information about volumes in this table.

Reconciliation of Gross Oil Reserves [1][2][3]
as at December 31, 2011
(forecast prices and costs)

	SCO			Bitumen			Light & Medium Oil		
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls
December 31, 2010									
Mining	2 084.3	541.5	2 625.8		36.7	36.7			
In Situ	821.6	461.5	1 283.1	397.3	1 849.9	2 247.2			
East Coast Canada							80.8	148.7	229.5
North America Onshore							10.5	6.5	17.0
Total Canada	2 905.9	1 003.0	3 908.9	397.3	1 886.6	2 283.9	91.3	155.2	246.5
North Sea							117.9	57.4	175.3
Other International							140.5	100.7	241.2
Total	**2 905.9**	**1 003.0**	**3 908.9**	**397.3**	**1 886.6**	**2 283.9**	**349.7**	**313.3**	**663.0**
Extensions & Improved Recovery [4]									
Mining									
In Situ	93.8	(93.8)		87.1	(87.1)				
East Coast Canada							2.2	143.7	145.9
North America Onshore							1.3	(0.4)	0.9
Total Canada	93.8	(93.8)		87.1	(87.1)		3.5	143.3	146.8
North Sea									
Other International							1.2	1.5	2.7
Total	**93.8**	**(93.8)**		**87.1**	**(87.1)**		**4.7**	**144.8**	**149.5**
Technical Revisions [5]									
Mining	33.8	11.2	45.0		(36.7)	(36.7)			
In Situ [8]	(191.3)	904.2	712.9	233.2	(1068.9)	(835.7)			
East Coast Canada							15.7	(17.1)	(1.4)
North America Onshore							0.6	(1.1)	(0.5)
Total Canada	(157.5)	915.4	757.9	233.2	(1105.6)	(872.4)	16.3	(18.2)	(1.9)
North Sea							26.3	(25.8)	0.5
Other International							1.8	2.8	4.6
Total	**(157.5)**	**915.4**	**757.9**	**233.2**	**(1105.6)**	**(872.4)**	**44.4**	**(41.2)**	**3.2**
Discoveries [6]									
Mining									
In Situ									
East Coast Canada									
North America Onshore									

Total Canada			
North Sea	24.6	13.8	38.4
Other International			
Total	**24.6**	**13.8**	**38.4**

Please see Notes (1) through (8) at the end of the reserves data section for important information about volumes in this table.

Reconciliation of Gross Oil Reserves [1][2][3] *(continued)*
as at December 31, 2011
(forecast prices and costs)

	SCO			Bitumen			Light & Medium Oil		
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls
Acquisitions									
Mining									
In Situ									
East Coast Canada									
North America Onshore									
Total Canada									
North Sea									
Other International									
Total									
Dispositions									
Mining									
In Situ									
East Coast Canada									
North America Onshore									
Total Canada									
North Sea							(15.7)	(9.4)	(25.1)
Other International									
Total							**(15.7)**	**(9.4)**	**(25.1)**
Economic Factors [7]									
Mining									
In Situ									
East Coast Canada									
North America Onshore									
Total Canada									
North Sea									
Other International									
Total									
Production									
Mining	(95.6)		(95.6)						
In Situ	(19.2)		(19.2)	(8.8)		(8.8)			
East Coast Canada							(24.0)		(24.0)
North America Onshore							(0.9)		(0.9)
Total Canada	(114.8)		(114.8)	(8.8)		(8.8)	(24.9)		(24.9)

North Sea							(16.9)		(16.9)
Other International							(5.1)		(5.1)
Total	**(114.8)**		**(114.8)**	**(8.8)**		**(8.8)**	**(46.9)**		**(46.9)**
December 31, 2011									
Mining	2 022.5	552.7	2 575.2						
In Situ	704.9	1 271.9	1 976.8	708.8	693.9	1 402.7			
East Coast Canada							74.7	275.3	350.0
North America Onshore							11.5	5.0	16.5
Total Canada	2 727.4	1 824.6	4 552.0	708.8	693.9	1 402.7	86.2	280.3	366.5
North Sea							136.2	36.0	172.2
Other International							138.4	105.0	243.4
Total	**2 727.4**	**1 824.6**	**4 552.0**	**708.8**	**693.9**	**1 402.7**	**360.8**	**421.3**	**782.1**

Please see Notes (1) through (8) at the end of the reserves data section for important information about volumes in this table.

Reconciliation of Natural Gas and NGL Reserves [(1)(2)(3)]
as at December 31, 2011
(forecast prices and costs)

	Natural Gas			NGLs		
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	bcf	bcf	bcf	mmbbls	mmbbls	mmbbls
December 31, 2010						
Canada North America						
Onshore	1 113.2	373.9	1 487.1	8.0	3.4	11.4
North Sea	11.5	4.4	15.9	0.8	0.3	1.1
Other International	251.1	281.1	532.2	7.9	9.2	17.1
Total	**1 375.8**	**659.4**	**2 035.2**	**16.7**	**12.9**	**29.6**
Extensions & Improved Recovery [(4)]						
Canada North America						
Onshore	5.1	11.1	16.2	0.1		0.1
North Sea						
Other International						
Total	**5.1**	**11.1**	**16.2**	**0.1**		**0.1**
Technical Revisions [(5)]						
Canada North America						
Onshore	41.4	(1.0)	40.4	0.2	(0.3)	(0.1)
North Sea	(0.1)	(2.3)	(2.4)		(0.2)	(0.2)
Other International	114.7	125.3	240.0	5.4	5.3	10.7
Total	**156.0**	**122.0**	**278.0**	**5.6**	**4.8**	**10.4**
Discoveries [(6)]						
Canada North America						
Onshore						
North Sea	1.5	1.2	2.7			
Other International						
Total	**1.5**	**1.2**	**2.7**			
Acquisitions						
Canada North America						
Onshore	0.2		0.2			
North Sea						
Other International						
Total	**0.2**		**0.2**			

Dispositions						
Canada North America						
Onshore	(55.6)	(31.5)	(87.1)	(0.6)	(0.2)	(0.8)
North Sea	(4.0)	(0.4)	(4.4)	(0.2)		(0.2)
Other International						
Total	**(59.6)**	**(31.9)**	**(91.5)**	**(0.8)**	**(0.2)**	**(1.0)**
Economic Factors (7)						
Canada North America						
Onshore	(52.2)	(32.1)	(84.3)	(0.1)		(0.1)
North Sea						
Other International	(2.1)	(0.9)	(3.0)	(0.1)		(0.1)
Total	**(54.3)**	**(33.0)**	**(87.3)**	**(0.2)**		**(0.2)**
Production						
Canada North America						
Onshore	(127.2)		(127.2)	(1.0)		(1.0)
North Sea	(1.8)		(1.8)	(0.1)		(0.1)
Other International	(29.2)		(29.2)	(1.3)		(1.3)
Total	**(158.2)**		**(158.2)**	**(2.4)**		**(2.4)**
December 31, 2011						
Canada North America						
Onshore	924.9	320.4	1 245.3	6.6	2.9	9.5
North Sea	7.1	2.9	10.0	0.5	0.1	0.6
Other International	334.5	405.5	740.0	11.9	14.5	26.4
Total	**1 266.5**	**728.8**	**1 995.3**	**19.0**	**17.5**	**36.5**

Please see Notes (1) through (8) at the end of the reserves data section for important information about volumes in this table.

Notes to Reserves Data Tables as at December 31, 2011

(1) The reserves data is based upon evaluations by the Evaluators with an effective date of December 31, 2011.

(2) See the Notes to Future Net Revenues Tables discussion for information on forecast and constant prices and costs.

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

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

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

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

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

(8) Technical revisions for In Situ probable reserves included a large increase in SCO probable reserves and a large decrease in bitumen probable reserves due to the inclusion of an assumption that the company's upgrading capacity will require significantly more bitumen from In Situ assets when Mining reserves are eventually depleted.

Definitions for Reserves Data Tables

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

Gross means:

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

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

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

Net means:

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

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

(c)

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

Reserves Categories

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

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

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

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

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

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

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

Developed reserves are those reserves that are expected to be recovered (i) from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production, or (ii) through installed extraction equipment and infrastructure that is operational at the time of the reserves estimate, if the extraction is by means not involving a well. The developed category may be subdivided into producing and non-producing.

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

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

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

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

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

Levels of Certainty for Reported Reserves

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

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

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

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates are prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods. Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

Future Net Revenues Tables and Notes

Net Present Value of Future Net Revenues Before Income Taxes

as at December 31, 2011
(forecast prices and costs)

	(in $ millions, discounted at % per year)					Unit Value [1]
	0%	5%	10%	15%	20%	$/boe
Proved Developed Producing						
Mining	65 036	40 083	27 354	20 207	15 843	15.88
In Situ	7 694	6 467	5 546	4 835	4 275	24.06
East Coast Canada	1 959	1 774	1 617	1 487	1 381	42.38
North America Onshore	3 026	2 136	1 657	1 361	1 158	12.89
Total Canada	77 715	50 460	36 174	27 890	22 657	17.07
North Sea	6 469	5 636	5 016	4 542	4 167	69.33
Other International	3 235	2 368	1 862	1 534	1 306	52.12
Total Proved Developed Producing	87 419	58 464	43 052	33 966	28 130	19.33
Proved Developed Non-Producing						
Mining						
In Situ						
East Coast Canada						
North America Onshore	65	46	34	26	19	6.34
Total Canada	65	46	34	26	19	6.34
North Sea	1 707	1 293	1 033	858	735	47.76
Other International	3 797	2 783	2 145	1 718	1 416	38.46
Total Proved Developed Non-Producing	5 569	4 122	3 212	2 602	2 170	38.80
Proved Undeveloped						
Mining						
In Situ	23 112	10 338	4 649	1 928	543	4.64
East Coast Canada	1 070	742	542	410	316	26.15
North America Onshore	167	92	49	22	7	3.91
Total Canada	24 349	11 172	5 240	2 360	866	5.06
North Sea	2 629	1 860	1 338	972	706	30.55
Other International	135	91	62	43	29	25.88
Total Proved Undeveloped	27 113	13 123	6 640	3 375	1 601	6.14
Proved						
Mining	65 036	40 083	27 354	20 207	15 843	15.88
In Situ	30 806	16 805	10 195	6 763	4 819	8.27
East Coast Canada	3 029	2 516	2 159	1 897	1 696	36.67
North America Onshore	3 258	2 274	1 740	1 409	1 184	11.88
Total Canada	102 129	61 678	41 448	30 276	23 542	13.11
North Sea	10 805	8 789	7 387	6 372	5 608	53.61
Other International	7 167	5 242	4 069	3 295	2 751	43.33
Total Proved	120 101	75 709	52 904	39 943	31 901	15.60

Probable						
Mining	28 852	9 564	4 403	2 563	1 755	9.21
In Situ	70 038	19 720	7 052	3 055	1 503	4.37
East Coast Canada	15 139	8 910	5 745	3 957	2 867	28.58
North America Onshore	1 350	666	386	245	165	7.65
Total Canada	115 379	38 860	17 586	9 820	6 290	7.51
North Sea	3 347	2 265	1 639	1 247	987	44.67
Other International	6 257	3 468	2 126	1 406	983	28.19
Total Probable	124 983	44 593	21 351	12 473	8 260	8.70
Proved Plus Probable						
Mining	93 888	49 647	31 757	22 770	17 598	14.43
In Situ	100 844	36 525	17 247	9 818	6 322	6.06
East Coast Canada	18 168	11 426	7 904	5 854	4 563	30.41
North America Onshore	4 608	2 940	2 126	1 654	1 349	10.80
Total Canada	217 508	100 538	59 034	40 096	29 832	10.73
North Sea	14 152	11 054	9 026	7 619	6 595	51.73
Other International	13 424	8 710	6 195	4 701	3 734	36.59
Total Proved Plus Probable	245 084	120 302	74 255	52 416	40 161	12.70

(1)
Unit values are future net revenues before income taxes, discounted at 10%, using net reserves.

Net Present Value of Future Net Revenues After Income Taxes

as at December 31, 2011
(forecast prices and costs)

	(in $ millions, discounted at % per year)				
	0%	5%	10%	15%	20%
Proved Developed Producing					
Mining	49 438	30 108	20 375	14 962	11 681
In Situ	6 845	5 746	4 925	4 295	3 801
East Coast Canada	1 486	1 377	1 243	1 138	1 052
North America Onshore	2 470	1 754	1 369	1 128	963
Total Canada	60 239	38 985	27 912	21 523	17 497
North Sea	2 086	1 850	1 663	1 515	1 397
Other International	1 132	842	671	561	483
Total Proved Developed Producing	63 457	41 677	30 246	23 599	19 377
Proved Developed Non-Producing					
Mining					
In Situ					
East Coast Canada					
North America Onshore	48	33	23	16	12
Total Canada	48	33	23	16	12
North Sea	659	506	411	348	303
Other International	2 360	1 775	1 396	1 135	947
Total Proved Developed Non-Producing	3 067	2 314	1 830	1 499	1 262
Proved Undeveloped					
Mining					
In Situ	16 996	7 154	2 851	839	(156)
East Coast Canada	790	515	376	279	208
North America Onshore	124	63	28	8	(4)
Total Canada	17 910	7 732	3 255	1 126	48
North Sea	1 010	731	537	397	293
Other International	58	40	28	19	13
Total Proved Undeveloped	18 978	8 503	3 820	1 542	354
Proved					
Mining	49 438	30 108	20 375	14 962	11 681
In Situ	23 841	12 900	7 776	5 134	3 645
East Coast Canada	2 276	1 892	1 619	1 417	1 260
North America Onshore	2 642	1 850	1 420	1 152	971
Total Canada	78 197	46 750	31 190	22 665	17 557
North Sea	3 755	3 087	2 611	2 260	1 993
Other International	3 550	2 657	2 095	1 715	1 443
Total Proved	85 502	52 494	35 896	26 640	20 993

Probable					
Mining	22 121	7 194	3 232	1 843	1 246
In Situ	51 925	14 182	4 837	1 932	823
East Coast Canada	11 081	6 063	3 932	2 676	1 893
North America Onshore	1 007	493	280	173	113
Total Canada	86 134	27 932	12 281	6 624	4 075
North Sea	1 284	885	651	504	405
Other International	2 911	1 566	934	601	410
Total Probable	90 329	30 383	13 866	7 729	4 890
Proved Plus Probable					
Mining	71 559	37 302	23 607	16 805	12 927
In Situ	75 766	27 082	12 613	7 066	4 468
East Coast Canada	13 357	7 955	5 551	4 093	3 153
North America Onshore	3 649	2 343	1 700	1 325	1 084
Total Canada	164 331	74 682	43 471	29 289	21 632
North Sea	5 039	3 972	3 262	2 764	2 398
Other International	6 461	4 223	3 029	2 316	1 853
Total Proved Plus Probable	175 831	82 877	49 762	34 369	25 883

Total Future Net Revenues
as at December 31, 2011
(forecast prices and costs)

(in $ millions, undiscounted)	Revenue	Royalties	Operating Costs	Development Costs	Abandonment Expenses	Future Net Revenue Before Deducting Future Income Tax Expenses	Future Income Tax Expenses	Future Net Revenue After Deducting Future Income Tax Expenses
Proved Developed Producing								
Mining	223 537	33 649	88 270	36 582		65 036	15 598	49 438
In Situ	23 124	1 701	10 809	2 843	77	7 694	849	6 845
East Coast Canada	5 009	1 038	1 305	448	259	1 959	473	1 486
North America Onshore	6 719	897	2 639	14	143	3 026	556	2 470
Total Canada	258 389	37 285	103 023	39 887	479	77 715	17 476	60 239
North Sea	7 550		935	66	80	6 469	4 383	2 086
Other International	3 868		441	180	12	3 235	2 103	1 132
Total Proved Developed Producing	269 807	37 285	104 399	40 133	571	87 419	23 962	63 457
Proved Developed Non-Producing								
Mining								
In Situ								
East Coast Canada								
North America Onshore	237	42	107	21	2	65	17	48
Total Canada	237	42	107	21	2	65	17	48
North Sea	2 342		629		6	1 707	1 048	659
Other International	5 835	749	1 205	80	4	3 797	1 437	2 360
Total Proved Developed Non-Producing	8 414	791	1 941	101	12	5 569	2 502	3 067
Proved Undeveloped								
Mining								
In Situ	108 481	15 527	41 702	27 597	543	23 112	6 116	16 996
East Coast Canada	2 833	624	604	506	29	1 070	280	790
North America Onshore	515	36	127	168	17	167	43	124
Total Canada	111 829	16 187	42 433	28 271	589	24 349	6 439	17 910
North Sea	4 585		960	959	37	2 629	1 619	1 010
Other International	277	24	54	63	1	135	77	58
Total Proved Undeveloped	116 691	16 211	43 447	29 293	627	27 113	8 135	18 978
Proved								
Mining	223 537	33 649	88 270	36 582		65 036	15 598	49 438
In Situ	131 605	17 228	52 511	30 440	620	30 806	6 965	23 841
East Coast Canada	7 842	1 662	1 909	954	288	3 029	753	2 276
North America Onshore	7 471	975	2 873	203	162	3 258	616	2 642
Total Canada	370 455	53 514	145 563	68 179	1 070	102 129	23 932	78 197
North Sea	14 477		2 524	1 025	123	10 805	7 050	3 755
Other International	9 980	773	1 700	323	17	7 167	3 617	3 550

Total Proved	394 912	54 287	149 787	69 527	1 210	120 101	34 599	85 502
Probable								
Mining	80 974	11 289	29 877	10 956		28 852	6 731	22 121
In Situ	259 749	46 872	90 543	51 537	759	70 038	18 113	51 925
East Coast Canada	29 175	7 906	3 349	2 632	149	15 139	4 058	11 081
North America Onshore	3 377	498	1 329	177	23	1 350	343	1 007
Total Canada	373 275	66 565	125 098	65 302	931	115 379	29 245	86 134
North Sea	4 047		597	86	17	3 347	2 063	1 284
Other International	9 167	1 113	1 313	481	3	6 257	3 346	2 911
Total Probable	386 489	67 678	127 008	65 869	951	124 983	34 654	90 329
Proved Plus Probable								
Mining	304 511	44 938	118 147	47 538		93 888	22 329	71 559
In Situ	391 354	64 100	143 054	81 977	1 379	100 844	25 078	75 766
East Coast Canada	37 017	9 568	5 258	3 586	437	18 168	4 811	13 357
North America Onshore	10 848	1 473	4 202	380	185	4 608	959	3 649
Total Canada	743 730	120 079	270 661	133 481	2 001	217 508	53 177	164 331
North Sea	18 524		3 121	1 111	140	14 152	9 113	5 039
Other International	19 147	1 886	3 013	804	20	13 424	6 963	6 461
Total Proved Plus Probable	781 401	121 965	276 795	135 396	2 161	245 084	69 253	175 831

Future Net Revenues by Production Group

as at December 31, 2011
(forecast prices and costs)

(before income taxes, discounted at 10% per year)	$ millions	$/boe [1]
Proved Producing		
Unconventional Mining	27 354	15.88
Unconventional In Situ	5 546	24.06
Total Unconventional [2]	32 900	16.85
Light & Medium Oil [3]	8 822	56.02
Natural Gas [4]	1 330	11.34
Total Proved Producing	43 052	19.33
Proved		
Unconventional Mining	27 354	15.88
Unconventional In Situ	10 195	8.27
Total Unconventional [2]	37 549	12.71
Light & Medium Oil [3]	12 466	47.95
Natural Gas [4]	2 889	16.32
Total Proved	52 904	15.60
Proved Plus Probable		
Unconventional Mining	31 757	14.43
Unconventional In Situ	17 247	6.06
Total Unconventional [2]	49 004	9.71
Light & Medium Oil [3]	21 432	39.48
Natural Gas [4]	3 819	14.82
Total Proved Plus Probable	74 255	12.70

(1) Per unit values use net reserves.

(2) Total Unconventional includes SCO and bitumen.

(3) Light & Medium Oil includes associated byproducts, including solution gas and NGLs.

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

Notes to Future Net Revenues Tables

Prices Realized

For prices realized by Suncor during 2011, please see the Production History section contained within this Statement of Reserves Data and Other Oil and Gas Information.

Forecast Prices and Costs

Crude oil, natural gas and other important benchmark reference pricing, as well as inflation and exchange rates utilized in the GLJ Reports and the Sproule Reports, are as per GLJ's price forecast dated January 1, 2012, as set out below. To the extent that there are fixed or presently determinable future prices or costs to which Suncor is legally bound by contractual or other obligations to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs have been incorporated into the forecast prices as applied to the pertinent properties. The forecast cost and price assumptions include increases in wellhead selling prices, take into account inflation with respect to future operating and capital costs, and assume the continuance of current laws and regulations. Price adjustments relating to factors such as product quality and transportation were applied on an individual property basis in cash flow calculations.

Forecast prices included a US$/Cdn$ exchange rate of 0.98, a Cdn$/€ exchange rate of 1.35 and a Cdn$/£ exchange rate of 1.60. Forecast costs included a 2% inflation factor, except for costs for Mining, which included 4% inflation for 2013-2015, 3% inflation for 2016 and 2% thereafter.

Constant Prices and Costs

For purposes of comparison to those issuers who are required to report reserves estimates using constant prices and costs in accordance with the rules and regulations of the U.S. Securities and Exchange Commission (SEC), Suncor also presents reserves estimates using constant prices and costs. Benchmark prices utilized for the purpose of disclosing supplementary reserves estimates under constant pricing assumptions are also set out in the table below. Prices are based on the arithmetic average of the first-day-of-the-month price for the product for each month of 2011.

Constant prices included a US$/Cdn$ exchange rate of 1.02, a Cdn$/€ exchange rate of 1.38 and a Cdn$/£ exchange rate of 1.58.

Prices used in Reserves Tables (1)

Forecast	WTI (2)	WCS (3)	Pentanes (4)	AECO (5)	Light Sweet (6)	Brent (7)	NBP (8)	B.C. Gas (9)
Year	US$/bbl	Cdn$/bbl	Cdn$/bbl	Cdn$/mmbtu	Cdn$/bbl	US$/bbl	Cdn$/mmbtu	Cdn$/mmbtu
2012	97.00	81.61	107.76	3.49	97.96	105.00	9.32	3.29
2013	100.00	82.63	108.09	4.13	101.02	105.00	9.74	3.93
2014	100.00	82.63	105.06	4.59	101.02	102.00	9.91	4.39
2015	100.00	82.63	105.06	5.05	101.02	100.00	10.20	4.85
2016	100.00	82.63	105.06	5.51	101.02	100.00	10.20	5.31
2017	100.00	82.63	105.06	5.97	101.02	100.00	10.20	5.77
2018	101.35	83.75	106.49	6.21	102.40	101.35	10.34	6.01
2019	103.38	85.44	108.65	6.33	104.47	103.38	10.55	6.13
2020	105.45	87.16	110.84	6.46	106.58	105.45	10.76	6.26
2021	107.56	88.92	113.08	6.58	108.73	107.56	10.98	6.38
2022+	+2.0%/year	+2.0%/year	+2.0%/year	+2.0%/year	+2.0%/year	+2.0%/year	+2.0%/year	+2.0%/year
Constant	US$/bbl	Cdn$/bbl	Cdn$/bbl	Cdn$/mmbtu	Cdn$/bbl	US$/bbl	Cdn$/mmbtu	Cdn$/mmbtu
All years	96.19	78.81	105.28	3.71	96.04	111.85	9.43	3.32

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

(2) NYMEX WTI crude oil at Cushing, Oklahoma. Price used when determining SCO reserves presented as In Situ and Mining reserves.

(3) WCS stream at Hardisty, Alberta. Price used when determining bitumen reserves presented as In Situ reserves.

(4) Edmonton pentanes plus. Price used when determining the cost of diluent associated with bitumen reserves presented as In Situ reserves. A bitumen/diluent ratio of approximately 2:1 was used. Price also used when determining certain NGL reserves.

(5) Natural gas price at AECO. Price used when determining natural gas reserves (primarily in Alberta) presented as North America Onshore reserves. Price also used when determining natural gas input costs for the production of SCO and bitumen reserves.

(6) Light sweet crude oil (40 API, 0.3% sulphur) at Edmonton, Alberta. Price used when determining light and medium oil reserves presented as North America Onshore reserves.

(7) Brent blend crude oil FOB North Sea. Price used when determining light and medium oil reserves presented as East Coast Canada reserves, North Sea reserves and Other International reserves.

(8)

National Balancing Point (U.K.). Price used when determining natural gas reserves presented as North Sea reserves and Other International reserves.

(9) Natural gas prices at B.C. Westcoast Station 2. Price used when determining natural gas reserves (primarily in B.C.) presented as North America Onshore reserves.

Disclosure of After-Tax Net Present Values of Future Net Revenue

Values presented in the table for Net Present Value of Future Net Revenues After Income Taxes reflect income tax burdens of assets at an individual asset level (for Mining, In Situ and East Coast Canada) or at a business area or legal entity level (for North Sea and North America Onshore) based on tax pools associated with that business area or legal entity. Income taxes for Other International assets are determined by their respective PSCs. Suncor's actual corporate legal entity structure for income taxes and income tax planning have not been considered, and, therefore, the total value for income taxes presented in the table may not provide an estimate of the value at the corporate entity level, which may be significantly different. The 2011 audited Consolidated Financial Statements and the MD&A should be consulted for information on income taxes at the corporate entity level.

Future Development Costs
as at December 31, 2011
(forecast prices and costs)

($ millions)	2012	2013	2014	2015	2016	Remainder	Total	Discounted At 10%
Proved								
Mining	2 173	2 231	1 634	1 332	1 345	27 867	36 582	16 661
In Situ	1 643	1 337	1 048	1 130	1 521	23 761	30 440	13 426
East Coast Canada	515	129	111	17	47	135	954	794
North America Onshore	15	73	39	24	23	29	203	157
Total Canada	4 346	3 770	2 832	2 503	2 936	51 792	68 179	31 038
North Sea	406	318	183	77	41		1 025	899
Other International	118	132	47	11	10	5	323	282
Total Proved	4 870	4 220	3 062	2 591	2 987	51 797	69 527	32 219
Proved Plus Probable								
Mining	2 254	2 321	1 697	1 389	1 411	38 466	47 538	18 779
In Situ	1 600	1 681	1 974	3 099	2 873	70 750	81 977	21 419
East Coast Canada	741	661	648	441	352	743	3 586	2 656
North America Onshore	62	156	87	24	23	28	380	310
Total Canada	4 657	4 819	4 406	4 953	4 659	109 987	133 481	43 164
North Sea	406	318	213	102	72		1 111	963
Other International	118	283	111	106	106	80	804	632
Total Proved Plus Probable	5 181	5 420	4 730	5 161	4 837	110 067	135 396	44 759

Development costs include costs associated with both developed and undeveloped reserves. Significant development activities for 2012 are expected to include:

For Mining, costs for mine train relocations and mine train replacements at Syncrude and new tailings management facilities for Oil Sands Base. Remaining development costs are sustaining capital investments, which maintain production capacities at existing facilities, and include costs for major maintenance, catalyst, truck and shovel replacement, and the replacements for utilities, roads and other facilities.

For In Situ, facility and new well costs for the Firebag Stage 4 expansion and new wells at MacKay River and Firebag to sustain bitumen supply for existing central processing facilities.

For East Coast Canada, costs for development drilling at Terra Nova, White Rose and Hibernia, procurement of subsea infrastructure for the HSEU, H_2S remediation activities, the FPSO swivel replacement and other dockside maintenance activities at Terra Nova, and early development activities for Hebron.

For North Sea, costs for development drilling and facility upgrades at Buzzard, including accommodations, sand management, and produced water reinjection, and early development activities for Golden Eagle.

For North America Onshore, costs for the development of the Wilson Creek and Ferrier fields in the Cardium oil formation.

For Other International, costs for upgrades and maintenance to facilities in Libya. Due to the sanctions and suspension of operations in Syria, no development costs were included for 2012.

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

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

Abandonment and Reclamation Costs

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

At December 31, 2011, Suncor estimated its undiscounted, uninflated abandonment and reclamation costs, net of estimated salvage value, for surface leases, wells, facilities and pipelines pertaining to its upstream assets to be approximately $7.2 billion (discounted at 10%, approximately $2.1 billion). Suncor estimates that it will incur $1.284 billion (undiscounted: 2012 $408 million, 2013 $463 million, 2014 $413 million) of its identified abandonment and reclamation costs during the next three years, over 85% of which is associated with mining operations. This cost estimate does not include the company's estimated abandonment and reclamation costs for its Refining and Marketing assets ($71 million, undiscounted and uninflated).

Approximately $2.2 billion (undiscounted) has been deducted as abandonment costs in estimating the future net revenues from proved plus probable reserves. This $2.2 billion represents the abandonment obligation for approximately 6,300 net reserves wells, including a forecasted number of future wells for undeveloped reserves, for our in situ and conventional activities. This figure counts in situ well pairs as one abandonment, whereas previous figures reported by Suncor counted in situ well pairs as two separate abandonments.

Abandonment and reclamation costs included in Suncor's $7.2 billion total that are excluded from the determination of future net revenues from reserves include, but are not limited to, costs related to the reclamation of disturbed land from oil sands mining activities, the treatment of oil sands tailings, the decommissioning of oil sands and natural gas processing facilities and well pads, lease sites, and the abandonment of wells to which no reserves have been assigned.

Additional Information Relating to Reserves Data

Gross Proved and Probable Undeveloped Reserves [1][2]

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

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

Gross Proved Undeveloped Reserves

(forecast prices and costs)

	Prior		2009		2010		2011	
	First Attributed	Total at December 31 2008	First Attributed	Total at December 31 2009	First Attributed	Total at December 31 2010	First Attributed	Total at December 31 2011
SCO (mmbbls)								
Mining								
In Situ	766.0	766.0	121.0	564.0	14.0	651.0		502.0
Total SCO	766.0	766.0	121.0	564.0	14.0	651.0		502.0
Bitumen (mmbbls)								
Mining								
In Situ				427.0	2.0	360.0	315.0	661.1
Total Bitumen				427.0	2.0	360.0	315.0	661.1
Light & Medium Oil (mmbbls)								
East Coast Canada			35.0	35.0	3.0	28.0	1.4	26.6
North America Onshore	0.1	0.1	0.2	0.3		0.2	0.1	0.3
Total Canada	0.1	0.1	35.2	35.3	3.0	28.2	1.5	26.9
North Sea [3]			68.0	68.0		19.0	24.6	43.3
United States [4]			8.3	8.3				
Other International [5]					6.0	6.0	1.8	5.8
Total Light & Medium Oil	0.1	0.1	111.5	111.6	9.0	53.2	27.9	76.0
Natural Gas (bcf)								
North America Onshore Canada	31.2	31.2	29.1	15.6	32.0	118.4	2.1	78.7
North Sea [3]						1.0	1.5	2.7
United States [4]			23.9	23.9				
Other International [5]			413.0	413.0				
Total Natural Gas	31.2	31.2	466.0	452.5	32.0	119.4	3.6	81.4

NGLs (mmbbls)								
North America								
Onshore Canada	0.1	0.1	0.3	0.4		0.1		0.1
North Sea [3]			1.0	1.0				0.1
Other International [5]			9.0	9.0				
Total NGLs	0.1	0.1	10.3	10.4		0.1		0.2
Total (mmboe)	771.4	771.4	320.5	1 188.4	30.4	1 084.2	343.5	1 252.8

Gross Probable Undeveloped Reserves
(forecast prices and costs)

	Prior		2009		2010		2011	
	First Attributed	Total at December 31 2008	First Attributed	Total at December 31 2009	First Attributed	Total at December 31 2010	First Attributed	Total at December 31 2011
SCO (mmbbls)								
Mining	617.0	617.0	264.0	264.0		215.0		263.0
In Situ	1 746.0	1 746.0	174.0	595.0	6.0	400.0	916.0	1 212.0
Total SCO	2 363.0	2 363.0	438.0	859.0	6.0	615.0	916.0	1 475.0
Bitumen (mmbbls)								
Mining						37.0		
In Situ				1 550.0	8.0	1 835.0	38.0	669.0
Total Bitumen				1 550.0	8.0	1 872.0	38.0	669.0
Light & Medium Oil (mmbbls)								
East Coast Canada			80.0	80.0	7.0	85.0	143.2	217.4
North America Onshore			5.1	5.1	0.3	3.5	0.7	2.0
Total Canada			85.1	85.1	7.3	88.5	143.9	219.4
North Sea (3)			35.0	35.0		15.0	13.8	17.1
United States (4)			3.8	3.8				
Other International (5)			62.0	62.0	8.0	11.0	3.8	14.5
Total Light & Medium Oil			185.9	185.9	15.3	114.5	161.5	251.0
Natural Gas (bcf)								
North America								
Onshore Canada	76.3	76.3	235.2	233.2	75.2	136.2	3.2	86.9
North Sea (3)			50.0	50.0		1.0	1.2	1.5
United States (4)			12.0	12.0				
Other International (5)			651.0	651.0		240.0	221.4	347.4
Total Natural Gas	76.3	76.3	948.2	946.2	75.2	377.2	225.8	435.8
NGLs (mmbbls)								
North America								
Onshore Canada	0.2	0.2	0.9	1.0	0.1	1.0		0.8
North Sea (3)			1.0	1.0				
Other International (5)			18.0	18.0		8.0	6.0	11.5
Total NGLs	0.2	0.2	19.9	20.0	0.1	9.0	6.0	12.3
Total (mmboe)	2 375.9	2 375.9	801.8	2 772.6	41.9	2 673.4	1 159.1	2 479.9

(1) The term First Attributed represents undeveloped reserves additions including acquisitions, discoveries and extensions pertaining to the year in which the events first occurred. Undeveloped reserves first attributed in 2009 primarily include those acquired as a result of the merger with Petro-Canada.

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

(3) In these tables, "North Sea" includes additional properties previously held by Suncor in the Netherlands portion of the North Sea.

(4) Undeveloped U.S. reserves were acquired in the merger with Petro-Canada in 2009 and subsequently disposed in 2010.

(5) In these tables "Other International" includes additional properties previously held by Suncor in Trinidad and Tobago.

Undeveloped In Situ reserves, which constitute approximately 93% of Suncor's gross proved undeveloped reserves and 76% of Suncor's gross probable undeveloped reserves, will take more than two years to develop. Management uses integrated plans to forecast future development. These detailed plans align current production, processing and pipeline capacities, capital spending commitments and future development for the next ten years, and are reviewed and updated annually for internal and external factors affecting planned activity. Reserves are developed as required to keep processing capacity full. The timing associated with developing undeveloped reserves is a function of the forecasts of the declining production from existing well pairs. Suncor has delineated In Situ reserves to a high degree of certainty through seismic data and core hole drilling, consistent with COGE guidelines. In most cases, proved reserves have been drilled to a density of 16 wells per section, well in excess of the eight wells per section required for regulatory approval. In order to determine the economic cutoffs of undeveloped reserves, geological information is tested against existing production analogues that use established technology.

Undeveloped Mining reserves, which constitute approximately 11% of Suncor's gross probable undeveloped reserves, relate solely to the Syncrude Aurora South mine, which has regulatory approvals substantially in place and is well-delineated by core hole drilling. The owners of the Syncrude joint venture do not expect that the Aurora South mine will come on-stream in this decade.

Undeveloped conventional (light and medium oil, natural gas and NGLs) reserves constitute approximately 7% of Suncor's gross proved undeveloped reserves and approximately 13% of Suncor's gross probable undeveloped reserves. As part of its active portfolio management process, Suncor reviews the economic viability of its conventional properties containing undeveloped reserves using industry standard economic evaluation techniques and its own pricing and economic environment assumptions. Through this active management process, Suncor selects some properties for further development activities, while others are held in abeyance, sold, or swapped. In developing the company's reserves, Suncor considers existing facility and gathering system capacity, capital allocation plans and remaining recoverable resources availability. Accordingly, in some cases, it will take longer than two years to develop all of the currently assigned undeveloped conventional reserves. With the exception of undeveloped reserves that Suncor may divest, Suncor plans to develop the majority of the conventional proved undeveloped reserves over the next five years and the majority of the conventional probable undeveloped reserves over the next seven years. Exceptions are development of some offshore properties which are limited by production facility capacity and development of some international properties constrained by daily contract quantities stipulated by PSCs.

Properties with no Attributed Reserves

The following table is a summary of properties to which no reserves are attributed as at December 31, 2011. For lands in which Suncor holds interests in different formations under the same surface area pursuant to separate leases, the area has been counted for each lease.

Country	Gross Hectares	Net Hectares
Canada	5 093 830	3 740 853
Libya	2 950 978	1 339 489
U.S. Alaska	1 161 123	387 002
Norway	501 791	209 691
Syria	345 194	345 194
U.K.	138 437	44 574
Australia (overriding royalty interest only)	113 027	
Total	10 304 380	6 066 803

Suncor holds interests in a diverse portfolio of undeveloped petroleum assets in Canada and in several international areas. These assets range from exploration properties in a very preliminary phase of evaluation, to discovery areas where tenure to the property is held indefinitely on the basis of hydrocarbon test results, but where economic development is not currently possible or has not yet been sanctioned. In many cases where reserves are not attributed to lands containing one or more discovery wells, the key limiting factor is the lack of available production infrastructure. Each year, as part of the company's active management process to review the economic viability of its conventional properties, some properties are selected for further development activities, while others are held in abeyance, sold, swapped or relinquished back to the mineral rights owner.

In 2012, Suncor's rights to explore, develop and exploit will expire for 189,374 net hectares in Canada, 131,308 net hectares in Alaska and 39,840 net hectares in the U.K. portion of the North Sea. No land tenure expiries are scheduled to occur for either Mining or In Situ properties for 2012. Substantial portions of expiring lands may have their tenure continued beyond 2012 through the conduct of work programs and/or the payment of prescribed fees to the rights owner.

Oil and Gas Properties and Wells

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

Suncor's Oil Sands operations recover bitumen through oil sands mining and in situ development in northern Alberta. Conventional activities are focused on the development and production of oil, natural gas, and NGLs from onshore reserves in Western Canada, Libya and Syria, and from reserves offshore Newfoundland and in the North Sea.

The following table is a summary of operated and non-operated oil and gas wells associated with the company's reserves as at December 31, 2011:

	Oil Wells	Natural Gas Wells

	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	253.0	236.9	134.0	130.7	4 268.0	2 916.4	206.0	168.6
British Columbia	15.0	9.6	6.0	5.8	235.0	200.5	87.0	70.2
Saskatchewan					738.0	268.1	91.0	43.5
Newfoundland	61.0	15.6	2.0	0.8				
North Sea	26.0	7.8	4.0	1.2				
Other International	213.0	106.5	77.0	40.0			6.0	6.0
Total	568.0	376.4	223.0	178.5	5 241.0	3 385.0	390.0	288.3

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

For In Situ properties, proved non-producing reserves and probable non-producing reserves are associated with wells that have been drilled within the last two years, which require further capital for completion and tie in to facilities to bring the wells on-stream. This capital requirement is significant enough that the reserves are not classified as developed. SAGD well pairs are counted as one well.

In Syria, wells previously reported as producing have been reclassified to non-producing, consistent with the reclassification of proved developed producing reserves and probable developed producing reserves to their respective non-producing categories.

The majority of remaining conventional non-producing reserves have been in their current non-producing state for less than four years and are forecast to be brought on-stream within the next two years. These remaining non-producing reserves are primarily associated with:

- Recently drilled wells to be brought on production in 2012;
- Secondary zones forecast to be brought on-stream over the next two years;
- Wells requiring workovers;
- Wells temporarily shut in due to operational issues at facilities; and
- Gas production being re-injected to maintain gas cap pressure on oil producing zones until depletion of the oil zones.

Costs Incurred

The table below summarizes the company's capital expenditures related to its reserves activities for the year ended December 31, 2011.

($ millions)		Exploration Costs	Proved Property Acquisition Costs	Unproved Property Acquisition Costs	Development Costs	Total
Canada	Mining and In Situ	57		200	4 362	4 619
Canada	East Coast Canada and North America Onshore	77		1	476	554
North Sea		97		29	74	200
Other International		36			37	73
Total		267		230	4 949	5 446

Exploration and Development Activities

The table below outlines the gross and net exploratory and development wells the company completed during the year ended December 31, 2011.

Total number of wells completed	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Canada				
Oil			73.0	64.6
Natural Gas	1.0	0.5	105.0	52.3
Dry Hole	2.0	2.0	2.0	1.2
Service			8.0	5.0
Stratigraphic Test	22.0	13.8	617.0	311.6
Total	25.0	16.3	805.0	434.7
North Sea				
Oil			4.0	1.2
Natural Gas				
Dry Hole	1.0	0.3		
Service			1.0	0.3
Stratigraphic Test				
Total	1.0	0.3	5.0	1.5
Other International				
Oil			4.0	2.5
Natural Gas				
Dry Hole	1.0	0.5	1.0	1.0
Service				
Stratigraphic Test				
Total	1.0	0.5	5.0	3.5

Significant exploration and development wells completed in 2011 included:

For Mining, core hole drilling programs and other survey work at Oil Sands Base and Syncrude to provide additional information on areas the company expects to mine in the near term.

For In Situ, infill wells at Firebag Stage 1 and Stage 2 well pads, new wells at MacKay River and Firebag to help sustain bitumen supply for existing central processing facilities, and core hole drilling at Firebag, MacKay River and Meadow Creek to further delineate reserves and resources.

For East Coast Canada, the Ballicatters exploration well, a production well at Terra Nova, and development drilling for Hibernia, the HSEU and the White Rose Extensions.

For International, exploration drilling on the Butch prospect in the Norway portion of the North Sea, development drilling at Buzzard, oil development wells in Libya, and one oil development well in Syria (prior to sanctions related to oil investment and, later, the suspension of operations).

For North America Onshore, development drilling of the Wilson Creek and Ferrier fields in the Cardium oil formation, the Medicine Hat shallow gas region, and the Kobes area of the Montney shale gas formation.

Production History

The table below outlines the company's historical production information, by product type, for each of the four financial quarters, as an average daily measure, for Canada, North Sea and Other International. Average price realized is net of transportation costs, but before royalties.

	2011			
	Three months ended			
	Mar 31	Jun 30	Sept 30	Dec 31
Canada				
Oil Sands [1]				
Average total production (mbbls/d)	360.6	277.2	362.5	356.8
Average In Situ bitumen production (mbbls/d)	87.3	85.8	83.8	101.4
Average price realized ($/bbl)	83.74	93.16	86.40	98.01
Royalties ($/bbl)	(3.33)	(5.49)	(6.28)	(8.17)
Total cash operating costs ($/bbl)	(36.42)	(49.73)	(37.06)	(40.42)
In Situ cash operating costs ($/bbl)	(22.00)	(24.15)	(27.05)	(29.15)
Light & Medium Oil				
Average total production (mbbls/d)	65.0	65.0	69.1	63.4
Average price realized ($/bbl)	104.01	112.19	111.30	111.77
Royalties ($/bbl)	(32.04)	(34.99)	(33.56)	(36.95)
Production costs ($/bbl)	(8.14)	(7.26)	(6.69)	(9.36)
Netback ($/bbl)	63.83	69.94	71.05	65.46
Natural Gas [2]				
Average total production (mmcfe/d)	411	402	375	365
Average price realized ($/mcfe)	4.52	4.90	4.56	4.31
Royalties ($/mcfe)	(0.44)	(0.54)	(0.48)	(0.48)
Production costs ($/mcfe)	(1.49)	(1.35)	(1.71)	(1.66)
Netback ($/mcfe)	2.59	3.01	2.37	2.17
North Sea				
Light & Medium Oil [3]				
Average total production (mboe/d)	65.7	32.7	33.1	55.0
Average price realized ($/boe)	93.74	113.24	111.60	106.41
Royalties ($/boe)	(0.00)	(0.00)	(0.00)	(0.00)
Production costs ($/boe)	(6.86)	(6.66)	(6.34)	(3.64)
Netback ($/boe)	86.88	106.58	105.26	102.77

Other International

Light & Medium Oil				
Average total production (mboe/d)	24.2			24.8
Average price realized ($/boe)	99.07			109.58
Royalties ($/boe)	(80.75)			(61.85)
Production costs ($/boe)	(2.85)			(8.12)
Netback ($/boe)	15.47			39.61
Natural Gas (4)				
Average total production (mboe/d)	17.1	16.9	18.9	16.0
Average price realized ($/boe)	84.58	95.28	95.49	91.69
Royalties ($/boe)	(32.04)	(38.54)	(43.28)	(35.11)
Production costs ($/boe)	(6.19)	(7.66)	(6.06)	(8.20)
Netback ($/boe)	46.35	49.08	46.15	48.38

(1) Suncor tracks cash operating cost for its Oil Sands operations, which includes more expenses than strictly production costs. For this reason, a netback calculation is not presented in this table. Also, most of Suncor's bitumen production is upgraded; therefore, a bitumen netback is not presented. Amounts presented include results from the company's share in the Syncrude joint venture.

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

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

(4) Volumes include approximate annual oil production of 1.5 mboe/d from Syria.

The following table provides the production volumes for each of Suncor's important fields for the year ended December 31, 2011.

	SCO and Bitumen	Light & Medium Oil	Natural Gas	NGLs	Total
	mbbls/d	mbbls/d	mmcfe/d	mbbls/d	mboe/d
Mining Suncor[1]	228.6				228.6
Mining Syncrude[1]	34.6				34.6
Firebag [2]	48.1				48.1
MacKay River [2]	27.9				27.9
Buzzard		41.9	4.3	0.3	42.9
Hibernia		30.9			30.9
White Rose		18.5			18.5
Terra Nova		16.2			16.2

(1) All production attributed to Mining represents SCO.

(2) Estimates of production representing a mixture of upgraded SCO and non-upgraded bitumen.

Production Estimates

The table below outlines the volume of the company's production of gross proved and gross proved plus probable reserves estimated for the year ending December 31, 2012, as is reflected in the estimates of gross proved reserves and gross probable reserves previously disclosed in the Summary of Oil and Gas Reserves tables. Production estimates for 2012 for proved plus probable reserves from: Suncor's mining operations (excluding Syncrude) are 232 mbbls/d of SCO, approximately 47% of total estimated production for 2012; and from Firebag are 72 mbbls/d of SCO and bitumen, approximately 15% of total estimated production for 2012.

	SCO		Bitumen		Light & Medium Oil		Natural Gas		NGLs	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	mbbls/d	mbbls/d	mbbls/d	mbbls/d	mboe/d	mboe/d	mmcfe/d	mmcfe/d	mboe/d	mboe/d
Canada										
Proved	325.3	296.9	21.2	19.4	40.9	32.9	287.1	243.9	2.3	1.7
Probable	24.2	21.7	0.4	(0.7)	14.3	10.3	8.7	7.1	0.2	0.1
Proved Plus Probable	349.5	318.6	21.6	18.7	55.2	43.2	295.8	251.0	2.5	1.8
North Sea										
Proved					54.0	54.0	5.8	5.8	0.5	0.5
Probable										
Proved Plus Probable					54.0	54.0	5.8	5.8	0.5	0.5

Other International

Proved	37.0	13.8
Probable		
Proved Plus Probable	37.0	13.8

Work Commitments

The practice of governments requiring companies to pledge to carry out work commitments in exchange for the right to carry out exploration for and development of hydrocarbons is common, particularly in unexplored or lightly explored regions of the world. The following table shows the estimated values of work commitments Suncor has made in regard to the lands it holds as at December 31, 2011. These commitments run through 2013 and are primarily for conducting seismic programs and drilling exploration wells.

Country/Area ($ millions)	2012	Total
Canada	1	24
North Sea	158	216
Other International	128	369

Forward Contracts and Transportation Obligations

Suncor may use financial derivatives to manage its exposure to fluctuations in commodity prices; however, Suncor did not have any such material financial derivative transactions in 2011. A description of Suncor's use of such instruments is provided in the 2011 audited Consolidated Financial Statements and related MD&A for the year ended December 31, 2011.

As a result of the merger, Suncor holds a commitment of 85,000 mcf/d of contract capacity on the Alliance Pipeline that expires in November 2015, which enables Suncor to transport high-energy, rich natural gas from northeastern B.C. and northwestern Alberta to the Alliance Pipeline terminus in Illinois. Subsequent to Suncor's 2010 divestitures, this commitment exceeds Suncor's production from the area. Suncor estimates its minimum commitment on the Alliance Pipeline to be approximately US$50 million per year. Natural gas for the Alliance Pipeline commitment is expected to be supplemented by supply purchased from third parties. Deliveries to Illinois are expected to continue for the term of the contract provided the sales price in Illinois exceeds, at a minimum, the variable cost of the transportation.

Tax Horizon

In 2011, Suncor was subject to cash tax in the local jurisdictions related to earnings from its North Sea and Other International production, but was not cash taxable in Canada on the majority of its Canadian earnings. Suncor's 2011 audited Consolidated Financial Statements were prepared using the 2014 effective Canadian tax rate to record income taxes, as this rate would apply to the reversal of long-term temporary differences. Based on projected future net earnings, Suncor may be cash taxable in Canada by 2013.

Contingent Resources

GLJ conducted an independent assessment of Best Estimate contingent resources volumes for all of Suncor's Mining properties and for Suncor's In Situ properties to which reserves are attributed (Firebag and MacKay River). For In Situ properties without attributed reserves, GLJ audited assessments of Best Estimate contingent resources volumes (approximately 41% of In Situ contingent resources) prepared by Suncor's internal qualified reserves evaluators. Best Estimate contingent resources for other properties were prepared by Suncor's internal qualified reserves evaluators. All contingent resources estimates were conducted in accordance with the COGE Handbook.

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 recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or lack of infrastructure or markets. 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.

There is no certainty that all or any portion of the contingent resources will be commercially viable to produce. Estimates of contingent resources have not been adjusted for risk based on the chance of development. There is no certainty as to the timing of such development. For movement of contingent resources to reserves categories, all projects must have an economic depletion plan and may require, among other things, additional delineation drilling, regulatory applications, or sanction from the company's Board and any joint venture owners to proceed with development.

In general, significant factors that may change contingent resources estimates include further delineation drilling, which could change the estimates either positively or negatively, future technology improvements, which would positively affect the estimates, and additional processing capacity that could affect the volumes recoverable or type of production. Additional facility design work, development plans, reservoir studies and delineation drilling are often completed in the course of preparing the company's application for regulatory approvals. Once there is a high level of certainty of receiving all regulatory and corporate approvals, and all other contingencies are removed, the resources may then be reclassified as reserves.

Effective December 31, 2011, Suncor's Best Estimate of gross contingent resources is set out in the table below. Volumes represent Suncor's working interest in properties with contingent resources.

Best Estimate Gross Contingent Resources	SCO	Bitumen	Light & Medium Oil	Natural Gas	NGLs	Total
	mmbbls	mmbbls	mmbbls	bcf	mmbbls	mmboe
Mining	4 582	2 156				6 738
In Situ	6 432	6 020				12 452
East Coast Canada			247	2 203		614
North America Onshore (1)			116	8 017	13	1 465
Total Canada	11 014	8 176	363	10 220	13	21 269
North America Onshore U.S.				133		22
North Sea (2)			45	36		52
Other International			481	245	1	522
As at December 31, 2011	11 014	8 176	889	10 634	14	21 865
As at December 31, 2010	12 462	5 291	956	10 370	17	20 454

(1) Contingent resources include offshore fields in the Arctic Islands.

(2) Contingent resources are offshore Norway.

Contingent resources increased to 21,865 mmboe at December 31, 2011 from 20,454 mmboe at December 31, 2010. Increases to contingent resources included extensions of the MacKay River and Meadow Creek leases, acquisition of additional leases in the Audet area, technical revisions for In Situ assets, recognition of potential Hibernia secondary zones, and volumes attributed to discoveries in the Ballicatters, Butch and Wilson Creek areas. The net effects of Suncor's transactions with Total E&P, which included the acquisition of an interest in Joslyn, the partial disposition of our interest in Fort Hills and a change in assumption that reclassified remaining Fort Hills reserves from SCO to bitumen, also increased total contingent resources. These increases were partially offset by the transfer of resources to proved plus probable reserves for Golden Eagle and Hebron, and asset dispositions.

Suncor has assumed that some Mining and some In Situ contingent resources will be upgraded and sold as SCO. To the extent that these volumes are not upgraded, but rather sold as bitumen, contingent resources volumes reported would be lower for SCO and higher for bitumen, and total contingent resources volumes would be higher because of the yield factor applied to bitumen volumes when upgraded into SCO. Conversely, to the extent that more volumes are upgraded, total contingent resources volumes would be lower.

Generally, the timing for the economic assessments of contingent resources will be determined by Suncor's long-term resource development plan and its forecast for economic conditions. Management uses integrated plans to forecast future development of resources. These plans align current and planned production, current and forecasted market conditions, processing and pipeline capacities, capital spending commitments and related future development plans. These plans are reviewed and updated annually for internal and external factors affecting these planned activities. In particular, as Suncor's Oil Sands reserves base depletes, the company anticipates that it will look to develop its other Mining and In Situ properties, at which time the assessment of the economic viability of specific properties with contingent resources will be made.

Details of Suncor's contingent resources and a categorization of the contingencies ascribed to these resources are provided below.

Mining Contingent Resources

Mining contingent resources comprise approximately 31% of Suncor's total contingent resources, with 59% of these contingent resources on properties in which Suncor has a 100% working interest and the remainder forming part of joint arrangements where Suncor has working interests varying from 12% to 40.8%.

Economic Contingencies

GLJ has tested the economic viability of the Fort Hills and Joslyn North projects, which constitute approximately 25% of total Mining contingent resources, and determined them to be economic. The economic status of remaining Mining contingent resources is currently undetermined; however, the company anticipates that the contingent resources will be economic to develop under current market conditions, as the potential development of these contingent resources would reflect the application of established technology and reasonable assumptions for mine pit design.

Non-Technical Contingencies

Given the concern within the industry with respect to the potential cost escalation of large mining projects, the reclassification of Mining contingent resources to reserves is largely contingent upon an assessment that development will be sanctioned and commence within a reasonable time frame. The Fort Hills and Joslyn North mining projects have substantially all regulatory approvals in place, but final investment decisions based on development plans currently being finalized await decision by the joint venture owners, and, as a result, it is Suncor's view that the development of these contingent resources in the near term is not sufficiently assured to support reclassification to reserves. For Suncor's remaining Mining contingent resources, regulatory permits must be obtained before a project sanction decision by Suncor's Board and joint venture owners, as applicable, is considered.

In Situ Contingent Resources

In Situ contingent resources comprise approximately 57% of Suncor's total contingent resources, with 59% of these contingent resources on properties in which Suncor has a 100% working interest and the remainder forming part of joint arrangements where Suncor has working interests varying from 10% to 75%. These contingent resources are all in the Athabasca oil sands area and over 80% of the contingent resources are in, or immediately adjacent to, existing MacKay River or Firebag operations.

The primary risk associated with developing In Situ contingent resources relates to actual production performance versus performance estimated based on the geological data used in the production forecast. The geological data varies substantially as a result of the density of core holes used in the analysis. The density can be as low as one well per section, and as high as 16 wells per section.

Economic Contingencies

The economic status of In Situ contingent resources is currently undetermined; however, the company anticipates that the contingent resources will be economic to develop under current market conditions. Technical net pay cutoffs are consistent with, and based upon, the same fiscal conditions as those used in the determination of proved plus probable reserves for Firebag and MacKay River, or are analogous to existing in situ operations successfully developed by other entities in the oil sands industry. Suncor anticipates that its In Situ contingent resources will be recoverable using established SAGD processes.

Contingent resources have been assigned to certain sections associated with Firebag and MacKay River development areas. These volumes have not been classified as proved plus probable reserves in part because drilling density is inadequate for reliable mapping of effective pay intervals. However, the company has two-dimensional seismic control, minimum mapped effective pay thicknesses of 15 metres for Firebag and 14 metres for MacKay River, and drilling density greater than or equal to one vertical well per section (except when that section is bound by sections with greater than or equal to one well per section). The company expects that an assessment of the economic viability of these resources will be undertaken when drilling density has increased such that it is adequate for reliable mapping of effective pay intervals and as the company's long-term plans require additional bitumen to keep existing processing capacities associated with these assets full.

Contingent resources for other In Situ properties (Chard, Kirby, Lewis, Meadow Creek and MacKay River outside of the development areas noted above) were assigned to sections with core holes, or lands within two legal subdivisions of a delineation well and having net continuous bitumen pay greater than 15 metres. These contingent resources require the completion of further reservoir studies and delineation drilling, as well as the preparation of development plans and facility designs prior to reserves being assigned. The company expects that an assessment of the economic viability of these contingent resources will be undertaken as the company's long-term plans require additional bitumen.

Non-Technical Contingencies

The reclassification of In Situ contingent resources to reserves is also largely contingent upon an assessment that development will be sanctioned and commence within a reasonable time frame. The contingent resources associated with development areas for Firebag and MacKay River have regulatory approvals in place, but a final investment decision is subject to an assessment of economic viability and approval by Suncor's Board. For remaining In Situ contingent resources, the company must still obtain regulatory approvals and project sanction by Suncor's Board and joint venture owners, as applicable.

Other Contingent Resources

Other contingent resources are mainly conventional sources of oil and gas associated with Suncor's Exploration and Production segment. These other contingent resources comprise approximately 12% of Suncor's total contingent resources and are anticipated to be recoverable using established technologies. These other contingent resources primarily include:

- For North America Onshore, discovered resources in the Arctic Islands, Mackenzie Delta, Mackenzie Corridor, Beaufort Sea, and in the Alaska Foothills, and a tight oil play in the Gilby/Wilson area of Alberta.

For East Coast Canada, extensions of existing producing oilfields and Hebron, natural gas resources associated with existing producing oilfields, and other hydrocarbon accumulations that are not currently producing, including those offshore Newfoundland and Labrador.

For North Sea, discoveries offshore Norway.

For Other International, in both Libya and Syria, undeveloped portions within existing producing fields and other discovered hydrocarbon accumulations that are not currently producing, and, for Syria, 2012 production estimates.

Economic Contingencies

Except as noted below, the economic status of other contingent resources is undetermined. In general, further reservoir studies and delineation drilling, and preparation of development plans and facility designs are required to make a determination as to whether these contingent resources would be economic or not under current conditions.

For North America Onshore, contingent resources associated with the Gilby/Wilson tight oil play have been determined to be economic. The economic status of contingent resources associated with certain fields in the Arctic Islands is undetermined, but anticipated to be economic provided the natural gas resources are able to be delivered to markets outside of North America. Remaining North America Onshore contingent resources are primarily in geographically remote areas and are sub-economic due to lack of processing and transportation infrastructure in these areas. These areas require commitments to identify the existence of sufficient resources for economic development, following which construction of processing facilities and/or transportation infrastructure would be required, which is not anticipated to occur within the next five years.

For East Coast Canada, contingent resources for Hebron and some for Terra Nova have been determined to be economic. The company anticipates that it will assess the economic viability of contingent resources for Hibernia and White Rose within the next five years and that these contingent resources will be economic to develop under current market conditions. Timing for completion of economic evaluation of remaining contingent resources is not anticipated to occur within the next five years.

For the North Sea, contingent resources are in the appraisal stage. The economic status of these contingent resources is undetermined, but the company anticipates that it will assess their economic viability within the next five years and that these contingent resources will be economic to develop under current market conditions.

For Other International, contingent resources in Syria are currently sub-economic, but would be economic in the absence of force majeure under the company's contractual obligations. In Libya, contingent resources associated with producing fields are economic, while the economic viability of resources associated with non-producing fields is undetermined, but the company anticipates that it will complete economic assessments for these fields in the next five years.

Non-Technical Contingencies

The reclassification of contingent resources associated with the Exploration and Production segment to proved plus probable reserves is primarily contingent upon the receipt of appropriate regulatory approvals, and an assessment that development will be sanctioned by Suncor's Board and joint venture partners, as applicable, and commence within a reasonable time frame. Contingent resources for some North America Onshore properties in geographically remote areas are also contingent upon the development of a suitable regulatory framework.

The estimated production for Syria for 2012 has been classified as contingent resources, contingent upon Suncor being able to record production and receive payment. In order for this to occur, sanctions that are applicable to Suncor and that were initiated as a result of political unrest in Syria must be lifted so that the company can conduct business with its joint venture partner in Syria. For remaining contingent resources associated with Suncor's Syrian assets, a daily contract quantity for production, which limits the rate at which gas can be produced, is the primary contingency. This production constraint prevents a portion of the resources from being produced within the contract period. This contingency could be removed through contract extension or a higher daily contract quantity at a sufficient sales price.

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, as well as the governments of the United States and other foreign jurisdictions in which we operate, all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these controls or regulations will affect the company's operations in a manner materially different than they would affect other oil and gas companies of similar size and with similar assets. All current legislation is a matter of public record, and the company is unable to predict what additional legislation or amendments may be enacted. The following discussion outlines some of the principal aspects of legislation, regulations and agreements governing Suncor's operations.

Pricing, Marketing and Exporting Crude Oil and Natural Gas

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

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

Internationally, prices for crude oil and natural gas fluctuate in response to changes in the supply of and demand for crude oil and natural gas, market uncertainty and a variety of other factors beyond Suncor's control. These factors include, but are not limited to, the actions of 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 apportionment of capacity on 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.

Recently, pipeline capacity to support the growth of the oil sands industry in Canada has been the subject of political and environmental debate. Suncor supports the responsible development of pipeline infrastructure that would open access to other markets.

Royalties, Incentives and Income Taxes

Canada

In addition to federal regulation, each province has legislation and regulations governing land tenure, royalties, production rates, environmental protection, and other matters. The royalty regime is a significant factor in the profitability of SCO, bitumen, crude oil, NGL 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 revenues received from the value of the gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery, depth of well, and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, from time-to-time, carved out of the owner's working interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests or net carried interests.

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

The Canadian federal corporate income tax rate levied on taxable income was 16.5% effective January 1, 2011 for active business income, including resource income, and decreased to 15% on January 1, 2012. The average provincial income tax rate for Suncor in 2011 was 10.69%, which is expected to decrease to 10.39% in 2014 when enacted provincial income tax rate reductions become effective.

Other Jurisdictions

Operations in the U.S are subject to the U.S. federal tax rate of 35% and various state-level taxes, primarily 4.63% in Colorado.

There are no royalties on production from the U.K. portion of the North Sea; however, the income tax rate on oil and gas profits is 62%. This rate increased from 50% effective March 23, 2011 after the U.K. government announced an increase in its supplementary charge from 20%

to 32%.

Suncor earns refundable tax credits related to eligible exploration spending in Norway at a rate of 78%.

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

Under our EPSAs in Libya, income taxes are payable. Suncor prepares corporate income tax declarations that are processed by the NOC who, in turn, obtains a tax clearance certificate from tax authorities that is forwarded to Suncor. The NOC remits taxes on Suncor's behalf. Until tax certificates are received, Suncor records both an income tax payable to the taxation authority and an offsetting income tax receivable from the NOC.

For our PSCs in Syria, Suncor has been advised that income taxes are not payable until the Ebla project reaches payout. When payable, income taxes shall be assumed, paid and discharged on behalf of Suncor by the GPC.

Land Tenure

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

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

Environmental Regulation

The company is subject to environmental regulation under a variety of Canadian, U.S., U.K., and other foreign, federal, provincial, territorial, state and municipal laws and regulations. These regulatory regimes are laws of general application that apply to us in the same manner as they apply to other international companies and enterprises in the energy industry. The regulatory regimes require us to obtain operating licences and permits in order to operate, and impose certain standards and controls on activities relating to mining, oil and gas exploration, development and production, and the refining, distribution and marketing of petroleum products and petrochemicals. Environmental assessments and regulatory approvals are generally required before initiating most new major projects or undertaking significant changes to existing operations. In addition, this legislation requires that the company abandon and reclaim well and facility sites to the satisfaction of provincial authorities and, in some cases, this burden may remain with the company even after disposition of an asset to a third party. Compliance with such legislation can require significant expenditures, and a breach of these requirements may result in suspension or revocation of necessary licences and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties. In addition to these specific, known requirements, we expect future changes to environmental legislation, including anticipated legislation for air pollution (Criteria Air Contaminants) and greenhouse gas (GHG) emissions that will impose further requirements on companies operating in the energy industry.

A number of statutes, regulations and frameworks are under development or have been issued by various provincial regulators that oversee oil sands development, including the recently announced Joint Canada-Alberta Implementation Plan for Oil Sands Monitoring. These statutes, regulations and frameworks relate to such issues as tailings management, water use and land use. While the financial implications of statutes, regulations and frameworks under development are not yet known, the company is committed to working with the appropriate regulatory bodies as they develop new policies, and to fully complying with all existing and new statutes, regulations and frameworks as they apply to the company's operations.

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

The scope of recent environmental regulation and initiatives has had an impact on many areas important to Suncor's operations, some of which are summarized in the following subsections:

Climate Change

Suncor operates in many jurisdictions that have regulated, or have proposed to regulate, industrial GHG emissions. Those jurisdictions that have regulated GHG emissions generally support policies based on (i) caps on the intensity of GHG emissions, (ii) a carbon price, possibly through a cap-and-trade system, (iii) a tax, (iv) a hybrid of a tax and a cap-and-trade system, and (v) policies including other measures such as low carbon fuel and renewable fuel standards. Suncor participates in the consultation process for the design of proposed regulations and other efforts to harmonize regulations across jurisdictions within North America, both directly and indirectly through industry associations.

Suncor believes that the responsibility for managing environmental and climate change related issues should be a shared responsibility across the company. A comprehensive roles and responsibilities matrix has been developed as part of Suncor's GHG management program. Suncor's CEO and COO hold top executive responsibility for sustainability issues. Together with the Vice President, Sustainable Development, the business units and selected internal technical representatives are responsible for setting operational sustainability goals and assessing progress, including energy efficiency across all areas of our business.

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

International Climate Change Agreements and Treaties

At the end of 2009, the United Nations Framework on Climate Change Conference of the Parties (UNFCC COP 15) was held in Copenhagen, Denmark. One of the major outcomes of this conference was the Copenhagen Accord. To signify agreement with the Copenhagen Accord, Canada subsequently committed to reducing its GHG emissions by 17% below 2005 levels by 2020, in line with the reduction commitment made by the U.S. However, the Copenhagen Accord does not contain any binding commitments for reducing CO_2 emissions, nor does it include any discussion of compliance mechanisms. The other focal point of the Copenhagen Accord was a commitment by all major emitting countries to provide funding, including $30 billion from 2010 to 2012, for developing countries for climate change mitigation and adaptation.

During COP 17 in Durban, South Africa, several nations, including Canada, Japan and Russia, announced their intentions not to commit to a second period under the Kyoto Protocol; however, Canada reaffirmed commitments for GHG reductions and funding under the Copenhagen Accord.

Canadian Federal GHG Regulations

The Canadian federal government has started to address emissions of specific sectors of the economy, including implementing vehicle emissions standards in line with the U.S., as well as performance standards for the thermal electrical power generating sector. Also in line with the U.S., Canada has adopted a renewable fuels standard, mandating that 5% of the gasoline supply come from renewable sources such as ethanol and that 2% of diesel supply come from bio-diesel. The Canadian federal government has stated that it will align its approach to GHG regulation with the approach of the U.S. and, in 2011, entered into preliminary discussions with the Canadian oil and gas industry on proposed regulations for the sector.

Canadian Provincial GHG Regulations

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

In July 2007, pursuant to the *Specified Gas Emitters Regulation* enacted under the *Climate Change and Emissions Management Act (Alberta)*, facilities emitting more than 100,000 tonnes of CO_2 equivalent (CO_{2e}) per year are subject to intensity limits (GHG emissions per unit of production) and are required to reduce their intensity limits by 12% from an established baseline. Five facilities operated by Suncor in Alberta (Oil Sands Base plants, MacKay River operations, Firebag operations, the Edmonton refinery and the Hanlan gas processing plant) are subject to, and continue to comply with, this legislation. In 2010, the total cost to comply with the Alberta regulations was approximately $11 million. Compliance in 2010 was achieved through reduced emissions per unit of production, purchase and retirement of offset credits and payments to Alberta's Climate Change and Emissions Management Fund (Alberta Technology Fund). In March 2012, Suncor expects to file compliance reports that show what actions the company took during 2011 to demonstrate that each facility either met its intensity target or took action to offset its emissions intensity. Compliance options available to Suncor include reducing emissions, using Alberta-sanctioned offset projects, or contributing to the Alberta Technology Fund. For the compliance period of January 1 to December 31, 2011, the compliance costs to Suncor are estimated to be between $10 million and $15 million, based on a cost of $15/tonne, which was in effect for 2011. Future costs may be subject to change, given that late in 2011, the *Specified Gas Emitters Regulation* was amended by the Government of Alberta, such that the contribution cost is no longer specified at the $15/tonne level. Instead, the contribution cost will be established by Order of the Minister.

Several Canadian provinces (including British Columbia, Ontario and Quebec) are members of the Western Climate Initiative (WCI), a multi-jurisdictional partnership created in 2007 to address climate change. Effective January 1, 2010, the *Greenhouse Gas Reduction Act (Cap and Trade)* enabled the British Columbia government to participate in the trading system being implemented by the WCI. Draft regulations, as well as offset regulations, have been posted by the British Columbia Climate Action Secretariat, but have yet to be finalized. The Province of British Columbia also enacted a carbon tax in 2008, which began at $10/tonne of CO_{2e} and escalates at $5/tonne per year until 2012 when it reaches its maximum of $30/tonne. This carbon tax is carbon neutral, in that revenues are recycled back to taxpayers via tax reductions and is applied on consumption. Under these regulations, Suncor's natural gas production and gathering facilities in B.C. are classified as one facility, which in aggregate exceed the 100,000 tonne threshold that requires the reporting of emissions to be verified by third parties. Suncor's refined product distribution terminals in B.C. are required to report emissions, but do not exceed the threshold that requires third-party verification.

In 2007, Quebec introduced a tax on hydrocarbon production and imports, with the revenues going into a Green Fund, to support transit and other emissions-reducing projects. This tax impacts Suncor's refining and marketing activities in the province.

During 2011, Quebec introduced regulations for a cap-and-trade system for GHG emissions. This system required Suncor to register as an emitter because the Montreal refinery produces more than 25,000 tonnes of CO_{2e} per year. Emitters must verify their emissions during specified compliance periods (the first period commencing January 1, 2013 and ending December 31, 2014), and must either reduce their emissions or purchase eligible compliance mechanisms to cover their emissions above a specified cap. Quebec is responsible for setting the cap for the province and allocating allowances to emitters in its jurisdiction. Quebec has deemed 2012 a transition year, with no cap imposed. Allowances are fungible across the WCI, such that Quebec-issued allowances can be bought and sold with the larger trading system, which currently consists solely of Quebec and California. It is anticipated that the Green Fund will eventually be merged with the cap-and-trade system.

Ontario is also a member of the WCI and implemented mandatory reporting regulations beginning with 2010 emissions, but has delayed action on any further GHG emissions regulations.

U.S. GHG Regulations

Several attempts were made during the past two years to enact GHG legislation in the United States, none of which made it through both the Senate and the House. In an effort to build a green economy, the President has opted to push for a clean energy standard that would reduce GHG emissions from the power sector and increase the use of cleaner sources of energy, including natural gas, nuclear power and "clean" coal. In addition, the President is pressing ahead by endorsing the U.S. Environmental Protection Agency (EPA) to regulate GHG emissions under the Clean Air Act. The implications of industry being regulated under the EPA and the timing of such regulation are as yet unknown. In the meantime, the EPA has implemented a mandatory GHG reporting rule for all large (emitting greater than 25,000 tonnes per year) facilities, which includes Suncor's Commerce City refinery.

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

The State of California has passed AB32, which provides for a Low Carbon Fuel Standard (LCFS). In December 2011, the United States District court ruled against California's LCFS, stating that it was in violation of the Commerce Clause of the United States Constitution. Suncor does not actively market into California; however, there were two aspects of the ruling that are pertinent to Suncor the discrimination against out-of-state producers (in this case, those that are reliant on coal-fired electrical power generation for the production of ethanol), and the attempt by California to use a life-cycle analysis as the basis for the LCFS that includes exploration and production processes outside of the State's jurisdiction. The State of California has stated that it will appeal the ruling. The outcome of this appeal is anticipated during 2012.

International Regulations

Phase II (2008-2012) of the European Union Emissions Trading Scheme (EU ETS) impacts Suncor's non-operated offshore production in the U.K. and Norway sectors of the North Sea. The EU ETS requires that member countries set emissions limits for installations in their country covered by the scheme and assigns such installations an emissions cap. Installations may meet their cap by reducing emissions or by buying allowances from other participants. Phase III of the EU ETS is scheduled to begin in 2013 and will run until 2020.

Land Use

In 2011, the Government of Alberta issued its draft Lower Athabasca Regional Plan (LARP), which covers the Lower Athabasca Region and includes Suncor's Oil Sands segment. The LARP, developed as part of the Land-Use Framework under the Alberta Land Stewardship Act, identifies new conservation areas, as well as management frameworks for the quality of air, surface water and groundwater. The new conservation areas do not overlap any of Suncor's leases. The management frameworks formalize a number of regulatory tools that are already used by the government to manage environmental aspects of oil sands development, and may require Suncor to have greater participation in the evaluation of environmental issues. The frameworks include the following:

Air. The framework is designed to maintain flexibility and to manage cumulative effects of development on air quality within the region, setting triggers and limits for nitrogen dioxide (NO_2) and sulphur dioxide (SO_2). The framework includes ambient air quality triggers and limits. Management actions are required when triggers are exceeded or limits are reduced.

Surface water. The framework builds on, but does not replace, existing provincial legislation and policy on water quality, and provides a framework in which to monitor and manage long-term, cumulative changes in water quality within the lower Athabasca River. The framework includes quality limits and triggers for various indicators, based on existing Alberta, Canadian Council of Ministers of the Environment, Health Canada and U.S. EPA guidelines. Management actions are required when triggers or limits are reached.

Groundwater. The framework aims to manage non-saline groundwater resources in a sustainable manner and protect resources from contamination and over-use. The framework aims to ensure timely detection of key changes to indicators and describes the management response that will be initiated if triggers or limits, including site-specific measures, are reached.

Reclamation and Tailings

In February 2009, the ERCB released Directive 74 *Tailings Performance Criteria and Requirements for Oil Sands Mining Schemes*. The directive establishes performance criteria for tailings operations and requirements for the approval, monitoring and reporting of tailings ponds and plans. Suncor is in the final stages of its transition from a consolidated tailings management plan to TRO$_{TM}$ operations, which is Suncor's new tailings management strategy. TRO$_{TM}$ was approved by the ERCB in June 2010. Suncor's mine plan is designed to facilitate the implementation of TRO$_{TM}$ through providing space for the drying of tailings and ensuring adequate and timely storage capacity for extraction tailings from both the Millennium and NSE mines.

The Government of Alberta also has in place the Mine Financial Security Program (MFSP), which holds oil sands miners responsible for all aspects of the suspension, abandonment, remediation and surface reclamation work at their mine sites, and custody of the site until a reclamation certificate has been issued by the government. The MFSP requires a base amount of security for each project in the form of letters of credit, which would provide the funds necessary to safely secure the site. Additional security is required under other conditions, such as failure to meet current reclamation plans or when the estimated remaining production life of the mine reaches certain levels; however, Suncor has not been required to provide any additional security. In 2011, the Government of Alberta finalized changes to the MFSP, but these changes did not significantly impact Suncor's existing or near-term requirements for providing additional security.

Hydraulic Fracturing

Hydraulic fracturing is the process of pumping a fluid or a gas under pressure down a well, which causes the surrounding rock to crack or fracture. The fluid, typically consisting of water, sand, chemicals and other additives, flows into the cracks where the sand remains to keep the cracks open and allow natural gas or liquids to be recovered. Fracturing fluids are produced back to the surface through the wellbore and are stored for reuse or future disposal in accordance with regional regulations, which may include injection into underground wells.

The Government of Canada manages use of chemicals through its Chemical Management Plan and New Substances Program. Some provinces require the details of fracturing fluids to be submitted to regulators. In Alberta, the ERCB requires that all fracturing operations submit regarding the quantity of fluids and additives.

While this process has been in use and improved upon for many generations, the proliferation of fracturing in recent years to access hydrocarbons in unconventional reservoirs, such as shale formations, has raised concerns about the interaction of fracturing fluids with the water supply. In the U.S., the process is regulated by state and local governments, but the EPA is considering undertaking a broad study as it pertains to the national Clean Water Act. Any U.S. rules on hydraulic fracturing could influence other jurisdictional regulation and force oil and gas companies, including Suncor, to cease using the process or to add pollution control technology to their operations. The implications of this activity being regulated under the EPA are as yet unknown.

Industry Collaboration Initiatives

For areas of environmental concern, the need for energy companies to increase collaboration with each other, and with their respective stakeholders, is a particularly critical issue for the oil sands industry. As part of the Oil Sands Leadership Initiative (OSLI), Suncor is working closely with like-minded companies to make tangible improvements to environmental, social and economic performance in the oil sands industry. These companies have come together to pool financial resources and expertise. In 2010, members of OSLI investigated new technologies to improve industry-wide reuse of tailings waste water and to make oil recovery more energy efficient, while also engaging new stakeholders and opinion leaders.

In addition, Suncor and six other oil sands companies announced the creation of the Oil Sands Tailings Consortium in December 2010, and agreed to work together in a unified effort to advance tailings management. Each company has pledged to share its existing tailings research and technology and to remove barriers to collaborating on future tailings research and development. In turn, the companies are committing to future research investments to further accelerate tailings technology advances.

Suncor's Sustainability Commitment

Suncor remains committed to reducing overall GHG emissions intensity, in addition to other goals related to improving energy efficiency, reducing water use, increasing land reclamation and reducing air emissions. We continue to actively work to mitigate our environmental impact, including taking action to reduce GHG emissions, investing in renewable forms of energy such as wind power and biofuels, accelerating land reclamation, installing new emissions abatement equipment and pursuing other opportunities, both internally as well as through joint venture initiatives, such as our role in OSLI. For further information, please see our Sustainability Report at www.suncor.com.

RISK FACTORS

The company is committed to a proactive program of enterprise risk management intended to enable decision-making through consistent identification of risks inherent to the assets and activities of Suncor. The company's enterprise risk committee (ERC), comprised of senior representatives from business and functional groups across Suncor, oversees entity-wide processes to identify, assess and report on the company's principal risks. A principal risk is an exposure that has the potential to materially impact the ability of one of our businesses or functions to meet or support a Suncor objective.

Commodity Price Volatility

Our financial performance is closely linked to prices for crude oil in our upstream business and prices for refined petroleum products in our downstream business, and, to a lesser extent, to natural gas prices in our upstream business, where natural gas is both an input and output of production processes. The values for all of these commodity prices can be influenced by global and regional supply and demand factors.

Crude oil prices are also affected by, among other things, global economic health and global economic growth (particularly in emerging markets), political developments, compliance or non-compliance with quotas imposed on OPEC members, access to markets for crude oil and weather. These factors impact the various types of crude oil and refined products differently and can impact differentials between light and heavy grades of crude oil (including blended bitumen), and between conventional and synthetic crude oil.

Suncor anticipates higher production of non-upgraded bitumen in future years, due mainly to expansion at Firebag. Due to its low viscosity, bitumen is blended with a light diluent or SCO and sold as a heavy crude oil. The markets for heavy crude are more limited than those for light crude, making them more susceptible to supply and demand changes. Heavy crude oil receives lower market prices than light crude, due principally to the lower quality and value of the refined product yield, and the higher cost to transport the more viscous product on pipelines. The price differential between light crude and WCS is particularly important for Suncor. WCS is a pool of heavy crude oil and blended bitumen production from Western Canada. The market price for WCS is influenced by regional supply and demand factors, including the availability and price of diluent, and by the availability and cost of accessing primary markets through pipeline systems. Future price differentials are uncertain and widening light/heavy differentials could have a negative impact on our business, especially price realizations for bitumen that Suncor is unable to upgrade.

Refined petroleum product prices and refining margins are also affected by, among other things, crude oil prices, the availability of crude oil and other feedstocks, levels of refined product inventories, regional refinery availability, marketplace competitiveness, and other local market factors.

Natural gas prices in North America are affected primarily by supply and demand, and by prices for alternative energy sources. All of these factors are beyond our control and can result in a high degree of price volatility.

Commodity prices and refining margins have fluctuated widely in recent years. Given the recent global economic uncertainty, we expect continued volatility and uncertainty in commodity prices in the near term, with the possibility that crude oil and refined petroleum products prices could revert to the low levels experienced in 2008 and 2009. A prolonged period of low prices could affect the value of our upstream and downstream assets and the level of spending on growth projects, could result in the curtailment of production on some properties and include an impairment of carrying value. Accordingly, low commodity prices, particularly for crude oil, could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Government Policy

Suncor operates under federal, provincial, state and municipal legislation in numerous countries. The company is also subject to regulation and intervention by governments in oil and gas industry matters, such as land tenure, royalties, taxes (including income taxes), government fees, production rates, environmental protection controls, safety performance, the reduction of GHG and other emissions, the export of crude oil, natural gas and other products, the company's interactions with foreign governments, the awarding or acquisition of exploration and production rights, oil sands leases 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.

Changes in government policy or regulation have a direct impact on Suncor's business, financial condition, results of operations and cash flow, as evidenced by such initiatives as the Alberta government's royalty review program in 2007, and, more recently, by trade sanctions in Libya and Syria imposed by Canadian and other international governments, and increased production taxes in the U.K. Changes in government policy or regulation can also have an indirect impact on Suncor, such as opposition to new North American pipeline systems, such as Keystone XL, or incrementally over time, through increasingly stringent environmental regulations or unfavourable income tax and royalty regimes. The result of such changes can also lead to additional compliance costs and staffing and resource levels, and also increase exposure to other principal risks of Suncor, including environmental or safety non-compliance and permit approvals.

Environmental Regulation

Changes in environmental regulation could have a material adverse effect on our business, financial condition, results of operations and cash flow by impacting the demand, formulation or quality of our products, or by requiring increased capital expenditures or distribution costs, which may or may not be recoverable in the marketplace. The complexity and breadth of changes in environmental regulation make it extremely difficult to predict the potential impact to Suncor. Management anticipates capital expenditures and operating expenses could increase in the future as a result of the implementation of new and increasingly stringent environmental regulations. Failure to comply with environmental regulation may result in the imposition of significant fines and penalties, liability for cleanup costs and damages, and the loss of important licences and permits, which may, in turn, have a material adverse effect on our business, financial condition, results of operations and cash flow.

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;
- The use of hydraulic fracturing to assist in the recovery and production of oil and natural gas;
- Issues relating to land reclamation, restoration and wildlife habitat protection;
- Reformulated gasoline to support lower vehicle emissions;

U.S. state or federal calculation and regulation of fuel life-cycle carbon content; and

Regulation or policy by foreign governments or other organizations to limit purchases of oil produced from unconventional sources, such as the oil sands.

Climate Change Regulation

Future laws and regulations may impose significant liabilities on a failure to comply with their requirements; however, Suncor expects the cost of meeting new environmental and climate change regulations will not be so high as to cause material disadvantage to the company or material damage to its competitive positioning. While it currently appears that GHG regulations and targets will continue to become more stringent, and while Suncor will continue efforts to reduce the CO_2 unit intensity of our operations, the absolute CO_2 emissions of our company will continue to rise as we pursue a prudent and planned growth strategy.

As part of our ongoing business planning, Suncor assesses potential costs associated with CO_2 emissions in our evaluation of future projects, based on our current understanding of pending and possible GHG regulations. Both the U.S. and Canada have indicated that climate change policies that may be implemented will attempt to balance economic, environmental and energy security concerns. In the future, we expect that regulation will evolve with a moderate carbon price signal, and that the price regime will progress cautiously. Suncor will continue to review the impact of future carbon constrained scenarios on our strategy, using a price range of $15-$45 per tonne of CO_2 equivalent as a base case, applied against a range of regulatory policy options and price sensitivities.

Although Suncor does not actively market into California, the implications of other states or countries adopting similar LCFS legislation could pose a significant barrier to our exports of oil sands crude if the importing jurisdictions do not acknowledge efforts undertaken by the oil sands industry to meet the emissions intensity reductions legislated by the Government of Alberta.

In general, there remains uncertainty around the outcome and impacts of proposed or potential future climate change and other related environmental regulation. The Canadian federal government has gone on record as saying that it will align GHG emissions legislation with the U.S. Although it remains unclear what approach the U.S. will take, or when, the Canadian federal government has indicated a preference for a sector specific approach; however, it is unclear what form any regulation will take for the oil and gas sector, and what type of compliance mechanisms will be available to large emitters. At this time, the company does not believe it is possible to predict the nature of any requirements or the impact on Suncor's business, financial condition, results of operations and cash flow. The impact of developing regulations cannot be quantified at this time given the current lack of detail on how systems will operate.

Land Reclamation

There are risks associated specifically with our ability to reclaim tailings ponds containing mature fine tailings with TRO_{TM} or other methods and technologies. Suncor expects that TRO_{TM} will help the company reclaim existing tailings ponds by reducing tailings. The success of TRO_{TM} or any other methods or technology and the time to reclaim tailings ponds could increase or decrease our decommissioning and restoration cost estimates. Our failure or inability to adequately implement our reclamation plans, including our planned implementation of TRO_{TM}, could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow. In recent years, Suncor has increased collaboration with other participants in the oil sands industry to share technology and knowledge and to research alternative methods for tailings management.

Royalties

Royalties can be impacted by changes in crude oil and natural gas pricing, production volumes, foreign exchange rates, and capital and operating costs, by changes to existing legislation or PSCs, and by results of regulatory audits of prior year filings and other unexpected events. Some of the issues where settlement with regulatory bodies may cause royalties expense or royalties payable to differ materially from provisions currently recorded include:

For Suncor's mining operations (not including Syncrude), the BVM is based on the terms of Suncor's RAA, which we believe places certain limitations on the interim BVM as recently enacted, which modified the BVM for additional quality and transportation adjustments. For the years 2009 to 2010, Suncor filed non-compliance notices with the Alberta government, citing that reasonable quality adjustments in the determination of the Suncor BVM were not considered by the Alberta government as permitted by Suncor's RAA. Suncor has also filed with the Alberta government a Notice of Commencement of Arbitration under the Suncor RAA. The owners of the Syncrude joint venture have also filed a non-compliance notice in respect of the determination of the bitumen value under its 2008 agreements with the Alberta government.

Suncor has also appealed the disallowance of certain costs under the New Royalty Framework in Alberta and certain costs under royalty agreements in Newfoundland and Labrador, such as insurance premiums.

The final determination of these matters may have a material impact on royalties payable to the respective governments and on the company's royalties expense.

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 and other uncertainties arising from foreign government sovereignty over the company's international operations, 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;

Compliance with existing and emerging anti-corruption laws, including the Foreign Corrupt Practices Act of the United States, the Corrupt Foreign Officials Act of Canada and the United Kingdom Bribery Act;

Renegotiation of contracts with governmental entities and quasi-governmental agencies;

Changes in laws and policies governing operations of foreign-based companies; and

Economic and legal sanctions (such as restrictions against countries experiencing political violence, or countries that other governments may deem to sponsor terrorism).

If a dispute arises in the company's foreign operations, the company may be subject to the exclusive jurisdiction of foreign courts or may not be able to subject foreign persons to the jurisdiction of a court in Canada or the U.S. In addition, 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.

In 2011, operations in both Libya and Syria were suspended as a result of the outbreak of political unrest and the resulting sanctions imposed by international governments. Discussions with the Libyan authorities continue on the status of existing contract terms, including production volumes and exploration commitments. There is still sufficient unpredictability underlying operations in this region, including the ramp up of production, the sustainability of current production rates and the extent of damage to the company's assets, which has not yet been fully assessed. As a result, there is no assurance that production will return to previous levels or continue at current levels.

In response to sanctions and escalating political unrest in Syria, Suncor declared force majeure in December 2011, withdrew its expatriate staff and stopped recording production from Syria. Suncor's assessment of the situation as at December 31, 2011 did not require the company to record an impairment charge against its assets in Syria; however, should the current situation persist or worsen, such that Suncor is unable to resume operations in the near term, the company believes its assets in Syria could be impaired in the future. There is no assurance as to when Suncor's production from Syrian assets will resume or return to previous levels. Suncor's operations in Syria represented approximately 3% of the company's consolidated net earnings and 3% of the company's cash flow from operations in 2011. The carrying value of Suncor's net assets in Syria at December 31, 2011 was approximately $900 million.

The impact that future potential terrorist attacks, regional hostilities or political violence may have on the oil and gas industry, and on our operations in particular, is not known at this time. This uncertainty may affect operations in unpredictable ways, including disruptions of fuel supplies and markets, particularly crude oil, and the possibility that infrastructure facilities, including pipelines, production facilities, processing plants and refineries, could be direct targets of, or collateral damage of, an act of terror, political violence or war. We may be required to incur significant costs in the future to safeguard our assets against terrorist activities or to remediate potential damage to our facilities. There can be no assurance that we will be successful in protecting ourselves against these risks and the related financial consequences.

EHS Regulatory Non-Compliance

The company is required to comply with a large number of EHS regulations under a variety of Canadian, U.S., U.K. and other foreign, federal, provincial, territorial, state and municipal laws and regulations, as described in the Industry Conditions Environmental Regulation section of this AIF. Failure to comply with these regulations may result in the imposition of fines and penalties, censure, liability for cleanup costs and damages, and the loss of important licences and permits, which could also have a material adverse effect on our business, financial condition, results of operations and cash flow. Compliance can be affected by the loss of skilled staff, inadequate internal processes and compliance auditing.

Operational Outages and Major Environmental or Safety Incidents

Each of our primary operating businesses Oil Sands, Exploration and Production, and Refining and Marketing demand significant levels of investment in the design, operation and maintenance of facilities, and, therefore, carry the additional economic risk associated with operating reliably or enduring a protracted operational outage. These businesses also carry the risks associated with environmental and safety performance, which is closely scrutinized by governments, the public and the media, and could result in a suspension of or inability to obtain regulatory approvals and permits, or, in the case of a major environmental or safety incident, civil suits or charges against the company.

Generally, our operations are subject to operational hazards and risks such as fires, explosions, blow-outs, power outages, severe winter climate conditions, and the migration of harmful substances such as oil spills, gaseous leaks, or a release of tailings into water systems, any of which can interrupt operations or cause personal injury or death, or damage to property, equipment, the environment, and information technology systems and related data and control systems.

The reliable operation of production and processing facilities at planned levels and our ability to produce higher value products can also be impacted by failure to follow operating procedures or operate within established operating parameters, equipment failure through inadequate maintenance, unanticipated erosion or corrosion of facilities, manufacturing and engineering flaws, and labour shortage or interruption. We are also subject to operational risks such as sabotage, terrorism, trespass, theft and malicious software or network attacks.

The efficient operation of our business is dependent on computer hardware and software systems. Information systems are vulnerable to security breaches by computer hackers and cyberterrorists. We rely on industry accepted security measures and technology to securely maintain confidential and proprietary information stored on our information systems. However, these measures and technology may not adequately prevent security breaches. In addition, the unavailability of the information systems or the failure of these systems to perform as anticipated for any reason could disrupt our business and could result in decreased performance and increased operating costs, causing our business and results of operations to suffer. Any significant interruption or failure of our information systems or any significant breach of security could adversely affect our business and results of operations.

In addition, all of our operations are subject to all of the risks connected with transporting, processing and storing crude oil, natural gas and other related products. Pipeline capacity constraints combined with plant capacity constraints could negatively impact our ability to produce at capacity levels. Disruptions in pipeline service could adversely affect commodity prices, Suncor's price realizations, refining operations and sales volumes, or limit our ability to deliver production. These interruptions may be caused by the inability of the pipeline to operate or by the oversupply of feedstock into the system that exceeds pipeline capacity. There can be no certainty that short-term operational constraints on pipeline systems arising from pipeline interruption and/or increased supply of crude oil will not occur. In addition, planned or unplanned shutdowns or closures of our refinery customers may limit our availability to deliver feedstock. All of these events could have negative implications on sales and cash from operating activities.

For Suncor's Oil Sands operations, mining oil sands ore, extracting bitumen from mined ore, producing bitumen through in situ methods, and upgrading bitumen into SCO and other products involve particular risks and uncertainties. Oil Sands operations are susceptible to loss of production, slowdowns, shutdowns or restrictions on our ability to produce higher value products, due to the interdependence of its component systems. 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, Suncor has two upgrader facilities that include three secondary upgrading units, which provide us with the flexibility to conduct periodic planned maintenance events on one facility while continuing production from the other.

For Suncor's upstream businesses, there are risks and uncertainties associated with drilling for oil and natural gas, the operation and development of such properties and wells (including encountering unexpected formations, pressures, ore grade qualities, or the presence of H_2S), premature declines of reservoirs, sour gas releases, uncontrollable flows of crude oil, natural gas or well fluids, other accidents, and pollution and other environmental risks.

Our Exploration and Production operations include drilling offshore of Newfoundland and Labrador and in the North Sea offshore of the U.K. and Norway, which are areas subject to hurricanes and other extreme weather conditions. Drilling rigs in these regions may be exposed to damage or total loss by these storms, some of which may not be covered by insurance. The consequence of catastrophic events, such as blow-outs, occurring in offshore operations can be more difficult and time-consuming to remedy. The occurrence of these events could result in the suspension of drilling operations, damage to or destruction of the equipment involved and injury or death of rig personnel. Successful remediation of these events may be adversely affected by the water depths, pressures and cold temperatures encountered in the ocean, shortages of equipment and specialists required to work in these conditions, or the absence of appropriate technology to resolve the event. Damage to the environment, particularly through oil spillage or extensive, uncontrolled fires or death, could result from these offshore operations. Our offshore operations could also be affected by the actions of our contractors and agents that could result in similar catastrophic events at their facilities, or could be indirectly affected by catastrophic events occurring at other third-party offshore operations. In either case, this could give rise to liability, damage to our equipment, harm to individuals, force a shutdown of our facilities or operations, or result in a shortage of appropriate equipment or specialists required to perform our planned operations.

In particular, East Coast Canada operations can be impacted by winter storms, pack ice, icebergs and fog. During the winter storm season (October to March), we may have to reduce production rates at our offshore facilities as a result of limited storage capacity and the inability to offload to shuttle tankers due to wave height restrictions. During the spring, pack ice and icebergs drifting in the area of our offshore facilities have resulted in precautionary shut in of FPSO production and drilling delays. In late spring and early summer, fog also impacts our ability to transfer personnel to the offshore facilities by helicopter.

Our Refining and Marketing operations are subject to all of the risks normally inherent in the operation of refineries, terminals, pipelines and other distribution facilities and service stations, including loss of product, slowdowns due to equipment failures, unavailability of feedstock, price and quality of feedstock or other incidents.

Losses resulting from the occurrence of any of these risks identified above could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow. Although we maintain a risk management program, which includes an insurance component, such insurance may not provide adequate coverage in all circumstances, nor are all such risks insurable. It is possible that our insurance coverage will not be sufficient to address the costs arising out of the allocation of liabilities and risk of loss arising from offshore operations. Suncor also has a captive insurance entity to provide additional business interruption coverage for potential losses.

Project Execution and Partner Risk

There are certain risks associated with the execution of our major projects and the commissioning and integration of new facilities within our existing asset base, the occurrence of which could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Project execution risk consists of three related primary risks:

- Engineering a failure in the specification, design or technology selection;
- Construction a failure to build the project in the approved time and at the agreed cost; and
- Commissioning and start-up a failure of the facility to meet agreed performance targets, including operating costs, efficiency, yield and maintenance costs.

Management believes the execution of major projects presents issues that require prudent risk management. Suncor may provide cost estimates for major projects at the conceptual stage, prior to commencement or completion of the final scope design and detailed engineering necessary to reduce the margin of error of such cost